570 pages

BC HYDRO – RUSKIN DAM AND POWERHOUSE UPGRADE PROJECT EXHIBIT B-10

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June 16, 2011

Ms. Alanna Gillis
Acting Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Gillis:

RE: Project No. 3698623
British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
Ruskin Dam Upgrade Project
Application for a Certificate of Public Convenience and Necessity

BC Hydro submits its responses to Round 2 information requests (**IRs**) as follows:

Exhibit B-10	Responses to BCUC IRs (Public Version), including responses to all Confidential BCUC IR No. 2 except responses to BCUC Confidential IRs 2.2.1, 2.2.1.1, 2.2.1.3, 2.2.2, 2.2.3 and 2.2.3.1.
Exhibit B-10-1	Responses to BCUC IRs (Confidential Version), including responses to BCUC Confidential IRs 2.2.1, 2.2.1.1, 2.2.1.3, 2.2.2, 2.2.3 and 2.2.3.1.
Exhibit B-10-2	Responses to Interveners IRs, including responses to Quigley Round 2 IRs except for those Quigley Round 2 IRs relating to electomagentic fields (**EMF**).

BC Hydro takes the opportunity to note the following:

1. **Confidential IR Responses** - As provided by section 42 of the B.C. *Administrative Tribunals Act* and section 1 of the BCUC's Confidential Filings Practice Directive, BC Hydro requests confidential filing with the BCUC for a number of confidential versions of BCUC IR responses and BCUC IR response attachments. The basis for each confidentiality request is set out in the public version of each response.

2. **IR Response Adequacy** - Consistent with past practice, BC Hydro requests that interveners who have issues regarding the adequacy of responses to their IRs contact BC Hydro counsel prior to taking any formal steps with the BCUC. Contact information for BC Hydro counsel is set out at section 1.4.2 of Exhibit B-1.

3. **Quigley Round 2 IRs** – BC Hydro received the Quigley Round 2 IRs (Exhibit C7-5) on June 3, 2011. BC Hydro has responded to all Quigley Round 2 IRs not relating to EMF. BC Hydro will work on a best efforts basis to respond to the EMF-related Quigley Round 2 IRs (seventeen IRs) by June 24, 2011.

For further information, please contact Geoff Higgins at 604-623-4121 or by e-mail at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Janet Fraser

Janet Fraser
Chief Regulatory Officer

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Enclosure

Copy to: BCUC Project No. 3698623 (Ruskin) Registered Intervener Distribution List.

British Columbia Hydro and Power Authority
Certificate of Public Convenience and Necessity Application
for the Ruskin Dam and Powerhouse Upgrade Project

1.0 Reference: Project Costs
Exhibit B-1, Chapter 2, Table 2-4
First Nations Costs

1.1 Please identify how much and where First Nations accommodations costs are included in the Project Costs, as illustrated in Table 2-4 of Exhibit B-1. If they have not been included, explain why.

2.0 Reference: Project Costs
Exhibit B-1, Appendix E
Authorized Amount

2.1 Appendix E shows total capital expenditures of $672.3M (authorized amount). Show how this reconciles to Table 2-4.

3.0 Reference: Project Costs
Exhibit B-7, BCUC 1.40.2
Cost Breakdown

BC Hydro states that the Project Manager, Assistant Project Manager, and Project Management Office Support total $6.57 million.

3.1 Please provide the cost, FTE and headcount included in the above $6.57 million and broken down for each of the categories above and for each year of the project.

4.0 Reference: Project Costs
Exhibit B-7, BCUC 1.2.1 Attachment
Third Unit Generation

"The average annual generation from Ruskin is 374 GW.h…It is evident from the load duration curve (Figure 3) that the third unit operates only about 6% of the time and produces about 3% of the average annual generation." (BCUC 1.2.1 Attachment, page 31 of 44)

4.1 Based on these assumptions, the average annual generation produced from the third unit is only 11.22 GWh. Using the assumptions of the energy evaluation provided in Exhibit B-1, Table 3-23, please calculate the annual incremental revenues that BC Hydro can obtain with the installation of the third unit.

4.2 Calculate the payback on the third unit based on its incremental generation over its incremental capital cost.

5.0 Reference: Project Costs
Exhibit B-7, BCUC 1.37.4
Third Party Assessment

"As part of ensuring that BC Hydro properly scoped the Project, BC Hydro engaged an independent third party – RW Beck – to conduct a condition assessment of the Powerhouse." (Exhibit B-7, BCUC 1.37.4)

"The Ruskin Powerhouse is essentially 80 years old, with the exception of U3, which is 60 years old…none of the major electrical and mechanical equipment have been replaced or refurbished since installation." (Exhibit B-1, Chapter 2, p. 15)

5.1 Given the age and condition of the Powerhouse, in addition to BC Hydro's internal assessment methodology, please explain why BC Hydro still found it necessary to spend $126,000 to conduct an independent conditions assessment.

5.1.1 Was BC Hydro's EHR Assessment not sufficient to indicate that the Powerhouse was deficient and that refurbishment or retrofitting was required?

6.0 Reference: Project Costs
Exhibit B-1, Section 2.4, p. 2

"The Project Expected amount is $718.1 million and the Authorized Amount is $856.9 million."

6.1 Please discuss how the regulatory requirements have contributed to the overall costs and how, in BC Hydro's view, the Commission process could be more efficient to lower this cost component of the Project.

6.2 Please explain why duplication of the consulting services of RW Beck, KCBL and MWH was required when their recommendations essentially arrived at the same conclusions.

6.2.1 What portion of the Investigative/Definition costs could have been avoided by not duplicating their scope of work? Please discuss.

7.0 Reference: Project Costs
Exhibit B-7, BCUC 1.41.1 and 1.41.2
Identification, Definition and Early Implementation Costs

Attachment 1 to BCUC 1.41.1 indicates that Early Implementation costs are expected to be $49.8 million in F2011 and $14.3 million in F2012. Carrying costs on these expenses between F2013 – F2018 amount to an additional $22.9 million.

7.1 Please discuss BC Hydro's traditional methods for capitalizing carrying costs on major capital projects that span over several years. Please include a discussion on the alternative methodologies for capitalizing carrying costs (AFUDC / IDC or CWIP). What are the pros and cons of using each method?

7.2 What is the rate impact to customers if BC Hydro was to recognize the financing costs as they were incurred during the construction period as opposed to paying for additional financing costs over the life of the assets?

8.0 Reference: Project Costs
Exhibit B-7, BCUC 1.41.1 and 1.41.3
Identification, Definition and Early Implementation Costs

The original questions seeks identification of the "activities plus carrying costs" that make up the $87 million, shown by year for which the costs were incurred. Carrying cost may be shown separately. As referenced in various IR responses from Exhibit B-7, items that are expected to be identified are (but limited to) the following:

- RW Beck assessment in 2007 of $82,048 (ref: Exhibit B-7, BCUC 1.37.4)
- RW Beck assessment in 2010 of $44,427 (ref: Exhibit B-7, BCUC 1.37.4)
- B&V Report in ? of $95,540 (ref: Exhibit B-7, BCUC 1.51.0)
- Hemmera Report in ? of $266,005 (ref: Exhibit B-7, BCUC 1.51.0)
- Internal evaluations of Powerhouse in ? of ? as included in all EARs/CARs over last 15 years (ref: Exhibit B-7, BCUC 1.55.1)
- KCBL Evaluation in ? of $282,918 (ref: Exhibit B-7, BCUC 1.55.1)
- Pacific Liaicon report in ? of $18,337 (ref: Exhibit B-7, BCUC 1.58.1)
- Ruskin Dam promotional video in ? of $13,500 (ref: Exhibit B-7, BCUC 1.60.1)
- "Others"…

(If the "other" activities and dollar values are not immediately available, then sum the EARs/CARs reports for the last 15 years or provide an order of magnitude estimate such that the Commission can understand the costs and timelines undertaken to plan and advance this Project.)

Please provide your response in the following format:

Sunk costs to July 2010:	up to F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012
Activity 1								
Activity 2								
…								
cumulative total							$39,472	
Incurred Aug-March 2011:								
Activity 1								
Activity 2 ….								
cumulative total							7,739	9,892
Overhead							1,270	1,623
IDC							1,347	2,741
TOTAL Definition and Early Implementation Costs by Fiscal Year by Activity							49,828	14,256

8.1 Please provide an itemized list of the Early Implementation Costs that relate to Right Abutment work.

8.2 Please provide an itemized list of the Early Implementation Costs that relate to Left Abutment work.

9.0 Reference: Project Costs
Exhibit B-7, BCUC 1.42.1
Authorized Amount

BC Hydro states the "Authorized Amount is the P90 value plus Management Reserves" (emphasis added).

9.1 Please explain how the above statement can be true when both Table 2-4 and Table 2-5 of Exhibit B-1 clearly show that the Authorized Amount already includes $40 million of management reserves.

10.0 Reference: Project Costs
Exhibit B-7-1, BCUC 1.45.1 Confidential – 1.45.2
Exhibit B-7, BCUC 1.45.2
Contingencies and Loadings

10.1 The contingency on the Expected amount of $56 million is calculated prior to the addition of loadings. Given that BC Hydro explains "Contingency is built around the general uncertainties" (Exhibit B-7, BCUC 1.39.2), which implies that it may or may not be needed, please explain the need to include another $23.1 million of loadings on the contingency.

10.1.1 Is it implied that when the Project progresses and if the contingencies are not used, the associated loadings will also be avoided?

10.2 Please explain why $56 million is different than the value of the P50 contingency shown in BCUC Confidential 1.45.1?

10.3 Please explain why $67 million is different than the value of the P90 contingency shown in BCUC Confidential 1.45.1?

11.0 Reference: Project Costs
Exhibit B-7, BCUC 1.45.4
Contingencies and Loadings

11.1 The 7.8 percent for **Line B** in the revised Table 2-5 does not appear to accurately portray the percentage of contingency on the Expected Amount since the $56 million contingency is calculated prior to the addition of loadings. Shouldn't the calculation be shown as $56 million / $446.5 million (from BCUC 1.45.2) = 12.5 percent?

12.0 Reference: Project Costs
Exhibit B-7, BCUC 1.40.1 Confidential
Project Cost Breakdown

12.1 Please provide the cost details as shown in the Table to BCUC 1.40.1 which includes contingencies on loadings. The Project cost totals should equal the Expected and Authorized amounts of $718.1 million and $856.9 million.

12.2 Please confirm that all the direct constructions costs in the Table to BCUC 1.40.1 are loaded figures.

13.0 Reference: Project Costs
Exhibit B-7, BCUC 1.46.2
Management Reserve

"Conditions during actual construction may materially vary from the conditions encountered during the geotechnical investigations..."

13.1 On Table 5-1 in Exhibit B-1, BC Hydro indicates that contingencies are already designed to mitigate "schedule delays due to unforeseen geotechnical findings" (Chapter 5, page 20). Does BC Hydro anticipate substantial variance in geotechnical conditions that wouldn't already be covered under the contingency figures? Please explain and further justify the management reserve based on the discussions.

14.0 Reference: Project Costs
Exhibit B-7, BCUC 1.58.2 - 1.58.3
Provisional Sums

"(P)rovisional sums are attached to <u>known</u> and <u>expected</u> items of work." [emphasis added]

"BC Hydro uses provisional sums (cash allowances), for work which is <u>difficult</u> or <u>impossible to define</u>…" [emphasis added]

"Additionally, provisional sums are included for scopes of work that have not been defined…"

14.1 Please explain how an item of work can be both "known and expected" yet "difficult / impossible to define" at the same time?

14.2 By identifying "known and expected" items of work, it signifies that the scope of work is being defined. Please explain how the first and last statements quoted in the preamble could both be true.

14.3 Please confirm that the total provisional sum included in the contractor estimate is $22.1 million.

15.0 Reference: Project Costs
Exhibit B-7, BCUC 1.58.5
Provisional Sums

"At the completion of the construction contract, provisional sums not used would be to BC Hydro's benefit, not the contractor's."

15.1 If this project was approved which includes the provisional sums, and it turns out that the provisional sums were not used, please explain why this benefit should not accrue to ratepayers?

15.2 If the unused portion of the provisional sums constantly creates an accrued benefit to BC Hydro, then what incentive does BC Hydro have to ensure that contractor costs are reasonable and prudent?

15.3 What is the portion of provisional sums as a percentage of total contractor costs?

"If work identified as provisional or alternate is uncovered during the course of construction, the BC Hydro construction management team negotiates equitable compensation to the contractor drawing down the value of the provisional sums."

15.4 Please explain what happens if the provisional sums are unable to cover the additional costs. Will these items then be covered under contingencies?

16.0 Reference: Project Need
Exhibit B-1, Section 3

16.1 Please provide an unredacted copy of all of the Project's final approved Business Case's (EAR - Expenditure Authorization Request) attachments supporting the justification, evaluation of alternatives and preferred/recommended/selected options and costs.

17.0 Reference: Project Description and Impacts
Exhibit B-7, BCUC 1.5.1.1, p. 1
Ruskin Facility Products

17.1 For greater clarity the IR was aimed at adding synch condense facilities to the replacement generators, not for a stand-alone unit. Please provide an order of magnitude cost estimate to add this option (possible blow down facilities, air receiver(s), controls and valves/piping etc.) whether or not there is a requirement. Note a response of "BC Hydro has not developed a cost estimate" is not an acceptable response.

17.1.1 Given that BGS will contribute little if any voltage support to the Lower Mainland grid could there be a future need of increased Var support from the RUS 69kV system.

18.0 Reference: Synchronous Condense Operation
Exhibit B-7, BCUC 1.5.1
Exhibit B-7, BCUC 1.55.2, PUBLIC Attachment 2, page 28 of 88

"The existing three Ruskin Facility 43.75 megavolt amps (MVA) 80 per cent lagging power factor (PF) generators are able to meet the voltage support requirement and maintain the local area voltage profile. The new generators proposed as part of the Project have comparable parameters and would provide a similar level of voltage support as the existing Ruskin Facility. Adding synchronous condense facilities to the replacement generators is not required for local voltage support."

"However, the benefits of synchronous condenser operation all accrue to BCTC – there is no benefit to BC Hydro. For that reason, synchronous condenser operation has been abandoned as an alternative at this point. If BCTC desires such operation, and is willing to fund the costs, this item could be analyzed during the Definition Phase. Synchronous condensing equipment will not be included in the construction cost estimate at this time."

18.1 Please provide any review by BCTC or the transmission group of BC Hydro that demonstrates the examination of adding synchronous condense facilities at Ruskin.

19.0 Reference: Project Description and Impacts
Exhibit B-7, BCUC 1.5.1.3, p. 1
Ruskin Facility Products

19.1 The response did not address if increasing the height of the rotor poles was an option. The total weight may not necessarily increase due to design optimization of a possible smaller air gap, using modern steel capable of higher magnetic flux density, lower weight and thickness of modern insulation allowing more turns per pole. To repeat, please provide an order of magnitude cost and note a response of "BC Hydro has not developed a cost estimate" is not an acceptable response as a budgetary quote should be available from a reputable supplier in short order if BC Hydro staff cannot provide an estimate.

19.1.1 What is the MVA and power factor of the replacement generators under consideration and what is the largest MW rating possible from the new turbines and existing water passage constraints?

20.0 Reference: Project Description and Impacts
Exhibit B-7, BCUC 1.6.1, pp. 1-2
Procurement Strategy

20.1 Could the DBO contract be written such that the contractor is responsible to replace all existing equipment and assume responsibility for the entire facility, thereby eliminating the conflicting interests and integration with existing components arguments stated in the response? Please discuss.

20.2 The original IR stated "where BC Hydro would retain ownership"- it did not contemplate any transfer of ownership. The risks to either party could be spelled out and agreed upon in a contract and the appropriate area "roped off" during construction or alternatively BC Hydro could accept a loss of some or all of the $20 million/year revenue by transferring the entire Powerhouse facility to the contractor during construction. Putting BC Hydro's preference aside (and any reference to an EPA in the original IR), would this option lower the overall cost of the Project? Please discuss further and provide a range of possible cost savings. **Note**: the argument stating Section 14 of the CEA may also rule out third party operation is understood and "BC Hydro has not developed a cost estimate" is not considered an adequate response.

21.0 Reference: Project Justification
Exhibit B-7, BCUC 1.8.1, pp. 1-5
Switchyard Work

21.1 Please comment on the viability and pros and cons of installing the Compressed Gas Insulated Switchgear (CGIS) in the former station service bay location which is now occupied by storage and/or a workshop. The response should confirm the estimated order of magnitude costs of $4.4 million more than the Authorized amount.

21.1.1 Please identify if any other location would be suitable for the CGIS switchgear/bus.

21.1.2 Please identify the order of magnitude in First Nations accommodation avoided costs that would result from installing the CGIS within the existing footprint of the powerhouse.

21.1.3 Please comment if the five 69 kV line terminals could remain on the powerhouse roof or would still have (as opposed to desirable) to be relocated to the proposed new location or elsewhere.

22.0 Reference: Switchyard Requirements
Exhibit B-7, BCUC 1.8.1

"As a result of the restricted space and configuration of the Switchyard, it is unavoidable to be no more than 3 m away from un-insulated 69 kV equipment when walking on the Powerhouse roof. This distance is within the LOA for unqualified electrical workers and accordingly, these workers cannot enter onto or perform work on the Powerhouse roof without either the supervision of qualified electrical workers or a suitable facility outage."

22.1 Please describe if it is possible to cordon off access on the Powerhouse roof or put physical barriers in place such that unqualified workers are unable to physically access un-insulated 69 kV equipment. If such physical barriers were put in place, please describe the frequency and amount of remaining activities on the Powerhouse roof after the Project that would continue to put unqualified workers within the Limits of Approach without a physical barrier in place.

23.0 Reference: Project Justification
Exhibit B-1, Appendix H-4, Section 4.3.1, p. 29

"Optional construction of a 2 room structure, to serve as a satellite control room, against the north side of the powerhouse, at the west (access bridge) end."

23.1 Please confirm that this option is not in the Project scope and discuss why not.

24.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, BCUC 1.25.2, Attachment 1, p. 3
Periodic Payments over Time

"The Impact Benefit Agreements BC Hydro is prepared to negotiate are not required by or limited to the Crown's duty to consult and accommodate."

24.1 Are these IBA's funded by the Shareholder or by ratepayers?

24.1.1 If funded by ratepayers, what is BC Hydro's position in respect to obtaining the Commission's approval for recovery of these expenditures in rates?

25.0 Reference: Project Costs
Exhibit B-7, BCUC 1.44.1, p. 1
Contingencies and Risks

Exhibit B-1, Section 3.4.1, p. 44
New verses Rehabilitate/Replace

Exhibit B-7, BCUC 1.54.1, p. 1
Evaluation of Alternatives

Exhibit B-7, BCUC 1.93.1, Attachment 3, pp. 44, 67
Background to Alternatives

"BC Hydro cannot feasibly implement the Project two, three or five years faster than has been proposed".

"In 2005, BC Hydro initially explored two options: (1) Rehabilitating/replacing the existing Powerhouse; and (2) Building a new powerhouse at the existing Powerhouse site. BC Hydro concluded in 2005 that building a new powerhouse at the existing site was approximately $109 million more costly (+50 per cent to -25 per cent cost estimate accuracy) than rehabilitating/replacing the existing Powerhouse."

"The Project…is challenging because it is a rehabilitation of an existing facility; has…small work space with live operating equipment…..must deal with some unknown Powerhouse equipment conditions….requires the operation of the facility …to maintain continuity of flow."

"The least critical construction sequence will be with four old gates available and all six bulkhead gates unobstructed by the old piers. The combined discharge capacity at that time, and with reservoir at El. 44 m (emphasis added), is estimated to be about 2815 m3/s (2175 m3/s through spillway gates, and 640 m3/s through bulkhead vertical lift gates). This corresponds to a return period of about 1000 years for hourly inflow.

The above estimates were derived with the assumption that discharge through the three Ruskin units (up to about 116 m3/s each) would not be available (emphasis added)."

"For Option 3 (auto-spill), as soon as the Ruskin Powerhouse becomes unable to provide discharge required to maintain the minimum tailwater level, a spillway gate would be automatically activated to spill at the required rate. Note that this option will be effective only when the reservoir level is above spillway crest elevation.

The auto-spill option applied to Spillway Gate #5 (or gates 1 *and* 5), is judged to be the preferred option for the following reasons:

1. Significantly lower cost than the >$10M for all other options
2. Acceptable Total Gas Pressure (TGP) performance (emphasis added)
3. Comparable or better reliability than options 1 or 2
4. Negligible incremental life safety risks in the proposed range and mode of operation

Some key considerations include:

These facilities would only be required to function under emergency conditions (full powerhouse outage).

Powerhouse by-pass and submerged LLO solutions likely offer the potential for minor improvements to TGP performance over the preferred option (emphasis added)."

25.1 Did BC Hydro thoroughly consider the total economic tradeoffs between Option 1 and Option2 [(1) Rehabilitating/replacing the existing Powerhouse; and (2) Building a new powerhouse at the existing Powerhouse site] as it would appear that Option 1 has significantly more unknowns thus requiring a $178 million contingency whereas Option 2 appears to cost $109 million more over the unloaded base case of Option1? On the surface it would appear that Option 1 may have been chosen before the loaded contingencies were added. Please provide the total loaded cost estimates for Option 1 and Option 2. To put it another way, the strategy of attempting to re-use as many old components as possible may end up costing more considering the added complexity and the time value of money.

25.1.1 The above comparisons should include a discussion on:

- The present value of lost energy associated with Option 2 (Exhibit B-1, Section 3.3.2, p. 41 states that 19 percent of Ruskin's generation is worth $7.9 million annually which translates to $7.9/0.19=$41.6 million annually for the facility).

- The risks to fish associated with maintaining flows either through the spillway (perhaps after the access bridge pier modification to reduce TGP are complete) or by blocking or removing one turbine to maintain flows through a penstock to reduce TGP until the first replacement unit is available to pass 120 cms (or greater) of water. **Note**: if required, an operator could monitor RUS spill 24/7 during periods of high risk or concerns of a forced outage to SFN. Also note, the response to Kwantlen IR's 1.7.1.1, Attachment 1, p. 74 "Ruskin gate configurations have been set in the Local Operating Order to utilize the outermost gates for spills up to 400 m3/s to keep TGP levels below 115 per cent. Instantaneous mortality of fish species is avoided with this mitigation (Falvey, Gulliver and Weitkamp 2008). Long term spills greater than 300 m3/s may result in chronic effects. One objective of the ongoing TGP monitoring program is to describe spill duration and rates that can have chronic effects on fish" and 1.7.3, p. 2 "spills above 400 cms are comparatively rare" and on p. 5 "The TDG management plan will serve as a key reference for TDG management during Project implementation and on-going operations. BC Hydro is targeting March 2012 for the delivery of the TDG management plan."

- With the 3 RUS units shut-down there is minimal risk that high inflows could not be passed utilizing the least critical construction sequence referenced above. Spills up to 120 cms can be safely passed.

- For Option 2 the avoided costs associated with the contractor having fewer restrictions and enabling the work to be completed in a shorter time frame (the original powerhouse and dam complex was completed in less than 2 years back in 1930 as indicated in Exhibit B-7, BCUC 1.76.2, Attachment 1, p. 11).

- The possibility of using a smaller bulkhead gate (at a lower cost) associated with a lower reservoir operation throughout the construction period.

- The avoided carrying costs associated with a shorter construction period (lower IDC and Corporate overhead, provisional amounts etc).

- Cessation of corporate loadings once a stand-alone asset is placed in service.

- The reduction in contingencies and unknowns as given in the response to BCUC 1.44.1 (not operating around live equipment, dealing with some unknown powerhouse conditions…in particular the matching of new and old turbine generator components).

- CEAA and First Nations considerations.

- The quality and total costs of the final product in terms of facility life expectancy, MDE withstand, the NPV of any long term avoided maintenance or Capital costs for the components that would not be replaced in Option 1 (for example draft tube liner repairs/replacement), NPV of any turbine efficiency gains, feasibility of installation of larger units, improved ergonomics and safety by design for the workforce, inclusion of CGIS in the powerhouse, power smart initiatives, removal of hazardous waste (lead paint, PCB's, spilled oil, mercury etc), environmental protection (oil spill containment, sewage treatment) and possible inclusion of penstock by-pass valves to assure continuity of flow.

Please note, this IR requests that BC Hydro prepare a cost estimate hence a response of "BC Hydro has not produced an estimate" is not an appropriate response. Please respond to the IR using available data/evidence to the best of its ability to produce an order of magnitude estimate.

26.0 Reference: Alternatives
Exhibit B-7, BCUC 1.53.2.1, p. 1
Evaluation of Alternatives

"The costs from F2013 to F2018 are IDC charges on the sunk costs."

26.1 Please explain the accounting treatment of the completion of a stand-alone asset (such as the Right Abutment, access bridge, a turbine/generator unit, powerhouse crane or switchyard etc.). When a stand-alone asset is placed into service does IDC, Corporate Overhead and any other loadings related to this stand-alone asset cease? If not, why not.

26.1.1 If loading charges for the stand-alone item do cease, please explain why the corresponding percentage of Investigative, Definition and early attention/sunk costs attributed to the specific asset are not also put into service in order to avoid continued overall loading costs until the entire project is complete.

26.2 In approving the CPCN, how can the Commission be assured that a proposed <u>material</u> item which is in scope will not be removed as was done with the SFL spill gate project (i.e. the emergency diesel generator, separate control room, redundant controls PAM panel and gate seal heaters that formed part of the project's justification were removed from the scope)? To put it another way, what assurance can BC Hydro provide to its ratepayers that they will materially receive the scope that is detailed in the Application which resulted from several years of investigative study and design considerations to arrive at a final (materially) scope (i.e. that this and the next generation of ratepayers will receive what they understand they are paying for and that quality will not be compromised in order to meet a budget).

27.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.55.1, p. 1
History of Evaluation

"BC Hydro cannot provide the individual cost of this evaluation as the costs were not segregated at the time the costs were incurred."

27.1 This evaluation would have been charged to an EAR that was raised to cover such costs. Please provide the 2005 costs for the Contractor Resource Code(s) charged against this/these EAR(s)

27.2 Please confirm that a Purchase Order was not raised for this evaluation. If a PO was raised then the evaluation invoice should be charged to this PO and be available from BC Hydro's Purchasing Department or service provider. Please provide the cost of this evaluation.

28.0 Reference: User Requirements
Exhibit B-7, BCUC 1.93.1, Attachment 4, pp. 8 to 21 of 406

28.1 Please explain why thermo-imaging cameras are required (Item 9.10).

28.2 Please explain how the limit of $2.5 million as a contribution for the double lane roadway was arrived at (Item 10.1).

28.3 Please confirm that all spillway gates do not need to be operable after MDE (Item 18.2).

28.4 Please explain why each gate must have its own control room rather than a control station (Item 24.1).

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

29.1 Is the replacement of U3's draft tube extension, requiring construction of a coffer dam, included in the Project scope? If not, why not?

29.2 Is a spare Unit transformer included in the Project scope?

29.2.1 Please explain if BC Hydro has a system spare transformer that would cover 69 kV generation facilities and Ruskin in particular. If not, why not?

29.3 Is a generator brake dust collection in scope? Please discuss the option of dynamic braking and why BC Hydro does not employ this feature in its generation facilities.

29.4 Is a turbine model test in scope? If not, why not?

29.5 Please describe the selected/preferred options for the spillway, intake and draft tube maintenance gates or indicate where they can be located in the Application.

29.5.1 Please provide a copy or reference the final report that recommends these preferred options with supporting reasons.

29.6 Please discuss the following IRs related to turbine capacity verses efficiency.

29.6.1 Is there merit in using different turbine efficiency designs in the proposed solution? Specifically, given the dispatch regime of the Ruskin facility is there any advantage to having say one unit designed for capacity efficiency and the other two units designed for peak efficiency? For instance design one unit to peak for required fish flows and the other two units for differing levels of plant output. Please discuss.

29.6.2 A typical Francis turbine's peak efficiency occurs around a 90% gate opening. Is it possible to design the turbine for maximum efficiency at maximum available flow? (i.e. further gate openings result in no additional power output due to the water passage flow restrictions.)

29.6.3 Are any modifications in scope to reduce the friction losses in the water passage? Please discuss the theoretical options available such as using a smooth penstock liner or paint and whether the final design will investigate these options.

29.7 Is a third source of cooling water supply from the tailrace (in addition to a tap and common header off each penstock) in scope? Please explain why or why not.

29.7.1 Will the cooling water pipes be constructed of stainless steel to ensure an operating life of 40+ years as was done at SFN? If not, why not?

29.7.2 Will all service water piping be constructed of stainless steel (raw water, fire protection, HVAC etc). If not, why not.

29.7.3 Will exhaust heat from the generators be utilized to heat the powerhouse and/or control room as a PowerSmart initiative? If not, why not?

29.7.3.1 Will exhaust heat from one unit be piped to a shut down unit in order to keep the stator dry and prolong the life of the windings? If not, why not?

29.8 Please clarify if the existing powerhouse cranes are to be replaced with a single 240 MT crane (or higher) or two 130 MT cranes?

29.8.1 Please clarify if the new crane capacity will accommodate the heaviest component(s) contemplated to be installed in the powerhouse.

29.8.2 Will the new crane(s) be capable of lifting the rotor and turbine in a single lift or must they be decoupled at the shaft?

29.8.3 Please confirm that the crane rails and support columns will support a 240 MT or greater lift.

29.8.4 Please comment if one of the old cranes could be utilized at WAH (or elsewhere) or if this option is considered uneconomic.

29.9 Please discuss if the shingle bolt flume could be utilized for fish (salmon) passage.

30.0 Reference: Dam Safety-Ruskin Dam
Exhibit B-7, BCUC 1.93.1, Attachment 4, p. 324
Spillway Shotcrete Assessment

30.1 Please state which of the 7 Options was chosen by BC Hydro for Implementation or describe where the preferred Option can be found in the Application.

30.1.1 Please reference where the direct and fully loaded costs are stated in the Application or provide same.

31.0 Reference: Manual Gate Operation
Exhibit B-7, BCUC 1.70.2
Exhibit B-7, BCUC 1.93.1, Attachment 4, page 73 of 406

"The existing gates are radial type (tainter) gates which are actuated by a sprocket/chain system. The gates were originally designed to be opened by a mobile cart which was rolled into place on the road deck and attached to the sprocket/chain drive system. Approximately ten years ago permanent hoist motors and gearboxes were installed for each gate under the road. These motors are at risk of being submerged during major flood events." (Exhibit B-7, BCUC 1.93.1, Attachment 4, page 73 of 406)

31.1 Is it possible to open the gates using a mobile system similar to the original if the existing motors become inoperable?

31.1.1 Is it possible to drive the gears with a portable drill motor or could this feature be added?

32.0 Reference: Incremental Energy
Exhibit B-1, Section 3.4.2,
Powerhouse Two versus Three Unit Configuration, p. 3-48
Exhibit B-7, BCUC 1.2.1, Attachment 1, page 28 of 44

"The annual energy is higher by 18.6 GWh in the three-unit alternative, and the value of energy is higher by $3.6 million using the TDF firm energy price from the Clean Power Call."

"The optimized load duration curves for Ruskin show that the plant is operating with three units for about 6% of the time (Figure 3). Generation from the third unit is in the order of 10 GW.h per annum with a value in the order of $0.5 million."

32.1 Please provide the analysis which quantifies that the total and incremental annual average energy from the third unit.

32.2 Please provide the annual amount of firm energy and non-firm energy associated with the third unit.

33.0 Reference: Project Costs
Exhibit B-1, Chapter 3, Section 3.4.2
Powerhouse – Two versus Three Unit Configuration; Table 3-12

33.1 BC Hydro explains that the incremental cost for installing the third turbine and generator at the completion date is $41.7 million compared to $52.4 million for the two unit alternative. Please advise whether both estimates include all loadings. If not, recalculate Table 3-12 showing the NPV of the benefit of the three versus the two unit alternative including loadings.

"The annual energy is higher by 18.6 GWh in the three-unit alternative, and the value of energy is higher by $3.6 million…" and

"Due to the need for flow continuity at the Ruskin Facility, the consequences of a coincident outage in a two unit facility would likely be a spill…"

33.2 Please define what BC Hydro considers to be incremental costs.

33.3 Please provide a table of the direct and fully loaded costs to supply and install the following items associated with the third unit: Intake entry modifications, operating gate, stop-logs and hoists; penstock and tunnel rehabilitation; new generator and runner; NDT of reused parts; turbine overhaul (embedded parts, new wicket gates and rehabilitation of bushings etc); static exciter; digital governor; cooling water system; protection and controls; draft tube repairs, stoplogs/bulkheads and monorail extension; unit and transformer fire protection; raw water, unit transformer and oil spill containment; unit circuit breaker and LV bus; 60 kV cable connection to switchyard; avoided larger size of switchyard and associated First Nations accommodation costs (if appropriate); and station service connections. Note the costs should be comparable to one third of the figures associated with the gensets as supplied in BC Hydro's Confidential response to BCUC 1.40.1 on p. 2 and since this IR is asking for an estimate, a response of "BC Hydro did not prepare an estimate" is not considered acceptable (please use the figures provided in the Application or supplied elsewhere in Exhibit B-7, BCUC IR 1 responses).

33.3.1 Please identify which of the above costs BC Hydro considers as incremental costs in a separate column in the above table.

33.4 Please discuss the NPV merits of completing the entire powerhouse structural upgrades and opting not to perform any other third unit upgrades until the unit fails beyond repair. The discussion should recognize that spare components will be available from the two units that will be replaced and also consider that the third unit need only run during periods of spill (which should be less frequent due to the larger replacement units). The option of keeping the stator dry utilizing waste heat from an operating unit may merit further investigation to prolong the life of the winding.

33.5 Did the increase of 18.6 GWh account for the larger units that would be installed by the Project (40 MW/unit or larger vs. the present 35 MW/unit)? If not, please provide the appropriate GWh revised figure and resultant NPV benefit of the Three Unit vs. Two Unit Alternative in Table 3-12.

33.6 Please discuss the viability of installing an inflatable rubber dam at the highway or railway bridge to avoid fish stranding either for the construction or post construction periods.

33.7 Please discuss the subject of adding pumped storage to Ruskin.

34.0 Reference: Two Unit versus Three Unit Configuration
Exhibit B-7-2, BCOAPO 1.9.1, p. 1

"Based on average daily discharge, there was only one year between 1986 and 2009, inclusive (i.e., 1 in 26 years, or 3.85 per cent of that time period), in which two units could handle all of the total discharge from the Ruskin Facility (Powerhouse and spillway combined) during the year. Due to flow variations within a year, the number of years where all flow could be handled by a given number of units may be less informative than the number of days that the required discharge could be handled by that number of units. During that same period, the total daily discharge from the Ruskin Facility (Powerhouse and spillway combined) could be handled by two units for 90.0 per cent of those days, and by three units for 97.8 per cent of those days."

34.1 Did the above response to the original IR account for larger units being installed by the Project? If not, please update the response considering replacing only two units and not the third unit.

35.0 Reference: Project Justification
Exhibit AMPC, IR 1.4.1, p. 2
Maintenance Practices

Exhibit B-7-1, IR 1.93.1 Attachment 5 , p. 108
MWH Report

"BC Hydro concludes pursuant to its Equipment Health Ratings (EHRs) that major Powerhouse equipment and ancillaries have reached "poor" or "unsatisfactory" equipment health ratings."

"According to long-term maintenance staff, the draft tube stoplogs have not been installed for over 30 years."

35.1 Please explain why maintenance in the draft tubes has not been performed and these assets have been allowed to deteriorate to "poor" or "unsatisfactory" asset for over 30 years.

35.1.1 Please explain if maintenance on the lower section of the runners has also not been performed for over 30 years and what effect this has had on the life of these assets.

35.1.2 Please explain why the Project has provision for new draft tube stop logs when the current practice is not to isolate this section of the water passage.

35.1.2.1 Please discuss the merits of installing the most robust turbine and draft tube components, not including new stop log isolation facilities and continuing to maintain the facility as per current practice. Please comment if these replacements would last for the anticipated remaining life of the Ruskin facility (40 or 50 years). Please provide an estimate of the NPV of the avoided costs.

35.1.2.2 Please discuss if not providing draft tube maintenance gates is a standard practice in BC Hydro (such as LaDore GS for around 40 years) and describe any material negative consequences of this strategy on the life of the asset(s).

35.1.3 Please discuss if this strategy is in keeping with RCM (Reliability Centered Maintenance) principles.

35.1.4 If "the draft tube stoplogs have not been installed for over 30 years" can BC Hydro assure the ratepayers that these new facilities once installed will, in fact, be maintained and utilized at periods supposedly less than once in 30 years.

36.0 Reference: Alternative Means of Carrying Out the Project
Exhibit B-1, Section 3.4.3, p. 50
Spillway Gates

36.1 Please confirm that Option 3 is the proposed option and describe if stoplogs and slots in the new road are to be incorporated, or if modifications to the temporary construction bulkhead will be utilized for gate isolation or if some other means will be employed.

36.1.1 Please discuss if a gantry crane will be provided to install/remove the spillway maintenance gates/stoplogs or if a rented mobile crane will be utilized.

36.1.1.1 If a rented mobile crane has been chosen, please explain why the dam roadway <u>needs</u> to be widened to two lanes when a mobile crane cannot be wider than a single lane to travel on the highway (without a permit).

37.0 Reference: Alternatives to the Proposed Project
Exhibit B-7, BCUC 1.95.1

37.1 Please comment on the feasibility of a revised Alternative A with the following characteristics:

i) Right Abutment seismic upgrades as in the proposed Project

ii) Left Abutment seismic upgrades as in the proposed Project

iii) Eliminate intake gates from Project scope and retain turbine inlet valves.

iv) Two new spillway gates and associated piers, rehabilitate remaining gates and stabilize remaining piers.

v) Powerhouse crane, superstructure, and substructure seismic upgrades as in the proposed Project

vi) Replace two units, with associated control, draft tube rehabs, new transformers and auxillary systems as in the proposed Project (retain old equipment for replacements on remaining unit – and operate as run to failure)

vii) Retain switchyard on Powerhouse roof

viii) install new access from east side of powerhouse and abandon bridge.

Please explain the constraints, if any, that would prevent the above-described project alternative from operating at the original reservoir level and any lost energy and revenue that would result if the reservoir could not be returned to the normal operating level. Please discuss the reliability in relation to public safety for the revised alternative.

37.2 Please provide a cost estimate in a Table format of the above described project that would enable a comparison to be made with the proposed project and Alternative A. **Note**: this IR asks BC Hydro to prepare an estimate, hence a response of "BC Hydro has not prepared an estimate" will be considered unacceptable.

37.3 Please provide an NPV analysis in a Table format of the above described project that would enable a comparison to be made with the proposed project and Alternative A.

38.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 1
First Nations Consultation

"A map provided to BC Hydro by the Matsqui, which is different from the map [in] Exhibit B-1 in that the Matsqui assert that their traditional territories stretch further to the north of the Fraser River."

38.1 Please confirm when the Matsqui provided this map to BC Hydro.

39.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, pp. 1-2
Bouchard and Kennedy Reports

39.1 Why was the 2008 Report not shared with the Kwantlen until March 25, 2011 and with the Matsqui until March 31, 2011?

39.2 Please report the comments, written, verbal or otherwise delivered, that the Kwantlen and the Matsqui have given BC Hydro in relation to these Reports.

40.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 2 and Attachment 1, pp. 27, 31
Preliminary Assessment of Kwantlen SOC

"BC Hydro's preliminary SOC assessment is that the Kwantlen have, on balance, a reasonable *prima facie* Aboriginal rights (including title) claim in the Project area... 'Reasonable' implies that the claim is not a weak claim but the available information may not be sufficient to conclude that a claim is a 'strong *prima facie'* claim." (BCUC 1.1.4.1, p. 2)

"By the 1850s, the Kwantlen were so entrenched in a village situated upstream from the second Fort Langley site that one of the rivers had become known in English as the Kwantlen River…subsequent ethnographic work, as reviewed above, associated this term with the village situated at the mouth of the Stave River, as well as the Stave River, itself, and the Stave River people." (Attachment 1, p. 27)

"…the Kwantlen people occupied the Stave River in the historic period, at least by the 1830s, after the demise of the original residents, the Skayuks." (Attachment 1, p. 31)

40.1 Why does BC Hydro consider the Kwantlen to have a reasonable claim to the Project area when the Bouchard and Kennedy Report found that the Kwantlen occupied the Stave River area at least by the 1830s?

41.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3 and Attachment 1, p. 31, and *Delgamuukw v. British Columbia* [1997] 3 S.C.R. 1010, para. 143
Preliminary Assessment of Kwantlen SOC

"The information BC Hydro has reviewed raises some question as to whether or not the Kwantlen had "exclusive pre-sovereignty occupation" (that is, on or before 1846) of the Project area sufficient to establish a claim of Aboriginal title." (BCUC 1.14.1, p. 3)

"…the Kwantlen people occupied the Stave River in the historic period, at least by the 1830s, after the demise of the original residents, the Skayuks." (Attachment 1, p. 31)

"In order to make out a claim for aboriginal title, the aboriginal group asserting title must satisfy the following criteria: (i) the land must have been occupied prior to sovereignty, (ii) if present occupation is relied on as proof of occupation pre-sovereignty, there must be a continuity between present and pre-sovereignty occupation, and (iii) at sovereignty, that occupation must have been exclusive." (*Delgamuukw*, para. 143)

41.1 Please point to specific evidence that supports BC Hydro's statement that its review of information raises some question as to whether or not the Kwantlen had exclusive pre-sovereignty occupation of the Project area sufficient to establish a claim of Aboriginal title.

41.1.1 Please discuss BC Hydro's statement given that the 2008 Bouchard and Kennedy Report found that the Kwantlen occupied the Stave River at least by the 1830s.

41.1.2 Please discuss BC Hydro's statement in relation to the test for Aboriginal title as set out in *Delgamuukw*. Please reference any other case law BC Hydro relied on to make its statement above.

41.2 Is it BC Hydro's conclusion that the Kwantlen did not have exclusive occupation of the Stave River area on or before 1846? If so, please specify the evidence to support this conclusion.

42.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3, and BCUC IR 1.14.1, Attachment 1, p. 37
Preliminary Assessment of Kwantlen SOC

"In respect of Aboriginal rights, such as fishing and traditional activities, the evidence suggests that the Kwantlen probably have a reasonable prima facie Aboriginal rights claim in the Stave River area. However, it is difficult to determine the precise scope and nature of any Aboriginal rights because there is limited information relating to traditional use in the Stave River area". (BCUC 1.14.1, p. 3)

"According to Duncan McLaren's 2003 Master's thesis, two Traditional Use Studies have been prepared relating to the Stave River area: one of these TUS studies was by T.H. Dandurand *et al.* (1996); and the other was by Ann Stevenson (1996).126 The first was prepared for BC Hydro, the Stó:lō Nation and the Kwantlen First Nation, while the second was prepared for the Stó:lō Nation and the Kwantlen First Nation." (Attachment 1, p. 37)

42.1 Please explain how limited information relating to traditional use in the Stave River exists when two traditional use studies have been done in the area.

42.1.1 Section 6 of the 2008 Kennedy and Bouchard Report identifies traditional uses such as fisheries, hunting and trapping, plant foods, large cedars, travel routes and others. Please explain how there is limited information relating to traditional use in the Stave River area given these identified traditional uses.

42.2 Did BC Hydro review its previously prepared TUS in its preliminary assessments of strength of claim?

42.3 What Kwantlen traditional uses did the 1996 TUS indentify?

42.4 Has BC Hydro received traditional use information from the interim TUS reports funded through the Kwantlen CFA?

43.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3
Preliminary Assessment of Kwantlen SOC

"In the ILM EAO Report, the EAO considered the Kwantlen's SOC in the context of Nodes Q to T of the ILM preferred project route, which is to the north of the Project area. In that context, the EAO concluded:

'The Kwantlen First Nation's main present-day community is within about three kilometres of the proposed Project alignment at Nodes Q to T. Since their ancestors appear to have occupied this area of the proposed Project alignment along the Fraser River at sovereignty, EAO considers that the Kwantlen First Nation's prima facie case for aboriginal rights (such as fishing, hunting and gathering listed above) and title in this segment of the proposed Project alignment is strong'."

43.1 Please confirm that the ILM Project alignment at Nodes Q to T includes the Stave River area.

43.2 Please file Appendix E to the ILM EAO Report which contains a description of the ILM Route Alignment Segments.

43.3 If the EAO concluded the Kwantlen have a strong *prima facie* case for rights and title in the Stave River area, why does BC Hydro conclude the Kwantlen have a reasonable claim? Please reference specific differences or different pieces of information used by the EAO and BC Hydro to make these conclusions.

44.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, Attachment 1, p. 1
2008 Bouchard and Kennedy Report

"The evidence supports the conclusion that Kwantlen people established and maintained a village site and more temporarily-occupied settlements in the Stave River area after all or most of the original Aboriginal occupants, the 'Skayuks' died, as a result of the first smallpox epidemics of the 1770s…these data indicate that below Stave Falls was an area of intensive Aboriginal use, while the area above the falls appears to have been occupied on a seasonal basis for specific activities. The area was particularly prized for its timber, especially for the cedar used for constructing canoes."

44.1 Please confirm that the conclusion regarding the Kwantlen's occupation of the Stave River area is that of the Report authors, Bouchard and Kennedy, and was made based on a review of the ethnographic evidence recounted in Sections 2.0 - 4.0 of the Report. If this is correct, did BC Hydro come to the same conclusion after its review of the same ethnographic evidence in the Report?

44.2 Was the village site established and maintained by the Kwantlen in the Stave River area occupied year-round or seasonally after the 1830s? Was the area below Stave Falls an area of intensive Aboriginal use by many different First Nations peoples or by the Kwantlen as of the 1830s?

44.3 Was the area below or above Stave Falls particularly prized for its timber? By whom was it prized? The Kwantlen or other Aboriginal groups?

45.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 5
Preliminary Assessment of Matsqui SOC

"The 2011 Kennedy Report and the 2008 Bouchard & Kennedy Report conclude that the various descriptions in the historical literature reflect the Matsqui's presence exclusively on the southern side of the Fraser River and seasonal use of mid-channel islands some distance east from the Stave River".

45.1 Did the Matsqui use the Stave River area seasonally or at all?

46.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.7, p. 2
BC Hydro Board Decision

46.1 What specific information on the impacts to Aboriginal rights and title did the BC Hydro Board of Directors have when making its decision on the Preferred Alternative?

46.2 Were the Application Executive Summary and Alternatives Analysis Table listed in BC Hydro's response to BCUC IR 1.97, the only two documents the Board reviewed before making their February 17, 2011 decision? If not, please provide a copy of the other documents.

46.3 Did the BC Hydro Board consider other information, such as in-person presentations, to make its February 17, 2011 decision?

47.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.27.1, Attachment 1
Consultation with the Matsqui

"In particular, BC Hydro has been engaged in consultation with Matsqui with respect to the ILM Project. As you note, the EAO found a medium strength of claim in the areas."

47.1 To the best of BC Hydro's knowledge, why have the Matsqui not registered as interveners in this Commission proceeding?

48.0 Reference: First Nations Consultation
Exhibit B-7-2, Response to Kwantlen IR 1.3.2
Project Cost Approval

48.1 If the BC Hydro Senior Executives approved $80,000 to continue with Identification phase work in March 2006, why did BC Hydro not notify the Kwantlen of the Project until November 2006 and other potentially affected First Nations until March 2007 and later?

48.2 If the BC Hydro Board of Directors approved $3 million for initial engineering work in August 2006, why did BC Hydro not notify the Kwantlen of the project until November 2006 and other potentially affected First Nations until March 2007 and later?

48.3 What was the earliest date that BC Hydro included the concept of upgrading Ruskin Dam in its Long Term Resource Plan or Integrated Resource Plan?

48.4 What was the earliest date that BC Hydro funded a study on the upgrade or future possibilities for the Ruskin Dam?

48.5 If either of the dates of inclusion in the Long Term Resource Plan, Integrated Resource Plan or of completion of the studies are earlier than March 2006, why did BC Hydro not notify the Kwantlen of the Project until November 2006 and other potentially affected First Nations until March 2007 and later?

49.0 Reference: Seismic Capability
Exhibit B-7, BCUC 1.2.1, Attachment 1, page 8 of 44

49.1 Please provide the Sandwell memos referenced as items (3), (4), (5) and (6) on page 8 of 44 of the Attachment to BCUC 1.2.1.

50.0 Reference: Crane Upgrade Costs
Exhibit B-7, BCUC 1.4.1

"BC Hydro rejected upgrading the existing cranes because while upgrading the existing cranes would be $1 million less than BC Hydro's proposal, this alternative would require significant work and would still have significant reliability risks."

"The proposed replacement of the existing crane system with a single 240 Ton crane at an estimated cost of $2.9 million results in lower cost compared to replacement with a dual crane system estimated to be $4.3 million."

50.1 Please reconcile these two statements.

50.2 Please describe the remaining reliability risks after upgrading of the existing cranes if this option was chosen instead of a new crane.

51.0 Reference: Powerhouse – New versus Rehabilitate/Replace
Exhibit B-7, BCUC 1.9.1

"With respect to the site on the left bank downstream of the existing Ruskin Facility, this location would require lengthy tunnels to be constructed, most of which would be constructed through earth instead of through bedrock. Bedrock dips steeply to the south and is likely at elevation -5 m, which is close to 10 m below the surface elevation. Designing the Powerhouse to meet seismic requirements without a solid foundation for both the new Powerhouse building and tunnels would be difficult and construction would be expensive."

51.1 Please describe the elevation of the new tunnels for a new powerhouse on the left bank and provide a more detailed analysis of the amount of tunnel in earth rather than bedrock.

52.0 Reference: Interest During Construction Costs
Exhibit B-7, BCUC 1.53.3

52.1 Please provide the earliest possible in-service date for each of the Decommissioning Alternatives and confirm the amount of IDC costs associated with each alternative.

53.0 Reference: Estimate Probability Distribution
Exhibit B-7, BCUC 1.53.4

53.1 Please provide the analysis for the P50 and P90 level of estimates using a normal distribution centered at the "most likely" estimate instead of a triangular distribution.

54.0 Reference: Energy Production
Exhibit B-7, BCUC 1.55.2, Attachment 1

54.1 Please explain why Scenario 1 in Attachment 1 (3 units) is dispatched for 1500 MW.h per day approximately 6 percent of the time [see Load Duration Curve – Daily (RUS – 3 units)], while in Scenario 4 [see Load Duration Curve – Daily (RUS – 2 units)] the facility is dispatched for 1500 MW.h per day approximately 9 percent of the time. It appears that for certain inflows, the 2 unit facility delivers more energy than the 3-unit facility.

54.2 Please explain why the 3-unit scenario does not provide more power for certain inflow sets than the 2-unit scenario, and when do these situations occur?

54.3 Please provide the annual generation for each unit at Ruskin since 2000, and the annual number of stops and starts for each unit.

55.0 Reference: Intake Modifications
Exhibit B-7, BCUC 1.55.2, Attachment 2, p. 12 of 88, p. 14 of 88

"The intake structures are not considered to be part of the water retaining structures; however, due to their importance in supporting power generation after an earthquake, they should be strengthened to the same seismic loading as the dam."

"Per the User Requirements, emergency shutoff of the water supply into the tunnels was to be considered. The User Requirements, however, did not include this capability as a requirement of the rehabilitation. The Identification Phase study has concluded that the benefits associated with the addition of an upstream control/emergency closure gate system at the intake warrants their addition. Emergency closure of the water supply with the existing Turbine Inlet Valves (TIV's) is not considered safe or dependable."

55.1 Please explain how the use of turbine inlet valves could be made "safe and dependable" considering that they have been used in other facilities and in this facility since it was built.

55.2 Please describe any failures BC Hydro has experienced with turbine inlet valves, and the consequences of those failures.

55.3 Please provide a detailed line item cost estimate of the proposed intake gate work and the other work being driven by the proposed new intake gates (control buildings, hoists, roadway/superstructure modifications, etc).

55.4 Please provide a detailed line item cost estimate of a replacement turbine inlet valve system.

55.5 Can a turbine inlet valve system be designed to have the same seismic withstand capability as the proposed intake gate system?

55.6 Please identify the potential lost generation attributable to a seismic event if turbine inlet valves are used instead of the proposed intake gates.

56.0 Reference: Access Bridge
Exhibit B-1, Section 2.2.2.2, Table 2-2, p. 2-28
Exhibit B-7-1, BCUC 1.40.1, CONFIDENTIAL Submission
Exhibit B-7, BCUC 1.55.2, PUBLIC Attachment 2, p. 51 of 88
Exhibit B-7-2, BCSEA 1.5.2

"The construction cost estimate provides for a $500,000 contingency for Access bridge repairs or new East side access road." (Exhibit B-7, BCUC 1.55.2, PUBLIC Attachment 2, p. 51 of 88)

56.1 Please provide a reconciliation of the costs associated with the access bridge in the above references and provide a detailed line item estimate for the access bridge work, in particular the cost of replacing the bridge bearings and armouring and encasing the intermediate pier.

56.2 Please identify any environmental issues addressed by the proposed access bridge work, and explain the requirement for BC Hydro to undertake this work. Also explain the consequences of not undertaking the proposed bridge repairs and instead constructing a new East side access road (and possibly a new vehicle access door).

56.3 Please provide a comparative cost estimate for removing the powerhouse access bridge and creating a dedicated access road to the east of the powerhouse. Please also discuss other issues arising from the potential relocation of the access road to the east side of the powerhouse including the interaction with the proposed right and left bank seismic stability improvements.

57.0 Reference: Value of Firm Energy and Capacity
Exhibit B-7, BCUC 1.56.1

57.1 Please describe if either the Clean Power Call RFP or Bioenergy Phase 1 RFP called for seasonally firm or hourly firm energy commitments.

57.2 Please describe the premium for hourly firm energy as compared to seasonally firm energy for both the Clean Power Call RFP or Bioenergy Phase 1 RFP, both as offered in the RFP (if applicable), and the range of awarded premiums (if applicable) for hourly firm products.

57.3 Please explain why the hourly firm energy premium above a seasonally firm energy profile does or does not adequately recognize the capacity associated with the firm energy.

57.4 Please explain why the BC Hydro power call RFPs do not provide for a value for firm capacity in addition to firm energy.

58.0 Reference: Spillway Gate Reliability
Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35
Exhibit B-7, BCUC 1.93.1, Attachment 3, p. 290 of 301
Exhibit B-7-2, CECBC 1.22.1

"…Operating rules should specify the maximum time period for which degraded conditions will be allowed to exist without contingency action." (Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35)

58.1 Please describe the maximum period for the return to service of unimproved gates if only two gates are replaced.

58.2 Please describe the probability and consequences of seismic failure of the spillway gates if the failure caused uncontrolled spill.

58.3 Please explain why it is not possible to only upgrade/replace a minimum number of gates in order to be assured of passing flows 99 percent of the time or 99.9 percent of the time following a seismic event.

58.4 How many new spillway gates are required to pass inflows for 99 percent and 99.9 percent of the time?

58.5 Please provide the percentage of time the facility is required to operate with one spillway gate open, two spillway gates open, etc., to maximum spillway gates open for the projected distribution of inflows.

58.6 Please discuss whether BC Hydro has considered a hybrid solution of a minimum number of new spillway gates and piers combined with seismically strengthening the remaining existing piers and rehabilitating the remaining existing spillway gates.

58.7 Please discuss the approach to redundancy and reliability for the spillway gate pump motor power supply. For instance, in addition to main and backup pump motors, each with a receptacle and bypass to allow supply and operation from a mobile generator set, the supply arrangement has a diesel generator, an uninterruptible power supply, three transfer switches, two connections to an external distribution feeder, and supply from the powerhouse station service bus (which itself has redundant sources). Does such an arrangement suffer from reliability issues simply from the shear number of components (as the number of devices goes up, the probability of failure of one of the devices goes up and hence the reliability of the system goes down)? Has a reliability analysis been performed to assess the required supply arrangement to achieve a probability of failure on demand of 1 in 1,000 to 1 in 10,000?

59.0 Reference: Spillway and Spillway Gates System
Exhibit B-7, BCUC 1.70.1

"The scope of work being undertaken for the spillway gates is primarily to address seismic risk; in particular, the gates must reliably operate after a seismic event to retain the reservoir, permit reservoir drawdowns to reduce loading on the Dam and water retaining structures, and to safely pass flows less than the PMF and as low as average annual inflow."

59.1 Please describe any critical review BC Hydro has undertaken to optimize the amount of seismic strengthening of the facility versus the amount spillway capability and explain why it is critical for all the spillway gates to be operable after a seismic event.

60.0 Reference: Right Abutment Seismic Capability
Exhibit B-7, BCUC 1.73.1

"While BC Hydro cannot quantify the exact amount of time it would take for a failure to result in an uncontrolled release, with high rates of seepage, the fills and sands may erode quickly towards the reservoir, possibly leading to a Dam breach."

60.1 Please discuss the seismically-induced failure mechanisms of the right abutment, including an estimate of the approximate potential elapsed time, both with and without the proposed Stage 2 work. Please confirm the Stage 2 right abutment cut-off wall work is being designed to withstand the MDE.

61.0 Reference: Site Seismicity
Exhibit B-7, BCUC 1.77.1

61.1 For the scope items in the proposed Project please identify (if possible) the incremental cost associated with the criterion of 0.71g as compared to 0.54g.

62.0 Reference: Spillway Gate Reliability
Exhibit B-7, BCUC 1.93.1, Attachment 3, pp. 173, 174 of 301

"The spillway gates will only be manually operated (remote or local) although there will be provisions made for local automatic spillway gate control and/or supervisory control if needed in the future."

"Four control stations will be available for each gate control; at the Powerhouse, Main Control Room Back-up Control Room, and at the SPOG. (The control rooms located on top of the piers are also known as the mechanical rooms). The control system will be robust, contain redundancy, and will also include at least one emergency by-pass."

62.1 Please explain why so many points of control are required for the spillway gates and how the increased device count affects overall reliability.

62.1.1 Please explain if the gate controls can be operated simultaneously from any control station or if the system relies on a local/remote selector switch that permits control from only a single control station at a time. If the latter, please explain how the gates can be operated during an emergency if access to the selector switch is not possible and the remaining control stations are "locked out" by the inaccessible L/R selector switch.

62.2 Please describe why a local control station at the gate HPU and the Powerhouse control room are insufficient to provide the required redundant control of the gates.

62.3 Please provide a cost estimate for the proposed Main Control Room and Back-up Control Room and the associated control wiring for the spillway gate controls.

63.0 Reference: Left Abutment
Exhibit B-7, BCUC 1.95.1

"Given that a local failure of the Left abutment has already occurred, BC Hydro does not view this as an acceptable risk trade-off."

63.1 Please describe the magnitude and provide photographs showing this Left Abutment failure.

64.0 Reference: Future Rate Increases
Exhibit B-7-2, AMPC 1.1.1

"As set out in footnote 17, page 3-11 of Exhibit B-1, the LTRF does not represent BC Hydro's view as to future Revenue Requirement Applications (RRAs), and any rate increases requested in future RRAs will be based on BC Hydro's assessment of its expected revenue and cost at the time of filing."

64.1 Has BC Hydro prepared an estimate or assessment of future rate increases, even if for internal purposes? If not, why not?

64.2 Please provide BC Hydro's most recent estimate or assessment of approximate annual rate increases through to F2022, along with the underlying assumptions.

65.0 Reference: IPP Purchases
Exhibit B-7-2, AMPC 1.1.2

"However, as noted in BC Hydro's response to Kwantlen IR 1.5.6, while the Clean Power Call is the best available proxy for future IPP energy purchases, past experience suggests that future IPP costs may be higher than the $129/MWh resulting from the Clean Power Call."

65.1 Please provide a copy of BC Hydro's 2011 Integrated Resource Plan (IRP) Consultation Workbook.

65.2 Please discuss the lower limit of the prices shown on pages 14 and 15 of BC Hydro's 2011 Integrated Resource Plan Consultation Workbook for the following technologies: biomass, wind, geothermal, run-of-river, large hydro, natural gas-fired generation and cogeneration and coal-fired generation with carbon capture and storage. Please include any assessment BC Hydro has performed that quantifies the amount of energy potentially available for $100/MWh or less for each resource technology.

65.3 Has BC Hydro stated in the 2011 Integrated Resource Plan public consultation forums that it expects to be able to procure a certain amount of power at the lower limits of the prices shown on pages 14 and 15 of BC Hydro's 2011 Integrated Resource Plan Consultation Workbook for each of the technologies shown?

65.4 Please provide BC Hydro's assessment of the blended cost of the next 5,000 and 10,000 GW.h of lowest-cost resource available using the price ranges shown on pages 14 and 15 of BC Hydro's 2011 Integrated Resource Plan Consultation Workbook.

65.5 Please discuss why the Clean Power Call based pricing should be used as the reference price for the value of the Ruskin facility products rather than BC Hydro's assessments in the IRP or other processes.

65.6 Please repeat the NPV analysis provided in Table 3-4 of Exhibit B-1 for the proposed Project, except use a capacity value of $0/kW-year and solve for the weighted average energy value necessary to provide a project NPV of zero. Using this weighted average energy value and a capacity value of $0/kW-year, please also provide the NPV for Alternatives A through E.

66.0 Reference: Seismic Standards
Exhibit B-7-2, AMPC 1.5.2

"BC Hydro is upgrading the Ruskin Facility, which was originally constructed in 1930, to current seismic and safety standards. However, these standards, which are described in Part II of this response in greater detail, are not "BC Hydro current standards", but rather are standards which are either set by or adopted by British Columbia (B.C.) government agencies such as the B.C. Comptroller of Water Rights, charged with administering the B.C. Dam Safety Regulation (Upper Dam, Right Abutment and Left Abutment seismic) and the B.C. Ministry of Energy and Mines' Safety Standards Branch, responsible for the B.C. Building Code (Powerhouse superstructure seismic) or by organizations such as the Canadian Dam Association (CDA) which reflect international best practices and are referred to by B.C. government agencies."

66.1 Has BC Hydro sought exemption from the applicability of the 0.71g criterion and other seismic criteria at the Ruskin facility or otherwise confirmed the applicability of those criteria with any regulatory authority? If not, why not?

67.0 Reference: Current Design Status
Exhibit B-7, BCUC 1.93.1, Attachment 4, p. 25 of 406

"This WDB is intended to be a "living document" and is updated as required during the life of the project."

67.1 Please confirm the referenced Interim Working Design Basis document, dated October 2008, is the most recent Working Design Basis document and reflects the proposed project in the Application. If not able to confirm, please provide an updated and current Working Design Basis document.

67.2 Please update Exhibit B-1, Table 2-2 with the most current WDB document information.

1.0 Reference: Project Costs
Exhibit B-1, Chapter 2, Table 2-4
First Nations Costs

2.1.1 Please identify how much and where First Nations accommodations costs are included in the Project Costs, as illustrated in Table 2-4 of Exhibit B-1. If they have not been included, explain why.

RESPONSE:

As set out in Exhibit B-7-2, BC Hydro's response to British Columbia Old Age Pensioners' Organization (BCOAPO) Information Request (IR) 1.14.2, the capital cost estimates for the Ruskin Dam and Powerhouse Upgrade Project (Project) set out in Table 2-4 of BC Hydro's Application (Exhibit B-1) to the British Columbia Utilities Commission (BCUC) for a Certificate of Public Convenience and Necessity (CPCN) for the Project do not include an allowance for currently expected accommodation-related costs.

BC Hydro provided the BCUC with an estimate of the total First Nation Impact Benefit Agreement (IBA)-related costs, which include accommodation-related costs, in Exhibit B-7-1, confidential response to BCUC IR 1.14.5. Please also refer to BC Hydro's response to BCUC IR 2.24.1 with respect to IBAs, and to BC Hydro's responses to the BCUC Confidential IR 2.2 series for further information regarding the development of the IBA-related cost estimate.

2.0 Reference: Project Costs
Exhibit B-1, Appendix E
Authorized Amount

2.2.1 Appendix E shows total capital expenditures of $672.3M (authorized amount). Show how this reconciles to Table 2-4.

RESPONSE:

The $672.3 million reference in the IR above does not include all capital and operating expenditures from the Authorized Amount of the Project. The following table shows all of the capital and operating expenditure inputs that have been taken from the Project cost estimate and used to calculate the Rate Impact provided in Appendix E.

Appendix E (Authorized Amount) - Inputs used for Rate Impact Analysis

Cost ($ million)	Appendix E Reference	Description
682.8	Tab 5.0, Sum of Rows 20 to 28	2012 to 2018 Capital Expenditures excluding IDC
10.5	Tab 5.0, Row 29	Asset Write-off Expense
48.5	Tab 5.0, Cell K67	Pre-2012 Capital Expenditures
19.4	Tab 5.0, Sum of Row 69	Demobilization
102.1	Tab 3.0, Sum of Row 200	Interest During Construction
863.3		**Total Amount used for Authorized Amount Rate Impact Analysis**

Section 2-4 (Project Costs) – Authorized Amount

Cost ($ million)		
856.9	Authorized Amount	Exhibit B-1, Table 2-4
10.5	Net Book Value expenses excluded from Table 2-4	Exhibit B-1, page 2-30, lines 5 and 6
867.4		**Total Authorized Amount including Net Book Value expense**

The difference between the sum of expenditures used in Appendix E versus that which is shown in section 2-4 is $4.1 million. This difference is attributed to

differences in the calculation of Interest During Construction (IDC) in the Rate Impact Analysis versus the Project expenditure schedule.

IDC values calculated for the Project expenditure schedule which informs Table 2-4 of Exhibit B-1 were calculated on a task-by-task basis, not on an aggregate basis. This differs from the model used to calculate the Rate Impact Analysis, which calculates IDC for each major asset category (and not on a task-by-task basis). As there are far more tasks than asset categories, the aggregation of tasks with different start and end dates into a single asset category results in IDC calculation differences.

At the time that BC Hydro filed the Application, it was aware of the above noted IDC variances. In carrying out the rate impact analysis, BC Hydro had identified this difference in IDC and worked to minimize differences to the extent possible. BC Hydro also notes that this IDC difference does not have any material impact on the rate impact analysis, as the difference is distributed over the period F2011 to F2018, and over the economic life of the assets thereafter.

3.0 Reference: Project Costs
Exhibit B-7, BCUC 1.40.2
Cost Breakdown

BC Hydro states that the Project Manager, Assistant Project Manager, and Project Management Office Support total $6.57 million.

2.3.1 Please provide the cost, FTE and headcount included in the above $6.57 million and broken down for each of the categories above and for each year of the project.

RESPONSE:

Please refer to Attachment 1 to this response.

4.0 Reference: Project Costs
Exhibit B-7, BCUC 1.2.1 Attachment
Third Unit Generation

"The average annual generation from Ruskin is 374 GW.h…It is evident from the load duration curve (Figure 3) that the third unit operates only about 6% of the time and produces about 3% of the average annual generation." (BCUC 1.2.1 Attachment, page 31 of 44)

2.4.1 Based on these assumptions, the average annual generation produced from the third unit is only 11.22 GWh. Using the assumptions of the energy evaluation provided in Exhibit B-1, Table 3-23, please calculate the annual incremental revenues that BC Hydro can obtain with the installation of the third unit.

RESPONSE:

There is no Table 3-23 in Exhibit B-1, and there is no discussion of energy evaluation on page 3-23 of Exhibit B-1.

As set out in section 3.4.2 of Exhibit B-1, although the third unit at the Ruskin Facility will provide a limited amount of additional energy due to avoided spill, the primary economic benefit (as distinguished from operating flexibility and reliability benefits) is the additional capacity provided by a third unit (U3) and the increased ability to shape energy production into High Load Hour periods and out of Low Load Hour periods. In this regard, please refer to Exhibit B-7-2, BC Hydro's response to Commercial Energy Consumers Association of British Columbia CECBC IR 1.19.1.

BC Hydro notes that revenues in a regulated enterprise are not determined by level or value of production, but by the Revenue Requirement as approved by the regulator, hence, "revenue" attributable to U3 is irrelevant. BC Hydro is of the view that the value of production and energy shaping is the relevant criteria to determine the economic impact of the decision to include a third generating unit as part of the Project Scope.

It is inappropriate to value a capacity resource such as U3 on the value of energy provided. As set out in Table 3-12 of Exhibit B-1, BC Hydro determined the incremental energy and the incremental value of energy from the Ruskin Facility with three generating units in place (i.e., after completion of the Project) as compared to the Ruskin Facility with two generating units in place. The three-unit facility provides incremental annual energy of 18.6 gigawatt hours (GWh), with an incremental value of $3.3 million compared to a two-unit facility, after adjusting for the firmness of the generation at the Ruskin Facility. Please also refer to BC Hydro's response to BCUC IR 2.32.2.

4.0 Reference: Project Costs
Exhibit B-7, BCUC 1.2.1 Attachment
Third Unit Generation

"The average annual generation from Ruskin is 374 GW.h…It is evident from the load duration curve (Figure 3) that the third unit operates only about 6% of the time and produces about 3% of the average annual generation." (BCUC 1.2.1 Attachment, page 31 of 44)

2.4.2 Calculate the payback on the third unit based on its incremental generation over its incremental capital cost.

RESPONSE:

As discussed in BC Hydro's response to BCUC IR 2.4.1, it is inappropriate to assess U3 in terms of incremental generation since in an economic view it is primarily a capacity resource (and a flexibility and reliability resource in a non-economic view).

As set out in Table 3-12 of Exhibit B-1, U3 provides an annual value of approximately $3.3 million through incremental generation and energy shaping at an incremental cost of $41.7 million. Accordingly, the simple payback period for U3 is 12.8 years which compares favourably to its approximately 60 to 80-year life.

5.0 Reference: Project Costs
Exhibit B-7, BCUC 1.37.4
Third Party Assessment

"As part of ensuring that BC Hydro properly scoped the Project, BC Hydro engaged an independent third party – RW Beck – to conduct a condition assessment of the Powerhouse." (Exhibit B-7, BCUC 1.37.4)

"The Ruskin Powerhouse is essentially 80 years old, with the exception of U3, which is 60 years old…none of the major electrical and mechanical equipment have been replaced or refurbished since installation." (Exhibit B-1, Chapter 2, p. 15)

2.5.1 Given the age and condition of the Powerhouse, in addition to BC Hydro's internal assessment methodology, please explain why BC Hydro still found it necessary to spend $126,000 to conduct an independent conditions assessment.

RESPONSE:

The foundation of BC Hydro's Equipment Health Rating (EHR) process is robust methodologies for assessing equipment condition. The documented methodologies, some of which have been reviewed and validated by external subject matter experts, enable an objective and repeatable assessment of equipment condition. This gives BC Hydro a high level of confidence that the EHR process provides a complete and accurate assessment of equipment condition.

Nonetheless, given that the cost of the Powerhouse upgrades (excluding construction management, project management, engineering and indirect construction costs) is approximately $200 million, BC Hydro considered it prudent to get a separate and independent assessment of the Powerhouse equipment. In addition to the EHR-assessed equipment, the RW Beck report entitled "Ruskin Power Plant Assessment Report" (RW Beck Report, found at Appendix B-3 to Exhibit B-1) includes an assessment of Powerhouse equipment for which EHR methodologies do not exist, including the Powerhouse superstructure and protection and control systems. In addition, the RW Beck Report provides probabilities of equipment failure and documents environmental and safety risks, neither of which are an output of BC Hydro's EHR process.

5.0 Reference: Project Costs
Exhibit B-7, BCUC 1.37.4
Third Party Assessment

"As part of ensuring that BC Hydro properly scoped the Project, BC Hydro engaged an independent third party – RW Beck – to conduct a condition assessment of the Powerhouse." (Exhibit B-7, BCUC 1.37.4)

"The Ruskin Powerhouse is essentially 80 years old, with the exception of U3, which is 60 years old…none of the major electrical and mechanical equipment have been replaced or refurbished since installation." (Exhibit B-1, Chapter 2, p. 15)

2.5.1.1 Was BC Hydro's EHR Assessment not sufficient to indicate that the Powerhouse was deficient and that refurbishment or retrofitting was required?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.5.1.

6.0 Reference: Project Costs
Exhibit B-1, Section 2.4, p. 2

"The Project Expected amount is $718.1 million and the Authorized Amount is $856.9 million."

2.6.1 Please discuss how the regulatory requirements have contributed to the overall costs and how, in BC Hydro's view, the Commission process could be more efficient to lower this cost component of the Project.

RESPONSE:

The BCUC regulatory review process cost component is not large in the context of the overall Project Expected and Authorized Amounts.

Generally, BC Hydro supports the BCUC's practice of facilitating informal meetings with public utilities and intervenors to discuss issues common to various proceedings. A good example is an issue raised by public utilities with respect to the volume of BCUC staff IRs generally. Nevertheless, BC Hydro understands from the BCUC-facilitated informal meetings and otherwise that intervenors rely on BCUC staff expertise in general and on BCUC staff IRs in particular, and thus it is difficult to determine with precision the appropriate balance with respect to the volume of BCUC staff IRs.

6.0 Reference: Project Costs
Exhibit B-1, Section 2.4, p. 2

"The Project Expected amount is $718.1 million and the Authorized Amount is $856.9 million."

2.6.2 Please explain why duplication of the consulting services of RW Beck, KCBL and MWH was required when their recommendations essentially arrived at the same conclusions.

RESPONSE:

As set out in Exhibit B-1, page 1-18 lines 18 to 24, to page 1-19 lines 1 to 7, there was no duplication of consulting services, as each of the three consultants was retained for a different purpose:

- **RW Beck was engaged to perform an independent condition assessment of the Powerhouse;**
- **Klohn Crippen Berger Ltd. was retained to determine whether constructing a new powerhouse near to the existing Powerhouse site was more cost-effective than BC Hydro's proposal to rehabilitate/replace the Powerhouse at the existing location; and**
- **MWH Global provided engineering design services related to the feasibility and preliminary design for rehabilitating/replacing the Powerhouse at the existing location.**

6.0 Reference: Project Costs
Exhibit B-1, Section 2.4, p. 2

"The Project Expected amount is $718.1 million and the Authorized Amount is $856.9 million."

2.6.2.1 What portion of the Investigative/Definition costs could have been avoided by not duplicating their scope of work? Please discuss.

RESPONSE:

There was no duplication. Please refer to BC Hydro's response to BCUC IR 2.6.2.

7.0 Reference: Project Costs
Exhibit B-7, BCUC 1.41.1 and 1.41.2
Identification, Definition and Early Implementation Costs

Attachment 1 to BCUC 1.41.1 indicates that Early Implementation costs are expected to be $49.8 million in F2011 and $14.3 million in F2012. Carrying costs on these expenses between F2013 – F2018 amount to an additional $22.9 million.

2.7.1 Please discuss BC Hydro's traditional methods for capitalizing carrying costs on major capital projects that span over several years. Please include a discussion on the alternative methodologies for capitalizing carrying costs (AFUDC / IDC or CWIP). What are the pros and cons of using each method?

RESPONSE:

BC Hydro respectfully submits that examination of methodologies for recovering costs associated with funds used by BC Hydro during the construction of a capital investment has been a subject explored in prior Revenue Requirements Application (RRA) proceedings and is more appropriately dealt with in such proceedings.

Nonetheless, BC Hydro can confirm that neither Allowance for Funds Used During Construction (AFUDC) nor Construction Work In Progress (CWIP) methodologies are permitted under International Financial Reporting Standards (IFRS). In addition, inclusion of CWIP in rate base is not an option available to BC Hydro as BC Hydro's understanding of Heritage Special Direction No. HC2 to the British Columbia Utilities Commission specifically disallows items that are not in-service such as CWIP from being part of rate base.

7.0 Reference: Project Costs
Exhibit B-7, BCUC 1.41.1 and 1.41.2
Identification, Definition and Early Implementation Costs

Attachment 1 to BCUC 1.41.1 indicates that Early Implementation costs are expected to be $49.8 million in F2011 and $14.3 million in F2012. Carrying costs on these expenses between F2013 – F2018 amount to an additional $22.9 million.

2.7.2 What is the rate impact to customers if BC Hydro was to recognize the financing costs as they were incurred during the construction period as opposed to paying for additional financing costs over the life of the assets?

RESPONSE:

BC Hydro respectfully submits that this IR is directed at accounting and cost recovery issues that are more appropriately addressed in RRAs and not capital project applications. Nevertheless, to be responsive, BC Hydro offers the following observations. If financing costs for construction activities were expensed in the years that they were incurred, customer rates increases would be higher than the rate increases shown in the Rate Impact Analysis provided for the Project[1] during the construction period. Upon completion of Project construction, rate increases would be lower than those shown in the Rate Impact Analysis provided for the Project.

However:

- **The recognition of financing costs at the time these costs are incurred during the construction period is inconsistent with the principle that an item must be used and useful before its costs are applied to customer rates. Under the used and useful principle, an asset (including the costs associated with development of the asset) should be included in the utility's rate base at the time that an asset is capable of and contributing to the provision of service (i.e., – the in-service dates of discrete and useful Project components such as the Right Abutment Work);**

- **The treatment noted in this IR is also inconsistent with the treatment of financing costs for capital projects used by other Canadian utilities, which like BC Hydro, recover borrowing costs associated with capital investment only when an asset has gone into service;**

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1 The Rate Impact for the Project is provided in Appendix E of Exhibit B-1, and revised in Exhibit B-7-2, Attachments 11 and 12 of BC Hydro's response to AMPC IR 1.1.1

- **Finally, BC Hydro notes that its method of capitalization of finance charges on capital expenditures to reflect the carrying cost of funds required for a project was accepted by BCUC as part of its review of BC Hydro's 2004/05 to 2005/06 RRA (F05-F06 RRA). Attachment 1 to this IR response is a copy of page 154 of BCUC's Decision for BC Hydro's F05-F06 RRA, which sets out BCUC's acceptance of BC Hydro's method of calculating IDC.**

7.4 Calculation of Interest During Construction

BC Hydro capitalizes finance charges on capital expenditures to reflect the carrying cost of the funds required for a project. The IDC rate is established at the beginning of each fiscal year based on the average expected annual finance cost to BC Hydro. The IDC rate is based on BC Hydro's incremental cost of borrowing and takes into consideration annual interest costs plus foreign exchange adjustments and amortizations of premiums, discounts and issue costs. The IDC rate is calculated using forecast short-term and long-term rates (Exhibit B1-8, BCUC IR 2.198.4.1).

Prior to April 1, 2003 a threshold of $50,000 in direct costs was required before IDC was charged. When the Peoplesoft Project Costing Model was implemented, there was no automation to determine applicability based on an approved amount or duration so either a manual process or significant customization would have been required. BC Hydro determined that there was not a significant impact of having the threshold and therefore a decision was made to have the threshold removed (T9: 1368-1369; Exhibit B1-54).

Commission Findings

The Commission Panel accepts the method of calculating the IDC rate and finds that a threshold for the calculation of IDC is not required.

7.5 FRSR/ARO

BC Hydro is changing its accounting for costs associated with the retirement of capital assets in F2005 due to a change in GAAP.

Consistent with the requirements of Section 3060-Capital Assets of the CICA Handbook, BC Hydro accounted for asset retirement costs by creating a provision for future removal and site restoration, which is a liability on BC Hydro's balance sheet that increases every year until the asset is de-commissioned. The yearly increase to the liability account on the balance sheet is reflected as depreciation expense on the statement of operations. Actual de-commissioning costs are charged against the liability on the balance sheet as incurred (Exhibit B1-1, p. 2-18).

8.0 Reference: Project Costs
Exhibit B-7, BCUC 1.41.1 and 1.41.3
Identification, Definition and Early Implementation Costs

The original questions seeks identification of the "activities plus carrying costs" that make up the $87 million, shown by year for which the costs were incurred. Carrying cost may be shown separately. As referenced in various IR responses from Exhibit B-7, items that are expected to be identified are (but limited to) the following:

- RW Beck assessment in 2007 of $82,048 (ref: Exhibit B-7, BCUC 1.37.4)
- RW Beck assessment in 2010 of $44,427 (ref: Exhibit B-7, BCUC 1.37.4)
- B&V Report in ? of $95,540 (ref: Exhibit B-7, BCUC 1.51.0)
- Hemmera Report in ? of $266,005 (ref: Exhibit B-7, BCUC 1.51.0)
- Internal evaluations of Powerhouse in ? of ? as included in all EARs/CARs over last 15 years (ref: Exhibit B-7, BCUC 1.55.1)
- KCBL Evaluation in ? of $282,918 (ref: Exhibit B-7, BCUC 1.55.1)
- Pacific Liaicon report in ? of $18,337 (ref: Exhibit B-7, BCUC 1.58.1)
- Ruskin Dam promotional video in ? of $13,500 (ref: Exhibit B-7, BCUC 1.60.1)
- "Others"

(If the "other" activities and dollar values are not immediately available, then sum the EARs/CARs reports for the last 15 years or provide an order of magnitude estimate such that the Commission can understand the costs and timelines undertaken to plan and advance this Project.)

Please provide your response in the following format:

Sunk costs to July 2010:	up to F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012
Activity 1								
Activity 2								
…								
cumulative total							$39,472	
Incurred Aug-March 2011:								
Activity 1								
Activity 2...								
cumulative total							7,739	9,892
Overhead							1,270	1,623
IDC							1,347	2,741
TOTAL Definition and Early Implementation Costs by Fiscal Year by Activity							49,828	14,256

2.8.1 Please provide an itemized list of the Early Implementation Costs that relate to Right Abutment work.

RESPONSE:

The table below presents the Project Early Implementation phase costs that relate to the Right Abutment Work:

	Up to F2011 ($)	F2011 ($000)	F2012 ($000)
Engineering Detailed Design	0	670	599
Procurement (Contract Preparation)	0	25	55
Construction Planning	0	25	55
Environmental Management and Planning	0	20	33
Early Contractor Involvement (constructability review)	0	0	251
TOTAL Early Implementation Costs by Fiscal Year by Activity	0	740	993

8.0 Reference: Project Costs
Exhibit B-7, BCUC 1.41.1 and 1.41.3
Identification, Definition and Early Implementation Costs

The original questions seeks identification of the "activities plus carrying costs" that make up the $87 million, shown by year for which the costs were incurred. Carrying cost may be shown separately. As referenced in various IR responses from Exhibit B-7, items that are expected to be identified are (but limited to) the following:

- RW Beck assessment in 2007 of $82,048 (ref: Exhibit B-7, BCUC 1.37.4)
- RW Beck assessment in 2010 of $44,427 (ref: Exhibit B-7, BCUC 1.37.4)
- B&V Report in ? of $95,540 (ref: Exhibit B-7, BCUC 1.51.0)
- Hemmera Report in ? of $266,005 (ref: Exhibit B-7, BCUC 1.51.0)
- Internal evaluations of Powerhouse in ? of ? as included in all EARs/CARs over last 15 years (ref: Exhibit B-7, BCUC 1.55.1)
- KCBL Evaluation in ? of $282,918 (ref: Exhibit B-7, BCUC 1.55.1)
- Pacific Liaicon report in ? of $18,337 (ref: Exhibit B-7, BCUC 1.58.1)
- Ruskin Dam promotional video in ? of $13,500 (ref: Exhibit B-7, BCUC 1.60.1)
- "Others"

(If the "other" activities and dollar values are not immediately available, then sum the EARs/CARs reports for the last 15 years or provide an order of magnitude estimate such that the Commission can understand the costs and timelines undertaken to plan and advance this Project.)

Please provide your response in the following format:

Sunk costs to July 2010:	up to F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012
Activity 1								
Activity 2								
…								
cumulative total							$39,472	
Incurred Aug-March 2011:								
Activity 1								
Activity 2...								
cumulative total							7,739	9,892
Overhead							1,270	1,623
IDC							1,347	2,741
TOTAL Definition and Early Implementation Costs by Fiscal Year by Activity							49,828	14,256

2.8.2 Please provide an itemized list of the Early Implementation Costs that relate to Left Abutment work.

RESPONSE:

The table below presents the Project Early Implementation phase costs that relate to the Left Abutment Work:

	Up to F2011 ($)	F2011 ($)	F2012 ($000)
Engineering Detailed Design	**0**	**0**	**866**
Procurement (Contract Preparation)	**0**	**0**	**10 (see below)**
Construction Planning	**0**	**0**	
Environmental Management and Planning	**0**	**0**	
TOTAL Early Implementation Costs by Fiscal Year by Activity	**0**	**0**	**876**

The Left Abutment Work represents a small component of scope of the larger Powerhouse ancillaries contract and therefore Early Implementation phase segregated procurement, construction planning, and environmental costs are not available and are anticipated to be minor (less than $10,000).

9.0 Reference: Project Costs
Exhibit B-7, BCUC 1.42.1
Authorized Amount

BC Hydro states the "Authorized Amount is the P90 value plus Management Reserves" (emphasis added).

2.9.1 Please explain how the above statement can be true when both Table 2-4 and Table 2-5 of Exhibit B-1 clearly show that the Authorized Amount already includes $40 million of management reserves.

RESPONSE:

The above statement is true; the Authorized Amount is the P90 plus the Management Reserve of $40 million.

10.0 Reference: Project Costs
Exhibit B-7-1, BCUC 1.45.1 Confidential – 1.45.2
Exhibit B-7, BCUC 1.45.2
Contingencies and Loadings

2.10.1 The contingency on the Expected amount of $56 million is calculated prior to the addition of loadings. Given that BC Hydro explains "Contingency is built around the general uncertainties" (Exhibit B-7, BCUC 1.39.2), which implies that it may or may not be needed, please explain the need to include another $23.1 million of loadings on the contingency.

RESPONSE:

The Expected Amount contingency included in the cost estimate is treated as a direct cost item. Contingency is calculated on the direct costs and attracts loadings. If the contingency did not have loadings added, it would be understated.

10.0 Reference: Project Costs
Exhibit B-7-1, BCUC 1.45.1 Confidential – 1.45.2
Exhibit B-7, BCUC 1.45.2
Contingencies and Loadings

2.10.1.1 Is it implied that when the Project progresses and if the contingencies are not used, the associated loadings will also be avoided?

RESPONSE:

Correct. If the contingency is not used, the associated loadings would not be applied to the unused contingency.

10.0 Reference: Project Costs
Exhibit B-7-1, BCUC 1.45.1 Confidential – 1.45.2
Exhibit B-7, BCUC 1.45.2
Contingencies and Loadings

2.10.2 Please explain why $56 million is different than the value of the P50 contingency shown in BCUC Confidential 1.45.1?

RESPONSE:

The reconciliation between the Monte Carlo analysis submitted as Exhibit B-7-1, Confidential Attachment 1 to BC Hydro's response to BCUC IR 1.45.1 and the contingency shown in Table 2-4 of Exhibit B-1 is as follows:

	($ million)
Base contingency calculated in September 2010	**51.7**
Net adjustment from Pacific Liaicon Report	**2.4**
Contingency for the Switchyard	**1.9**
Total Contingency (Table 2-4)	**56.0**

Please also refer to BC Hydro's response to BCOAPO IR 2.4.1 for a discussion of the Pacific Liaicon Report.

10.0 Reference: Project Costs
Exhibit B-7-1, BCUC 1.45.1 Confidential – 1.45.2
Exhibit B-7, BCUC 1.45.2
Contingencies and Loadings

2.10.3 Please explain why $67 million is different than the value of the P90 contingency shown in BCUC Confidential 1.45.1?

RESPONSE:

The $67.1 million is the *incremental* contingency on the Authorized Amount. The $123.1 million is the *total* Authorized Amount contingency (which by definition includes Expected Amount contingency) with management reserves.

11.0 Reference: Project Costs
Exhibit B-7, BCUC 1.45.4
Contingencies and Loadings

2.11.1 The 7.8 percent for **Line B** in the revised Table 2-5 does not appear to accurately portray the percentage of contingency on the Expected Amount since the $56 million contingency is calculated prior to the addition of loadings. Shouldn't the calculation be shown as $56 million / $446.5 million (from BCUC 1.45.2) = 12.5 percent?

RESPONSE:

No. The calculation is labelled as "Percentage of Expected Amount" and is correctly shown.

12.0 Reference: Project Costs
Exhibit B-7, BCUC 1.40.1 Confidential
Project Cost Breakdown

2.12.1 Please provide the cost details as shown in the Table to BCUC 1.40.1 which includes contingencies on loadings. The Project cost totals should equal the Expected and Authorized amounts of $718.1 million and $856.9 million.

RESPONSE:

The table provided in Exhibit B-7-1, BC Hydro's Confidential response to BCUC IR 1.40.1 included direct and indirect construction costs, contingencies, and inflation. It did not include "contingencies on loadings," first because it did not include loadings at all, and second because contingencies are not applied to loadings: loadings are applied to contingencies. Contingencies are unidentifiable but expected[1] costs included in direct or indirect costs of construction, as applicable, and hence attract loadings for overhead and IDC.

BC Hydro has attached a table similar to that provided in the response to BCUC IR 1.40.1 with the difference that the table below includes overhead and IDC loadings as well as Management Reserve. This table is provided as Confidential Attachment 1 to this IR response.

As provided in section 42 of the B.C. *Administrative Tribunals Act* (ATA) and the BCUC's Confidential Filings Practice Directive, BC Hydro requests confidential treatment of Confidential Attachment 1 to this IR response on the basis that its disclosure will result in: 1) undue financial loss to BC Hydro and undue financial gain to contractors it will be negotiating with to undertake construction or to supply and install equipment; 2) significant prejudice to BC Hydro's competitive negotiation position with these contractors; and 3) BC Hydro has consistently treated the commercial and financial information contained in this IR response on a confidential basis.

BC Hydro has aggregated this information for public disclosure on the public version of this IR response to avoid disclosing the expected costs of identifiable segments of Project work.

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1 "*Contingency – An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, and/or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs."* Association for the Advancement of Cost Engineering International; Recommended Practice No. 10S-90. A contingency is expected to be expended on items that cannot be identified in advance, but are likely to occur (with varying degrees of confidence) over the course of the project.

									Total	
Costs in $ millions	F2012[1]	F2012	F2013	F2014	F2015	F2016	F2017	F2018	**Expect.**	**Auth.**
General, Mob / Demob, and Taxes		0.11	3.03	2.45	2.45	2.24	1.86	0.27	12.40	12.40
Right Abutment										
Rebuild Spillway Piers										
Replace Spillway Gates & Hoists		1.83	13.43	15.68	16.02	20.52	16.31	1.95	85.73	85.73
Bridge										
Spillway Resurfacing										
Powerhouse Superstructure Upgrades										
Powerhouse Substructure Upgrades										
Powerhouse Crane, Access Bridge, Monorail										
Powerhouse Controls and Ancillary Equipment		3.00	25.47	39.24	49.76	44.22	29.66	10.12	201.46	201.46
Turbines & Generators										
Direct Supply (transformers, exciters, etc)										
Switchyard Construction										
Construction Management		0.82	4.64	4.62	4.64	4.64	4.64	1.55	25.56	25.56
		5.75	46.58	61.99	72.86	71.62	52.47	13.88	325.16	325.16
Project Management and Engineering		10.17	4.74	4.96	4.96	5.29	5.75	4.47	40.33	40.33
Indirect Construction Costs		0.49	2.76	2.76	2.76	2.79	2.77	0.35	14.68	14.68
		16.41	54.08	69.72	80.58	79.71	60.99	18.70	380.17	380.17
Contingency - Expected		1.81	10.19	10.19	10.17	10.30	11.09	2.19	55.94	55.94
Incremental Contingency - Authorized		2.18	12.26	12.25	12.23	12.38	13.28	2.57		67.15
Demolition				1.58	2.71	2.71	2.71	0.67	10.37	10.37
Inflation - Expected		0.60	2.94	5.50	8.45	10.49	10.17	3.23	41.37	41.37

1 Includes Prior periods.

									Total	
Costs in $ millions	F2012[1]	F2012	F2013	F2014	F2015	F2016	F2017	F2018	**Expect.**	**Auth.**
Incremental Inflation - Authorized		0.07	0.56	0.83	1.11	1.41	1.82	0.38		6.17
Overhead – Expected		3.09	11.03	14.00	16.24	16.41	13.14	3.64	77.55	77.55
Incremental Overhead – Authorized		0.37	2.10	2.15	2.19	2.26	2.43	0.44		11.94
IDC Expected		0.14	3.31	8.35	14.39	18.34	17.54	3.56	65.64	65.64
Incremental IDC – Authorized		0.02	0.56	1.50	2.47	3.51	4.67	0.91		13.64
Management Reserve								40.00		
Implementation Phase Costs		24.67	97.03	126.07	150.53	157.52	137.83	76.29	631.04	769.95
Identification and Definition Phases (loaded ex. IDC)	48.48	11.51							60.00	60.00
IDC on Identification and Definition Phases	1.35	2.74	3.34	3.85	4.08	4.31	4.55	2.78	718.04	856.94
	49.83	20.99	79.47	99.24	114.14	115.58	98.24	27.35	487.86	561.18

12.0 Reference: Project Costs
Exhibit B-7, BCUC 1.40.1 Confidential
Project Cost Breakdown

2.12.2 Please confirm that all the direct constructions costs in the Table to BCUC 1.40.1 are loaded figures.

RESPONSE:

The Total Direct Construction Costs shown in the Table provided in the Confidential Attachment 1 to BC Hydro's response to BCUC IR 1.40.1, Exhibit B-7-1, are not loaded. The request in BCUC IR 1.40.1 was for "Total Direct Construction Cost", which is unloaded by definition.

13.0 Reference: Project Costs
Exhibit B-7, BCUC 1.46.2
Management Reserve

"Conditions during actual construction may materially vary from the conditions encountered during the geotechnical investigations..."

2.13.1 On Table 5-1 in Exhibit B-1, BC Hydro indicates that contingencies are already designed to mitigate "schedule delays due to unforeseen geotechnical findings" (Chapter 5, page 20). Does BC Hydro anticipate substantial variance in geotechnical conditions that wouldn't already be covered under the contingency figures? Please explain and further justify the management reserve based on the discussions.

RESPONSE:

BC Hydro does not anticipate a geotechnical variation beyond what has been allowed for in its base contingency. If BC Hydro anticipated a large geotechnical variation, BC Hydro would have addressed the risk with its contingency. The Management Reserve addresses in part unanticipated geotechnical variations on the Right Abutment.

BC Hydro has a history of successfully completing many complex geotechnical projects such as the W.A.C. Bennett Dam and Mica Dam. On some of these projects, despite extensive geotechnical investigations, unknown (latent) geotechnical issues arose that had an impact on the cost and schedule of those projects. The Management Reserve on the Project is for the event that an unknown geotechnical issue is encountered during the course of construction.

The purpose of the Management Reserve is to mitigate the risk of BC Hydro requiring additional funds to deal with construction risk that was greater than the known geotechnical information at the time the cost estimate was prepared.

Please also refer to Exhibit B-7-2, BC Hydro's response to CECBC IR 1.21.1 with respect to the soil sampling that has occurred at the Right Abutment.

14.0 Reference: Project Costs
Exhibit B-7, BCUC 1.58.2 - 1.58.3
Provisional Sums

"(P)rovisional sums are attached to <u>known</u> and <u>expected</u> items of work." [emphasis added]

"BC Hydro uses provisional sums (cash allowances), for work which is <u>difficult</u> or <u>impossible to define</u>…" [emphasis added]

"Additionally, provisional sums are included for scopes of work that have not been defined…"

2.14.1 Please explain how an item of work can be both "known and expected" yet "difficult / impossible to define" at the same time?

RESPONSE:

The issue of known but indefinable work items can arise on renovation or rehabilitation work. Some examples of known but indefinable scopes of work are outlined below:

- **Integrating new equipment with old equipment, such as fitting a new runner to an old shaft. The components will have to be machined to fit together properly, but it is impossible to estimate how much machining will be required until the two components are matched up at site.**
- **The presence of lead paint on a particular surface or component that is to be retained. It is hard to quantify how thick the paint will be, how difficult it will be to remove, or the exact method of containment until the unit is taken out of service and disassembled.**
- **For underwater work, such as anchoring the intake tower inverts, it is impossible to determine the condition of the concrete to verify the design of the anchor prior to actually drilling the holes for the anchor for the following reasons:**
  - **The units are running to meet the current system requirements;**
  - **The intake inverts are nearly 60 feet below the normal reservoir operating level making inspection and testing of the subsurface prior to construction difficult; and**

  - **Drawdown to investigate the inverts is not practical and will have a high financial cost and environmental impacts.**

- **Draft Tube repairs are another known and partially defined scope.**
  BC Hydro has investigated both the Moody Cones and the Unit 3 Draft Tube and determined a preliminary scope of work. However, up to four more years of unit operation will have occurred from the time the inspection took place and the time of repair. The additional damage done during this period of operation is indefinable, but is likely to occur. In addition, it is likely that more damage will be uncovered once the demolition commences.

- **Drilling into an existing structure such as anchoring the new piers to the existing spillway crest. The exact location of the original rebar is not known and cannot be known until the drilling is started. If there is more rebar or are unfavorable splice locations significant extra drilling will be required. Therefore the absolute quantity of drilling is not definable with any degree of certainty in advance of the work taking place.**

14.0 Reference: Project Costs
Exhibit B-7, BCUC 1.58.2 - 1.58.3
Provisional Sums

"(P)rovisional sums are attached to known and expected items of work." [emphasis added]

"BC Hydro uses provisional sums (cash allowances), for work which is difficult or impossible to define…" [emphasis added]

"Additionally, provisional sums are included for scopes of work that have not been defined…"

2.14.2 By identifying "known and expected" items of work, it signifies that the scope of work is being defined. Please explain how the first and last statements quoted in the preamble could both be true.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.14.1.

14.0 Reference: Project Costs
Exhibit B-7, BCUC 1.58.2 - 1.58.3
Provisional Sums

"(P)rovisional sums are attached to known and expected items of work." [emphasis added]

"BC Hydro uses provisional sums (cash allowances), for work which is difficult or impossible to define…" [emphasis added]

"Additionally, provisional sums are included for scopes of work that have not been defined…"

2.14.3 Please confirm that the total provisional sum included in the contractor estimate is $22.1 million.

RESPONSE:

The total amount of provisional sums listed in Exhibit B-7, BC Hydro's response to BCUC IR 1.58.3 is $22.1 million. The provisional sums are BC Hydro's estimate, not a contractor's estimate.

15.0 Reference: Project Costs
Exhibit B-7, BCUC 1.58.5
Provisional Sums

"At the completion of the construction contract, provisional sums not used would be to BC Hydro's benefit, not the contractor's."

2.15.1 If this project was approved which includes the provisional sums, and it turns out that the provisional sums were not used, please explain why this benefit should not accrue to ratepayers?

RESPONSE:

Exhibit B-7, BC Hydro's response to BCUC IR 1.58.5 should have said "…provisional sums not used would be to BC Hydro <u>and its ratepayers benefit</u>, …". Any amount not spent by BC Hydro would not be recovered in rates.

15.0 Reference: Project Costs
Exhibit B-7, BCUC 1.58.5
Provisional Sums

"At the completion of the construction contract, provisional sums not used would be to BC Hydro's benefit, not the contractor's."

2.15.2 If the unused portion of the provisional sums constantly creates an accrued benefit to BC Hydro, then what incentive does BC Hydro have to ensure that contractor costs are reasonable and prudent?

RESPONSE:

Any unused portion of the provisional sums or other contract items would not create an accrued benefit to BC Hydro.

BC Hydro processes and procedures require approvals for contract changes. Use of a provisional sum account results in a contract change and therefore requires a due diligence review by BC Hydro of the need for the work and the contractor proposed scope, cost and schedule to perform the work before a contract change order can be issued.

15.0 Reference: Project Costs
Exhibit B-7, BCUC 1.58.5
Provisional Sums

"At the completion of the construction contract, provisional sums not used would be to BC Hydro's benefit, not the contractor's."

2.15.3 What is the portion of provisional sums as a percentage of total contractor costs?

RESPONSE:

The $22.1 million of assigned provisional sums represent about 6.8 per cent of the total direct construction cost of $325.2 million.

15.0 Reference: Project Costs
Exhibit B-7, BCUC 1.58.5
Provisional Sums

"If work identified as provisional or alternate is uncovered during the course of construction, the BC Hydro construction management team negotiates equitable compensation to the contractor drawing down the value of the provisional sums."

2.15.4 Please explain what happens if the provisional sums are unable to cover the additional costs. Will these items then be covered under contingencies?

RESPONSE:

Yes. If the provisional sums are not sufficient to cover the cost of the additional work associated with the provisional item, contingency will be required to make up the shortfall.

16.0 Reference: Project Need
Exhibit B-1, Section 3

2.16.1 Please provide an unredacted copy of all of the Project's final approved Business Case's (EAR - Expenditure Authorization Request) attachments supporting the justification, evaluation of alternatives and preferred/recommended/selected options and costs.

RESPONSE:

BC Hydro's final approved Business Case is the Ruskin Dam and Powerhouse Upgrade Project Application for a Certificate of Public Convenience and Necessity. This document contains the supporting justification, evaluation of alternatives and preferred/recommended/selected options and costs. Please also refer to Exhibit B-7, BC Hydro's response to BCUC IR 1.97.0, Attachment 3 for a copy of the Expenditure Authorization Request.

17.0 Reference: Project Description and Impacts
Exhibit B-7, BCUC 1.5.1.1, p. 1
Ruskin Facility Products

2.17.1 For greater clarity the IR was aimed at adding synch condense facilities to the replacement generators, not for a stand-alone unit. Please provide an order of magnitude cost estimate to add this option (possible blow down facilities, air receiver(s), controls and valves/piping etc.) whether or not there is a requirement. Note a response of "BC Hydro has not developed a cost estimate" is not an acceptable response.

RESPONSE:

BC Hydro determined that synch-condense capability would not provide benefit to the local Lower Mainland (LM) 69 kilovolt (kV) Network. As set out in section 2.1.3 of Exhibit B-1 the Ruskin Facility currently provides, and post Project will continue to provide, Volt-ampere reactive (VAr) support. Synchronous condense capability will not enhance this capability.

Nevertheless, BC Hydro provided a high level (+100 per cent/-50 per cent) order of magnitude cost estimate as follows:

- **Provide sync-condense capability when tailrace is below runner (Tailrace level below elevation 5.5 m): $200,000/unit,**

- **Provide sync-condense capability even during freshet (tailrace level up to elevation 5.5 m): $430,000/unit,**

- **Provide sync-condense capability even during Probable Maximum Flood (PMF)(tailrace level elevation at elevation 10.0 m): $730,000/unit.**

All of these costs are direct and do not include owner's costs such as project management, environmental management, etc. nor to these costs include loadings i.e., capital overhead, contingency, etc. The above three scenarios exist given the high variability in the Ruskin Facility tailrace level.

17.0 Reference: Project Description and Impacts
Exhibit B-7, BCUC 1.5.1.1, p. 1
Ruskin Facility Products

2.17.1.1 Given that BGS will contribute little if any voltage support to the Lower Mainland grid could there be a future need of increased Var support from the RUS 69kV system.

RESPONSE:

The IR premise is not correct with respect to Burrard Thermal Generating Station's (Burrard) contribution of voltage support. Pursuant to section 13(b) of the *Clean Energy Act* (CEA), BC Hydro can operate Burrard to "provide transmission support services" which includes voltage support. Burrard provides effective voltage support to the local LM Transmission Network because it is located close to Meridian Substation, a major 500 kV substation.

As set out in section 2.1.3 of Exhibit B-1, the Ruskin Facility currently provides VAr support to the local LM 69 kV Transmission Network and the local distribution system. The Powerhouse Work is necessary to allow the Ruskin Facility to continue to provide the current level of VAr support. Please refer to BC Hydro's response to Association of Major Power Customers (AMPC) IR 2.9.4. Increased VAr support at the Ruskin Facility would provide only marginal benefit to either the local 69 kV Transmission Network or distribution system.

However, the Ruskin Facility cannot effectively provide the VAr support to the LM 230 kV and 500 kV Transmission Network because the local LM 69 kV Transmission Network has high impedances compared to the LM 230 kV and 500 kV Transmission Network impedances, and it is not effective to transfer reactive power in this case.

Please also refer to BC Hydro's response to CECBC IR 2.1.1.

18.0 Reference: Synchronous Condense Operation
Exhibit B-7, BCUC 1.5.1
Exhibit B-7, BCUC 1.55.2, PUBLIC Attachment 2, page 28 of 88

"The existing three Ruskin Facility 43.75 megavolt amps (MVA) 80 per cent lagging power factor (PF) generators are able to meet the voltage support requirement and maintain the local area voltage profile. The new generators proposed as part of the Project have comparable parameters and would provide a similar level of voltage support as the existing Ruskin Facility. Adding synchronous condense facilities to the replacement generators is not required for local voltage support."

"However, the benefits of synchronous condenser operation all accrue to BCTC – there is no benefit to BC Hydro. For that reason, synchronous condenser operation has been abandoned as an alternative at this point. If BCTC desires such operation, and is willing to fund the costs, this item could be analyzed during the Definition Phase. Synchronous condensing equipment will not be included in the construction cost estimate at this time."

2.18.1 Please provide any review by BCTC or the transmission group of BC Hydro that demonstrates the examination of adding synchronous condense facilities at Ruskin.

RESPONSE:

The transmission planning group has reviewed the replacement of the generators at the Ruskin Facility although no report has been issued. The existing three Ruskin Facility 43.75 megavolt amps (MVA) 80 per cent lagging power factor (PF) generators are able to provide adequate local reactive VAr support. The new replacement generators would have comparable electrical parameters and provide a similar level of reactive VAr support. Therefore, adding synchronous condense facilities to the replacement generators is not required.

19.0 Reference: Project Description and Impacts
Exhibit B-7, BCUC 1.5.1.3, p. 1
Ruskin Facility Products

2.19.1 The response did not address if increasing the height of the rotor poles was an option. The total weight may not necessarily increase due to design optimization of a possible smaller air gap, using modern steel capable of higher magnetic flux density, lower weight and thickness of modern insulation allowing more turns per pole. To repeat, please provide an order of magnitude cost and note a response of "BC Hydro has not developed a cost estimate" is not an acceptable response as a budgetary quote should be available from a reputable supplier in short order if BC Hydro staff cannot provide an estimate.

RESPONSE:

Given the existing water passages and available head, BC Hydro estimates the maximum capacity of the generating units to be 44 MW. While it is not possible to increase the generator diameter (refer to Exhibit B-7, BC Hydro's response to BCUC IR 1.5.1.3), it would be possible to increase the generator height. However, the resulting generator would not be matched to the proposed turbine. The turbine capacity is determined by existing water passages and the hydraulic resources at Ruskin Facility. The new generators are assumed to have a rating of 50 MVA and the new plant power factor is assumed to be 0.85. The intended upgraded generator output in its current dimensions is already higher than the proposed turbine output.

There are no benefits to building a generator with a greater capacity than the turbine, but there would be increased costs. Accordingly BC Hydro has not provided the requested cost estimate because BC Hydro respectfully submits that the requested cost estimate is not relevant and cannot assist the BCUC with respect to its decision of whether to issue or deny a CPCN for the Project. It is BC Hydro's expectation that to prepare such an estimate would be in the order of three to four weeks and would require confirmation from generator suppliers. In addition, BC Hydro currently has a Request for Proposal to provide turbines and generators open for public bid. BC Hydro respectfully submits that it would be inappropriate to request a manufacturer to provide such a cost.

19.0 Reference: Project Description and Impacts
Exhibit B-7, BCUC 1.5.1.3, p. 1
Ruskin Facility Products

2.19.1.1 What is the MVA and power factor of the replacement generators under consideration and what is the largest MW rating possible from the new turbines and existing water passage constraints?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.19.1.

20.0 Reference: Project Description and Impacts
Exhibit B-7, BCUC 1.6.1, pp. 1-2
Procurement Strategy

2.20.1 Could the DBO contract be written such that the contractor is responsible to replace all existing equipment and assume responsibility for the entire facility, thereby eliminating the conflicting interests and integration with existing components arguments stated in the response? Please discuss.

RESPONSE:

As set out in Exhibit B-7, BC Hydro's response to BCUC IR 1.6.1, it is doubtful that a third party contractor could operate a Heritage Asset such as the Ruskin Facility given the prohibition contained in section 14 of the CEA. BC Hydro also notes that it would not be rational to have a third party operate the Ruskin Facility because it is operated as part of the integrated cascading Stave River System. The result could be potential conflicts and inefficiencies where a third party is operating the Ruskin Facility and BC Hydro is operating the remaining Stave River System.

Nevertheless, if a contractor or supplier was engaged on this basis it would put them in the position of assuming all or most of the risks involved in the design, construction, and operation of a hydroelectric facility, but without the guaranteed return allowed to a public utility. In essence, this suggestion simply replaces BC Hydro as the operator of the facility with the contractor or supplier. Since that supplier does not have the diversified generation portfolio, customer base, or access to the transmission and distribution assets of an integrated utility, they are of necessity a higher-risk operation. A higher risk implies a higher cost of capital, which in turn creates a higher cost to the ultimate purchasers of the energy.

20.0 Reference: Project Description and Impacts
Exhibit B-7, BCUC 1.6.1, pp. 1-2
Procurement Strategy

2.20.2 The original IR stated "where BC Hydro would retain ownership"- it did not contemplate any transfer of ownership. The risks to either party could be spelled out and agreed upon in a contract and the appropriate area "roped off" during construction or alternatively BC Hydro could accept a loss of some or all of the $20 million/year revenue by transferring the entire Powerhouse facility to the contractor during construction. Putting BC Hydro's preference aside (and any reference to an EPA in the original IR), would this option lower the overall cost of the Project? Please discuss further and provide a range of possible cost savings. **Note**: the argument stating Section 14 of the CEA may also rule out third party operation is understood and "BC Hydro has not developed a cost estimate" is not considered an adequate response.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.20.1 for a discussion of why this is not considered a viable contracting strategy.

21.0 Reference: Project Justification
Exhibit B-7, BCUC 1.8.1, pp. 1-5
Switchyard Work

2.21.1 Please comment on the viability and pros and cons of installing the Compressed Gas Insulated Switchgear (CGIS) in the former station service bay location which is now occupied by storage and/or a workshop. The response should confirm the estimated order of magnitude costs of $4.4 million more than the Authorized amount.

RESPONSE:

BC Hydro assumes the room being described in this IR is the main floor of the North wing (at elevation 14.55 m). While currently being used as storage space, the room still houses the existing temporary station service.

In the ultimate configuration of the Powerhouse, this space will house both the final station service and low side circuit breakers for each generating unit. The central passage between each of the two tall roll-up doors on opposite walls of this space is required to provide convenient access to service the Unit 3 transformers. Site staff has a desire to maintain some storage or equipment staging in this room as it provides a convenient area to house equipment at the main entry level of the powerhouse building. Given these intended uses for the room, BC Hydro had determined that other facilities could not be included in this space, including installing compressed gas insulated switchgear (GIS).

The order of magnitude cost of $4.4 million more than the Authorized Amount referenced in Exhibit B-7, BC Hydro's response to BCUC IR 1.8.1 would likely be similar for the GIS- related hypothetical posed by this IR.

21.0 Reference: Project Justification
Exhibit B-7, BCUC 1.8.1, pp. 1-5
Switchyard Work

2.21.1.1 Please identify if any other location would be suitable for the CGIS switchgear/bus.

RESPONSE:

Most possible locations for a conventional air insulated switchyard would be suitable for a GIS switchyard. However, a GIS switchyard is more expensive than an air insulated switchyard. This increased cost is only warranted where site constraints preclude the use of air insulated equipment. These conditions do not exist at the Ruskin Facility, and accordingly, the cost-effective option of an air insulated switchyard has been chosen.

21.0 Reference: Project Justification
Exhibit B-7, BCUC 1.8.1, pp. 1-5
Switchyard Work

2.21.1.2 Please identify the order of magnitude in First Nations accommodation avoided costs that would result from installing the CGIS within the existing footprint of the powerhouse.

RESPONSE:

As set out in Exhibit B-7, BC Hydro's response to BCUC IR 1.8.1, installing a compact GIS switchyard within the Powerhouse footprint entails leaving the Switchyard on the Powerhouse roof (Option 2). Option 2 is not a feasible solution for the reasons set out in that IR response and therefore would not be undertaken by BC Hydro.

It is difficult to estimate what, if any, accommodation-related costs would be avoided if the Switchyard were not relocated. BC Hydro is proposing the Switchyard Work, which entails moving the Switchyard from the Powerhouse to an area near the Powerhouse on land owned by BC Hydro. There is a minimal footprint increase of approximately 50 m x 100 m on previously disturbed land with no evidence of species at risk that could theoretically be avoided by Option 2. In addition, the proposed location of the Switchyard has been modified to avoid known archaeological sites and resources. Finally, there may be environmental benefits associated with relocating the Switchyard such as anticipated beneficial effects on vegetation by reducing and controlling invasive weed species, and reduction in Great Blue Heron mortalities; refer to Exhibit B-1, page 5-16, lines 23 to 28.

In any event, as explained in BC Hydro's response to Confidential BCUC IR 2.2.1, the focus in producing an Impact Benefits Agreement (IBA) cost estimate is on producing an overall cost estimate. The estimate prepared and filed with the BCUC as Exhibit B-7-1, BC Hydro's confidential response to BCUC IR 1.14.5 is not broken down between specific Project-related environmental impacts.

21.0 Reference: Project Justification
Exhibit B-7, BCUC 1.8.1, pp. 1-5
Switchyard Work

2.21.1.3 Please comment if the five 69 kV line terminals could remain on the powerhouse roof or would still have (as opposed to desirable) to be relocated to the proposed new location or elsewhere.

RESPONSE:

To meet WorkSafeBC's Limits of Approach (LOA) requirements, the 69 kV line terminals and disconnects should be relocated from the Powerhouse roof or would entail redesign to permit retention on the Powerhouse roof. Please refer to Exhibit B-7, BC Hydro's response to BCUC IR 1.8.1 for the reasons why BC Hydro has rejected undertaking the Switchyard Work on the Powerhouse roof.

22.0 Reference: Switchyard Requirements
Exhibit B-7, BCUC 1.8.1

"As a result of the restricted space and configuration of the Switchyard, it is unavoidable to be no more than 3 m away from un-insulated 69 kV equipment when walking on the Powerhouse roof. This distance is within the LOA for unqualified electrical workers and accordingly, these workers cannot enter onto or perform work on the Powerhouse roof without either the supervision of qualified electrical workers or a suitable facility outage."

2.22.1 Please describe if it is possible to cordon off access on the Powerhouse roof or put physical barriers in place such that unqualified workers are unable to physically access un-insulated 69 kV equipment. If such physical barriers were put in place, please describe the frequency and amount of remaining activities on the Powerhouse roof after the Project that would continue to put unqualified workers within the Limits of Approach without a physical barrier in place.

RESPONSE:

It is not possible to cordon off access to the Powerhouse roof with physical barriers to prevent an unqualified worker from coming within their LOA for the 69 kV equipment. Upon entry onto the Powerhouse roof, a worker is immediately within the LOA for an unqualified worker. In addition, an unqualified worker walking around the perimeter of the switchyard (following the roof parapet) will come within LOA for various circuit breaker disconnect switches.

23.0 Reference: Project Justification
Exhibit B-1, Appendix H-4, Section 4.3.1, p. 29

"Optional construction of a 2 room structure, to serve as a satellite control room, against the north side of the powerhouse, at the west (access bridge) end."

2.23.1 Please confirm that this option is not in the Project scope and discuss why not.

RESPONSE:

Confirmed, the satellite control room is not part of the current Project scope.

During the Identification and early Definition phases of the Project, BC Hydro investigated alternatives to the current control room to improve worker safety. Since there was not sufficient space on the North West side to build a complete control room which could house all of BC Hydro's standard control equipment, a secondary "satellite" control room was considered and eliminated from the Project scope for the following reasons:

1. **The satellite control room results in redundant maintenance requirement for control equipment.**

2. **The proposed external fire escape and egress corridor past the transformers will provide a safe means of entry to the existing control room during a plant emergency without the need to enter the Powerhouse generating hall or walk close to the transformers.**

3. **Given that the Ruskin Facility is considered to be an "un-manned" powerhouse, the secondary satellite control room was deemed an unnecessary cost.**

24.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, BCUC 1.25.2, Attachment 1, p. 3
Periodic Payments over Time

"The Impact Benefit Agreements BC Hydro is prepared to negotiate are not required by or limited to the Crown's duty to consult and accommodate."

2.24.1 Are these IBA's funded by the Shareholder or by ratepayers?

RESPONSE:

As set out in BC Hydro's response to BCUC IR 2.1.1, the estimate provided in Exhibit B-7-1, Confidential Attachment 1 to BC Hydro's response to BCUC IR 1.14.5 is an estimate of total First Nation IBA-related costs, and as such encompasses more than accommodation-related costs. For example:

- **Such an IBA would also address legal risks such as the legal risks set out in Exhibit B-7, BC Hydro's response to BCUC IR 1.32.1, and thereby provide regulatory certainty for the Project. Exhibit B-7, Attachment 1 to BC Hydro's response to BCUC IR 1.25.2 states: "… benefits may be set out in benefit agreements between BC Hydro and the First Nation, providing certainty to First Nations of project-related benefits, and legal and regulatory certainty for BC Hydro on specific projects"; and**

- **Such an IBA could also strengthen First Nation-BC Hydro relationships. Exhibit B-7, Attachment 1 to BC Hydro's response to BCUC IR 1.25.2 states: "Often, BC Hydro provides benefits to First Nations that not only accommodate residual impacts, but also help to provide for long-term benefits to First Nations, to strengthen the working relationship between BC Hydro and First Nations, and to contribute to community development opportunities".**

Accordingly, BC Hydro views the cost of IBAs associated with the Project to be ratepayer costs because they are directly related to Project implementation.

IBA costs would be included in the capital cost of the Project and would be recovered through depreciation. BC Hydro seeks to recover such costs through RRA proceedings.

24.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, BCUC 1.25.2, Attachment 1, p. 3
Periodic Payments over Time

"The Impact Benefit Agreements BC Hydro is prepared to negotiate are not required by or limited to the Crown's duty to consult and accommodate."

2.24.1.1 If funded by ratepayers, what is BC Hydro's position in respect to obtaining the Commission's approval for recovery of these expenditures in rates?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.24.1.

25.0 Reference: Project Costs
Exhibit B-7, BCUC 1.44.1, p. 1
Contingencies and Risks
Exhibit B-1, Section 3.4.1, p. 44
New verses Rehabilitate/Replace
Exhibit B-7, BCUC 1.54.1, p. 1
Evaluation of Alternatives
Exhibit B-7, BCUC 1.93.1, Attachment 3, pp. 44, 67
Background to Alternatives

"BC Hydro cannot feasibly implement the Project two, three or five years faster than has been proposed".

"In 2005, BC Hydro initially explored two options: (1) Rehabilitating/replacing the existing Powerhouse; and (2) Building a new powerhouse at the existing Powerhouse site. BC Hydro concluded in 2005 that building a new powerhouse at the existing site was approximately $109 million more costly (+50 per cent to -25 per cent cost estimate accuracy) than rehabilitating/replacing the existing Powerhouse."

"The Project…is challenging because it is a rehabilitation of an existing facility; has…small work space with live operating equipment…..must deal with some unknown Powerhouse equipment conditions….requires the operation of the facility …to maintain continuity of flow."

"The least critical construction sequence will be with four old gates available and all six bulkhead gates unobstructed by the old piers. The combined discharge capacity at that time, and with reservoir at El. 44 m (emphasis added), is estimated to be about 2815 m3/s (2175 m3/s through spillway gates, and 640 m3/s through bulkhead vertical lift gates). This corresponds to a return period of about 1000 years for hourly inflow.

The above estimates were derived with the assumption that discharge through the three Ruskin units (up to about 116 m3/s each) would not be available (emphasis added)."

"For Option 3 (auto-spill), as soon as the Ruskin Powerhouse becomes unable to provide discharge required to maintain the minimum tailwater level, a spillway gate would be automatically activated to spill at the required rate. Note that this option will be effective only when the reservoir level is above spillway crest elevation.

The auto-spill option applied to Spillway Gate #5 (or gates 1 *and* 5), is judged to be the preferred option for the following reasons:

1. Significantly lower cost than the >$10M for all other options

2. Acceptable Total Gas Pressure (TGP) performance (emphasis added)
3. Comparable or better reliability than options 1 or 2
4. Negligible incremental life safety risks in the proposed range and mode of operation

Some key considerations include:

These facilities would only be required to function under emergency conditions (full powerhouse outage).

Powerhouse by-pass and submerged LLO solutions likely offer the potential for minor improvements to TGP performance over the preferred option (emphasis added)."

2.25.1 Did BC Hydro thoroughly consider the total economic tradeoffs between Option 1 and Option2 [(1) Rehabilitating/replacing the existing Powerhouse; and (2) Building a new powerhouse at the existing Powerhouse site] as it would appear that Option 1 has significantly more unknowns thus requiring a $178 million contingency whereas Option 2 appears to cost $109 million more over the unloaded base case of Option1? On the surface it would appear that Option 1 may have been chosen before the loaded contingencies were added. Please provide the total loaded cost estimates for Option 1 and Option 2. To put it another way, the strategy of attempting to re-use as many old components as possible may end up costing more considering the added complexity and the time value of money.

RESPONSE:

Yes, BC Hydro thoroughly considered the economic and other trade-offs between Option 1 (undertaking the Powerhouse Work as proposed) and Option 2 (complete demolition and removal of the existing powerhouse, followed by construction of a new powerhouse at the same location with three units with a total nameplate capacity of 105 MW). The remainder of this IR response is structured as follows:

- **Part 1 confirms that the 2005 cost estimates for both Option 1 and Option 2 are loaded;**

- **Part 2 explains why Option 2 is not a feasible alternative means of carrying out the Powerhouse Work;**

- **Part 3 explains why BC Hydro respectfully declines to provide the requested cost estimate information for Option 2 given that Option 2 is not**

feasible and developing the cost estimate would take a minimum of six months to complete.

Part 1 – 2005 Cost Estimate

The 2005 cost estimates are loaded:

	($ million)
Option 2 (loaded)	**272.5**
Option 1 (loaded)	**164.0**
Difference	**108.5**

Please refer to the BC Hydro memo entitled "Ruskin G.S. Cost Estimates for 'Rehabilitation of Existing Powerhouse' and 'Rebuild New Powerhouse on Existing Location' " dated January 12, 2006, provided as Attachment 1 to this IR response.

Based on the cost difference in 2005, BC Hydro rejected Option 2. Option 2 was revisited in 2007, at which time KCBL took the 2005 cost estimate for Option 2 referred in this IR and revised it. KCBL concluded that Option 2 "would likely cost at least $126 million (including contingency, corporate overhead and IDC) more than" Option 1, that is $329 million vs. $213 million ($2007); refer to the KCBL Report, pages 8 and 9 of 37. Again, based on the cost difference between Option 1 and Option 2, BC Hydro rejected Option 2.

Part 2 – Option 2 Not Feasible

BC Hydro does not consider Option 2 to be a feasible option. Among other permitting requirements, Option 2 would trigger both the need for a *Fisheries Act* Authorization and the *Canadian Environmental Assessment Act* (CEAA). Fisheries and Oceans Canada (DFO) would be the CEAA Responsible Authority. DFO can review alternative means of carrying out the project under subsection 16(1)(e) of CEAA, and BC Hydro expects that DFO would reject Option 2 under section 20 of CEAA given that there is a feasible alternative – namely Option 1 (undertaking the Powerhouse Work as proposed) – which will not cause significant adverse environmental effects (no harmful alternation, disruption or destruction of fish habitat (referred to as HADD)):

- **As set out at page 5 of 37 of the Klohn Crippen Berger Ltd. report (KCBL Report) provided at Exhibit B-7, Attachment 1 to BC Hydro's response to BCUC IR 1.2.1, implementing Option 2 would require that the powerhouse be off-line for the complete removal and reconstruction of the powerhouse, and other buildings and foundations as required. The powerhouse would likely be off-line for multiple periods. Given that approximately 100 m^3/s is**

required to maintain downstream water levels to prevent impact to aquatic habitat, pumping is an impractical and expensive option. Similarly, careful staging of the units for refurbishment would still require some periods of full plant outages given constraints with the extremely close proximity of U1 and U2 to each other and the higher intake on U3. Spilling would remain the only viable option during portions of the construction period to maintain downstream flow, which would have environmental effects – including causing HADD - that could be avoided by Option 1;

- **As set out at page 6 of 37 of the KCBL Report, Option 2 would also require use of a cofferdam to isolate the work area so that it can be pumped dry for the demolition and new construction. A modern draft tube would project about 8 m further downstream than the Moody cone draft tubes in the existing powerhouse. The cofferdam would have to be constructed far enough downstream to allow for the projection of the draft tube and provide construction access. This would cause HADD over a large area.**

Even if it is assumed that Option 2 would pass CEAA review and that a *Fisheries Act Authorization* would issue, there are "significant unknowns" with respect to Option 2:

- **Additional Regulatory Risk - There is a risk that Option 2 would trigger the B.C. *Environmental Assessment Act* (BCEAA) on the basis that BC Hydro is no longer modifying an existing facility, but is constructing a new facility. Option 1 does not trigger BCEAA;**

- **Additional First Nation Consultation and Public Engagement Risk - There would be significant unknowns in terms of First Nation consultation and public engagement, given that Option 2 will cause greater environmental effects than Option 1, which in turn raises the issue of what, if any, mitigation measures would be acceptable;**

- **Additional Engineering Uncertainty – There are a number of engineering challenges associated with implanting a configuration that is different from the proposed Project scope. With respect to Option 2, the engineering challenges include but are not limited to the coffer dam, tunnels, and powerhouse configuration given penstock location constraints. For example, design of a modern draft tube would require a deeper excavation with preference to a longer downstream passage. The limited detail on the bedrock condition would create challenges for a deeper draft tube, and a longer draft tube would entail a larger building footprint.**

Part 3 – Reasons for not providing requested Option 2 cost estimate

BC Hydro is not providing the requested cost estimate for the following two reasons:

- **As set out in Part 2 of this response Option 2 is not feasible because, in BC Hydro's view, DFO will not grant a *Fisheries Act* Authorization and will not give a favourable CEAA decision. For this reason BC Hydro would not undertake Option 2.**

- **Developing a feasibility cost estimate would take at least six months because, among other things, detailed geotechnical engineering work would need to be completed, design layouts produced, quantity surveys undertaken and finally a cost estimate generated.**

Inter-office memo

TO:	Murray Kroeker	**DATE:**	12 January 2006
FROM:	Bill Earis	**FILE:**	RUS05REH B103

SUBJECT: **Ruskin G.S. Cost Estimates for 'Rehabilitation of Existing Powerhouse' and 'Rebuild New Powerhouse on Existing Location'**

As requested, a revised overview level (+ 50%/ - 25%) expected cost estimates for 'Rehabilitation of Existing Powerhouse' and 'Rebuild Powerhouse on Existing Location' at Ruskin G.S.:

Rehabilitation of Existing Powerhouse (unloaded):	$ 132,861,000
Rehabilitation of Existing Powerhouse (loaded):	$ 164,064,000
Rebuild Powerhouse on Existing Location (unloaded):	$ 220,473,000
Rebuild Powerhouse on Existing Location (loaded):	$ 272,471,000

Attached is the Cost Estimate Summary and Details and InfoPM cashflows which provide the details for the revised estimate. Asset retirement and contingency calculations were revised from the previous cost estimate 423-1228.10-0202-01, dated 06 December 2005.

For details on the decommissioning Cost Estimate for Ruskin Dam please refer to Job # 423-1228.10-0201-02 dated Jan 10 2006.

Thank you for the opportunity to provide this estimate and please contact me if you require further assistance.

Bill Earis, M. Eng., P. Eng.

RSP/vjm
Attachments

c: F.Bonn (job # 423-1228.10-0202-02)
J. Boots

RUSKIN

Rehabilitation of Existing Powerhouse
Rebuild Powerhouse on Existing Location

		Rehabilition (Market Conditions)	Rebuild (Market Conditions)
1	MOBILIZATION/DEMOBILIZATION	$3,780,000	$6,319,000
2	SITE ACCESS	$94,000	$94,000
3	POWERHOUSE REHABILITATION	$64,579,000	-
4	POWERHOUSE DEMOLITION	-	$11,365,000
5	POWERHOUSE CONSTRUCTION	-	$103,063,000
6	POWERHOUSE ELECTRICAL	$8,559,000	$8,559,000
7	TRANSMISSION	$313,000	$313,000
8	OIL AND HAZARDOUS MATERIAL	$625,000	$625,000
9	INSTRUMENTATION	$125,000	$125,000
10	WATER DIVERSION AND CONTROL	$70,000	$70,000
11	ENVIRONMENT (DIRECT)	$1,223,000	$2,171,000
12	CONSTRUCTION MANAGEMENT AND SERVICES	$5,556,000	$9,289,000
	DIRECT CONSTRUCTION COST	$84,924,000	$141,993,000
13	PROJECT MANAGEMENT AND ENGINEERING	$9,715,000	$16,244,000
14	ENVIRONMENT (INDIRECT)	$790,000	$1,267,000
15	OTHER	$394,000	$476,000
16	ASSET RETIREMENT	$3,500,000	$4,500,000
	INDIRECT CONSTRUCTION COST	$14,399,000	$22,487,000
	TOTAL CONSTRUCTION COST WITHOUT CONTINGENCY	$99,323,000	$164,480,000
17	CONTINGENCIES	$33,538,000	$55,993,000
	TOTAL CONSTRUCTION COST	$132,861,000	$220,473,000

RUSKIN

Rehabilitation of Existing Powerhouse
Rebuild Powerhouse on Existing Location

WBS	Feature	Item	Description	Unit	Rehabilitation of Existing Powerhouse				Remove & Rebuild Powerhouse on Existing Location, Upgrading the Dam the Right Abutment and Replacing the Penstock			
					Quantity	Unit Price	Amount	Amount (Market Conditions)	Quantity	Unit Price	Amount	Amount (Market Conditions)
H200	1		MOBILIZATION/DEMOBILIZATION									
	1	1	Mob/demob	LS	5%	$60,470,114	$3,023,506	$3,779,383	5%	$0	$0	$0
	1T	S	Sub-Total :				$3,023,506	$3,779,383			$0	$0
H205	2		SITE ACCESS									
	2	1	Additional access roads	LS	1	$75,000	$75,000	$93,750			$0	$0
	2T	S	Sub-Total :				$75,000	$93,750			$0	$0
H210	3		POWERHOUSE REHABILITATION									
	3	1	Removal of unit 3 walls	LS	1	$100,388	$100,388	$125,485			$0	$0
	3	2	Installation of cladding/steel bracing or cast-in-place concrete	LS	1	$659,525	$659,525	$824,406			$0	$0
	3	3	Seismic upgrading of original powerhouse	LS	1	$584,817	$584,817	$731,022			$0	$0
	3	4	Additional seismic upgrading	LS	1	$93,384	$93,384	$116,730			$0	$0
	3	5	Consulting services (completed final design)	LS	1	$116,730	$116,730	$145,913			$0	$0
	3	6	Pressure wash and concrete treatment	LS	1	$233,460	$233,460	$291,825			$0	$0
	3	7	Supply and install 3 Francis turbines - 105 MW W2W	LS	1	$49,600,000	$49,600,000	$62,000,000			$0	$0
	3	8	Tailrace upgrades	LS	1	$275,000	$275,000	$343,750			$0	$0
	3T	S	Sub-Total :				$51,663,304	$64,579,130			$0	$0
H215	4		POWERHOUSE ELECTRICAL									
	4	1	Switchyard	LS	1	$6,847,360	$6,847,360	$8,559,200			$0	$0
	4T	S	Sub-Total :				$6,847,360	$8,559,200			$0	$0
H220	5		TRANSMISSION									
	5	1	Transmission upgrades	LS	1	$250,000	$250,000	$312,500			$0	$0
	5T	S	Sub-Total :				$250,000	$312,500			$0	$0
H225	6		OIL AND HAZARDOUS MATERIAL									
	6	1	Containment and removal of mercury switches, lead, etc	LS	1	$250,000	$250,000	$312,500			$0	$0
	6	2	Asbestos removal and disposal	LS	1	$250,000	$250,000	$312,500			$0	$0
	6T	S	Sub-Total :				$500,000	$625,000			$0	$0
	7		INSTRUMENTATION									
H230	7	1	Instrumentation monitoring/removal	LS	1	$100,000	$100,000	$125,000			$0	$0
	7T	S	Sub-Total :				$100,000	$125,000			$0	$0
H235	8		WATER DIVERSION AND CONTROL									
	8	1	Water control	LS	1	$56,250	$56,250	$70,313			$0	$0

RUSKIN
Rehabilitation of Existing Powerhouse
Rebuild Powerhouse on Existing Location

WBS	Feature	Item	Description	Unit	Rehabilitation of Existing Powerhouse: Quantity	Unit Price	Amount	Amount (Market Conditions)	Remove & Rebuild Powerhouse on Existing Location, Upgrading the Dam the Right Abutment and Replacing the Penstock: Quantity	Unit Price	Amount	Amount (Market Conditions)
	14T	S	Sub-Total :				$3,500,000	$3,500,000			$0	$0
			Indirect Powerhouse Rehab Construction Cost				$13,407,721	$14,398,493			$0	$0
			Total Powerhouse Rehab Construction Cost W/O Contingency				$81,346,341	$99,321,768			$0	$0
	15		CONTINGENCIES									
	15	1	Percentage of Construction Cost %	%	35%	$77,846,341	$27,246,219	$33,537,619	35%	$0	$0	$0
	15T	S	Sub-Total :				$27,246,219	$33,537,619			$0	$0
			TOTAL POWERHOUSE REHAB COST				$108,592,560	$132,859,386			$0	$0
H200	16		MOBILIZATION/DEMOBILIZATION									
	16	1	Mob/demob	LS	5%	$0	$0	$0	5%	$101,108,010	$5,055,401	$6,319,251
	16T	S	Sub-Total :				$0	$0			$5,055,401	$6,319,251
H205	17		SITE ACCESS									
	17	1	Additional access roads	LS			$0	$0	1	$75,000	$75,000	$93,750
	17T	S	Sub-Total :				$0	$0			$75,000	$93,750
H240	18		POWERHOUSE DEMOLITION									
	18	1	Removal of roof	LS			$0	$0	1	$37,500	$37,500	$46,875
	18	2	Removal of partitions	LS			$0	$0	1	$37,500	$37,500	$46,875
	18	3	Removal of generators	tonnes			$0	$0	609	$600	$365,400	$456,750
	18	4	Removal of turbines	tonnes			$0	$0	420	$600	$252,000	$315,000
	18	5	Removal of electrical equipment, transformers, switchgear, etc	LS			$0	$0	1	$200,000	$200,000	$250,000
	18	6	Removal of core ducts, etc.	LS			$0	$0	1	$200,000	$200,000	$250,000
	18	7	Building concrete and rebar demo	cm			$0	$0	20,000	$400	$8,000,000	$10,000,000
	18T	S	Sub-Total :				$0	$0			$9,092,400	$11,365,500
H245	19		POWERHOUSE CONSTRUCTION									
	19	1	New concrete	cm			$0	$0	20,000	$1,125	$22,500,000	$28,125,000
	19	2	New rebar (60kg/cm)	kg			$0	$0	1,200,000	$5	$6,075,000	$7,593,750
	19	3	New architectural cladding, roof, fixtures, etc.	LS			$0	$0	1	$4,000,000	$4,000,000	$5,000,000
	19	4	Supply and install 3 Francis turbines - 105 MW W2W	LS			$0	$0	1	$49,600,000	$49,600,000	$62,000,000
	19	5	Tailrace upgrades	LS			$0	$0	1	$275,000	$275,000	$343,750
	19T	S	Sub-Total :				$0	$0			$82,450,000	$103,062,500
H215	20		POWERHOUSE ELECTRICAL									
	20	1	Switchyard	LS			$0	$0	1	$6,847,360	$6,847,360	$8,559,200

RUSKIN

Rehabilitation of Existing Powerhouse
Rebuild Powerhouse on Existing Location

					Rehabilitation of Existing Powerhouse				Remove & Rebuild Powerhouse on Existing Location, Upgrading the Dam the Right Abutment and Replacing the Penstock			
WBS	Feature	Item	Description	Unit	Quantity	Unit Price	Amount	Amount (Market Conditions)	Quantity	Unit Price	Amount	Amount (Market Conditions)
P100	27	3	Procurement	%	3%	$0	$0	$0	3%	$113,594,411	$3,407,832	$3,748,615
	27T	S	Sub-Total :				$0	$0			$14,767,273	$16,244,000
S600	28		ENVIRONMENT (INDIRECT)									
	28	1	Environmental assessment and regulatory reviews	LS			$0	$0	1	$504,300	$504,300	$554,730
	28	2	Water Use Plan redevelopment	LS			$0	$0	1	$22,700	$22,700	$24,970
	28	3	Public and First Nations Consultation	LS			$0	$0	1	$475,000	$475,000	$522,500
	28	4	Archaeological issues	LS			$0	$0	1	$150,000	$150,000	$165,000
	28T	S	Sub-Total :				$0	$0			$1,152,000	$1,267,200
	29		OTHER									
S200	29	1	Properties	LS			$0	$0	1	$50,000	$50,000	$55,000
S400	29	2	Communications	LS			$0	$0	1	$32,500	$32,500	$35,750
S500	29	3	Legal	LS			$0	$0	1	$25,000	$25,000	$27,500
S700	29	4	Aboriginal relations	LS			$0	$0	1	$200,000	$200,000	$220,000
S800	29	5	Stakeholder Engagement	LS			$0	$0	1	$125,000	$125,000	$137,500
	29T	S	Sub-Total :				$0	$0			$432,500	$475,750
	30		ASSET RETIREMENT									
S900	30	1	Asset retirement	LS			$0	$0	1	$4,500,000	$4,500,000	$4,500,000
	30t	S	Sub-Total :				$0	$0			$4,500,000	$4,500,000
			Indirect Powerhouse Rebuild Construction Cost				$0	$0			$20,851,773	$22,486,950
			Total Powerhouse Rebuild Construction Cost W/O Contingency				$0	$0			$134,446,184	$164,479,964
	31		CONTINGENCIES									
	31	1	Percentage of Construction Cost %	%	35%	$0	$0	$0	35%	$129,946,184	$45,481,164	$55,992,987
	31T	S	Sub-Total :				$0	$0			$45,481,164	$55,992,987
			TOTAL POWERHOUSE REBUILD COST				$0	$0			$179,927,348	$220,472,951

FKB Project Annual Cashflow Report ($000s) Page 1

Project: FRED1 Dummy Project - Rehab Powerhouse

ESP #:
Forecast ISD: 31-JAN-2010
Project Manager: FKB FK(FRED) BONN

Task	Description	Total	Prior Years	Prior 12 Mo 04/05	Current Year 05/06	Year 2 06/07	Year 3 07/08	Year 4 08/09	Year 5 09/10	Year 6 10/11	Year 7 11/12	Year 8 12/13	Year 9 13/14	Year 10 14/15	To Complete
Capital:		**Parent #:**			**Client #:**										
0000	Dummy Project - Rehab Powerhou	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A100	Project Management	1568.7	0.0	0.0	0.0	204.9	488.9	563.0	283.3	28.6	0.0	0.0	0.0	0.0	0.0
B100	Engineering	6153.3	0.0	0.0	0.0	3412.5	1724.6	447.3	454.3	114.7	0.0	0.0	0.0	0.0	0.0
H100	Construction Management	4165.3	0.0	0.0	0.0	544.1	1298.2	1494.9	752.3	75.8	0.0	0.0	0.0	0.0	0.0
H110	Construction Services	1659.3	0.0	0.0	0.0	258.0	620.2	579.0	202.0	0.0	0.0	0.0	0.0	0.0	0.0
H200	Mob/Demob	3881.3	0.0	0.0	0.0	2388.2	914.2	312.8	266.0	0.0	0.0	0.0	0.0	0.0	0.0
H205	Site Access	98.8	0.0	0.0	0.0	1.5	29.0	50.3	18.0	0.0	0.0	0.0	0.0	0.0	0.0
H210	Powerhouse Rehabilition	68056.3	0.0	0.0	0.0	1064.7	19952.6	34661.4	12377.6	0.0	0.0	0.0	0.0	0.0	0.0
H215	Powerhouse Electrical	9020.1	0.0	0.0	0.0	141.1	2644.5	4594.0	1640.5	0.0	0.0	0.0	0.0	0.0	0.0
H220	Transmission	329.3	0.0	0.0	0.0	5.2	96.6	167.7	59.9	0.0	0.0	0.0	0.0	0.0	0.0
H225	Oil and Hazardous Materials	658.7	0.0	0.0	0.0	10.3	193.1	335.5	119.8	0.0	0.0	0.0	0.0	0.0	0.0
H230	Instrumentation	129.3	0.0	0.0	0.0	7.4	122.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H235	Water Diversion and Control	74.1	0.0	0.0	0.0	1.2	21.7	37.7	13.5	0.0	0.0	0.0	0.0	0.0	0.0
H325	Environment (Direct)	1288.6	0.0	0.0	0.0	20.2	377.8	656.3	234.4	0.0	0.0	0.0	0.0	0.0	0.0
P100	Procurement	2288.1	0.0	0.0	0.0	2288.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S200	Properties	57.9	0.0	0.0	0.0	1.9	19.0	27.3	9.6	0.0	0.0	0.0	0.0	0.0	0.0
S400	Communications	37.6	0.0	0.0	0.0	1.2	12.3	17.8	6.3	0.0	0.0	0.0	0.0	0.0	0.0
S500	Legal	28.9	0.0	0.0	0.0	0.9	9.5	13.7	4.8	0.0	0.0	0.0	0.0	0.0	0.0
S600	Environment (Indirect)	834.3	0.0	0.0	0.0	213.9	218.8	222.6	28.4	28.9	29.7	30.1	30.7	31.3	0.0
S700	Aboriginal Relations	173.6	0.0	0.0	0.0	5.7	57.0	82.0	28.9	0.0	0.0	0.0	0.0	0.0	0.0
S800	Stakeholder Engagement	115.7	0.0	0.0	0.0	3.8	38.0	54.7	19.3	0.0	0.0	0.0	0.0	0.0	0.0
Z-CONT	Contingency	35203.2	0.0	0.0	0.0	7995.7	8199.9	8363.8	8508.0	2135.9	0.0	0.0	0.0	0.0	0.0
CONT	Contingency (0.00%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital Direct Inflated		135822.4	0.0	0.0	0.0	18570.4	37037.7	52681.7	25026.9	2383.9	29.7	30.1	30.7	31.3	0.0
Capital Direct Uninflated as of 12.JAN.2006		(129359.4)	(0.0)	(0.0)	(0.0)	(18252.7)	(35699.6)	(49858.6)	(23259.8)	(2183.3)	(26.5)	(26.3)	(26.3)	(26.3)	(0.0)
Overhead		8828.5	0.0	0.0	0.0	1207.1	2407.5	3424.3	1626.8	155.0	1.9	2.0	2.0	2.0	0.0
IDC		15665.8	0.0	0.0	0.0	435.7	2176.4	5770.4	7283.3	0.0	0.0	0.0	0.0	0.0	0.0
Capital Totals		160316.6	0.0	0.0	0.0	20213.2	41621.6	61876.4	33937.0	2538.8	31.6	32.0	32.7	33.3	0.0
Retirement/Dismantling:		**Parent #:**			**Client #:**										
S900	Asset Retirement	3746.9	0.0	0.0	0.0	0.0	0.0	0.0	3746.9	0.0	0.0	0.0	0.0	0.0	0.0
Retirement Direct Inflated		3746.9	0.0	0.0	0.0	0.0	0.0	0.0	3746.9	0.0	0.0	0.0	0.0	0.0	0.0

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Justification : ********* Report Summary *********

Project	Description	PAR	Total	Prior Years	Prior 12 Mo 04/05	Current Year 05/06	Year 2 06/07	Year 3 07/08	Year 4 08/09	Year 5 09/10	Year 6 10/11	Year 7 11/12	Year 8 12/13	Year 9 13/14	Year 10 14/15	To Complete
Capital:																
FRED1	Dummy Project - Rehab		135822.4	0.0	0.0	0.0	18570.4	37037.7	52681.7	25026.9	2383.9	29.7	30.1	30.7	31.3	0.0
Capital Direct Inflated			135822.4	0.0	0.0	0.0	18570.4	37037.7	52681.7	25026.9	2383.9	29.7	30.1	30.7	31.3	0.0
Capital Direct Uninflated as of 12-JAN-2006			(129359.4)	(0.0)	(0.0)	(0.0)	(18252.7)	(35699.6)	(49858.6)	(23259.8)	(2183.3)	(26.5)	(26.3)	(26.3)	(26.3)	(0.0)
Overhead			8828.5	0.0	0.0	0.0	1207.1	2407.5	3424.3	1626.8	155.0	1.9	2.0	2.0	2.0	0.0
IDC			15665.8	0.0	0.0	0.0	435.7	2176.4	5770.4	7283.3	0.0	0.0	0.0	0.0	0.0	0.0
Capital Totals			160316.6	0.0	0.0	0.0	20213.2	41621.6	61876.4	33937.0	2538.8	31.6	32.0	32.7	33.3	0.0
OMA/Other:																
FRED1	Dummy Project - Rehab		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OMA/Other Direct Inflated			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OMA/Other Direct Uninflated as of 12-JAN-2006			(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
OMA/Other Totals			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Retirement/Dismantling:																
FRED1	Dummy Project - Rehab		3746.9	0.0	0.0	0.0	0.0	0.0	0.0	3746.9	0.0	0.0	0.0	0.0	0.0	0.0
Retirement Direct Inflated			3746.9	0.0	0.0	0.0	0.0	0.0	0.0	3746.9	0.0	0.0	0.0	0.0	0.0	0.0
Retirement Direct Uninflated as of 12-JAN-2006			(3500.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(3500.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Retirement Totals			3746.9	0.0	0.0	0.0	0.0	0.0	0.0	3746.9	0.0	0.0	0.0	0.0	0.0	0.0
Grand Totals			**164063.5**	**0.0**	**0.0**	**0.0**	**20213.2**	**41621.6**	**61876.4**	**37683.9**	**2538.8**	**31.6**	**32.0**	**32.7**	**33.3**	**0.0**

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Project: RUPE1 Dummy Project - Rebuild New Powerhouse

ESP #:
Forecast ISD: 31-JAN-2010
Project Manager: RSP RS(RUPINDER) POONI

Task	Description	Total	Prior Years	Prior 12 Mo 04/05	Current Year 05/06	Year 2 06/07	Year 3 07/08	Year 4 08/09	Year 5 09/10	Year 6 10/11	Year 7 11/12	Year 8 12/13	Year 9 13/14	Year 10 14/15	To Complete
Capital:		**Parent #: 111111**			**Client #:**										
0000	Dummy Project - Rebuild New Po	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A100	Project Management	2622.9	0.0	0.0	0.0	342.6	817.4	941.3	473.7	47.7	0.0	0.0	0.0	0.0	0.0
B100	Engineering	10288.4	0.0	0.0	0.0	5705.7	2883.5	747.9	759.5	191.7	0.0	0.0	0.0	0.0	0.0
H100	Construction Management	6963.7	0.0	0.0	0.0	909.7	2170.3	2499.2	1257.7	126.8	0.0	0.0	0.0	0.0	0.0
H110	Construction Services	2773.8	0.0	0.0	0.0	431.3	1036.8	967.9	337.8	0.0	0.0	0.0	0.0	0.0	0.0
H200	Mob/Demob	6489.6	0.0	0.0	0.0	3993.1	1528.6	523.1	444.8	0.0	0.0	0.0	0.0	0.0	0.0
H205	Site Access	98.8	0.0	0.0	0.0	1.5	29.0	50.3	18.0	0.0	0.0	0.0	0.0	0.0	0.0
H215	Powerhouse Electrical	9020.1	0.0	0.0	0.0	141.1	2644.5	4594.0	1640.5	0.0	0.0	0.0	0.0	0.0	0.0
H220	Transmission	329.3	0.0	0.0	0.0	5.2	96.6	167.7	59.9	0.0	0.0	0.0	0.0	0.0	0.0
H225	Oil and Hazardous Materials	658.7	0.0	0.0	0.0	10.3	193.1	335.5	119.8	0.0	0.0	0.0	0.0	0.0	0.0
H230	Instrumentation	129.3	0.0	0.0	0.0	7.4	122.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H235	Water Diversion and Control	74.1	0.0	0.0	0.0	1.2	21.7	37.7	13.5	0.0	0.0	0.0	0.0	0.0	0.0
H240	Powerhouse Demolition	11977.5	0.0	0.0	0.0	187.4	3511.5	6100.2	2178.4	0.0	0.0	0.0	0.0	0.0	0.0
H245	Powerhouse Construction	108611.7	0.0	0.0	0.0	1699.1	31842.6	55316.4	19753.6	0.0	0.0	0.0	0.0	0.0	0.0
H825	Environment (Direct)	2288.2	0.0	0.0	0.0	35.8	670.8	1165.4	416.2	0.0	0.0	0.0	0.0	0.0	0.0
P100	Procurement	3825.8	0.0	0.0	0.0	3825.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S200	Properties	57.9	0.0	0.0	0.0	1.9	19.0	27.3	9.6	0.0	0.0	0.0	0.0	0.0	0.0
S400	Communications	37.6	0.0	0.0	0.0	1.2	12.3	17.8	6.3	0.0	0.0	0.0	0.0	0.0	0.0
S500	Legal	28.9	0.0	0.0	0.0	0.9	9.5	13.7	4.8	0.0	0.0	0.0	0.0	0.0	0.0
S600	Environment (Indirect)	1338.2	0.0	0.0	0.0	343.1	350.9	357.0	45.5	46.4	47.6	48.2	49.2	50.2	0.0
S700	Aboriginal Relations	231.5	0.0	0.0	0.0	7.6	76.0	109.3	38.6	0.0	0.0	0.0	0.0	0.0	0.0
S800	Stakeholder Engagement	144.7	0.0	0.0	0.0	4.7	47.5	68.3	24.1	0.0	0.0	0.0	0.0	0.0	0.0
Z-CONT	Contingency	58773.8	0.0	0.0	0.0	13349.2	13690.2	13963.9	14204.5	3566.0	0.0	0.0	0.0	0.0	0.0
CONT	Contingency (0.00%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital Direct Inflated		226764.2	0.0	0.0	0.0	31005.8	61773.8	88003.9	41806.8	3978.6	47.6	48.2	49.2	50.2	0.0
Capital Direct Uninflated as of 12.JAN.2006		(215973.0)	(0.0)	(0.0)	(0.0)	(30475.4)	(59541.8)	(83288.0)	(38854.9)	(3643.9)	(42.4)	(42.2)	(42.2)	(42.2)	(0.0)
Overhead		14739.7	0.0	0.0	0.0	2015.4	4015.3	5720.3	2717.4	258.6	3.1	3.1	3.2	3.3	0.0
IDC		26150.1	0.0	0.0	0.0	727.5	3631.5	9631.4	12159.7	0.0	0.0	0.0	0.0	0.0	0.0
Capital Totals		267653.9	0.0	0.0	0.0	33748.8	69420.6	103355.5	56684.0	4237.2	50.7	51.4	52.4	53.5	0.0
Retirement/Dismantling:		**Parent #: 111111**			**Client #:**										
S900	Asset Retirement	4817.4	0.0	0.0	0.0	0.0	0.0	0.0	4817.4	0.0	0.0	0.0	0.0	0.0	0.0

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Justification : ********* Report Summary *********

Project	Description	PAR	Total	Prior Years	Prior 12 Mo 04/05	Current Year 05/06	Year 2 06/07	Year 3 07/08	Year 4 08/09	Year 5 09/10	Year 6 10/11	Year 7 11/12	Year 8 12/13	Year 9 13/14	Year 10 14/15	To Complete
Capital:																
RUPE1	Dummy Project - Rebuil		226764.2	0.0	0.0	0.0	31005.8	61773.8	88003.9	41806.8	3978.6	47.6	48.2	49.2	50.2	0.0
Capital Direct Inflated			226764.2	0.0	0.0	0.0	31005.8	61773.8	88003.9	41806.8	3978.6	47.6	48.2	49.2	50.2	0.0
Capital Direct Uninflated as of 12-JAN-2006			(215973.0)	(0.0)	(0.0)	(0.0)	(30475.4)	(59541.8)	(83288.0)	(38854.9)	(3643.9)	(42.4)	(42.2)	(42.2)	(42.2)	(0.0)
Overhead			14739.7	0.0	0.0	0.0	2015.4	4015.3	5720.3	2717.4	258.6	3.1	3.1	3.2	3.3	0.0
IDC			26150.1	0.0	0.0	0.0	727.5	3631.5	9631.4	12159.7	0.0	0.0	0.0	0.0	0.0	0.0
Capital Totals			267653.9	0.0	0.0	0.0	33748.8	69420.6	103355.5	56684.0	4237.2	50.7	51.4	52.4	53.5	0.0
OMA/Other:																
RUPE1	Dummy Project - Rebuil		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OMA/Other Direct Inflated			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OMA/Other Direct Uninflated as of 12-JAN-2006			(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
OMA/Other Totals			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Retirement/Dismantling:																
RUPE1	Dummy Project - Rebuil		4817.4	0.0	0.0	0.0	0.0	0.0	0.0	4817.4	0.0	0.0	0.0	0.0	0.0	0.0
Retirement Direct Inflated			4817.4	0.0	0.0	0.0	0.0	0.0	0.0	4817.4	0.0	0.0	0.0	0.0	0.0	0.0
Retirement Direct Uninflated as of 12-JAN-2006			(4500.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(4500.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Retirement Totals			4817.4	0.0	0.0	0.0	0.0	0.0	0.0	4817.4	0.0	0.0	0.0	0.0	0.0	0.0
Grand Totals			**272471.3**	**0.0**	**0.0**	**0.0**	**33748.8**	**69420.6**	**103355.5**	**61501.4**	**4237.2**	**50.7**	**51.4**	**52.4**	**53.5**	**0.0**

25.0 Reference: Project Costs
Exhibit B-7, BCUC 1.44.1, p. 1
Contingencies and Risks
Exhibit B-1, Section 3.4.1, p. 44
New verses Rehabilitate/Replace
Exhibit B-7, BCUC 1.54.1, p. 1
Evaluation of Alternatives
Exhibit B-7, BCUC 1.93.1, Attachment 3, pp. 44, 67
Background to Alternatives

"BC Hydro cannot feasibly implement the Project two, three or five years faster than has been proposed".

"In 2005, BC Hydro initially explored two options: (1) Rehabilitating/replacing the existing Powerhouse; and (2) Building a new powerhouse at the existing Powerhouse site. BC Hydro concluded in 2005 that building a new powerhouse at the existing site was approximately $109 million more costly (+50 per cent to -25 per cent cost estimate accuracy) than rehabilitating/replacing the existing Powerhouse."

"The Project…is challenging because it is a rehabilitation of an existing facility; has…small work space with live operating equipment…..must deal with some unknown Powerhouse equipment conditions….requires the operation of the facility …to maintain continuity of flow."

"The least critical construction sequence will be with four old gates available and all six bulkhead gates unobstructed by the old piers. The combined discharge capacity at that time, and with reservoir at El. 44 m (emphasis added), is estimated to be about 2815 m3/s (2175 m3/s through spillway gates, and 640 m3/s through bulkhead vertical lift gates). This corresponds to a return period of about 1000 years for hourly inflow.

The above estimates were derived with the assumption that discharge through the three Ruskin units (up to about 116 m3/s each) would not be available (emphasis added)."

"For Option 3 (auto-spill), as soon as the Ruskin Powerhouse becomes unable to provide discharge required to maintain the minimum tailwater level, a spillway gate would be automatically activated to spill at the required rate. Note that this option will be effective only when the reservoir level is above spillway crest elevation.

The auto-spill option applied to Spillway Gate #5 (or gates 1 *and* 5), is judged to be the preferred option for the following reasons:

1. Significantly lower cost than the >$10M for all other options
2. Acceptable Total Gas Pressure (TGP) performance (emphasis added)

3. Comparable or better reliability than options 1 or 2
4. Negligible incremental life safety risks in the proposed range and mode of operation

Some key considerations include:

These facilities would only be required to function under emergency conditions (full powerhouse outage).

<u>Powerhouse by-pass and submerged LLO solutions likely offer the potential for minor improvements to TGP performance over the preferred option</u> (emphasis added)."

2.25.1.1 The above comparisons should include a discussion on:

- The present value of lost energy associated with Option 2 (Exhibit B-1, Section 3.3.2, p. 41 states that 19 percent of Ruskin's generation is worth $7.9 million annually which translates to $7.9/0.19=$41.6 million annually for the facility).
- The risks to fish associated with maintaining flows either through the spillway (perhaps after the access bridge pier modification to reduce TGP are complete) or by blocking or removing one turbine to maintain flows through a penstock to reduce TGP until the first replacement unit is available to pass 120 cms (or greater) of water. **Note**: if required, an operator could monitor RUS spill 24/7 during periods of high risk or concerns of a forced outage to SFN. Also note, the response to Kwantlen IR's 1.7.1.1, Attachment 1, p. 74 "Ruskin gate configurations have been set in the Local Operating Order to utilize the outermost gates for spills up to 400 m3/s to keep TGP levels below 115 per cent. Instantaneous mortality of fish species is avoided with this mitigation (Falvey, Gulliver and Weitkamp 2008). Long term spills greater than 300 m3/s may result in chronic effects. One objective of the ongoing TGP monitoring program is to describe spill duration and rates that can have chronic effects on fish" and 1.7.3, p. 2 "spills above 400 cms are comparatively rare" and on p. 5 "The TDG management plan will serve as a key reference for TDG management during Project implementation and on-going operations. BC Hydro is targeting March 2012 for the delivery of the TDG management plan."
- With the 3 RUS units shut-down there is minimal risk that high inflows could not be passed utilizing the least critical construction sequence referenced above. Spills up to 120 cms can be safely passed.

- For Option 2 the avoided costs associated with the contractor having fewer restrictions and enabling the work to be completed in a shorter time frame (the original powerhouse and dam complex was completed in less than 2 years back in 1930 as indicated in Exhibit B-7, BCUC 1.76.2, Attachment 1, p. 11).
- The possibility of using a smaller bulkhead gate (at a lower cost) associated with a lower reservoir operation throughout the construction period.
- The avoided carrying costs associated with a shorter construction period (lower IDC and Corporate overhead, provisional amounts etc).
- Cessation of corporate loadings once a stand-alone asset is placed in service.
- The reduction in contingencies and unknowns as given in the response to BCUC 1.44.1 (not operating around live equipment, dealing with some unknown powerhouse conditions…in particular the matching of new and old turbine generator components).
- CEAA and First Nations considerations.
- The quality and total costs of the final product in terms of facility life expectancy, MDE withstand, the NPV of any long term avoided maintenance or Capital costs for the components that would not be replaced in Option 1 (for example draft tube liner repairs/replacement), NPV of any turbine efficiency gains, feasibility of installation of larger units, improved ergonomics and safety by design for the workforce, inclusion of CGIS in the powerhouse, power smart initiatives, removal of hazardous waste (lead paint, PCB's, spilled oil, mercury etc), environmental protection (oil spill containment, sewage treatment) and possible inclusion of penstock by-pass valves to assure continuity of flow.

Please note, this IR requests that BC Hydro prepare a cost estimate hence a response of "BC Hydro has not produced an estimate" is not an appropriate response. Please respond to the IR using available data/evidence to the best of its ability to produce an order of magnitude estimate.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.25.1.

26.0 Reference: Alternatives
Exhibit B-7, BCUC 1.53.2.1, p. 1
Evaluation of Alternatives

"The costs from F2013 to F2018 are IDC charges on the sunk costs."

2.26.1 Please explain the accounting treatment of the completion of a stand-alone asset (such as the Right Abutment, access bridge, a turbine/generator unit, powerhouse crane or switchyard etc.). When a stand-alone asset is placed into service does IDC, Corporate Overhead and any other loadings related to this stand-alone asset cease? If not, why not.

RESPONSE:

The loadings applied to actual project costs are IDC and Capital Overhead.

When a stand-alone asset within a larger capital project is available for use, the asset is placed into service and the project costs attributed to that specific asset are transferred to Capital Assets in Service. When costs are transferred to Capital Assets in Service, IDC and Capital Overhead on those costs cease.

26.0 Reference: Alternatives
Exhibit B-7, BCUC 1.53.2.1, p. 1
Evaluation of Alternatives

"The costs from F2013 to F2018 are IDC charges on the sunk costs."

2.26.1.1 If loading charges for the stand-alone item do cease, please explain why the corresponding percentage of Investigative, Definition and early attention/sunk costs attributed to the specific asset are not also put into service in order to avoid continued overall loading costs until the entire project is complete.

RESPONSE:

For purposes of project estimating, common costs for this Project were considered to go into service at the end of the Project. For estimating purposes, any potential increase in accuracy of IDC is offset by the number of assumptions that must be made as to the timing of in-service dates, cumulative common costs to that date, future common costs that may be applicable to the assets (for instance, for as-built drawings, testing, and similar costs) and the effort to apportion the common costs appropriately.

In practice, as per BC Hydro policy for large capital expenditures, common costs associated with a project such as Identification Phase, Definition Phase, and Early Implementation Phase costs are transferred from unfinished construction to specific capital assets in-service in stages proportionate to the components put in-service at the time.

26.0 Reference: Alternatives
Exhibit B-7, BCUC 1.53.2.1, p. 1
Evaluation of Alternatives

"The costs from F2013 to F2018 are IDC charges on the sunk costs."

2.26.2 In approving the CPCN, how can the Commission be assured that a proposed material item which is in scope will not be removed as was done with the SFL spill gate project (i.e. the emergency diesel generator, separate control room, redundant controls PAM panel and gate seal heaters that formed part of the project's justification were removed from the scope)? To put it another way, what assurance can BC Hydro provide to its ratepayers that they will materially receive the scope that is detailed in the Application which resulted from several years of investigative study and design considerations to arrive at a final (materially) scope (i.e. that this and the next generation of ratepayers will receive what they understand they are paying for and that quality will not be compromised in order to meet a budget).

RESPONSE:

BC Hydro does not accept that the changes listed in this IR with respect to the Stave Falls Spillway Gates Replacement Project (SFL Project) were material changes to the SFL Project scope. The listed changes resulted from detailed design, and were reported to the BCUC through the reporting requirement BC Hydro offered as part of BC Hydro's SFL Project filing.

In any event, as set out at page 1-3, line 5 of Exhibit B-1, BC Hydro is seeking a CPCN "for the Project as proposed". BC Hydro does not expect that there will be material changes to the proposed scope of the Project. This IR is correct that BC Hydro has undertaken significant work to arrive at the Project scope summarized in Tables 2-1 and 2-2 of Exhibit B-1. BC Hydro followed good corporate governance in arriving at the scope of the Project. For example:

- **Alternative Means of Carrying out the Project - BC Hydro and third parties examined alternative means of carrying out the Project; please refer to Exhibit B-1, sections 3.4.1 to 3.4.4 and to Exhibit B-7-2, BC Hydro's response to Kwantlen First Nation (Kwantlen) IR 1.2.1. Through such examination BC Hydro determines if a particular means of carrying out a part of the Project is feasible or not;**

- **Environmental Due Diligence - BC Hydro has undertaken a number of Project-related environmental studies following good environmental**

assessment practice, summarized in Hemmera Envirochem Inc.'s (Hemmera) Summary of Environmental Information, Assessment and Mitigation (SEIAM) report found at Attachment 1 to BC Hydro's response to Kwantlen IR 1.2.1.

- **As one example, in conjunction with Kwantlen, BC Hydro conducted archaeological surveys of the entire Project area as it is currently defined, including the proposed Switchyard site and the likely location of any Right of Way (ROW) realignment of the circuits to connect to the new Switchyard. BC Hydro has committed to further consultation with Kwantlen and engagement with local stakeholders regarding the final location of this ROW. Please refer to Attachment 1 to this IR for a series of maps indicating the extent of archaeological surveys. Attachment 1 has been redacted to prevent the public disclosure of specific archaeological sites. If additional Project work areas are required at a later date, the appropriate environmental studies, engagement and permitting, if any, would be completed to assess the suitability of the proposed additional work area, and such studies would be sent to Kwantlen as part of the on-going consultation process. Please also refer to Attachment 2 which lists the various archaeological studies that have been conducted with respect to the Project;**

- **BC Hydro engaged with federal and provincial government agencies to determine regulatory requirements, and has committed to submitting a final draft copy of the Environmental Management Plan (EMP) to DFO and the B.C. Ministry of Environment prior to finalization of the EMP. Please refer to Exhibit B-7, BC Hydro's response to BCUC IR 1.13.1 and to Attachment 5 to BC Hydro's response to Ruskin Townsite Residential Association IR 2.1.1 for a copy of draft EMP. Please also refer to BC Hydro's response to Clean Energy Association of B.C. IR 2.11.1 concerning additional examples of environmental due diligence, and how the SEIAM report accords with practices under the CEAA and the BCEAA, even though the Project does not trigger either Act;**

- **Internal Reviews of Estimates and Design – As part of normal project management practices, BC Hydro subjected the design and the Project cost estimate to review by discipline leads and the Office of the Chief Engineer. In addition, the Project design has been presented and discussed at a number of Ruskin Dam Safety Advisory Board (Advisory Board) meetings through the course of the work, and the Advisory Board's views were incorporated into the subsequent designs.**

However, BC Hydro has been clear that consultation is on-going with Kwantlen, and that BC Hydro continues to refine Project design. For example, with respect to the Upper Dam Work, refinement continues on final spillway gate structural reinforcement details, and orientation and equipment configuration of the spillway gate control rooms; please refer to Exhibit B-7-2, BC Hydro's response to Kwantlen IR 1.2.1. This is to be expected given that the Project is not yet in the Implementation phase. Please also refer to BC Hydro's response to BCUC IR 2.67.1 with respect to the status of the Working Design Basis document.

If the BCUC issues a CPCN for the Project as proposed, BC Hydro will keep the BCUC and intervenors informed of the Project during implementation through semi-annual reporting; refer to Exhibit B-1, page 1-4, lines 22 to 25 to page 1-5, lines 1 to 2. The BCUC and intervenors could test any material departures from the Project scope as part of a prudency review in a future RRA.

Figure 6. Study Area for Seismic Upgrade Works.

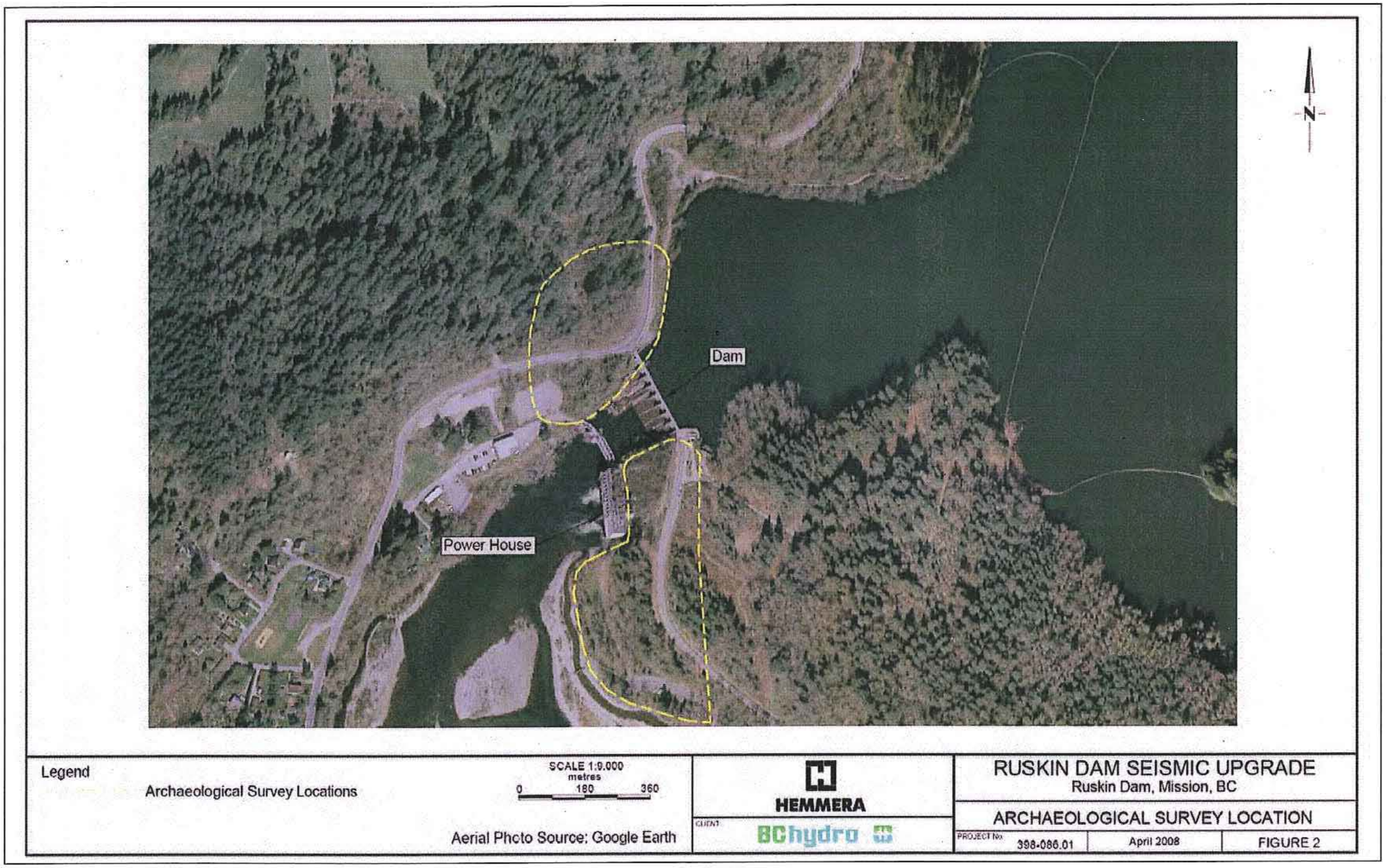
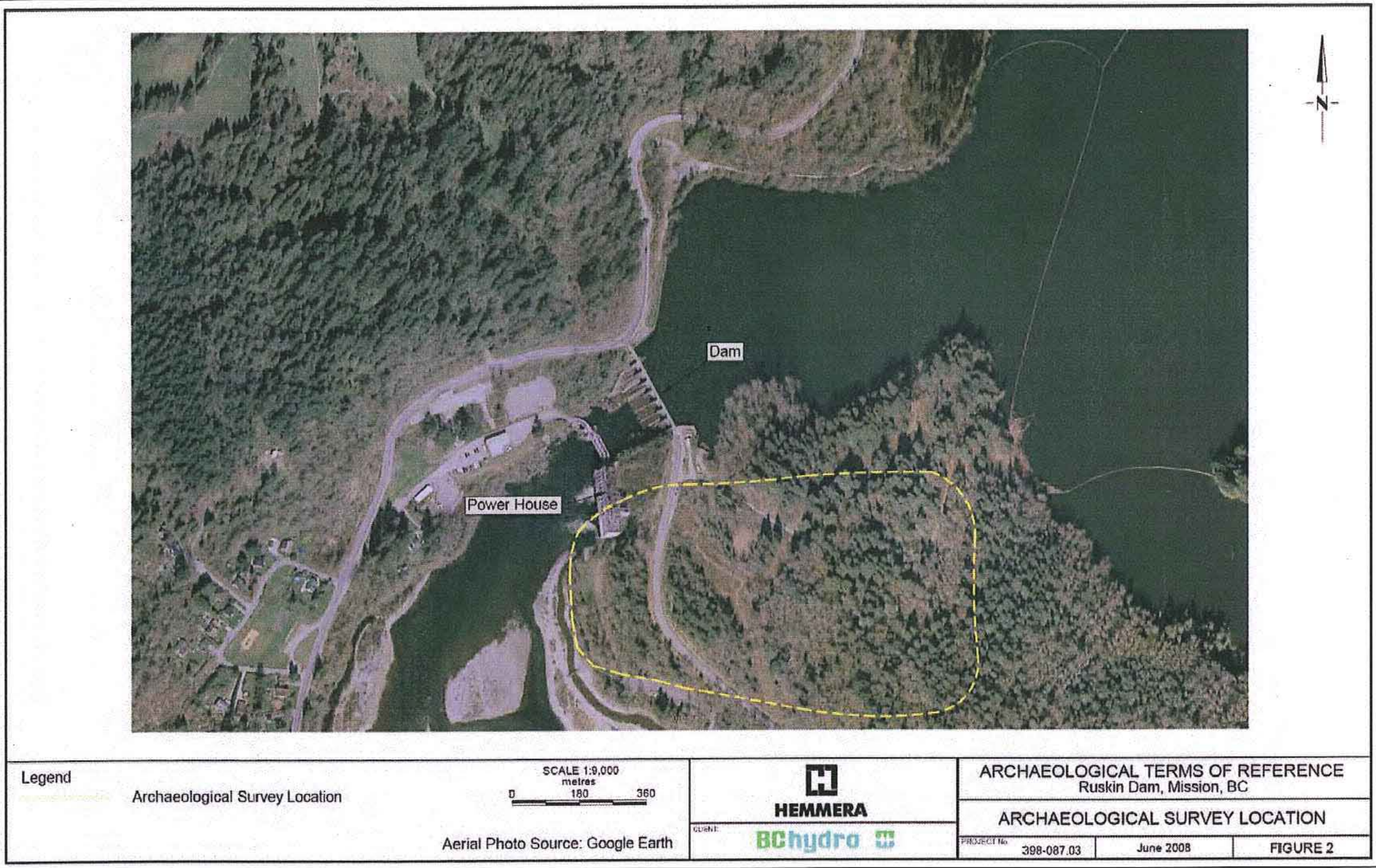


Figure 6. Study Area.



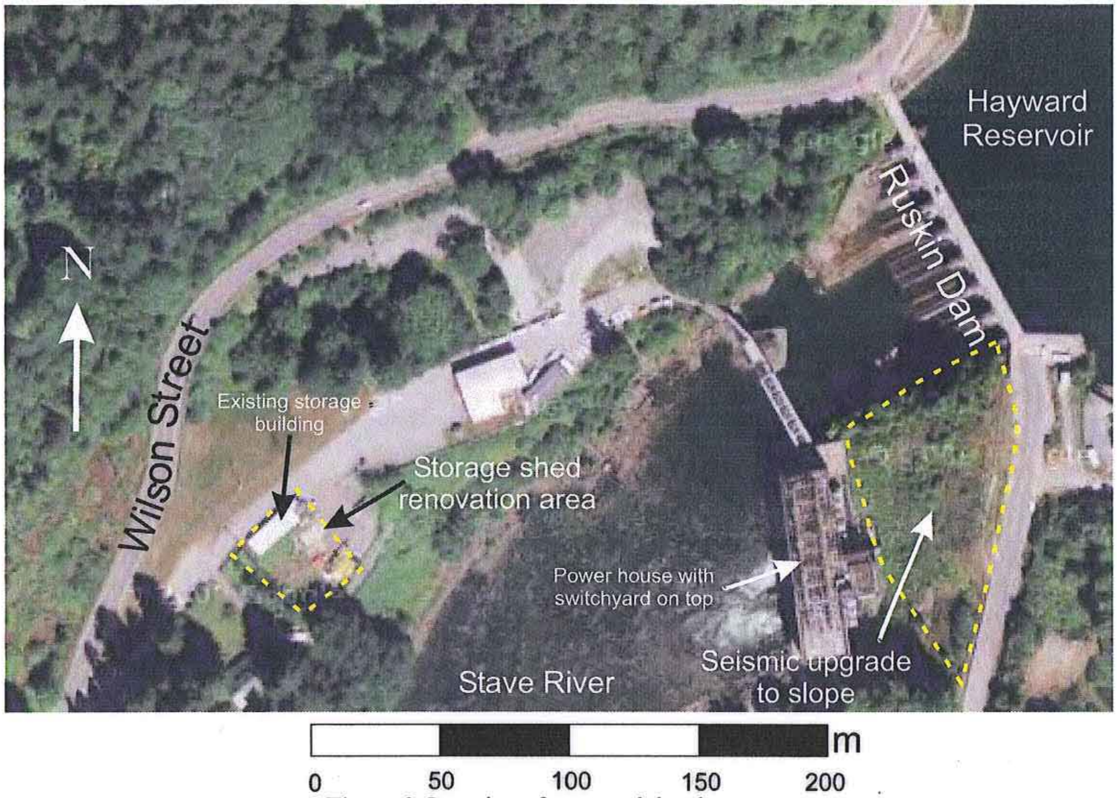


Figure 2. Location of proposed developments.

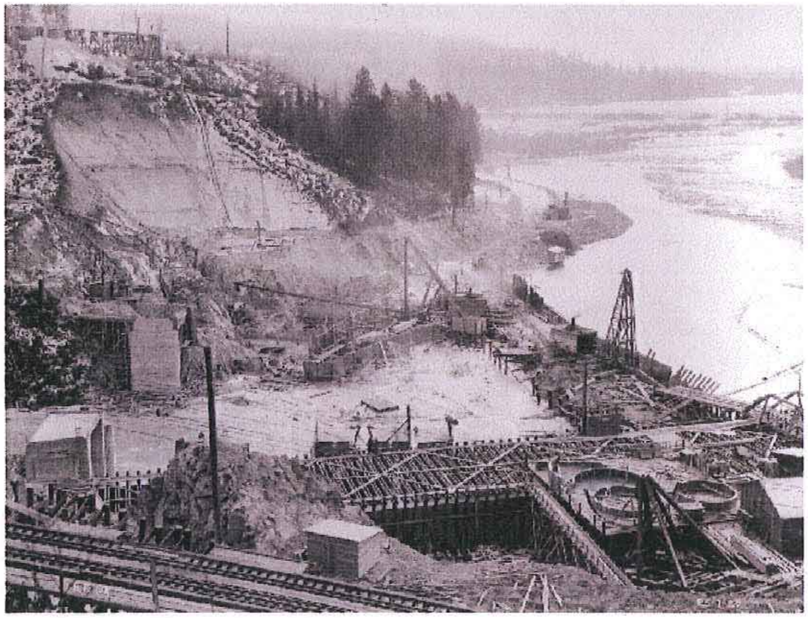


Figure 3. Photograph No. R.P. 134 Ruskin Development, View Taken from the West Side Showing Power House Site, Downstream Temporary Cofferdam, and Railway Bridge Piers. By John Clark (1930).

[redacted]

Recommended boundary of proposed switchyard location

[redacted]

Current (approximate) boundary of proposed switchyard footprint that would impact DhRo57.

Archaeological Site DhRo57

Mary Hairsine's grave marker (approximate location, not to scale).

Figure 9. Map indicating the recommended relocation of the proposed switchyard replacement area so as to avoid DhRo57 and Mary Hairsine's grave.

Conclusion

We are grateful to have had the opportunity to undertake this archaeological impact assessment project. The research resulted in the identification of archaeological deposits that have refined the boundary of DhRo57, and have mapped the location of Mary Hairsine's grave marker.

List of Archaeological Studies

Cordillera Archaeology (2009): Report for an Archaeological Inventory and Impact Assessment for the Ruskin Switchyard Replacement Project.	An independent archaeological review of the proposed Ruskin switchyard location. Study involved surface inspection and subsurface testing for the proposed relocation of the Ruskin Switchyard.
Cordillera Archaeology (2009). Report for an Archaeological Inventory and Impact Assessment for the Ruskin Dam Seismic Upgrade Project.	An independent archaeological review of potential Spoil Locations 2 and 3 on the west side of the Stave Reservoir, and the general area west of the current dam which will be affected by seismic upgrading.
Cordillera Archaeology (2009). Interim Report of Archaeological Investigations at Site DhRo-59, Ruskin Dam, Stave River, BC.	Interim report for controlled excavation completed at archaeological site DhRo 59.
Cordillera Archaeology (2010): Final Report For An Archaeological Impact Assessment Of Proposed Ancillary Developments For Upgrades To The Ruskin Dam: Volume I –Main Entrance And Left Abutment	An independent archaeological review for the location of an existing storage building near the main entrance to the dam facility, and of the left abutment area on the east side of the Stave River located south of the dam and west of Hayward Street.
Cordillera Archaeology (2010): Final Report For An Archaeological Impact Assessment Of Proposed Ancillary Developments For Upgrades To The Ruskin Dam: Volume II – Proposed Switchyard Location.	This study provided for additional testing at DhRo 57 in order to accurately delineate boundaries and the mapping of an historic grave marker near this location to determine any potential conflict with development.
Cordillera Archaeology (2010): Final Report Of Archaeological Investigations At The Ruskin Dam Site, Dhro-59: Volume III.	Final report for controlled excavation completed at archaeological site DhRo 59.

27.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.55.1, p. 1
History of Evaluation

"BC Hydro cannot provide the individual cost of this evaluation as the costs were not segregated at the time the costs were incurred."

2.27.1 This evaluation would have been charged to an EAR that was raised to cover such costs. Please provide the 2005 costs for the Contractor Resource Code(s) charged against this/these EAR(s)

RESPONSE:

As set out in Exhibit B-7, BC Hydro's response to BCUC IR 1.55.1, the 2005 evaluation was conducted internally and there were no Contractor Resource Codes charged to the Project during this time.

27.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.55.1, p. 1
History of Evaluation

"BC Hydro cannot provide the individual cost of this evaluation as the costs were not segregated at the time the costs were incurred."

2.27.2 Please confirm that a Purchase Order was not raised for this evaluation. If a PO was raised then the evaluation invoice should be charged to this PO and be available from BC Hydro's Purchasing Department or service provider. Please provide the cost of this evaluation.

RESPONSE:

Confirmed. A Purchase Order was not raised for this evaluation because the evaluation was conducted internally. Please refer to BC Hydro's response to BCUC IR 2.27.1.

28.0 Reference: User Requirements
Exhibit B-7, BCUC 1.93.1, Attachment 4, pp. 8 to 21 of 406

2.28.1 Please explain why thermo-imaging cameras are required (Item 9.10).

RESPONSE:

Thermo-imaging cameras are used for site security in dark, remote areas to gain a better operational picture of the site and possible encroachment into key areas. In the case of the Project, it has been determined that this technology will not be required due to the presence of sufficient ambient lighting from the site and adjoining public areas.

28.0 Reference: User Requirements
Exhibit B-7, BCUC 1.93.1, Attachment 4, pp. 8 to 21 of 406

2.28.2 Please explain how the limit of $2.5 million as a contribution for the double lane roadway was arrived at (Item 10.1).

RESPONSE:

BC Hydro is not seeking a $2.5 million contribution from the District of Mission (Mission); please refer to Exhibit B-7, BC Hydro's response to BCUC IR 1.30.3 for the reasons why BC Hydro is not seeking a contribution from Mission.

The $2.5 million was the estimated incremental cost of widening the Dam Crossing to a two-lane roadway at the time of the referenced report. Please refer to Exhibit B-7-2, BC Hydro response to AMPC IR 1.5.2 for the current cost estimates of the incremental cost of the second lane and sidewalk for the Dam Crossing.

28.0 Reference: User Requirements
Exhibit B-7, BCUC 1.93.1, Attachment 4, pp. 8 to 21 of 406

2.28.3 Please confirm that all spillway gates do not need to be operable after MDE (Item 18.2).

RESPONSE:

Confirmed; however, at least two of five new spillway gates must be operable post-MDE.

28.0 Reference: User Requirements
Exhibit B-7, BCUC 1.93.1, Attachment 4, pp. 8 to 21 of 406

2.28.4 Please explain why each gate must have its own control room rather than a control station (Item 24.1).

RESPONSE:

This user requirement stemming from preliminary design anticipated that adding additional control locations would decrease the likelihood of gates failing to open under adverse circumstances, through provision of redundancy and reduced chances of common cause failure.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.1 Is the replacement of U3's draft tube extension, requiring construction of a coffer dam, included in the Project scope? If not, why not?

RESPONSE:

The U3 draft tube extension does not require replacement. Proposed work to the draft tubes only entails installation of the draft tube stoplog system. The stoplog system requires cutting into the roof of the U3 draft tube extension and installation of gate guides. This work can be safely performed without the use of a coffer dam.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.2 Is a spare Unit transformer included in the Project scope?

RESPONSE:

No. A spare unit transformer is not part of the Project scope.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.2.1 Please explain if BC Hydro has a system spare transformer that would cover 69 kV generation facilities and Ruskin in particular. If not, why not?

RESPONSE:

BC Hydro does not have a spare transformer that could be used at the Ruskin Facility. Generation transformers are custom order items often specific to each generating station. BC Hydro has not maintained a spare transformer for the Ruskin Facility in anticipation of the Project.

BC Hydro's decision on carrying spare transformers is based on the probability and consequences of a transformer failure. Generator unit transformers have an expected life of approximately 30 to 40 years. It is anticipated that sometime in the future a spare transformer will be acquired for the Ruskin Facility.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.3 Is a generator brake dust collection in scope? Please discuss the option of dynamic braking and why BC Hydro does not employ this feature in its generation facilities.

RESPONSE:

A generator brake system including brake dust collection is part of the Turbine and Generator supplier/install contract. If a generator supplier proposes a cost effective option of dynamic braking then BC Hydro will perform a technical review of the option at that time.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.4 Is a turbine model test in scope? If not, why not?

RESPONSE:

Yes, as set out at page 5-9 lines 9 to 19 of Exhibit B-1, a turbine model test is part of the turbine supplier's scope of work.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.5 Please describe the selected/preferred options for the spillway, intake and draft tube maintenance gates or indicate where they can be located in the Application.

RESPONSE:

Spillway options are listed in Exhibit B-1, section 3.4.3. Please also refer to Attachment 3 to BC Hydro's response to BCUC IR 1.93.1 which is the Ruskin Dam Preliminary Design Report and in particular section 6.0, which sets out the spillway options selection analysis.

Intake gate options are summarized in Exhibit B-7, Attachment 5 to BC Hydro's response to BCUC IR 1.93.1 (Powerhouse Alternative Assessment Report) on pages 20 to 28 of 144, where Alternative B2 was ultimately selected.

Draft tube maintenance gate options are summarized in Exhibit B-7, Attachment 5 to BC Hydro's response to BCUC IR 1.93.1 (Powerhouse Alternative Assessment Report) on pages 111 to 117 of 144, where Alternative B1 was ultimately selected.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.5.1 Please provide a copy or reference the final report that recommends these preferred options with supporting reasons.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.29.5.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.6 Please discuss the following IRs related to turbine capacity verses efficiency.

RESPONSE:

Please refer to BC Hydro’s response to BCUC IRs 2.29.6.1 and 2.29.6.2.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.6.1 Is there merit in using different turbine efficiency designs in the proposed solution? Specifically, given the dispatch regime of the Ruskin facility is there any advantage to having say one unit designed for capacity efficiency and the other two units designed for peak efficiency? For instance design one unit to peak for required fish flows and the other two units for differing levels of plant output. Please discuss.

RESPONSE:

BC Hydro decided to target three units designed for peak efficiency for the following reasons:

1. **It is more cost-effective to have the turbine manufacturer only design one common turbine runner and there would also be impacts to the Project schedule if the manufacturer is required to produce two designs.**

2. **Having three identical units provides simpler operating procedures during planned or forced unit outages.**

3. **Wider operating ranges provide a maintenance benefit. Units designed to operate over a larger efficiency range are far less likely to operate at or outside their range limits. Operation of units outside their limits would result in vibration/cavitation issues which would lead to increased wear and tear (and reduced life) on the units.**

4. **The proposed turbines designed to maximize efficiency over a greater range of flows (a flatter efficiency curve) provide BC Hydro with a greater range of flexibility in the power that can be generated at the Ruskin Facility, and how the units will be utilized in the future given that:**

   a. **The flatter efficiency curves generally translate into broader operating ranges. This is a tradeoff BC Hydro has accepted and will continue to accept given that there is a limited efficiency "sacrifice" to gain substantial increase in operating ranges.**

   b. **Often hydraulic and/or environmental constraints require BC Hydro to run "off the peak", which for a "peak capacity" unit is typically at a lower efficiency than that of a flatter designed curve. This would either limit BC Hydro's ability to operate a "peak capacity" unit, or require BC Hydro to**

constantly cycle this unit on and off which would impact the life expectancy of the unit.

c. **From the system perspective, the recent increase of variable generation wind and non-dispatchable run-of-river hydro results in the need to balance loads in real-time. System generation must be dispatchable to a much greater degree than historical demands. Units with the "flat efficiency curve" offer a more effective way to meet this need as these units will provide the variable required energy without operating outside their intended limits.**

d. **The increase of variable wind and run-of-river energy has resulted in a need for 'balancing reserves' and 'regulation' in BC Hydro's (and other operators') systems. Flexibility in unit output provided by the ability to change output while using water effectively has become more critical for BC Hydro both for operating its own system and for providing access to dispatchability services as a marketable asset. Please refer to page 3-32 and 3-33 of Exhibit B-1 for a discussion of the value of dispatchability services and increasing demand in the Western Electricity Coordinating Council region due to among other things the increasing penetration of intermittent resources.**

The benefits outlined in 4 c-d are largely attributable to the additional capacity provided by a three-unit Powerhouse.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.6.2 A typical Francis turbine's peak efficiency occurs around a 90% gate opening. Is it possible to design the turbine for maximum efficiency at maximum available flow? (i.e. further gate openings result in no additional power output due to the water passage flow restrictions.)

RESPONSE:

Yes, a turbine rating curve could be designed to target the maximum efficiency and capacity at the maximum discharge possible given the water passage restrictions.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.6.3 Are any modifications in scope to reduce the friction losses in the water passage? Please discuss the theoretical options available such as using a smooth penstock liner or paint and whether the final design will investigate these options.

RESPONSE:

The most significant modification to the water passage which results in a reduction in head losses is the replacement of the Turbine Inlet Valve with an inlet gate. Otherwise, modifications to the tunnel and penstock are not being considered:

- **Improvements to the steel penstock through use of smooth coatings would have limited benefit as disturbances in the boundary layer at the pipe surface are likely more influenced by the rivets and the short (approximately 30 m) corrugated pipe section.**

- **The concrete section of the tunnel already has a relatively smooth surface. Given the short concrete tunnel segment (less than 70 m) and large diameter (6.1 m), improvements to the concrete surface are likely to result in negligible head loss gains.**

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.7 Is a third source of cooling water supply from the tailrace (in addition to a tap and common header off each penstock) in scope? Please explain why or why not.

RESPONSE:

The cooling water supply and raw water is only to be drawn from the penstocks. While a backup supply pumped from the tailrace would be preferred, during normal tailrace levels (at elevation 1.7 m) feasible pump locations in the powerhouse resulted in pump systems requiring too great a suction lift to guarantee trouble free operation.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.7.1 Will the cooling water pipes be constructed of stainless steel to ensure an operating life of 40+ years as was done at SFN? If not, why not?

RESPONSE:

All water supply pipes are intended to be constructed of stainless steel to provide the desired operating life.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.7.2 Will all service water piping be constructed of stainless steel (raw water, fire protection, HVAC etc). If not, why not.

RESPONSE:

All water supply pipes are intended to be constructed of stainless steel to provide the desired operating life.

British Columbia Utilities Commission Information Request No. **2.29.7.3** Dated: **May 18, 2011** British Columbia Hydro & Power Authority Response issued **June 16, 2011**	Page 1 of 1
British Columbia Hydro & Power Authority **Ruskin Dam and Powerhouse Upgrade Project CPCN Application**	**Exhibit: B-10**

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.7.3 Will exhaust heat from the generators be utilized to heat the Powerhouse and/or control room as a PowerSmart initiative? If not, why not?

RESPONSE:

Exhaust heat from the generators will be used to heat the Powerhouse generating hall and potentially the space currently being used as the machine shop. An energy study was performed to investigate if the waste heat from the generators could be utilized for the north wing of the Powerhouse and also the Ruskin Facility offices located near the generating station. The report determined that the most efficient means of utilizing the waste heat from the generator would be with a heat pump system. This report also determined that given the relatively small heating loads outside of the main Powerhouse open area, the limited occupancy over the year (especially during the winter months), and climatic conditions, a heat recovery heat pump system would not be economic. In short, capital costs would be high compared to the minor energy savings that could be realized.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.7.3.1 Will exhaust heat from one unit be piped to a shut down unit in order to keep the stator dry and prolong the life of the windings? If not, why not?

RESPONSE:

Waste heat from the generators was not intended to be used to keep the stator of neighbouring units dry. Vendors will likely prescribe thermostat controlled electric heaters to service this purpose. Given the limited capacity of the Ruskin Facility units, increased costs, increased complexity and temperate climate of the area in which the Ruskin Facility is situated, installation of equipment for using generator waste heat in this manner was not viewed as a cost-effective solution.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.8 Please clarify if the existing powerhouse cranes are to be replaced with a single 240 MT crane (or higher) or two 130 MT cranes?

RESPONSE:

The existing Powerhouse cranes are to be replaced with a single 240 Metric Tonne (MT) crane.

British Columbia Utilities Commission Information Request No. **2.29.8.1** Dated: **May 18, 2011** British Columbia Hydro & Power Authority Response issued **June 16, 2011**	Page 1 of 1
British Columbia Hydro & Power Authority **Ruskin Dam and Powerhouse Upgrade Project CPCN Application**	**Exhibit:** **B-10**

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.8.1 Please clarify if the new crane capacity will accommodate the heaviest component(s) contemplated to be installed in the powerhouse.

RESPONSE:

The new crane will have sufficient capacity to accommodate the heaviest component during installation. This is expected to be the weight of the rotor (at 500,000 pounds or 227 MT).

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.8.2 Will the new crane(s) be capable of lifting the rotor and turbine in a single lift or must they be decoupled at the shaft?

RESPONSE:

The rotor and turbine will have to be decoupled before removal. There is insufficient headroom within the Powerhouse to lift and carry the rotor shaft and turbine as a single unit.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.8.3 Please confirm that the crane rails and support columns will support a 240 MT or greater lift.

RESPONSE:

The crane rails will be replaced to accommodate the loads from the new crane. The support columns are strong enough to support the maximum crane lift.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.8.4 Please comment if one of the old cranes could be utilized at WAH (or elsewhere) or if this option is considered uneconomic.

RESPONSE:

BC Hydro determined that reuse of the cranes at Wahleach Generating Station near Hope in the Fraser Valley would not be economic. Exhibit B-7, BC Hydro's response to BCUC IR 1.4.1 discussed the costs and risks associated with refurbishment vs. replacement for the Powerhouse crane.

29.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.93.1, Attachment 2
User Requirements

2.29.9 Please discuss if the shingle bolt flume could be utilized for fish (salmon) passage.

RESPONSE:

The shingle bolt flume has been removed.

BC Hydro has reviewed the issue of whether the Ruskin Facility could be redesigned in such a way to permit this fish passage. Please refer to Exhibit B-1, Appendix H-1, page 271 of 345:

- **BC Hydro engaged experts – Global Fisheries Consultants Ltd., Hay & Company Consulting Inc. and White Pine Environmental Resources Inc. – who concluded in a report entitled "Evaluation of Restoring Historic Passage for Anadromous Fish at BC Hydro Facilities" (Fish Passage Report) dated June 2001 that the existing Ruskin Facility had major impediments to reintroduction of salmon and therefore it would not be feasible to provide upstream and downstream passage. A copy of the Fish Passage Report is provided as Attachment 1 to this response, and in particular refer to the summary and Table 4/section 7.3, conclusion 2; and**

- **BC Hydro also developed a "Fish Passage Framework for BC Hydro Facilities" (Fish Passage Framework). A copy of the Fish Passage Framework is provided as Attachment 2 to this response.**

Copies of the Fish Passage Report and the Fish Passage Framework were sent to Kwantlen on November 24, 2010.

Evaluation of Restoring Historic Passage for Anadromous Fish at BC Hydro Facilities

Eicher fish screens pass downstream migrants at Puntledge Diversion Dam

JUNE 2001

Prepared for

Power Supply Environment
BC Hydro
Burnaby, BC

Prepared by

W. Bengeyfield
Global Fisheries Consultants Ltd., White Rock, BC

D. Hay and S. Joyce
Hay & Company Consulting Inc., Vancouver, B.C.
J. Greenbank
White Pine Environmental Resources Inc., Vancouver, BC

Evaluation of Restoring Historic Passage for Anadromous Fish at BC Hydro Facilities

June 2001

Prepared for

Power Supply Environment
BC Hydro
Burnaby, BC
V3N 4X8

Prepared by

W. Bengeyfield
Global Fisheries Consultants Ltd., White Rock, BC

D. Hay and S. Joyce
Hay & Company Consultants Inc., Vancouver, BC

J. Greenbank
White Pine Environmental Resources Inc., Vancouver, BC

Summary

A study of the feasibility of restoring historic access for anadromous stocks was suggested as a potential fish restoration objective in the *Strategic Plan* of the Bridge-Coastal Fish & Wildlife Restoration Program. BC Hydro commissioned the present scoping study to identify the hydroelectric facilities which had blocked historic access, and to evaluate the biological, technical and management risks and potential for successful re-introduction at each candidate facility.

Five dams—Coquitlam (1914), Alouette (1924), Ruskin (1930), Terzaghi (1948), and Wilsey (1929)—now owned by BC Hydro were found to have blocked the historic access of anadromous fish populations at the time of construction. Fish passage structures were not provided at these five dams according to individual agreements with the Federal Fisheries Department which waived their general requirement that all manmade obstructions in rivers were to be provided with a fish ladder. Three other dams—Comox (1912), Puntledge (1912) and Seton (1956)—were built on anadromous-bearing rivers where the Federal Fisheries Department insisted that fish ladders be provided.

From BC Hydro's perspective, an anadromous fish re-introduction project could have long-term liabilities, whether the project succeeds or fails, that are additional to the initial costs of providing passage structures. Potential risks to future operations would need further discussion and resolution with the fish resource agency before a collaborative re-introduction project was initiated.

The study examined the existing information on facilities and on the passage requirements of adult and juvenile anadromous fish. The most important factors affecting re-introduction were dam height, interbasin diversion of water, reservoir drawdown, upstream habitat capability, and biological interactions with resident fish populations. Financial cost was not considered in this pre-feasibility study; however, costs were expected to range significantly according to the level of complexity of the necessary passage structures.

Interbasin diversions impose two major difficulties for anadromous fish populations. First, juvenile fish seeking to migrate out of the reservoir would be attracted to the large flow volumes diverted to the other river system, and be less likely to locate the comparatively minor flow over the dam. To screen and collect the juvenile migrants at the diversion intakes, and transport them to the diminished river below the dam is considered technically challenging. In general, downstream passage of juveniles has been successful at reservoirs and facilities where large flows are either released through turbines or spillways, or where smaller diversion flows are released from surface withdrawals. There is no precedent known for the successful bypass of fish from a reservoir where flow is withdrawn at depth from the reservoir at a location distant from the dam. Three of the five candidate reservoirs (Alouette, Coquitlam, Carpenter) divert large proportions of their water to other watersheds through tunnels whose intakes are located approximately 16, 3 and 5 km away from the respective dams. Second, the biological ability of returning adults to find the diminished flows of the natal river, and not stray to the diversion discharge is a concern with respect to future spawning escapements. The intrabasin diversion factor alone suggested a reduced likelihood of successful re-introduction at Alouette, Coquitlam, and Carpenter reservoirs; other major impediments were also associated with these sites.

Ruskin Dam was also judged to have major impediments to anadromous re-introduction; specifically, insufficient habitat capability within Hayward Reservoir and its tributaries, and dam height.

Wilsey Dam at Shuswap Falls was considered the only potential candidate facility for anadromous re-introduction, with chinook and coho salmon as the principal target species. A detailed feasibility study was recommended to develop conceptual designs and cost estimates, and to engage the fisheries resource agencies in preparing a stock management plan.

Evaluation of Restoring Historic Passage for Anadromous Fish at BC Hydro Facilities

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Evaluation of Restoring Historic Passage for Anadromous Fish at BC Hydro Facilities

1. INTRODUCTION

1.1 Background

Anadromous salmonid fish are distributed throughout the Bridge River-Coastal Generation Area but are not present in the Peace or Columbia systems[1]. The Bridge-Coastal Area includes 29 principal dams located within 15 major watersheds in the Vancouver Island, Lower Mainland, coastal British Columbia, and Interior Fraser regions (Figure 1). Construction of the dams in the Bridge-Coastal Area occurred over a sixty-year period, from 1902 (Buntzen Dam) to 1962 (Clayton Falls Dam); most of these were built by other developers and later consolidated under the responsibility of BC Hydro.

Several of these dams blocked the historic migrations of salmon and steelhead. Yet, all of Bridge-Coastal's regulated rivers continue to support anadromous fish populations downstream of the facilities, with the exceptions of Clowhom and Buntzen dams where minimal freshwater habitat exists between the historic barriers and the ocean.

BC Hydro began a preliminary review of anadromous fish passage at its facilities in mid-2000, about the same time that the Strategic Plan for the Bridge–Coastal Fish and Wildlife Restoration Program was developed (BCRP 2000). That preliminary passage review has been largely re-drafted here to include (i) the updated historical information that was provided in the Watershed Plans (BCRP,Vol.2), and (ii) an overview of technical feasibility at appropriate facilities.

1.2 Study Objectives

[1] Anadromous fish formerly ascended the Columbia River into Canada prior to the development of Grand Coulee Dam that began in 1933; it did not have a fishway due to its height of 168 m (550 feet).

The scope of this study is to identify the principal factors affecting the issue of re-introducing anadromous stocks where they were present at the time of dam construction. It assembles existing and new biological and technical details in order to screen for candidate facilities that would be suitable for a further study of passage costs and benefits.

The objectives of this study are to:

(1) review the status of all Bridge-Coastal facilities to determine whether anadromous salmonids migrated to habitats upstream of the dam at the time of initial construction;

(2) describe conditions at facilities that did not have historic anadromous stocks;

(3) review the current conditions at facilities that have anadromous stocks;

(4) review the historic and current conditions at facilities that excluded anadromous stocks;

(5) present the historical decisions that led to the waiver of requirements for a fish passage structure;

(6) assess, at an overview level, the feasibility of restoring access for historic stocks by considering biological, technical and operational constraints;

(7) identify the current deficiencies in information; and

(7) recommend facilities for a detailed feasibility study, as warranted.

This study identifies which of BC Hydro's dams blocked historic access by anadromous fish, and at a pre-feasibility level, assesses whether the provision of passage structures and the general operations at those facilities could be harmonized with a re-introduction of fish species that will become self-supporting wild stocks.

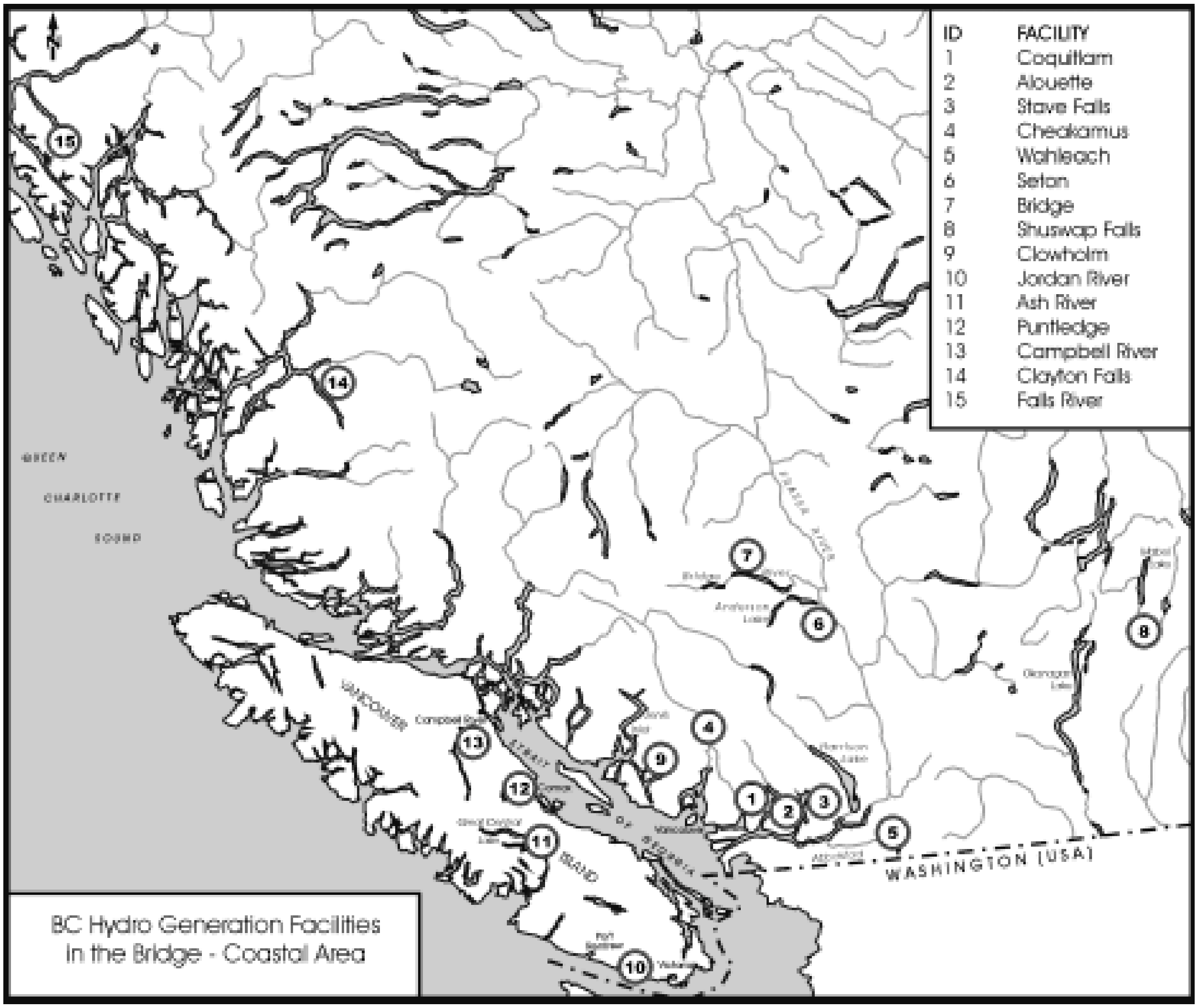

Figure 1. Map of Bridge-Coastal facility locations.

2. DEFINITION OF TERMS

Certain technical terms are presented here in order to clarify their specific meaning within the context of this report.

The term ***anadromous fish*** is used in a restricted sense for convenience and refers here only to the larger sized salmonid species, *i.e.*, steelhead trout or the five native species of Pacific salmon that necessarily must migrate between freshwater and marine environments. The other anadromous species in BC waters—cutthroat trout, Dolly Varden char, sturgeon sp., lamprey sp. and others—were excluded from this analysis for one or more reasons:

- their historic distribution and abundance was poorly documented; or
- their ability to use the common upstream passage structures provided at dams is generally less than salmon and steelhead.

The terms ***population, run*** or ***stock*** are used interchangeably to refer to a distinct genetic group of the same species that tend to migrate to a river and interbreed at a particular place and time. There is much recent scientific discussion about what theoretical minimum numbers of individuals it takes to constitute a viable population. At an overview level, we consider a *run* to be an annual presence of reasonably significant numbers[2], although some endangered stocks, particularly steelhead, have managed to persist with fewer spawners.

Habitat capacity refers to the current existing condition of a waterbody or locality to produce fish biomass; ***habitat capability*** refers to the sum of existing capacity plus the potential gain in fish productivity if the habitat could be improved by construction of complexing features or increased if migration barriers could be made passable.

A ***historic*** population refers specifically to a salmon or steelhead population that is known to have migrated to natal habitats upstream of a hydroelectric dam prior to its construction. This

[2] The US National Marine Fisheries Service considered that 100 spawning pairs was the minimum population size required to avoid irretrieveable genetic losses. Considering the variance in managing for annual escapements, a target spawning population for a new re-introduced stock of Pacific salmon should probably contain at least 1000 pairs.

definition suggests that (i) pre-dam migratory access was possible in most years; and (ii) the number of fish returning to upstream habitat was a substantive portion of the total stock. An historic population is not indicated by occasional or small numbers of fish that were able to ascend natural barriers opportunistically during unusual passage conditions every few years. In other words, where upstream distribution was irregular due to natural obstructions, we infer that the main stock was historically supported by the capacity of downstream habitats.

Due to their exploratory nature and innate attraction to strong current flows, anadromous fish will often ascend a stream and test a barrier before returning downstream to spawn. The exploratory nature of adult salmonids prior to spawning has enabled them to colonize newly accessible rivers as glaciers retreated from lowlands. While anadromous stocks are known for their fidelity to a ***natal*** (home) stream, a low incidence (1-3%) of spawners may stray naturally to other streams, sometimes at considerable distance (Lister *et al.* 1981). ***Straying*** is the phenomenon of adult fish spawning in a stream other than the stream in which it was planted as a fry or from which it emerged as a result of natural spawning . Straying adults may enhance species success because they sometimes find new streams to colonize and begin new stocks, or introduce new genetic components to local stocks. Spawners arriving early in the migration, especially during good flow conditions, tend to explore more than late arrivals, and sometimes dig false redds in inappropriate locations before moving elsewhere for final spawning (Briggs 1953). Reports of fish jumping at waterfalls may be attributable to exploration and straying, and do not always indicate there is a natal area upstream. Some historic sightings of adult fish may not represent the final location of spawning.

Physical obstructions, barriers or ***blockages*** that impede upriver fish migration occur naturally, such as waterfalls, high velocity chutes, or beaver dams, or they may be hydroelectric or irrigation dams without fishways. Some are ***absolute*** barriers, such as the 30 m vertical Elk Falls in the lower Campbell River; smaller ***partial*** barriers occur in many rivers where upstream passage depends on the coincidence of favorable conditions of streamflow, water temperature, fish size and vitality.

Anadromous fish require passage in two directions at hydro dams during two life stages: upstream passage for the adult fish during its spawning migration is generally considered to be the requisite first step; however, successful passage in both directions is required for stock viability. An ***upstream passage structure*** is designed to enable adult anadromous fish to ascend a dam from the river up into the reservoir. Fishways or fish ladders are the most common type of upstream passage structure although other devices exist. A ***downstream passage structure*** enables the juvenile anadromous fish to migrate from the reservoir elevation down to the river below the dam.

Where downstream passage structures are not provided at dams, migrants take one of two other routes: (i) water ***spills***, or (ii) ***entrainment*** through the turbine into the tailrace. Provision of safe downstream passage conditions can be more difficult to achieve than adult upstream passage, since the smolts are particularly sensitive to injury and often incur mortality or injury when they use any of the three routes. In the early years, downstream migration was rarely considered to need special structures, and juveniles were left to find their own way out of the reservoir. Later, it was realized that downstream losses could be significant as the fish passed the dams, and particularly when the project involved a diversion of flow to another basin or into the powerhouse (see ***diversion of water flow*** below).

Entrainment of fish into facility intakes or diversion structures differs in magnitude of impact according to two categories of fish: (i) anadromous stocks whose life cycle requires a seasonal migration downstream past the dam to the sea; and (ii) resident fish species that undergo local downstream movements. Entrainment of anadromous stocks is usually considered to be more serious because of their obligatory need to access the marine environment, and their traditional abundance and economic value. Fish screen structures are often prescribed to mitigate entrainment impacts, but screens also cause mortality and have other technical limitations regarding fish size, maximum approach velocities, and debris cleaning, that can restrict their application (Rainey 1985). Entrainment of resident fish is poorly understood and studies are currently underway in Canada and the US on this aspect (RL&L Environmental Services Ltd. 2000).

Impingement is the physical contact of fish against trash racks, fish or debris screens or other objects during their entrainment through a facility. The rate of mortality or injury sustained by fish tends to increase as branches and small wood debris collect on the racks and reduce the available open area. Impingement can be reduced by more frequent maintenance cleanings, but this operation may affect fish in other ways because plant shutdowns are necessary.

Diversion of water flow is a technique used at certain hydroelectric projects to increase the amount of power produced by (i) increasing the vertical drop of water, or (ii) increasing the available quantity of water to be stored. A diversion dam impounds flows from one drainage and redirects the water to a new location via penstock, tunnel or canal. This causes a reduction in the quantity of water continuing down the original channel. This 'splitting' of flows can be adjusted by mechanical devices to suit short-term hydroelectirc operations, but the long-term power production from a diversion project has been designed to operate using consistent quantities of water removed from the original channel. Diversions either shunt water from one basin to another (interbasin), or within the same basin. Interbasin diversion projects create significant challenges to the re-introduction of anadromous salmonids (Section 6.2.1).

3. STUDY APPROACH

3.1 Assumptions

BC Hydro has the authority to operate as specified in its water licenses issued under the Provincial Water Act. This study assumes that BC Hydro would be disinclined to consider fish passage initiatives if they pose significant risks to future operations. At the same time, it is also BC Hydro's corporate environmental policy to protect habitat capability, in terms of fish production potential, associated with their facilities. BC Hydro fully supports cooperation with environmental agencies and attempts to harmonize the production of hydroelectric power and fish as benefits to society. In the past decade, BC Hydro has been proactive in its attempts to mitigate long-standing fish impacts when new technologies or opportunities arise, such as the Eicher screens at the Puntledge Diversion Dam, the louvers at the Seton Dam, and recent collaboration with the fisheries resource agencies on the Salmon River fishway and screen structures. BC Hydro remains committed to continue all reasonable efforts to protect the interest of the fisheries.

BC Hydro has agreed to consider providing passage structures for anadromous fish through the Bridge Coastal Restoration Program where the historic distribution of such stocks had been blocked by dam construction. BC Hydro is not obligated to provide such passage now, since the Department of Fisheries and Oceans' *No Net Habitat Loss Policy* is not retroactive. When construction began in 1903 on the first hydroelectric dam in British Columbia (Coquitlam), the statute to provide fishways at dams was already in force. The dams that did block anadromous fish were constructed with the knowledge and approval of the Federal Fisheries Department when the licenses were granted (Appendix C). Where the agency determined that stocks would be impacted, they clearly insisted on a fishway as indicated by the protracted case of Comox Dam between 1912 and 1922.

The following conditions for a proposed re-introduction of anadromous fish are assumed by BC Hydro:

1. That BC Hydro, having responsibility for the present operation of their facilities to produce electrical power, would consider the prospect of restoring anadromous fish stocks through the Bridge Coastal Restoration Program at those locations where fish access to former historic habitats had been blocked by construction of the dams;

2. That BC Hydro would reserve all future rights to alter its primary operations on short-term notice without conditions, to accommodate other water management priorities or uses as defined in the respective Water Use Plans at their discretion, and would not be subjected to charges under the various fisheries acts if such actions prove to have an adverse impact on the re-introduced fish or their habitats above the dam;

3. That BC Hydro would consider contributing some or all costs through the Bridge Coastal Restoration Program to design, plan, install and modify such passage structures at their facilities, and furthermore agree to maintain them in good working order, all of which as jointly agreed by both BC Hydro and the relevant fisheries agencies;

4. That BC Hydro expects that the initiating agency(ies) would contribute all costs to the planning, development and management of the target stocks, including all aspects of the necessary biological pilot studies discussed later in Section 7.1;

5. That BC Hydro would consider sharing through the Bridge Coastal Restoration Program in reasonable costs to increase the present habitat capacity in the upper watershed if this is judged to be a limiting factor; and

6. That the re-establishment of such stocks will be entirely the responsibility of the relevant fisheries agency(ies) with the ultimate plan that the population(s) will become self-supporting (*i.e.*, wild stocks) after a reasonable and defined start-up period, and if this condition cannot be achieved within said period, that all future responsibility and costs for the ongoing management, daily operations and special flow variances, that may be requested of BC Hydro outside of a Water Use Plan to support the population from time to time, will be entirely born by the relevant fisheries agency (ies).

3.2 Framework for Re-introduction

Any new initiative to re-introduce anadromous fish stocks in historic habitats above a dam will incur large financial expenditures, and has the potential to constrain the efficiency of future operations to produce power. The implications to BC Hydro are significant, and the success of a stock re-introduction initiative is by no means assured. This report presents a framework to organize the complexities of the concept at an overview level, and applies this framework to the five hydro dams where historic access was compromised. The facilities will be examined through the screening process of the framework shown in Figure 2. An example of the specific decision process is shown in Figure 3.

The major elements of this framework were previously outlined in the recent Strategic Plan[3] of the BCRP (2000). The topic of re-introduction had been raised briefly during the Plan's information workshops held in Kamloops, Nanaimo and Vancouver, where the interest appeared to focus on the technical feasibility of providing upstream passage structures.

The BCRP Plan subsequently acknowledged that technical feasibility was indeed important, but that biological, operational, and management considerations had equally critical roles in the future success of such a venture. The BCRP Plan did not apply these considerations to the individual facilities, in part because determinations of historic fish access had not been fully completed. The Plan did recommend that a future study should "*address the feasibility of restoring historic access for anadromous stocks*" within the fish restoration objectives of certain watershed plans.

The BCRP Plan outlined the following approach regarding anadromous re-introduction:

> "*Proposals to re-establish former anadromous runs to the Puntledge, Alouette, Stave, Coquitlam, Bridge or Shuswap reservoirs would require careful analysis and planning. Consideration should be given not only to technical feasibility, but also to the biological soundness and the management implications for agencies and BC Hydro alike for developing and fostering a new run, as outlined: (some points adapted from Triton 1994)*

[3] BCRP, Vol. 2, Chap.1, Section 3.2—*Feasibility of Re-establishing Anadromous Fish Stocks.*

Figure 3. Decision Process.

STEP I. DETERMINE CANDIDATE FACILITIES

FACILITY A (B, C, ..)

1. Was an anadromous fish population present upstream of the dam at the time of its construction?
Yes ……….. 2
No …….. STOP

STEP II. ASSESS BIOLOGICAL FEASIBILITY

2. Does sufficient habitat exist upstream of the dam that is useable under present WUP operations, to support the life cycles and target numbers of the proposed species necessary to achieve a self-sustaining wild population?
Yes …..……. 3
Uncertain: Conduct field biophysical study of appropriate factors, then answer No.2.
No ……… STOP

3. If existing habitat is insufficient (re: No.2), could additional habitat capacity be (i) constructed, (ii) made accessible, or (iii) made suitable by changing BCH operations?
Yes ……… 4
No ……. STOP

4. Are biological interactions expected that would negatively impact resident fish populations?
Yes …..… STOP
Uncertain: Conduct study and consult MELP, then answer No.4.
No ………..… 5

STEP III. ASSESS TECHNICAL FEASIBILITY

5. Does the project divert significant portions of reservoir inflows at critical biological seasons to another basin?
Yes …..… STOP
No ……….. 6

6. Does the height or layout of the dam preclude the construction of an upstream fish passage structure?
Yes ..…..… 7
No ……… 8

7. Is there outside support for annual trap and haul operations to return adult spawners above the dam?
Yes ……… 8
No ……. STOP

8. Proceed with a detailed feasibility study of re-introducing anadromous fish at Facility, including conceptual design and options for upstream and downstream structures, forecast of costs, and negotiating agreements with agencies re: concerns presented in Section 3.1.

*"**Biological Soundness***

- *What donor stock is available? Does it have genetic links to, or exhibit vital characteristics of, the historic stock? Has the target species been transplanted successfully elsewhere (e.g., Andrew & Killick 1957)?*

- *What are the ecological implications of re-introducing the target species as competitor or predator to the population dynamics within the present reservoir? Is this species a potential host or vector for disease transmission?*

- *Are sufficient spawning, rearing and overwintering habitats available in the reservoir and its tributaries to sustain the necessary life stages? If not, what is the feasibility and cost of enhancing or creating such habitat? Are the key habitats at risk to future forestry impacts?*

- *What population size and habitat quantities are necessary to make the stock self-sustaining?*

- *Can aquatic productivity of the current reservoir be restored to match the levels in the original habitat?*

Technical and Engineering

- *Are there physical impediments to upstream migration in the river that require alteration?*

- *What is the proposed route to bypass the downstream migration of juveniles? Test the survival rates of downstream passage through existing turbines and over spillways under the range of expected flow conditions. What survival rates would be necessary to allow the new population to become established?*

- *If unaided [downstream] passage mortality were too high, what additional structures would be suitable for retrofit (surface or gatewell collectors, fish screens, louvers) based on the size characteristics of the migrant fish?*

- *What is the inherent mortality rate of these passage structures?*

Management

- *What changes to BC Hydro operations would be required to facilitate a successful reintroduction? Would the fishway be able to operate at different reservoir levels during upstream and downstream migration? Would water releases be necessary to get adults upriver in some years? What is the stranding potential during downstream migration that may require higher flow releases? What are the probabilities of spills at this facility at critical biological periods?*

- *Will the expected fisheries on this new stock be managed to permit the stock to increase without compromising other stocks, or is the new stock likely to co-mingle with other stocks that will be fished at high exploitation rates? Have other unmanageable sources of mortality, such as the seal predation at Puntledge River, been identified that may further impact juvenile production or adult escapements?*

The foregoing criteria suggest a complex set of biological, physical and management conditions that must be present before anadromous stocks are successfully restored to a former watershed. Whether a fishway can be constructed to provide passage over a particular dam may be one of the easier challenges to overcome." - BCRP (2000).

As a result of the BCRP recommendation, the present study was commissioned to present existing and new data that advance some of these questions. Our approach follows that of the BCRP which suggested that the feasibility of successful re-introduction must address a wider scope of additional components beyond the technical ability and cost to provide fish passage structures.

4. METHODS & SOURCES

The determination of historic presence of anadromous fish began with a review of Hirst (1991) and subsequent updating and corrections by BCRP (2000). Our study has made further substantial efforts to search and clarify the situations at Clowhom, Elsie Lake, and Sugar Lake dams where anadromous presence has been alleged but not substantiated. Enquiries were made to fisheries agencies' personnel, reports and files; BC Archives in Victoria; Federal Archives in Burnaby; Pacific Salmon Commission archives in Vancouver; and contacts with local informants.

Information on existing habitat capacity upstream of the dams was gleaned largely from government and consultant reports obtained from BC Hydro and the BC Ministry of Environment, Lands and Parks (MELP), Surrey. Biological data was also found in Internet searches of the FISS / FishWizard database; a search of MELP files for Coquitlam, Alouette and Hayward reservoirs; contact with the Greater Vancouver Water District; and discussions with MELP fisheries staff.

Descriptive statistics of the facilities and data about the existing fish passage structures were provided by Power Supply Engineering, BC Hydro. Physical characteristics of each facility, such as dam type and height, and the annual operations that regulate water movements for power production are integral to assessing compatibility with the re-introduction of fish.

The assessment of technical feasibility at the five facilities was made by Hay & Company Consultants Inc., Vancouver, BC. Their information is presented as full reports in Appendices E and F. We have abstracted some of their key conclusions in our discussion.

5. HISTORIC PRESENCE OF ANADROMOUS FISH

5.1 Determination of Historic Presence and Target Species

We examined records for the 29 major facilities located within the Bridge-Coastal Area to identify facilities which blocked anadromous fish (Table 1). For the latter, facility and biological data were summarized in Appendix D. Facilities which had no documented blockage of anadromous passage were dismissed from further discussion but facility characteristics relevant to fish passage were summarized in Appendix A.

The group of eight dams with confirmed anadromous presence was divided into facilities that (i) were provided with passage structures, and (ii) those currently without passage structures. The detailed summaries of these facilities are presented in Appendices B and C, respectively.

Where information was found on historic anadromous stocks, we documented the species, their abundance and former habitats to the extent possible. Such information forms the basis of the target stocks for potential re-introduction. Archival material reviewed during this research suggested that the identification of species by fisheries agency personnel was at times in error, such as the mention of chum salmon in the upper Shuswap River system, and landlocked Atlantic salmon in Comox Lake in the period 1918-1923. Early correspondence suggested that the public was also confused about the common names of fish species.

Future historical research may uncover documentation that adds other dams to the category of historic anadromous presence. Our archival research indicated that the Federal and Provincial fish agencies, even in the earliest decades of the century, had a surprising and considerable awareness about the distribution of salmonid resources and their spawning grounds in many parts of the Bridge-Coastal Area. Unconfirmed reports of anadromous passage at Clowhom, Elsie Lake, or Sugar Lake dams, if true, most likely represented small numbers of fish that were able to ascend, on an irregular basis, the significant natural barriers below those sites. Applications to construct the facilities listed in Appendix A would have been scrutinized by the Federal Fisheries Department who determined that substantive salmon populations were not present.

Table 1. Principal dams in the Bridge Coastal Generation Area.

WATERSHED Dam	First Completed	Original Developer	Historic Anadromous Fish Presence*
CAMPBELL RIVER			
Strathcona Dam	1958	B.C. Power Commission	No
Ladore Dam	1949	B.C. Power Commission	No
John Hart Dam	1945	B.C. Power Commission	No
QUINSAM RIVER			
Wokas Lake Dam	1957	B.C. Power Commission	No
Quinsam Diversion Dam	1958	B.C. Power Commission	No
SALMON RIVER			
Salmon Diversion Dam	1958	B.C. Power Commission	No
HEBER RIVER			
Heber Diversion Dam	1958	B.C. Power Commission	No
PUNTLEDGE RIVER			
Comox Dam	1912	Wellington Collieries Ltd.	Yes
Puntledge Diversion Dam	1912	Wellington Collieries Ltd.	Yes
ASH RIVER			
Elsie Dam	1957	B.C. Power Commission	No
JORDAN RIVER			
Bear Creek Dam	1911	Vancouver Island Power Co.	No
Jordan Diversion Dam	1911	Vancouver Island Power Co.	No
Elliott Dam	1971	B.C. Hydro	No
ALOUETTE RIVER			
Alouette Dam	1924	Burrard Power Co.	Yes
STAVE RIVER			
Stave Falls Dam	1911	Western Canada Power Co.	No
Ruskin Dam	1930	B.C. Electric Railway Co.	Yes
COQUITLAM / BUNTZEN			
Coquitlam Dam	1904	B.C. Electric Railway Co.	Yes
Buntzen Dam	1902	B.C. Electric Railway Co.	No
JONES CREEK (WAHLEACH)			
Wahleach Dam	1951	B.C. Electric Co.	No
Boulder Cr. Diversion Dam	1951	B.C. Electric Co.	No
BRIDGE RIVER			
La Joie Dam	1948	B.C. Electric Co.	No
Terzaghi (Mission) Dam	1948	B.C. Electric Co.	Yes
SETON RIVER			
Seton Dam	1956	B.C. Electric Co.	Yes
MIDDLE SHUSWAP RIVER			
Sugar Lake Dam	1929	West Canadian Hydroelectric Corp.	No
Wilsey (Shuswap Falls) Dam	1929	West Canadian Hydroelectric Corp.	Yes
CHEAKAMUS RIVER			
Cheakamus Dam	1957	B.C. Electric Co.	No
CLOWHOM RIVER			
Clowhom Dam	1952	B.C. Power Commission	No
BIG FALLS CREEK			
Falls River Dam	1930	Northern B.C. Power Co.	No
CLAYTON FALLS			
Clayton Falls Dam	1962	B.C. Power Commission	No

* at time of construction

5.2 Facilities With Current Anadromous Stocks

The Puntledge-Comox, Seton, and Salmon systems currently support salmon and steelhead stocks upstream of the four dams. Anadromous fish were historically present at Puntledge Diversion (constructed 1912), Comox (1912) and Seton (1956). These three dams were built or retrofitted with an upstream passage structure. Comox Dam did not have a useable fishway for 10 years until September 1922 when the Federal Fisheries Department and Canadian Collieries (Dunsmuir) Limited finally came to agreement.

Salmon Diversion Dam (built 1958) was not one of the eight dams classified as having anadromous fish present at construction. It represents a special category where anadromous fish were historically present, but were subsequently blocked by railway debris downstream of the dam site (J. Bomford, MELP, pers. comm.). After the dam was built, the debris was cleared and fish returned to the dam in 1976 (Appendix B).

Downstream passage structures have been provided at three of the four facilities (Appendices B and E). Juvenile fish at Comox Dam generally pass through the gates but this has never been identified as a concern by the fisheries agencies. At Salmon and Puntledge, fish screens remove juvenile downstream migrants from the diverted flows. Seton Dam incorporated a variety of downstream passage structures but their combined effectiveness has been low under some discharge conditions. In 1999, BC Hydro began testing louvers to deflect migrants closer to the intakes of the passage structures and thereby improve their efficiency.

5.3 Facilities That Excluded Anadromous Stocks

Five of the 29 major Bridge-Coastal dams blocked the historic access of anadromous stocks because they were not provided with upstream passage structures. These dams were Coquitlam[4] (built 1914), Alouette (1924), Ruskin (1930), Terzaghi (1948[5]), and Wilsey (1929). Details of the individual case histories of the five dams are provided in Appendix C.

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[4] The small initial Coquitlam Dam had a fishway, but the larger replacement dam was constructed three years later without a fishway.

[5] Federal Fisheries approval was obtained in 1920.

6. DISCUSSION OF FACTORS

6.1 Historical Context

During the search for historic information, we reviewed available files of agency correspondence related to obstructions of salmon rivers, and the provision of fish passage structures at dams as required by the Fisheries Act. These files provided historical reasons given by the Federal Fisheries Department for granting variances to the fishway requirement.

6.1.1 Awareness of Obstruction Impacts

The Fisheries Act regulations pertaining to dams and obstruction of fish passage preceded the the first hydroelectric development in British Columbia (Coquitlam-Buntzen project) in 1903 (Koop 1994). Federal Fisheries correspondence files show that the Department was very much concerned with obstructions ranging from hydroelectric and irrigation dams, log jams, and beaver dams throughout the Province (Prince 1903).

Five BC Hydro dams—Coquitlam (1914), Alouette (1924), Wilsey (1929), Ruskin (1930) and Terzaghi (1948)—permanently blocked salmon passage. These five facilities were granted variances from the Federal fishway requirement, while three dams—Comox (1912), Puntledge Diversion (1912) and Seton (1956) constructed during this period were required to have fish ladders. Comox Dam, constructed coincidently with the Puntledge Diversion Dam which had a proper fishway, was represented by the owner that the gates and log sluice opening would allow fish passage to Comox Lake. When Federal Fisheries recognized this was not satisfactory, it took ten years of correspondence and meetings before a fishway was finally retrofitted to pass fish. Official correspondence concerning Coquitlam Dam in 1903 and Comox Dam in 1912 exemplified the early diligence by the Federal Fisheries Department in enforcing the fish passage regulations.

After reviewing much correspondence in the archival files of the Federal Fisheries Department and the Pacific Salmon Commission, one is impressed with the broad awareness of fish stocks and obstruction problems around British Columbia that existed prior to and during World War I.

Senior Federal officials at headquarters in New Westminster /Vancouver had consolidated this knowledge and applied remedial action with fair consistency. The Department's knowledge, though imperfect at times, was considerable despite the obvious difficulties in communication and logistics of the era. Similar to today, the public was sometimes instrumental in petitioning for the local fishery overseers to investigate passage obstructions or pollution incidents.

6.1.2 Avoidance of Salmon-Bearing Rivers

One of the interesting questions that arose during this study was why more hydroelectic dams had not been built on salmon-bearing rivers. The apparent answer is that the early hydroelectric plants were sufficient to service the small population of people in BC before World War II and there was little domestic need to overbuild capacity and dam the larger fish-bearing rivers. However, the economic boom in the early 1950s fostered an ambitious scheme to develop hydroelectric power throughout the Fraser River mainstem. The largest facility in this scheme was the Moran Dam, located upstream of Lillooet, BC, which would use 220 m (720 feet) of head. The physical scale of seven planned mainstem dams would have precluded all future salmon passage upstream of Hope, B.C. The experiences of the Hells Gate blockage of fish passage in 1913-14 had illustrated the magnitude of effects to be expected from building high dams on the Fraser mainstem. In fact, permanent fishways at Hells Gate had been only finally completed in 1947, less than a decade before the Moran project was proposed.

The potential effects of the fish-power problem, as it was called, on the salmon runs of the Fraser River were debated by the fisheries and power industries between 1951 and 1953. These positions were published in a series of annual British Columbia Natural Resources Conferences held in Victoria, BC. It appears that the early Columbia River experiences of Rock Island (1933), Bonneville (1938), and Grand Coulee (1941) dams provided potent arguments that prevented damming of the Fraser River (Netboy 1977). Recent technological advances in long distance power transmission meant that distant geographic areas could be explored for alternate power sources (Larkin 1956). Finally, the outcome of the debate was the decision that power development in BC would not follow the Columbia model, and the Fraser scheme was abandoned.

Following the Moran decision, BC Hydro's subsequent dams that were built on salmon-bearing rivers were either (i) sited to avoid anadromous passage problems (Quinsam, Heber, Salmon, Elsie Lake, Elliott, Clowhom, Cheakamus, Clayton Falls, Wahleach) or (ii) provided with fish passage structures (Seton). Other pending proposals on major fish streams were curtailed, *e.g.,* the smaller Ash River project compared to the larger proposal with dams on Great Central Lake, Stamp River and Sproat Lake (Water Powers of British Columbia 1954).

In 1950, prior to the fish-power debates over the Fraser mainstem, the Aluminum Company of Canada (Alcan) was granted a conditional water license to divert waters in the upper Fraser and Skeena watersheds to the Kemano River on the north coast. Although fish passage was not an issue at Kenney Dam because it was built upstream of Cheslatta Falls, the significant loss of diverted flows had serious consequences on chinook and other stocks downstream in the Nechako mainstem (DFO 1984). In 1978 Alcan proposed diverting more water from the Nechako basin, but the loss of more Nechako flow was forecast to warm the Fraser mainstem and cause passage problems downstream. In 1995, following the release of the BC Utilities Commission report, Premier Mike Harcourt cancelled the Kemano Completion Project.

6.2 Operational Considerations

This study has assumed that if fish passage initiatives posed significant changes to future operations, BC Hydro would have to consider the overall societal benefit. BC Hydro strives to operate their power projects to achieve the maximum power efficiency that is possible within the existing conditions of natural inflow, environmental constraints, and social needs. Section 3.1 presented BC Hydro's concerns that a re-introduction program could constrain their flexibility to adapt to future operating scenarios.

This report has focused on the feasibility of providing engineered structures to enable fish to pass upstream and downstream of a dam. It has not considered the potential for major changes to current operations, such as ceasing to generate power and instead spilling all inflows during the juvenile migration period. Spilling of surface water during the typical smolt migration for 4-8 weeks between April and June could represent a considerable loss of generation, require the reservoir to be already full prior to the spill (normally reservoirs are filled by the spring freshet), and reduce flexibility to adjust the storage schedule to account for annual variations in snowpack and runoff.

Other constraints could include re-designing and renovating the spillway at the dam to reduce passage mortality rates or levels of total gas pressure downstream. River channels downstream of diversion projects may now experience flooding due to their diminished hydraulic capacity associated with human encroachment, or may contain features such as fish habitat complexes or infrastructure development that would now be exposed to the full spring freshet from the watershed. At the diversion projects, the fish, wildlife and human populations that had adapted to large flows in the augmented river channel would now experience little or no spring flows during the spill down the original channel. Determination of all potential constraints would require a detailed analysis of each candidate facility that is outside the scope of this study.

6.2.1 Interbasin Diversion Projects

Within the Bridge-Coastal Area, three of the five facilities where historic fish passage was blocked represent large interbasin diversion projects—Coquitlam, Alouette, and Terzaghi. The principal effects of interbasin diversions on the biology of anadromous fish are (i) diminished flows within the reservoir leading to the dam outlet, (ii) diminished flows down the original river channel, and (iii) increased flows out of the reservoir at the diversion intake structure.

An anadromous fish re-introduction program in an interbasin diversion project is considered to incur major new risks associated with juvenile and adult migrations, that are beyond other biological constraints to be discussed in Section 6.4:

(i) Downstream migrations

Smolts and steelhead kelts seeking to leave the reservoir would be attracted to the significant outflows of the diversion where a majority of the annual production each year would be entrained. Survivors of turbine passage would be released into a foreign channel carrying their homestream water which would reduce adult success when seeking the diminished discharge from their natal river. Therefore a requirement to provide suitable fish screens may be anticipated from the agencies who may be concerned about reducing entrainment at such intakes (i) to reduce the future incidence of false attraction by returning adults, and (ii) to prevent the turbine losses expected at large changes in hydraulic head.

It should be recognised that each component of a migrant protection program—screening, and possibly fish collection, handling and transportation—will confer its own level of mortality. The numbers and quality of the smolt populations that are finally released, after screening and handling, below a dam may be of similar magnitude to those that would have survived passage through a turbine, depending on turbine type and hydraulic conditions. Survival rates of 85% or greater are typical at dams with 30 m of head (Bell 1981), but rates drop to 50% where the head reaches 120 m (Eicher Associates 1987). The rates of mortality associated with various protection measures or turbine passage are influenced by the specific flow conditions encountered during migration.

Other issues with protection programs include annual smolt salvages that need to be scheduled with respect to the variable migration periods each year. Smolt deliveries to the downstream release point should be made every 2-3 days. While the majority of migrants may pass in a 6 week period, depending on species and conditions, smaller numbers of fish may migrate in virtually all months. The survival of such outliers likely contributes to the adaptability and genetic diversity of the stock, so there is some risk if the annual smolt salvages are limited to the dominant outmigration group.

Interbasin diversion projects typically release a minor percentage of flows below the dam to maintain downstream fish populations in the diminished channel. These small outflows could attract some of the migrants seeking to leave the reservoir and therefore may require a passage structure there in addition to the remote screening operation. Another problem is that once the fish arrive below the dam by whatever route, the flow volume in the river channel may be insufficient to transport large numbers of fish downstream without high losses to predation. Increasing the flow down the mainstem channel during smolt migration would tend to benefit fish passage but would reduce power generation.

Finally, juvenile migrants originating from above the dam would co-mingle with other juveniles from downstream populations and, at least briefly, compete for food and territory in the flow-diminished channel.

(ii) Upstream migrations

Adult salmonids have a unique homing ability. Without this ability, such species would have much less genetic diversity because reproductive opportunities would not be linked to spatial coordinates. The stock concept depends on the fidelity of its cohorts to return to spawn at the same time at a 'proven' location. Finding the home stream is critical to maintaining discrete stocks that are adapted to local conditions. Adult salmonids have difficulties in homing to their natal stream in diverted basins, as discussed for Seton sockeye by Fretwell (1989). For this report, *the diversion of significant proportions of water into another basin is a serious impediment to anadromous re-introduction* because of the loss of migratory cues in the diminished river where the adult fishway would be built, and the attraction of the fish to the 'false' system where the diverted water was discharged.

The rate of straying would likely increase in those systems where returning adults encounter strong cues of homestream water discharged at considerable distance away from their original river. For example, some Coquitlam adults could arrive at the Buntzen powerhouse in Indian Arm, Alouette adults could arrive at Ruskin Dam, and Carpenter adults could be attracted into Seton Lake. Attraction to diversion sources can prevent or at least delay the timely arrival of fish on the spawning grounds and may increase pre-spawning mortality.

6.2.2 Reservoir Drawdowns

The water level in each reservoir has a maximum elevation (full pool) that is established by the dam's height. Reservoir drawdown or filling refers to the lowering or raising of a reservoir's water level. Drawdown fluctuations are a necessary part of BC Hydro’s operations when total inflow to the reservoir is less than the flow released for power production or maintaining water levels in downstream habitats. In most Bridge-Coastal watersheds, the typical pattern is to fill the reservoirs during the fall rains, draw down through the winter to meet power demands, and refill during the spring snowmelt period. The power generation capability of each facility was designed to use a particular range of reservoir elevations based on electrical demand and reservoir inflows. Significant changes to drawdown extent or timing would affect power production. Operations at each facility are currently being re-examined by the Water Use Plan process.

Drawdowns directly affect access to habitat and use by fish. Drawdowns can strand fish in shallow basins, flood or de-water redds, and reduce or increase fish access at tributary mouths. For this assessment, drawdown operations would have particular impacts on fall-spawning sockeye salmon, a historic species at Coquitlam, Alouette and Terzaghi dams. The re-introduction of sockeye, and kokanee for that matter, may be generally infeasible in reservoirs where (i) extensive winter drawdowns expose their spawning habitats along beaches, and (ii) tributary spawning capacity is limited.

Drawdowns also have indirect effects on fish populations. Fish-food organisms in natural lakes are most prolific along shoals and shallow shorelines, but in reservoirs these zones produce significantly less food organisms, in part due to the fluctuations in water level. In general, the loss of biological productivity in aquatic and riparian habitats is roughly proportional to the range of the water elevations, and is further modified by the frequency, duration and seasons in which the drawdowns occur. The reduced biological productivity of a reservoir relative to its former lake environment, if present, must be considered a potential constraint to an anadromous re-introduction proposal.

6.2.3 Flow Quantity and Fish Passage

The quantity of downstream flow often affects fish passage. During the upstream migration period, flow volumes and their effects on water temperatures in the lower river can be critical. In some rivers, successful passage may occur over a narrow range of suitable flows, and above or below which, fish passage becomes impossible. A different river may be passable over a broad range of flow conditions except the absolute extremes. The ability of a dam to regulate downstream flows is a potential tool that can be used to increase fish passage at obstructions in the lower river. Once the adults have arrived below a dam, the ability of adult fish to locate and use a fishway also depends on certain flow volumes.

Downstream migrations are also affected by flow releases. The release of water past a dam gives migratory cues to fish travelling through the reservoir to the outlet. Once in the river below the dam, the particular flow conditions can affect the survival of migrants in terms of travel time, passage around other structures, and predation.

6.3 Technical Considerations

The reader is referred to the new report ***Fish Passage At Dams: An Overview of Technical and Engineering Aspects,*** prepared by Hay & Company Consultants Inc., Vancouver, B.C. and presented in Appendix F.

One of the significant conclusions of this report noted that "*projects where downstream passage of juveniles has been achieved are associated with reservoirs and facilities where juveniles have moved downstream through the reservoir to a location where large flows are either released through turbines or spillways, or to a location where smaller diversion flows are released from surface withdrawals. There is no precedent known for the successful bypass of fish from a reservoir where flow is withdrawn at depth from within the reservoir at a point distant from the spillway*" [p.7]. With regard to the five candidate facilities for anadromous re-introduction, the three interbasin diversion projects—Coquitlam, Alouette, and Terzaghi—represent a unique technical challenge.

6.4 Biological Considerations

A successful re-introduction of anadromous fish will depend upon the unique biological and hydraulic conditions at each of the five facilities, including fish habitat capability and resident fish populations in the reservoir and downstream channel, and the current regime of flow regulation that is developed through the Water Use Plan process. A directed assessment of anadromous re-introduction has only been made for the Middle Shuswap watershed.

Accordingly, we reviewed habitat studies in the other four watersheds and compiled some data developed for resident stocks to suggest habitat capacity for anadromous stocks (Appendix C).

6.4.1 Habitat Capability

The most critical part of the biological component is:

> ***There must be sufficient spawning <u>and</u> juvenile habitat capability above the dam for the target stock(s) to become self-sustaining, i.e., they become wild stocks without hatchery supplementation.***

This rationale follows the preferred hierarchy of measures outlined in the Restoration Strategy of the BCRP with respect to the role of artificial production in providing the initial colonization efforts needed to establish a new wild run.

The capacity of a reservoir basin to produce fish will vary according to the match between quality and quantity of the habitats present, and the available species and their life history preferences. The relative availability or absence of certain habitat types, as determined by chance physiographic conditions, will favor or reduce the abundance of particular species. Adjoining basins likely contain different combinations of habitats, and therefore each may confer a slight advantage to different species. Therefore the matching of new stocks to the habitats available in the newly accessible reservoir should be carefully considered.

Adult and juvenile stages differ considerably in basic habitat requirements. Adult habitats tend to be more homogeneous among species, whereas juvenile habitats tend not to overlap between different species. For example, spawning beds of anadromous species often overlap spatially (except for beach-spawning sockeye salmon), although there are some differences in hydraulic characteristics. Juveniles of different species characteristically segregate during their active growing seasons into habitats that are more discrete in time and space. This tendency is more apparent in large systems which provide greater physical diversity of habitat than small creeks. Species segregation decreases during periods of inactivity during overwintering and the summer low-flow period when living space is physically constricted. Therefore selection of a target species should be based primarily on the suitability of juvenile rearing habitat in the system, given that sufficient generic spawning habitat is available.

If re-introduction is constrained by habitat capacity, there may be some opportunity to increase capacity by constructing new habitat area, complexing existing habitats, or removing natural barriers to inaccessible habitat. Accurate assessment of habitat capacity requires thorough collection and analysis of field data, and should be directed by an experienced field biologist.

6.4.2 Biological Interactions

The dynamic interactions that occur between a new stock, the existing fish populations, and the ecosystem are difficult to anticipate. Introducing a new species, although formerly present, would have some effects on local biological communities, such as competition for food or habitat resources, predation, or disease transmission.

Interspecific competition for food resources can affect other wildlife species besides fish. At the same time, the new species will increase the forage base for predators of all types. In balance, the addition of a new and relatively abundant anadromous stock would enrich local values for biodiversity and productivity. This is the principal ecological benefit of a re-introduction program (Section 7.2).

According to the competitive exclusion theory, some negative consequences would be expected to arise when two closely related species, such as steelhead and rainbow trout, or sockeye and kokanee, have to now share the available habitat resources, particularly during the rearing cycle, with each pair preferring similar habitat characteristics. This is a problem to the extent that rearing areas could actually be in short supply relative to the number of juveniles in the system. In reality, most species have inherent behavioral flexibility in their ability to utilize 'sub-optimal' habitats on occasions when high densities of fish must co-exist. Still it is important to assess whether the habitat capacity available to resident fish might be reduced significantly by anadromous stocks.

A new species introduced into upper portions of a watershed may be a potential vector to transmit diseases to existing stocks, even to those downstream of the dam. For example, sockeye can be particular carriers of IHN (infectious hematopoietic necrosis) that will also infect chinook and other salmonids (Wood 1979). Accordingly, the Puntledge River Hatchery has intentionally excluded adult sockeye from entering the watershed above the diversion dam where the hatchery takes its water supply.

The latter situation suggests that one strategy to reduce undesirable interactions such as overspawning, would be to manage passage at the new ladder to intentionally exclude non-historic stocks. In many cases, non-historic species would include pink or chum salmon whose limited jumping ability tends to restrict their distribution to the lower reaches of a watershed. Pink salmon production at Seton has become so successful that their abundance may affect habitat utilization by other species. Restricting the ascent of non-historic species would have associated costs, and it is possible that some watersheds may benefit from their additional presence. This aspect should be considered at a detailed feasibility level.

6.4.3 Physiological Effects

Regulation of stream flow can change water quality parameters in a mainstem river, such as temperature and total gas pressure (TGP) that in turn affects the physiology of the fish in the system and their migratory performance or success. Water temperature is one of the most powerful influences on fish behavior and health, and plays a critical role in the migration and performance of fish using a fishway. Water stored behind a dam can warm to the same extent as a natural lake, and this warming is largely determined by the intensity of solar radiation, temperature of tributary inflows, and volume of inflows relative to the reservoir volume (water exchange rate). However, vertical temperature stratification in summer may develop differently in a reservoir than a lake because the latter always spills the warmer surface layer, whereas some reservoirs may discharge cooler water from a deeper outlet near or below the summer thermocline. These situations will affect the temperature of the water released below the dam, and have subsequent effects on migratory ability to ascend fishway structures or other partial obstructions encountered by the fish farther downstream.

Other physiological effects of regulated flows and temperatures on adult migration, particularly for stocks with long travel distances such as Seton, Bridge and Middle Shuswap, include energy expenditure and the timing of reproductive maturation (*e.g.*, Gilhousen 1960).

6.5 Management Considerations

The study framework has necessarily focused on the portion of fish life cycles that occur within BC Hydro's watersheds, and would be subject to the altered regime of drawdowns and diversions on reservoir and tributary habitats, downstream flows on mainstem habitats, and passage conditions at facilities. However it is important to recall that anadromous migrations expose the population to additional mortality from natural losses and various fisheries outside the natal watershed. These external sources of mortality are potentially more limiting to total population survival than are the density-dependent losses imposed on juveniles by power production in the freshwater environment (van Winkle 1977).

The fisheries resource agencies have the expertise and the responsibility for the biological planning of a wild stock re-introduction initiative. One of their tasks will be to determine a critical population size required for the target stock to become self-sustaining. Another task will be to propose how future harvests will be managed to ensure this sustainability.

Harvest management of the fisheries has not been included in the study framework because it is clearly outside of BC Hydro's control, yet the provision of passage structures and associated efforts represents a very significant commitment. The success or failure of any re-introduction program may ultimately depend on the agency's willingness and ability to manage future harvest levels.

7. RISK ASSESSMENT AND CONCLUSIONS

7.1 Risks of Anadromous Re-introduction

Establishment of a new stock of anadromous fish, especially in a physical environment regulated for power production, is a challenging undertaking. Many attempted cases of colonization in unregulated waters have failed, or have required ongoing supplementation from artificial sources. The likelihood of successful colonization decreases in rough proportion to the degree that the proposed environment has a water regime that is altered by diversions, reservoir storage, drawdowns, spilling, entrainment, and downstream variability in discharge outside of the natural hydrograph. Risks generally increase because water flow in a system is interlinked with diversity and suitability of fish habitat. Unnatural timing and quantities of flow typically reduce levels of aquatic productivity and may conflict with innate biological behaviors of the fish.

From BC Hydro's perspective, a re-introduction project has potential long-term liabilities whether the project succeeds or fails. There are risks and uncertainty within every component of the framework described in Section 3.2. It is possible that BC Hydro could undertake a technically challenging and expensive project to construct upstream and downstream passage structures, maintain them in good working order, possibly make commitments to adjust drawdown or downstream flow regimes, and for unknown biological reasons, the stock fails or cannot reach self-sustaining levels. There would be a tendency to fix rather than abandon the situation, given the large investments by both parties to date. Such additional measures could incur considerable costs for an indeterminate period.

Therefore a cautionary approach must be adopted to minimize technical and biological uncertainty. Triton's (1994) report suggested a phased approach to conduct pilot tests on the biological feasibility of anadromous re-introduction by trapping and trucking the adults upstream and the juveniles downstream. The trap and truck operations would be interim measures that allow the program to field-test the biological realities of the selected stocks and their adaptability to the reservoir's hydrological regime. The biological response should be measured for at least two complete 2-4 yr (species-dependent) cycles, to ensure that the chosen stocks are returning in sufficient abundance to warrant the costs of constructing permanent passage structures.

Determination of the evaluation criteria for the pilot study would be agreed by both parties in advance, and a timetable set out for planning and budgetary purposes.

Current relationships between BC Hydro and the fisheries resource agencies suggest there could also be risks to present or future power operations if a re-introduction project is successful. Once a new fish population has been established in a reservoir, there may be a tendency over time to forget the cooperative spirit under which the project was first initiated, possibly to the extent that an agency may decide to apply a new unilateral policy that imposes major changes on power operations in order to protect this population if it goes into decline, since the long-term survival of many salmonid stocks is already questionable.

7.2 Benefits of Anadromous Re-introduction

This report has focused almost entirely on risk issues that are associated with a re-introduction initiative. This is a prudent and sensible approach that supports both fiscal and biological responsibility from BC Hydro and the fisheries resource agencies. However, the identified limitations on re-introduction notwithstanding, there are obvious benefits for human economies and local ecological webs if anadromous fish resources could be returned to former watersheds. These include the social and economic benefits to various fisheries from increased abundance of an anadromous stock, and the increased annual nutrients contributed by spawner carcasses that benefit other plants and animals beyond the boundaries of the immediate aquatic environment. The question is whether the risk of such an undertaking can be justified when all societal benefits and costs are considered. The magnitude of expense and effort to restore anadromous passage into some reservoirs is not justified where re-introduction is incompatible with the operating system.

7.3 Conclusions

This study examined the possibility of re-establishing anadromous fish stocks in the five reservoirs where historic runs were present. The available information for each case was examined at an overview assessment level to judge biological, operational, and technical feasibility. The preliminary screening process has identified and evaluated the five candidate facilities where passage was blocked (Table 4).

Table 4. Impediments to Restoring Anadromous Fish Passage

IMPEDIMENTS	COQUITLAM	ALOUETTE	RUSKIN	TERZAGHI	WILSEY
Significant Dam Height	•		●	●	•
Interbasin Diversion Effects	◆	◆		◆	
Significant Drawdown	●	•		●	
Domestic Water Supply	●?				
Upstream Habitat Capability	●?	●?	◆	•	
Biological Interactions	•	•	•	•	•

•	MINOR
●	MAJOR
●?	LIKELY MAJOR
◆	NOT VIABLE

The information deficiencies regarding historic fish abundance and original habitat capability were not considered to be critical at this overview level. Although data about historic abundance was lacking at most facilities, the evaluation framework did not require precise numbers but instead relied on information that a substantive anadromous population did exist. Among the five candidate reservoirs, habitat inventory data is particularly poor for Coquitlam and Alouette reservoirs. However, even if extraordinary habitat was found to be available, the significant issues associated with major diversion operations would appear to preclude further consideration of re-introducing anadromous stocks at those facilities.

Therefore, the conclusions of this study are:

1. Wilsey Dam at Shuswap Falls is the only facility with sufficient characteristics to warrant a further detailed study as a candidate for a re-introduction initiative.

2. Ruskin Dam is considered impracticable for anadromous re-introduction. The technical difficulties to provide upstream and downstream passage structures at the 60 m high dam are not justified by the low capability of tributary habitat in the reservoir. Also, general biological productivity is low due to high turnover rate which includes the additional water diverted out of Alouette Reservoir.

3. The three reservoirs involved in significant interbasin diversions—Coquitlam, Alouette, and Carpenter—are considered impracticable candidates for anadromous re-introduction with current technology. There are major uncertainties over the technical feasibilty and scale of smolt screening, collection and transport requirements, and the biological problems anticipated with adult homing and juvenile migration cues.

4. Sockeye salmon have particular biological attributes that may decrease their suitability as a target species for re-introduction in reservoirs:

- new runs of sockeye are comparatively difficult to establish (Killick 1956)

- the success of beach spawning may be reduced by winter reservoir drawdowns, hence sufficient river spawning habitat must be available to support the population

- sockeye rearing capacity may be limited by low plankton availability due to high flushing rates in some reservoirs
- sockeye are implicated in the transmission of IHN disease which affects chinook, kokanee, and rainbow trout /steelhead
- sockeye smolts are comparatively sensitive to mechanical damage at screens, and during collection, handling or transportation.

8. RECOMMENDATIONS

1. Before proceeding further with a re-introduction initiative at Wilsey Dam, the fish resource agencies should i) express their respective views of such an initiative at this early stage, and assuming there is a mutual interest among all parties to proceed, (ii) outline any further data requirements the agencies would feel are necessary in a detailed feasibility phase.

2. Given such interest, BC Hydro would then undertake a detailed feasibility study on Wilsey Dam to develop the technical engineering plans and associated costs to construct and operate both upstream and downstream passage structures that would be acceptable to the agency (ies) at that site. For their part, the Federal agency should prepare their own feasibility proposal that indicates their conceptual plans, biological jusitication, target donor stocks, and also addresses BC Hydro's concerns over the issues of risk and future liabilities discussed earlier.

3. BC Hydro should include a biological component in their detailed feasibility study that will (i) further substantiate the assumptions made about the suitability of Wilsey Dam; (ii) search the literature to document the results of re-introduction efforts involving the same species elsewhere; (iii) review the experiences and practices of stock management at the Shuswap Falls Hatchery; and (iv) assess the potential interactions of the target species with resident fish stocks in upstream habitats. The biological review will provide an independent and cautionary assessment of the assumptions developed in the agency's plan, and assess the likelihood of achieving the program goal. Such analysis is prudent before BC Hydro commits to a further test phase.

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Appendix A

Facilities Without Historic Anadromous Fish Stocks

Appendix A1

CAMPBELL RIVER PROJECT

A1.1 Project Operation

The Campbell River development consists of three dams on the Campbell mainstem (Figure A1-1). The lowermost is John Hart Dam which impounds John Hart Reservoir and diverts water to a powerhouse located downstream of Elk Falls. The middle reservoir is Lower Campbell Lake, impounded by Ladore Dam, which also receives additional flows from the Salmon River and Quinsam River diversions. Its powerhouse is adjacent to Ladore Dam. This project also includes the Loveland Bay Saddle Dam (6m high by 80m long), and the Big Slide Saddle Dam (4m high by 15m long). The uppermost Strathcona Dam impounds Upper Campbell Reservoir which also backs up into Buttle Lake. This reservoir receives additional water from the Heber River diversion which augments Elk River inflows. The powerhouse is located at the toe of Strathcona Dam.

Normal (non-spill) operation of the Campbell River Project is governed by the discharge capacities at Strathcona (175.6 m^3/s), Ladore (161.5 m^3/s) and John Hart (124.0 m^3/s). Since John Hart has the lowest discharge capacity and is the generating station farthest downstream, the system is usually operated to its discharge maximum of 124 m^3/s. During periods of high inflow when it is necessary to control rising levels in Upper Campbell Lake, Strathcona discharges are often increased to 176.5 m^3/s; this results in spills at Ladore and John Hart.

A1.2 Facility Summary

DAM	**Strathcona**	**Ladore**	**John Hart**
Dependable capacity (MW)	60	47	126
Dam function	storage	storage	diversion
Date constructed	1955	1949	1945
Date operational	1958	- - *	1947
Date reconstructed	1986-88	1955-57	1988
Height (m)	53	37	30
Length (m)	510	94	250
RESERVOIR	**Upr Campbell L. / Buttle Lake**	**Lower Campbell Lake**	**John Hart**
Present area (ha)	6769	2610	346
Watershed area (km^2)	1249	1849	*no data*
Elevation above sea level (m)	221	178	139
Normal drawdown range (m)	21.4	15.2	1.2
Mean depth (m)	15 / 70	17	12
Maximum depth (m)	90 / 130	60	23
Mean annual discharge 1984-2000 (m^3/s)	*no data*	97.64	94.89
DIVERSION	**to powerhouse**	**to powerhouse**	**to powerhouse**
Structure type	canal (1km)	tunnel	penstock (1.9km)
Licensed flow (m^3/sec)	263	161	116
Fish flow release (m^3/sec)	none	none	34
Mainstem w/ diminished flow (km)	3	0.7	2

* dashes (- -) mean not applicable

A1.3 Fish Species and Natural Obstructions

The three dams (Strathcona, Ladore, and John Hart) on the Campbell River mainstem are located upstream of Elk Falls, the historic barrier to anadromous fish. Elk Falls is 30 m high and occurs 5.6 km upstream of tidewater. Above Elk Falls, resident cutthroat and rainbow trout and Dolly Varden char are found in each of the three reservoirs and connecting river sections. Ladore Falls, at 9 m high, and a second falls and rapids a short distance downstream (White 1919) possibly blocked upstream movement by original riverine stocks (BCR Strategic Plan 2000).

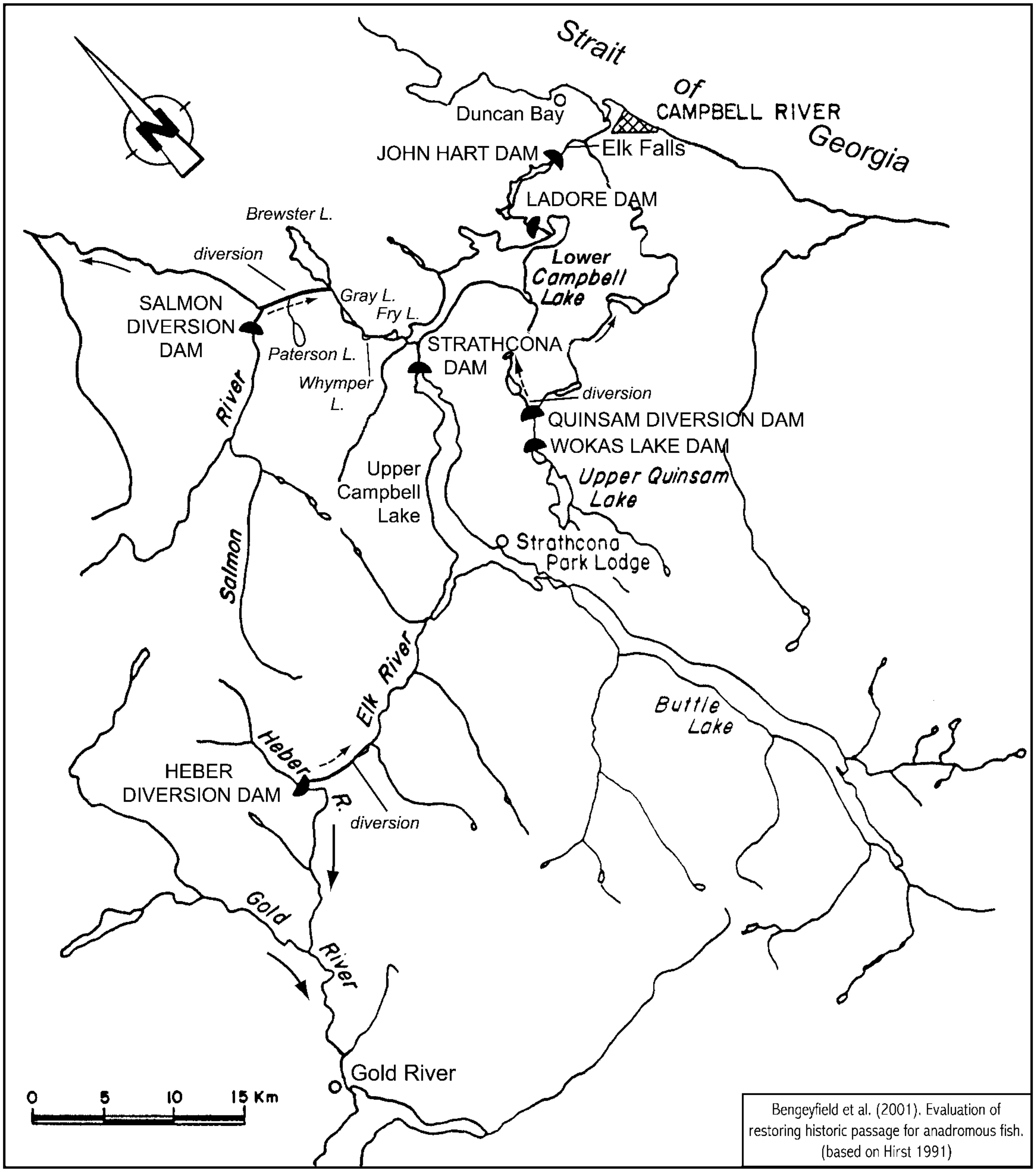

Figure A1-1. The Campbell River Hydroelectric Project.

A1.4 Summary of Potential for Anadromous Fish Passage

Anadromous fish were not present at any of the Campbell River dams, and there is virtually no opportunity to construct upstream passage structures at Elk Falls. There is little biological justification due to the relatively small amount of tributary habitat available, at least in the John Hart Reservoir. Further constraints include the heights of each dam, and provision of downstream passage facilities for juvenile fish.

A1.5 Campbell River Literature Cited

Bridge-Coastal Restoration Strategic Plan. 2000. Campbell River Watershed (Chap.2). Vol.2: Watershed Plans. BC Ministry of Fisheries, Dept. Fisheries & Oceans, and BC Hydro. 47 p.

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Appendix A2

HEBER DIVERSION DAM

A2.1 Project Operation

The Heber River Dam diverts seasonal flows from the upper Heber River via pipeline and channel for about 5 km into Crest Lake then through the Drum lakes into the Elk River which enters Upper Campbell Lake Reservoir (Figure A2-1). Crest Creek, a former tributary to Heber River, is also diverted into the Drum lakes by a dyke. The headpond behind Heber Dam is small. A large pool ~10 m diameter occasionally requires gravel removal by backhoe equipment. The Crest Creek diversion dyke does not impound any water (Lewis *et al.* 1996). The Heber-Crest diversion contributes to power generation at all three power stations on the Campbell River mainstem (Figure A1-1).

A2.2 Facility Summary

DAM	**Heber Diversion**
Dependable capacity (MW)	0
Dam function	diversion
Date operational	1956
Date reconstructed	1958
Height (m)	7
Length (m)	120
RESERVOIR	**headpond**
Present area (ha)	0
Watershed area (km^2)	55
Elevation above sea level (m)	353.6
Normal drawdown range (m)	- -
Maximum depth (m)	5.5
Mean annual discharge (m^3/s)	
DIVERSION	**to Upper Campbell L.**
Structure type	penstock (3.6km); channel (0.3km)
Licensed flow (m^3/sec)	3.5
Fish flow release (m^3/sec)	0.6
Mainstem w/ diminished flow (km)	15 (to Gold R. confluence)

* dashes (- -) mean not applicable

A2.3 Fish Species and Natural Obstructions

A tributary to Gold River, the upper section of Heber River at the diversion dam contains resident rainbow trout and Dolly Varden char. A 4 m high waterfall located 6.8 km downstream of the dam has blocked all upstream passage by anadromous fish. Summer steelhead use the next 7.5 km down to another set of 2.5-3 m falls. The lowermost 0.9 km of the river above its confluence with the Gold River is used by the five species of salmon and winter steelhead (Griffith 1994).

The Heber diversion dam is a barrier to the upstream passage of resident fish. For rainbow trout, this is likely irrelevant, due to a significant cascade feature only 200 m above the dam, and other obstructions and barriers further upstream. However for Dolly Varden, the dam may have eliminated historic use of Hunter Creek as a nursery stream for the mainstem population downstream of the dam. In addition, the crossing of the Heber River mainstem by the diversion pipeline may also represent a barrier to the upstream passage of resident fish (Griffith 1995).

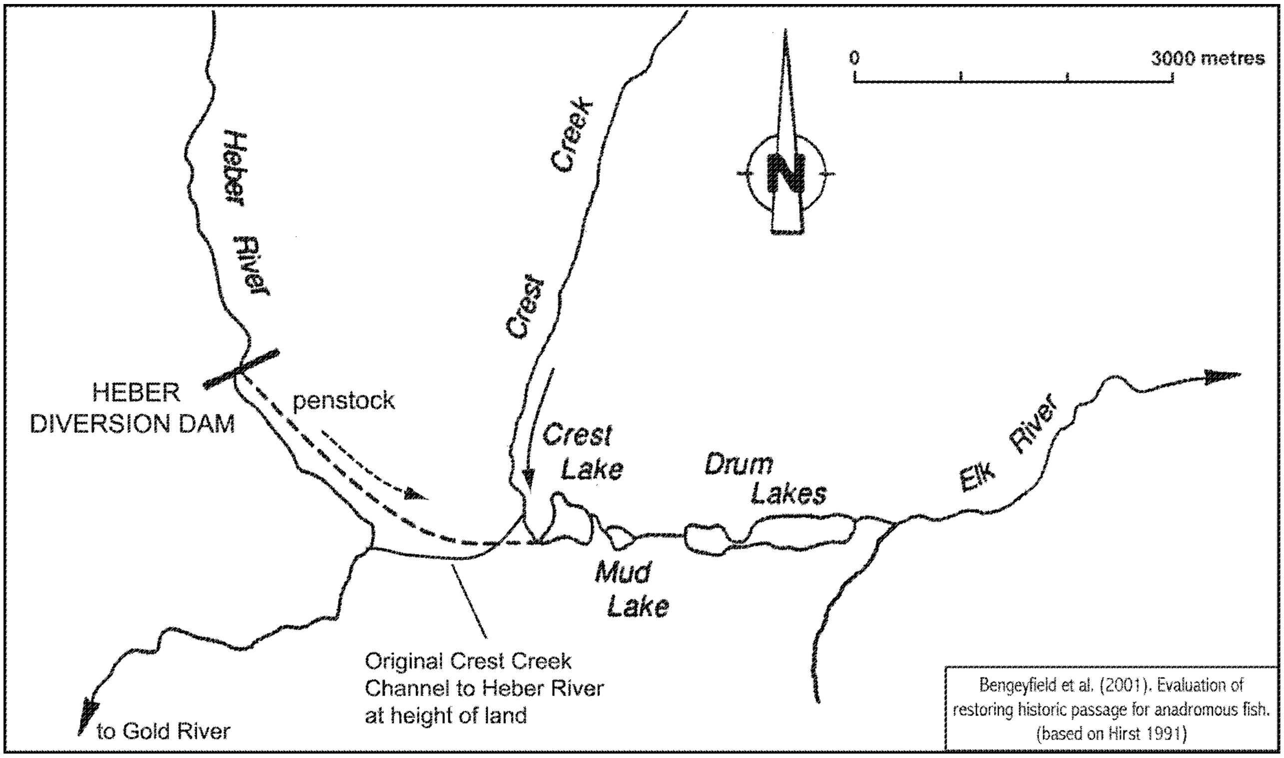

Figure A2-1. Heber River Diversion Dam.

A2.4 Summary of Potential for Anadromous Fish Passage

At least two natural waterfalls prevent salmon from reaching the Heber diversion dam while steelhead are blocked by the upper falls. If future passage at both falls was provided, summer steelhead and resident fish populations would likely compete with introduced salmon stocks for the limited habitat area, which is presently exacerbated by the diversion of water to the Campbell system.

A2.5 Heber River Literature Cited

Bridge-Coastal Restoration Strategic Plan. 2000. Campbell River Watershed (Chap.2). Vol.2: Watershed Plans. BC Ministry of Fisheries, Dept. Fisheries & Oceans, and BC Hydro. 47 p.

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Appendix A3
QUINSAM DIVERSION DAM

A3.1 Project Operation

The Quinsam project consists of the Quinsam Dam across the outlet of Wokas Lake and a diversion dam further downstream. Quinsam water is diverted for 9 km through Gooseneck Lake, then Snakehead Lake, Miller Creek and into Lower Campbell Lake for electrical generation at the Ladore and John Hart power stations (Figure A3-1).

A3.2 Facility Summary

DAM	**Wokas Lake**	**Quinsam Diversion**
Dependable capacity (MW)	0	0
Dam function	storage	diversion
Date operational	1956	1958
Height (m)	2.4 -9	5 -15
Length (m)	31	43.6
RESERVOIR	**Wokas Lake**	**headpond**
Present area (ha)	60	0.5
Watershed area (km^2)	80.7	88
Elevation above sea level (m)	360	302
Normal drawdown range (m)	4.7	3.1
Mean depth (m)	34 (max)	2
Mean annual discharge (m^3/s)	no data	9
DIVERSION	**to Lwr Campbell L.**	**to Lwr Campbell L.**
Structure type	channel	channel
Licensed flow (m^3/sec)	4.7	4.7
Fish flow release (m^3/sec)	0.3 - 1.7	0.3 - 1.7
Mainstem w/ diminished flow (km)	- - *	37 (to Campbell R.)

* dashes (- -) mean not applicable

A3.3 Fish Species and Natural Obstructions

In 1957, cutthroat trout were the only species recorded from Upper Quinsam/Wokas Lake when a BC Fish and Wildlife crew sampled the lake with gillnets (Lough *et al.* 1992), although stocking records indicate that brook trout (*Salvelinus fontinalis*) and steelhead had once been planted there around 1930. Cutthroat and rainbow trout presently occur in Miller Creek.

The lower Quinsam River was used historically by pink, chum and chinook salmon, and steelhead. Before diversion, coho once spawned in the outlet of Lower Quinsam Lake; steelhead and some chinook were recorded in the 1930s as far upstream as the cascades 0.8 km below Lower Quinsam Lake. In the fall of 1942 thousands of coho were reported immediately below the falls (DFO 1944). Upstream passage through this section now occurs only if water levels are high and the fish are strong. Low post-project flows can prevent pinks from ascending several smaller cascades below Lower Quinsam Lake.

Anadromous access to the diversion dam is blocked by two impassable falls, 4 m and 15 m high, situated 0.7 and 1 km respectively downstream of Middle Quinsam Lake. Hirst (1991) reported that "steelhead and coho have been occasionally reported as ascending the falls into Middle Quinsam Lake". This seems unlikely due to the height of the falls; however fry of those two species have been outplanted annually since the 1970s into Middle Quinsam Lake by Quinsam Hatchery. The hatchery continues to stock coho fry throughout the upper Quinsam watershed below the diversion dam, but steelhead outplants were discontinued in recent years due to a change in MELP strategy (Vancouver Island Steelhead Recovery Plan).

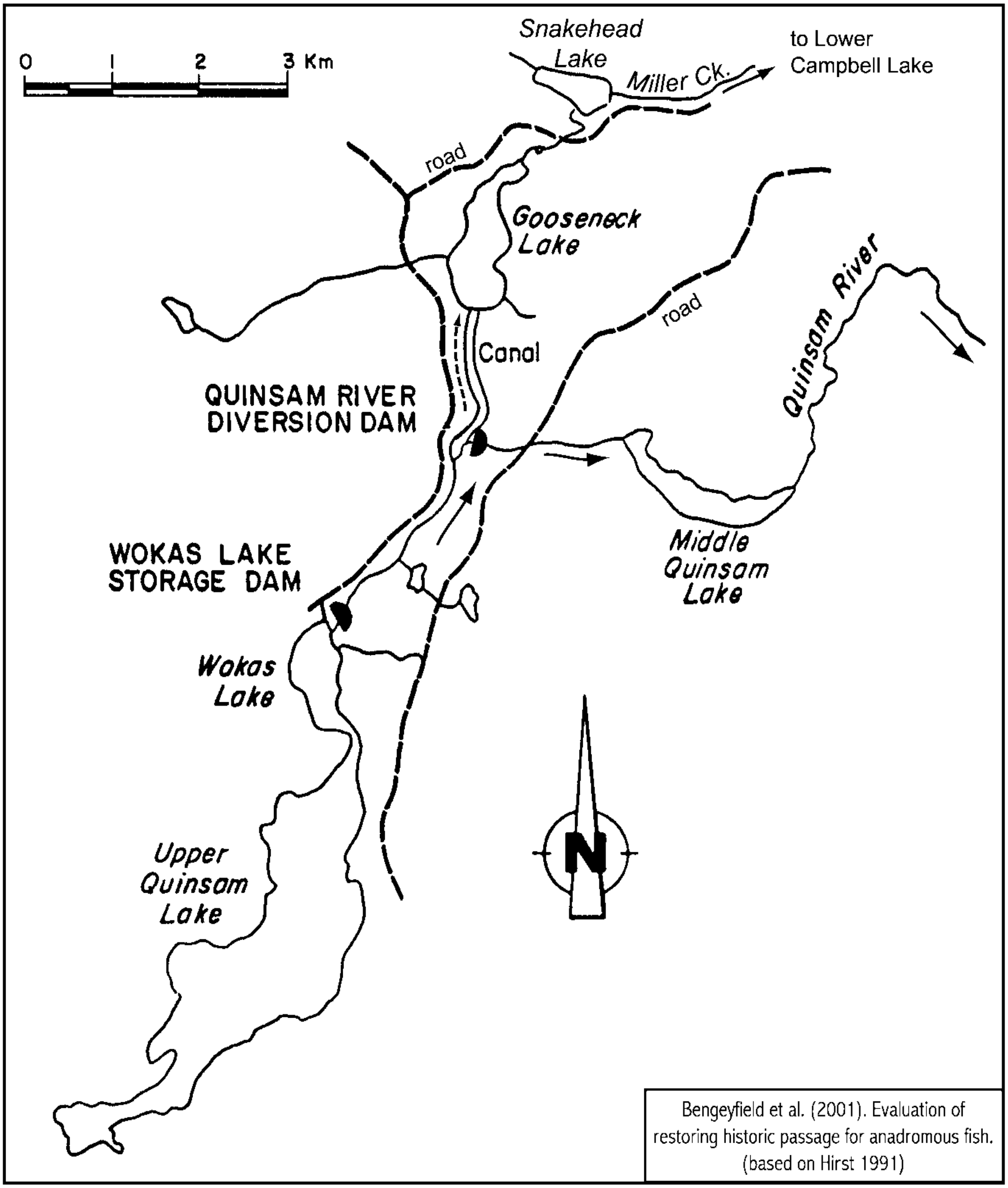

Figure A3-1. Quinsam River Diversion Project.

A3.4 Summary of Potential for Anadromous Fish Passage

Anadromous stocks were not present at either the Wokas Lake Dam or the Quinsam Diversion Dam at the time of construction due to two impassable falls 0.7-1 km below Middle Quinsam Lake. Provision of upstream and downstream passage structures past these barriers seems unlikely from the view of (i) costs, (ii) reduced flows from the diversion, and (iii) limited habitat area. Presently, the upper Quinsam watershed below the diversion dam receives annual outplantings of juvenile coho from Quinsam Hatchery. While the diversion dam does not require passage facilities for anadromous stocks, the reduced flow regime sometimes reduces the ability of anadromous fish to pass the main cascades located downstream of Quinsam Lake.

A3.5 Quinsam River Literature Cited

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Appendix A4

ELSIE LAKE DAM

A4.1 Project Operation

The Ash River project, completed in 1959 by the B.C. Power Commission, consists of Elsie Dam and four saddle dams, one of the latter is on the original outlet channel of Elsie Lake (Figure A4-1). Flow averaging 10.7 m^3/s per day is diverted from the Elsie Lake Reservoir year round into a power tunnel and penstock 7.8 km long to a powerhouse on the shoreline of Great Central Lake (GCL). GCL is drained by the Stamp River which combines with the Sproat River to become the Somass River and enters the head of Alberni Inlet.

Elsie Lake Reservoir typically spills from October to May because inflows are much greater than turbine capacity during this period. The plant usually operates at maximum capacity year round, except in late summer when inflows are low and the generating unit is usually taken out of service for maintenance. Fish in GCL are often attracted to the powerhouse discharge, and anglers congregate there (Powell 1995). The diversion of Ash River now augments the live storage volume of GCL which has two outlets: (i) a 3 m high dam operated by Pacifica (originally MacMillan Bloedel) at the lake outlet since 1930; and (ii) a low wood dam rebuilt in 1981 by the Department of Fisheries and Oceans (DFO) to control water intake to the Robertson Creek spawning channel.

A4.2 Facility Summary

DAM	Elsie
Project dependable capacity (MW)	27
Dam function	storage, diversion
Date constructed	1957
Date operational	1959
Height (m)	19 avg
Length (m)	185
RESERVOIR	**Elsie Lake**
Present area (ha)	672
Watershed area (km^2)	218
Elevation above sea level (m)	320
Normal drawdown range (m)	15
Mean water depth (m)	8
Maximum depth (m)	30
Mean annual inflow (m^3/s)	21
DIVERSION	**to powerhouse**
Structure type	tunnel, penstock
Licensed flow (m^3/sec)	10.8
Fish flow release (m^3/sec)	0.3-0.7
Mainstem w/ diminished flows (km)	25
Approx. km from diversion intake to dam	4

A4.3 Fish Species and Natural Obstructions

Anadromous fish stocks were historically absent from Elsie Lake prior to 1957 when hydro construction started. Impeded by the Stamp River Falls, anadromous fish did not regularly reach the lower Ash River until at least 1902 when remedial works to create fish passage to Great Central Lake began. Griffith (1993) surveyed the major falls that occur in the 25 km between Elsie dam and the Stamp River. Lanterman Falls at 5.5 km above the Stamp confluence was judged a barrier to all migrating adults except summer steelhead (Horncastle 1977), but it is believed that coho salmon ascended in some flow conditions (BCR Strategic Plan). Dickson Falls, located 10 km above the confluence and 15 km downstream of Elsie Lake, was considered a total barrier to anadromous species. Selective blasting by BC Fish & Wildlife Branch in 1975-76 has subsequently allowed summer steelhead to ascend above Dickson Falls and they now reach the base of Elsie Dam. Discussions about provision of an upstream passage structure continue in 2001. The reduced post-project flows, relative to historic unregulated conditions, may facilitate the passage of summer steelhead at Lanterman and Dickson falls (Griffith 1993).

Both agencies continue to discuss the potential impacts of releasing hatchery coho fry above Dickson Falls on steelhead, resident rainbow and cutthroat trout and char stocks. Many Ash tributaries downstream of the dam are ephemeral or blocked by obstructions or steep gradient (Griffith 1993). Juvenile steelhead were released into Elsie Lake for seven years between 1982-92 with annual numbers ranging from 39,000 to 215,000 fish (Triton 1995).

Hirst (1991: p.36) stated "The Ash River reaches above Elsie Lake total some 30 km and contain several small lakes; it is likely that these reaches were used by coho and possibly chinook before impoundment took place." His assessment of abundant fish habitat upstream is accurate, but Hirst's statement of anadromous fish presence is not. It may be based on the fact that the "original project design called for collection facilities at the powerhouse for adult migrants (species not stated) attracted to the outflows, and the use of tank trucks to haul them to the Ash River,..but these facilities were apparently never developed (p.37)."

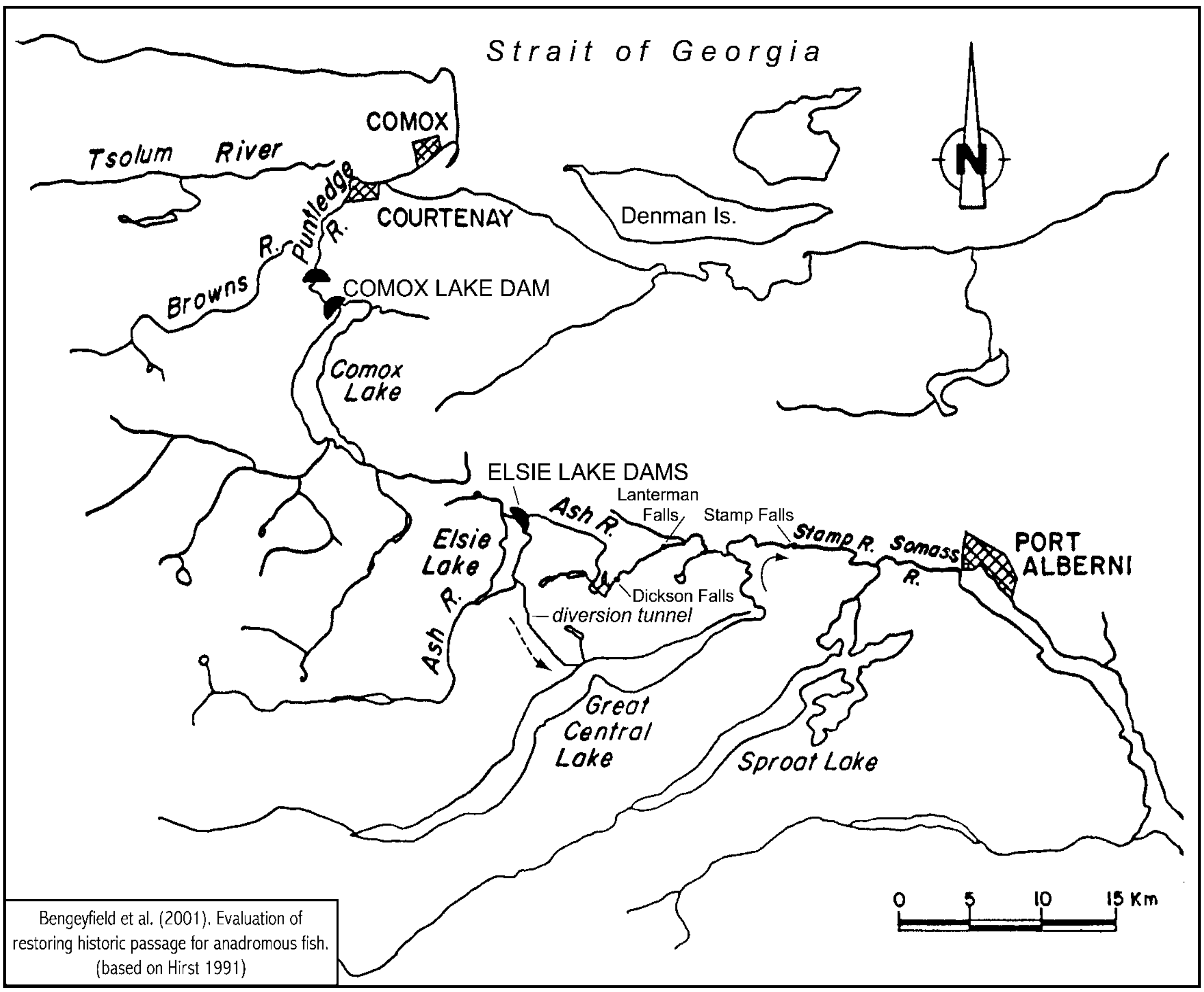

Figure A4-1. Ash River Diversion Project.

A4.4 Summary of Potential for Anadromous Fish Passage

There is no confirmed evidence of anadromous fish above Dickson Falls, including Elsie Lake, prior to dam construction in 1957 (BCR Strategic Plan 2000; R. Stennes, DFO, Pt. Alberni). Previously, salmon stocks had great difficulty reaching the Ash River or GCL until remedial works at the Stamp River falls began in 1902. Reduced post-project flows in the Ash mainstem and remedial blasting at Dickson Falls in 1976 has improved upstream passage conditions for steelhead and coho salmon. While considerable fish habitat is accessible upstream of the 19 m high dam, the potential for anadromous production in the upper Ash system would be constrained by the significant proportion of flow diverted to GCL , and by large annual changes in reservoir elevation which could affect spawning success. Such operations would likely reduce the proportion of juvenile migrants that would orient to the dam's spillway or release gates; many would tend to follow the principal discharge entering the diversion intake 4 km away. Passage survival through the Ash River powerhouse has not been measured. Other potential problems could be the attraction of returning spawners to the powerhouse discharge, or interspecific effects between steelhead and resident trout stocks (*e.g.*, Bengeyfield 1995).

A4.5 Ash River Literature Cited

Bengeyfield, W. 1995. Puntledge River discussion paper on stocking strategies in the upper watershed. Global Fisheries Consulting Ltd. report to BC Hydro, 64 p.

Bridge-Coastal Restoration Strategic Plan. 2000. Ash River Watershed (Chap. 4). Vol.2: Watershed Plans. BC Ministry of Fisheries, Dept. Fisheries & Oceans, and BC Hydro. 17 p.

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Horncastle, G.S. 1977. Somass River inventory. Unpubl. rep. BC Fish & Wildlife Branch, Nanaimo, BC. 59 p.

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Powell, C. 1995. Draft – Ash River Environmental Integrity Review – Fisheries Resource Component. Prepared by B.C. Hydro, Safety and Environment, Strategic Fisheries. 19 p.

Appendix A5

JORDAN RIVER PROJECT

A5.1 Project Operation

The Jordan River project, renovated in 1971, consists of a new Elliott Dam that diverts water via a 5.3 km tunnel and 1.6 km penstock to a new powerhouse on the west bank near the mouth of the river. Upstream from Elliott Dam are the older Jordan Diversion Dam and the Bear Creek Dam (Figure A5-1). The latter two were initially constructed in 1911-13, and upgraded in 1969-71 and 1985-88 (Diversion Dam).

Primary storage is now in the Diversion Reservoir, named because it originally diverted water in a flume that bypassed 9 km of river channel to the original 26 MW powerhouse on the east side of the river constructed in 1911 by the Victoria Light & Power Company. The Jordan River facility has a large turbine capacity relative to its inflow and storage capacity. When the turbine is operating at full capacity and inflow is low, the reservoirs can be drafted from full pool to minimum levels in about three days. Consequently, the facility can be operated only sparingly and for short duration. Its major role is to provide backup peaking capability to the electric system.

A5.2 Facility Summary

DAM	Bear Creek	Jordan Diversion	Elliott
Project dependable capacity (MW)	- - *	- -	170
Dam function	storage	storage, diversion	storage, diversion
Date constructed	1911	1911	1969
Date reconstructed	1969; 1985	1969	1971
Height (m)	19	39.9	27.4
Length (m)	337	232	270
RESERVOIR	**Bear Creek**	**Jordan Diversion**	**Elliott**
Present area (ha)	75	193	16
Watershed area (km^2)	22	122	165
Elevation above sea.level (m)	411	386	336
Normal drawdown range (m)	8	18.3	10.7
Maximum water depth (m)	15	40	27.4
Mean annual discharge 1984-2000 (m^3/s)	4.95		12.36
DIVERSION			**to powerhouse**
Structure type	- -	- -	tunnel (5.3 km) penstock (1.6 km)
Licensed flow (m^3/sec)	- -	- -	10.4
Fish flow release (m^3/sec)	0	0	0
Mainstem w/ diminished flows (km)	- -	- -	9

* dashes (- -) mean not applicable

A5.3 Fish Species and Natural Obstructions

All of the Jordan dams were constructed upstream of a succession of natural falls on the mainstem Jordan River that blocked anadromous fish passage (Griffith 1996). Beginning downstream, the first set of falls 3-6 m high is located 1.2 km above the river mouth, and 400 m upstream of the present powerhouse tailrace, although these may have been passable to coho and steelhead in some pre-project years. The second falls (5 m) and third falls (6 m) are 550 m and 750 m upstream of the tailrace, respectively; a fourth barrier (Sherbot 2000). Downstream of the canyon, the river once contained chum, pink and coho salmon as well as steelhead and anadromous cutthroat trout. These populations are largely reduced or gone, due to toxic seepage from copper mine sites and tailings between Elliott Dam and the present powerhouse (Aquametrix 1997). The excavated tailrace of the original powerhouse supported pink and chum spawning from 1949 to 1971 before the powerhouse was moved west across the river.

Historic and current resident sportfish species are rainbow and cutthroat trout; Dolly Varden were possibly present historically (BCR Strategic Plan 2000). Historic fish populations in the upper Jordan River basin were limited by the absence of lakes and low summer flows; the reservoirs have increased overall fish habitat capacity and population sizes despite local impacts from entrainment and drawdown (Griffith 1996). Summer flows in the mainstem river between Elliott Dam and the powerhouse tailrace are non-existent or very low; tributaries are either dry or short flowing trickles with isolated pools.

A5.4 Summary of Potential for Anadromous Fish Passage

Anadromous fish were unable to reach the Jordan reservoir locations at the time of construction due to three barrier falls beginning about 1 km upstream of the ocean. Costs to surmount this series of natural obstructions would be very high. The Jordan system would be further constrained for potential anadromous production by lack of upper tributary habitat, lack of summer flows in tributaries, poor water quality due to large reservoirs drawdowns, height of the three dams, and continuing toxic levels of dissolved copper in the lower river and estuary.

A5.5 Jordan River Literature Cited

Aquametrix Research Ltd. 1997. Suitability of the lower Jordan River for salmon rearing: potential impact of sedimentary metals. Report for Western Forest Products, Jordan River Forest Operations, Jordan River, BC.

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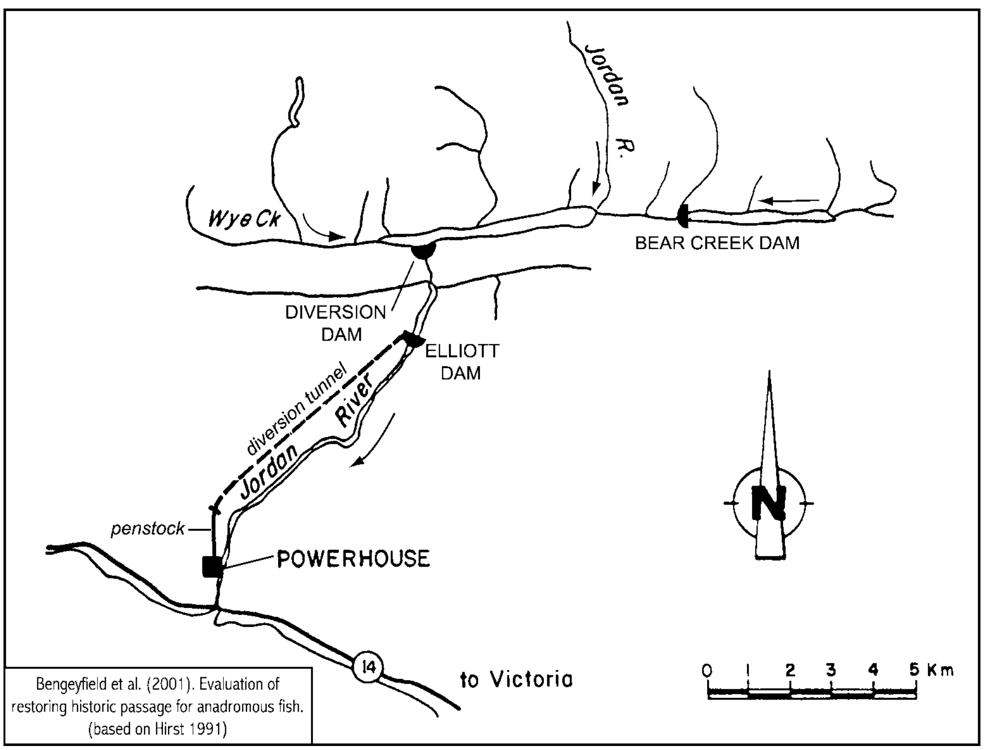

Figure A5-1. Jordan River Project.

Appendix A6

STAVE FALLS DAM

A6.1 Project Operation

Stave Reservoir serves as the storage reservoir for the Stave Falls and Ruskin generating plants; it also receives inflows from the diversion of Alouette Lake (Figure A6-1). Stave Falls Dam and Blind Slough Spillway Dam were completed and in service in 1911. Blind Slough Dam was built on the original river channel. There are powerhouses at the base of Stave and Ruskin dams. Stave Reservoir is at its highest levels during the fall and late spring due to high inflows. The reservoir is usually drawn down during winter to produce electricity and to accommodate spring snowmelt volume. Releases of 38 m^3/sec from Stave Falls must be coordinated with releases from Ruskin for fisheries purposes from October 1 to May 31 (Lewis *et al.* 1996).

A6.2 Facility Summary

DAM	**Stave Falls**
Dependable capacity (MW)	50
Dam function	storage
Date constructed	1911
Date reconstructed	1923 (raised)
Height (m)	26
Length (m)	67
RESERVOIR	**Stave Lake**
Present area (ha)	5858
Watershed area (km^2)	1170
Elevation above sea level (m)	81
Normal drawdown range (m)	9.1
Mean depth (m)	35
Maximum depth (m)	101
Mean annual discharge (m^3/s)	132
DIVERSION	**to powerhouse**
Structure type	penstock (43-99m)
Licensed flow (m^3/sec)	238
Fish flow release (m^3/sec)	28 - 84

A6.3 Fish Species and Natural Obstructions

There is no documented presence of anadromous fish above Stave Falls when the dam was constructed in 1911 (BCR Strategic Plan 2000). District Supervisor of Fisheries, A.P. Halladay, wrote that it was very doubtful that salmon ever ascended the falls. He suggested that kokanee in the lake resulted from anadromous accessibility at some post-glacial, though pre-historic, period (IPSFC 1938). Stave Falls and its associated rapids descended about 24 m over a short but unspecified distance. Andrew & Killick (1957) and Triton (1994) discussed in detail the issues and options for providing anadromous fish passage over Ruskin and Stave dams.

Rainbow and cutthroat trout, Dolly Varden char and kokanee represent the present sportfish species. Most tributaries are steep and fluctuate widely in discharge. Historically, Winslow Creek supported large numbers of spawning kokanee about midway up to Winslow Lake (Andrew & Killick 1957). These authors estimated there was potential spawning area in Winslow Creek and the upper Stave mainstem for about 25,000 sockeye each. Bruce *et al.* (1994) recently evaluated Cardinalis Creek, Isle Slough, Tingle Creek and Winslow Creek for limiting factors and enhancement opportunities.

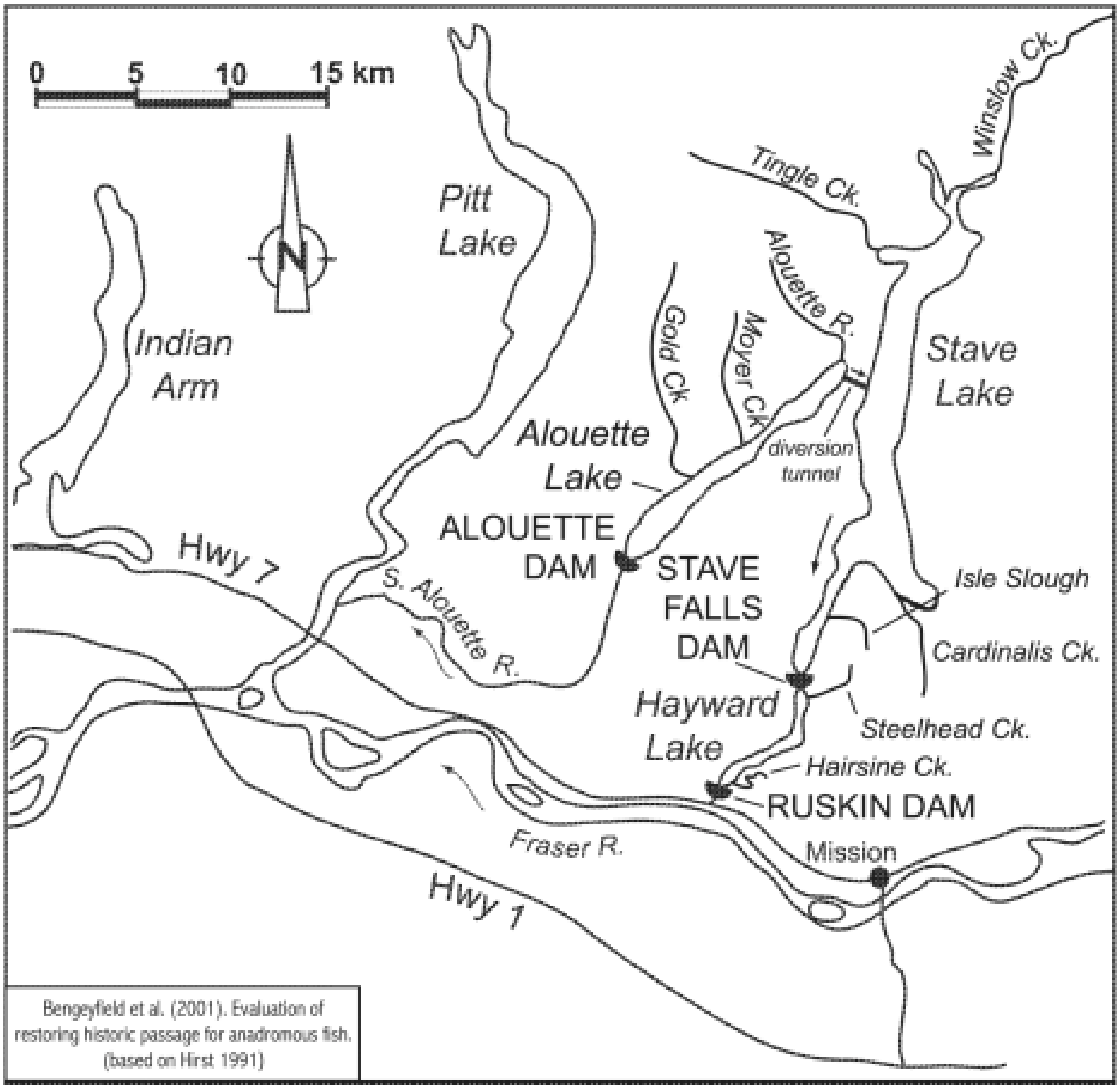

Figure A6-1. The Alouette-Stave Diversion Project.

A6.4 Summary of Potential for Anadromous Fish Passage

There was no historical presence of anadromous fish; however, Triton (1994) discussed the possibilities of providing anadromous access when the powerhouse was redeveloped. Potential introduction would be constrained by the necessity to provide passage in both directions (or accept turbine mortality rates as per Hamilton & Andrew 1954) over 59 m high Ruskin Dam as well as Stave Falls Dam. Sockeye that chose to spawn along reservoir beaches or tributary fans would suffer losses from the 9 m or more drawdown zone. Resident populations of sport species in Stave Reservoir appear to be limited by low overall productivity, a large population of predators and competitors, and limited spawning and fry rearing habitat and nutrient levels in four major tributaries (Bruce *et al.* 1994). These same factors would presumably affect the potential introduction of anadromous stocks (Triton 1994).

A6.5 Stave River Literature Cited

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Bridge-Coastal Restoration Strategic Plan. 2000. Stave River Watershed (Chap.7). Vol.2: Watershed Plans. BC Ministry of Fisheries, Dept. Fisheries & Oceans, and BC Hydro. 25 p.

Bruce, J.A., T.L. Slaney and R.J. Fielden. 1994. Stave Lake: Baseline fisheries study and enhancement recommendations. Prepared for B.C. Hydro Environmental Resources Division by Aquatic Resources Ltd. 101 p.

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IPSFC. ca. 1938. Obstructions - history. International Pacific Salmon Fisheries Commission, Archive files 1180.1-15, -16 and -19.

Lewis, A.F., G.J. Naito, S.E. Redden and BC Hydro Safety & Environment. 1996. Fish flow studies project: fish flow overview report. BCH Safety & Environment Rept. No. EA:95-06, 144 p.

Triton Environmental Consultants Ltd. 1994. Stave River System – fish passage study. Prepared for B.C. Hydro. 116 p.

Appendix A7

WAHLEACH DAM

A7.1 Project Operation

The Wahleach Project, completed in 1952 by the B.C. Electric Company, consists of a storage/diversion dam across the outlet of Wahleach Lake with water passing from the lake through a tunnel and penstock down to a powerhouse on the Fraser River. A small dam across Boulder Creek diverts water into Wahleach Lake (Figure A7-1). The reservoir has a large drawdown relative to its mean depth (Lewis *et al.* 1996).

Wahleach Lake follows the usual pattern for Lower Mainland reservoirs (BC Hydro 1994). During winter, inflow is low while load demand is high. The reservoir is drafted during this period to meet generation requirements. In spring, inflow is high due to snowmelt, load demand is reduced, and the reservoir fills. In fall, heavy rains can cause flash inflows that lead to spilling.

A7.2 Facility Summary

DAM	**Wahleach**	**Boulder Cr. Diversion**
Dependable capacity (MW)	58	- - *
Dam function	storage, diversion	diversion
Date constructed	1951-2	1951-2
Date operational	1952	1952
Height (m)	21	3.5
Length (m)	418	180
RESERVOIR	**Wahleach Lake**	**none**
Present area (ha)	489	- -
Orig. lake area (ha)	278	- -
Watershed area (km^2)	93 (incl. Boulder)	no data
Elevation above sea level (m)	642	
Normal drawdown range (m)	19.8	- -
Mean depth (m)	13	- -
Maximum depth (m)	29	- -
Mean annual discharge 1984-2000 (m^3/s)	6.22	included
DIVERSION	**to Fraser R. side channel**	**to Wahleach Reservoir**
Structure type	tunnel, penstock	channel
Licensed flow (m^3/sec)	13.3	- -
Fish flow release (m^3/sec)	0.4 - 1.4	0.4 - 0.8
Mainstem w/ diminished flows (km)	7.8	0.8

* dashes (- -) mean not applicable

A7.3 Fish Species and Natural Obstructions

There are no reports of anadromous stocks reaching Wahleach Lake at time of hydro construction due to barrier falls about 1.5 km above the Fraser River and steep gradient throughout the middle reaches of Jones Creek (BCR Strategic Plan 2000). In fact, Wahleach Lake was originally barren of sport fish (Mottley 1936). The lake was subsequently stocked with rainbow and cutthroat trout and kokanee prior to impoundment. Spawning and rearing habitat for trout and kokanee appears sufficient for the system in Jones, Flat, and Glacier tributaries, but access problems may occur in spring if the reservoir elevation is low (Hirst 1991). Construction of the two dams has blocked the potential movement of trout between Boulder Creek, Jones Creek and the reservoir (BCR Strategic Plan 2000).

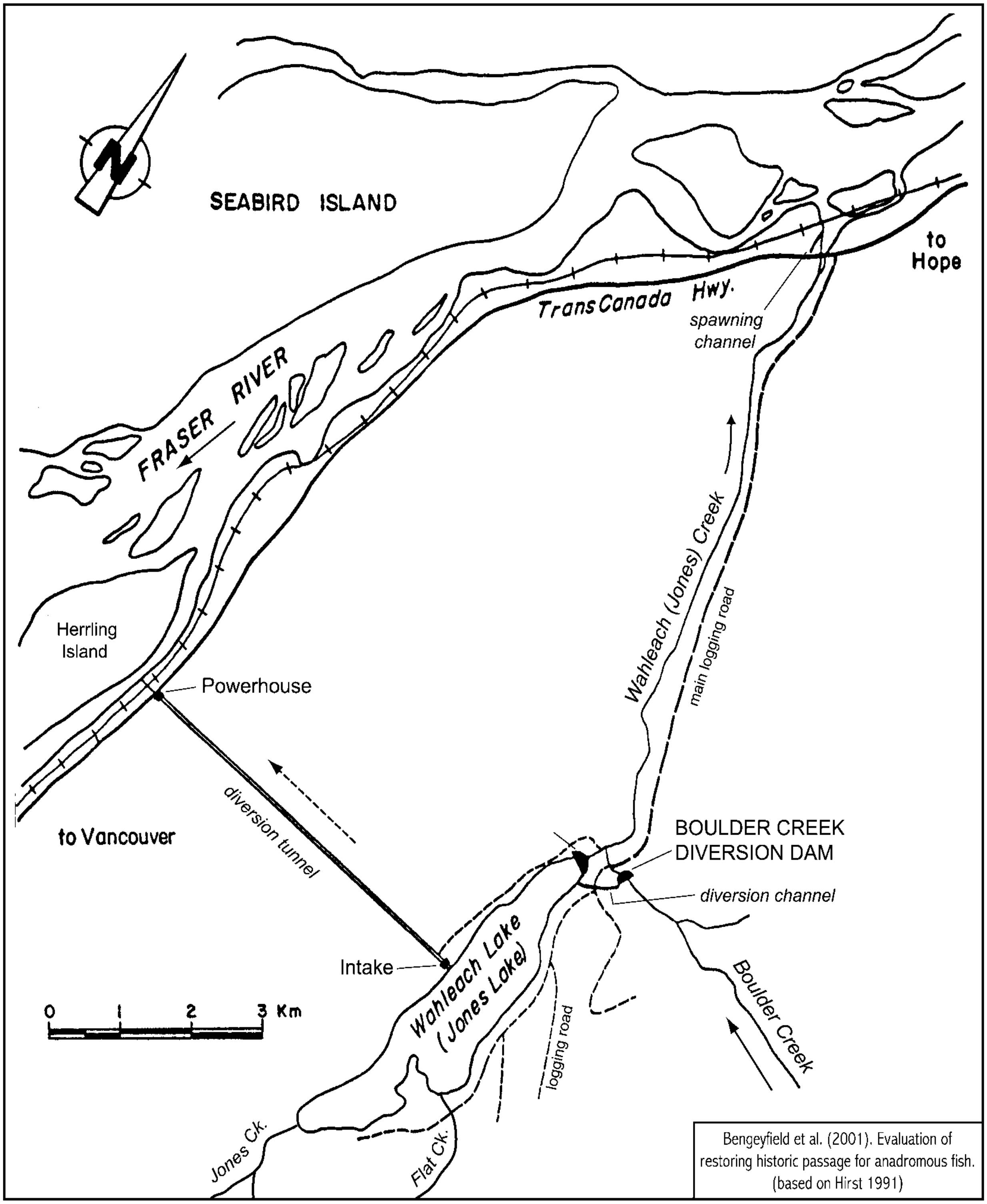

Figure A7-1. Wahleach Diversion Project.

A7.4 Summary of Potential for Anadromous Fish Passage

There were no historic anadromous stocks at Wahleach Lake before impoundment. The cost of providing adult fish access up the natural channel of Jones Creek would be very high and the structures would experience periodic washouts from unstable banks as occurred recently (Hartman and Miles 1997). Passage over the 21 m high dam, and the problem of screening juvenile migrants at the diversion intake and transporting them 2.5 km to the dam and back into Jones Creek would be further constraints. Adult fish could be attracted to the major discharge from the powerhouse at Herrling Island instead of the reduced flows in Jones Creek farther up the Fraser River.

A7.5 Wahleach Lake Literature Cited

Bridge-Coastal Restoration Strategic Plan. 2000. Jones Creek (Wahleaach Lake) Watershed (Chap.9). Vol.2: Watershed Plans. BC Ministry of Fisheries, Dept. Fisheries & Oceans, and BC Hydro. 15 p.

B.C. Hydro. 1994. Report on the electric system operations review, 2 vols.. Prep. for the Minister of Employment and Investment and the Minister of Energy, Mines and Petroleum Resources for B.C.

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Lewis, A.F., G.J. Naito, S.E. Redden and BC Hydro Safety & Environment. 1996. Fish flow studies project: fish flow overview report. BCH Safety & Environment Rept. No. EA:95-06, 144 p.

Mottley, C. McC. 1936. A biological survey of Jones Lake. Rept. B.C. Prov. Game Comm. for 1935. No. 27. p. 27-30.

Appendix A8

LA JOIE DAM

A8.1 Project Operation

The Bridge River project consists of La Joie Dam which impounds Downton Lake and Terzaghi Dam farther downstream which impounds Carpenter Lake (Figure A8-1). Downton Reservoir has a total average inflow of 40 m^3/s (BC Hydro 1994). Additional inflow to Carpenter Reservoir is 51 m^3/s for a total diversion typically about 91 m^3/s into Seton Lake. The diversion from Carpenter Reservoir drops through tunnels and penstocks to two powerhouses on Seton Lake Reservoir. Diverted Bridge River water also produces power through the Seton powerhouse before it is discharged into the Fraser River about 10 km downstream of its original confluence. High inflows occur from May to August from snow and glacial melt. Inflow from September to April is usually low. Occasional heavy rainstorms from August to early October cause high inflow to the reservoirs which can result in spilling, on average about 1 year in 3.

A8.2 Facility Summary

DAM	Lajoie
Dependable capacity (MW)	24
Dam function	storage
Date constructed	1948
Date reconstructed	1956-7
Height (m)	83
Length (m)	1033
RESERVOIR	**Downton**
Present area (ha)	2400
Orig. lake area (ha)	0
Watershed area (km^2)	998
Elevation above sea level (m)	707-749
Normal drawdown range (m)	49
Mean depth (m)	30
Maximum depth (m)	80
Mean annual discharge (m^3/s)	40
DIVERSION	**none**
Structure type	- - *
Licensed flow (m^3/sec)	- -
Fish flow release (m^3/sec)	no
Mainstem w/ diminished flows (km)	- -

* dashes (- -) mean not applicable

A8.3 Fish Species and Natural Obstructions

No anadromous species were reported historically above La Joie Falls (BCR Strategic Plan 2000). Rainbow trout, bull trout, Dolly Varden char, kokanee and mountain whitefish are the current resident sportfish. The La Joie Project flooded two sets of falls, named Lajoie and Zoltique, about 800 m apart on the Bridge mainstem. The downstream barrier, La Joie Falls, was reported to be about 50 feet vertical (Heyworth 1930). A historic photograph taken prior to construction in 1948 suggests that the wide valley now occupied by Downton Reservoir was vegetated by marshy flats and that few trees were present (Triton 1992). The Bridge River system upstream of La Joie Dam has relatively cold nutrient-poor water.

A8.4 Summary of Potential for Anadromous Fish Passage

Anadromous fish are not documented historically above La Joie Falls. The potential for future anadromous introduction is extremely unlikely, with respect to the technical feasibility and cost of constructing facilities for upstream and downstream passage over the 83 m high dam with a reservoir drawdown of 49 m. The natural low productivity and cold temperatures associated with the Bridge Glacier at the system's headwater would constrain biological productivity. Finally, passage in both directions would also be required at 60 m high Terzaghi Dam, as well as a mechanism to prevent smolt entrainment at the diversion intakes.

A8.5 Bridge River Literature Cited

Bridge-Coastal Restoration Strategic Plan. 2000. Bridge River Watershed (Chap.10). Vol.2: Watershed Plans. BC Ministry of Fisheries, Dept. Fisheries & Oceans, and BC Hydro. 35 p.

B.C. Hydro. 1994. Report on the electric system operations review, 2 vols. Prep. for the Minister of Employment and Investment and the Minister of Energy, Mines and Petroleum Resources for B.C.

Heyworth, J.O. ~1930? Extracts from J.O. Heyworth's preliminary report on the water power of the Bridge River. Schedule "G". MS rept. 12 p.

Lewis, A.F., G.J. Naito, S.E. Redden and BC Hydro Safety & Environment. 1996. Fish flow studies project: fish flow overview report. BCH Safety & Environment Rept. No. EA:95-06, 144 p.

Triton Environmental Consultants Ltd. 1992. Bridge River fisheries enhancement. Report to B.C. Hydro, Environmental Resources, Vancouver, BC. 91 p.

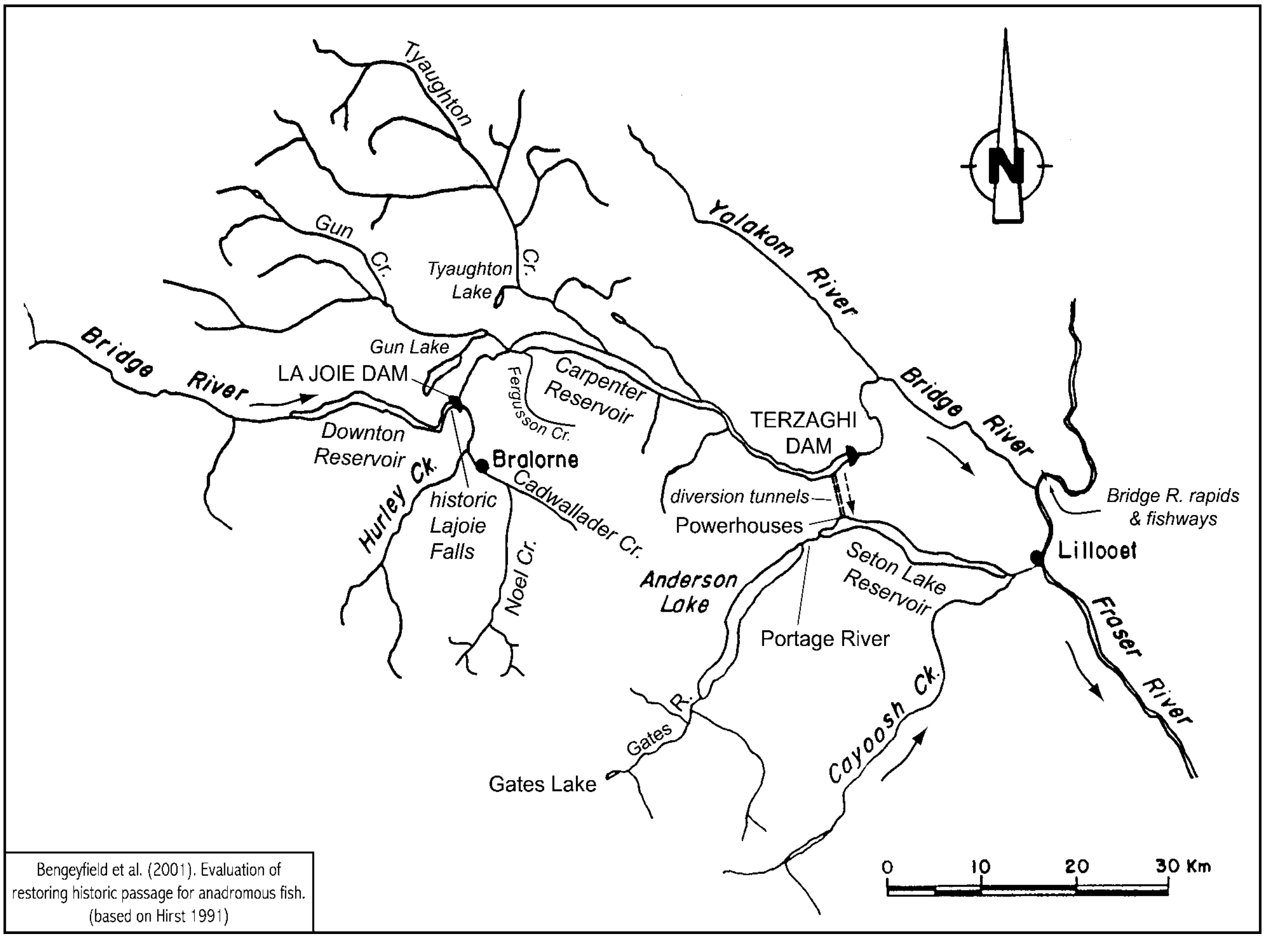

Figure A8-1. LaJoie Dam in the Bridge River Diversion Project.

Appendix A9

SUGAR LAKE (PEERS) DAM

A9.1 Project Operation

The initial plans for a power project at Shuswap Falls were developed prior to 1912 by the Couteau Power Company based in Vancouver, B.C. The Shuswap Falls generating station, Wilsey Dam and Peers Dam were constructed and owned by West Canadian Hydroelectric Corporation and went into service in 1929. The project consists of impounded storage in Sugar Lake controlled by Peers (Sugar Lake) Dam, and power generation from Wilsey Dam at Shuswap Falls 31 km downstream (Figure A9-1). The B.C. Power Commission acquired the Shuswap Falls project in 1945. Reservoir operation tends to delay the onset of spring freshet flows and elevates winter flows in December-February (Lister 1990).

A9.2 Facility Summary

DAM	**Sugar Lake**
Dependable capacity (MW)	0
Dam function	storage
Date constructed	1928
Date operational	1929
Height (m)	13
Length (m)	98
RESERVOIR	**Sugar Lake**
Present area (ha)	2217
Orig. lake area (ha)	1564
Watershed area (km^2)	1170
Elevation above sea level (m)	601.6
Normal drawdown range (m)	7.8
Mean depth (m)	35
Maximum depth (m)	83
Mean annual discharge 1984-2000 (m^3/s)	40.56
DIVERSION	**none**
Structure type	- - *
Licensed flow (m^3/sec)	- -
Fish flow release (m^3/sec)	5
Mainstem w/ diminished flows (km)	- -

* dashes (- -) mean not applicable

A9.3 Fish Species and Natural Obstructions

There is no documented historic evidence of anadromous stocks in Sugar Lake (BCR Strategic Plan 2000), but some chinook salmon were able to ascend Shuswap Falls and used the intervening 20 mile section of river prior to their blockage by Wilsey Dam in 1929. Anecdotal reports of salmon in Sugar Lake (French 1995) may have been kokanee, the landlocked form of sockeye salmon. In early correspondence the height of Brenda Falls was erroneously reported as "38 feet sheer" but verbal reports by early surveyors stated that the sheer drops were no more than 3m (10 feet). Fee and Jong (1984: p.3) cited correspondence from Robinson (1941) as “Robinson suggested that fish passage was impossible above the natural barrier of Brenda Falls.”

Kokanee, Dolly Varden char, mountain whitefish, and rainbow and cutthroat trout are presently in Sugar Lake, as well as several non-sportfish species (FISS 2000).

A9.4 Summary of Potential for Anadromous Fish Passage

There is no documented evidence of historic anadromous fish in Sugar Lake. Reservoir impoundment raised the elevation of the original Sugar Lake by about 7 meters. The reservoir area is now 2,217 ha after flooding 653 hectares of land (BCRP 2000). Today both the 13 m high Sugar Lake (Peers) Dam plus Brenda Falls would require upstream passage facilities. Fish habitat capability has apparently not been estimated for the upper mainstem or tributaries above Sugar Reservoir. Water level fluctuations in Sugar Lake have reduced productivity from shoals and the littoral zone. Reservoir operations and drawdown may interfere with sockeye spawning success. Competition between resident sport species and any introduced anadromous stocks could be an issue. Timing of downstream juvenile migration would generally coincide with normal spilling; if spillway mortality rates were acceptable, a downstream passage structure might be unnecessary.

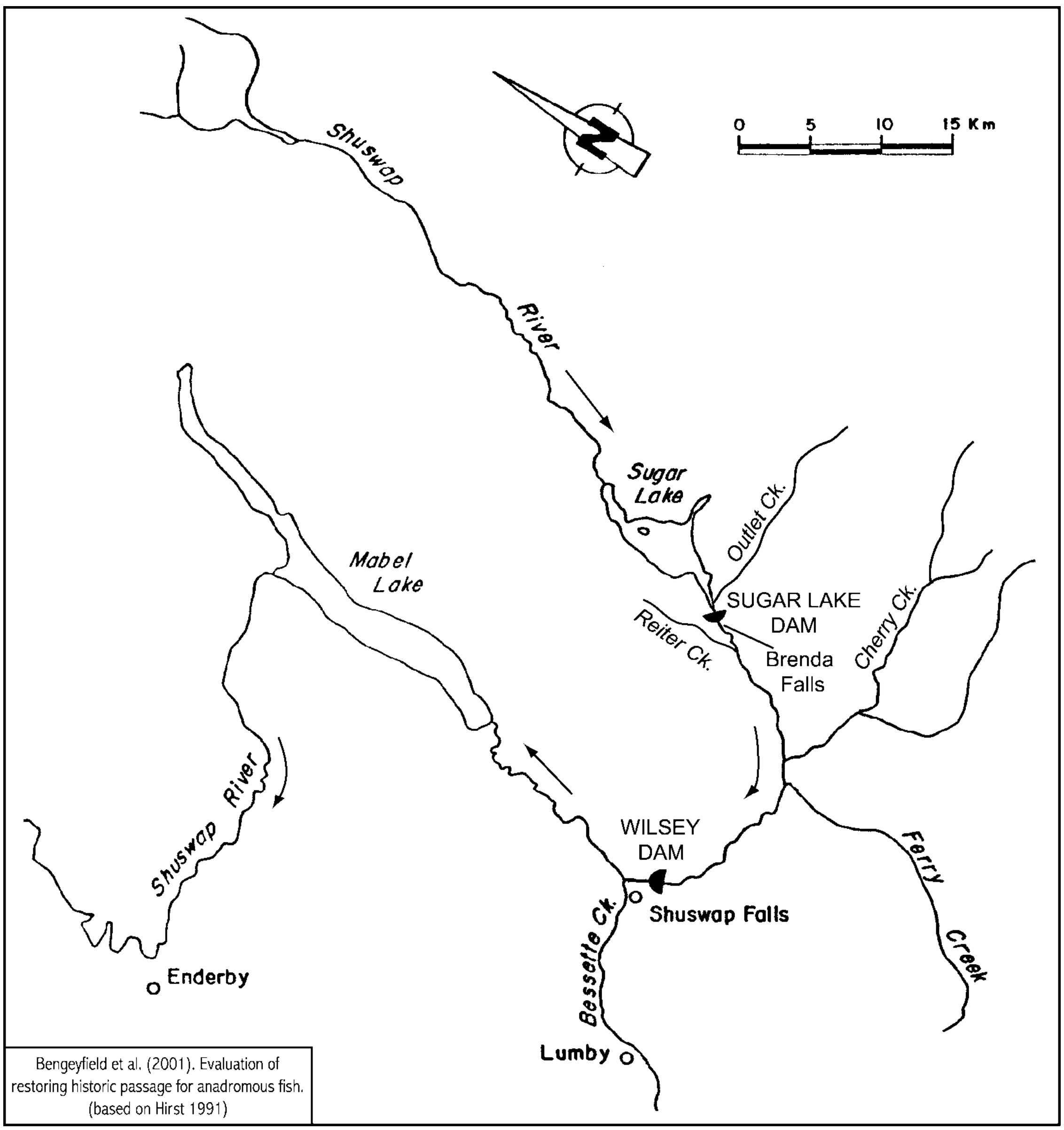

Figure A9-1. Location of Sugar Lake (Peers) Dam.

A9.5 Middle Shuswap River Literature Cited

BCRP Bridge-Coastal Restoration Strategic Plan. 2000. Middle Shuswap Watershed (Chap.12). Vol.2: Watershed Plans. BC Ministry of Fisheries, Dept. Fisheries & Oceans, and BC Hydro. 26 p.

Fee, J. and J. Jong. 1984. Evaluation of chinook and coho outplanting opportunities in the Middle Shuswap River above and below Shuswap Falls. 2 vol. report by Alpha-Bioresource Environrnental Consultants, Victoria, BC to Department of Fisheries and Oceans. DSS Contract 04SB.FP576-3-2462. vol 1- 76 p.; vol.2- 116 p. + app.

FISS 2000. Fisheries inventory database. www.pisces.env.gov.bc.ca/FishWizard.asp

French, D.E. 1995. Historic review of anadromous salmonid passage above Shuswap Falls, British Columbia. MS final rept. for DFO Western Region, Vancouver, BC. Contract FP94-5389. 26 p.

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Lister, D.B. 1990. An assessment of fisheries enhancement potential of BC Hydro operations at Shuswap River. Unpubl. rept. by D.B. Lister & Assoc. Ltd. for BCH Environmental Resources. 35 p.

Robinson, C.H. 1941. Letter to Commissioner F.R. Buler, Game Dept, Vancouver, BC. re: water storage dam at Sugar Lake. May 20.

Appendix A10

CHEAKAMUS DAM

A10.1 Project Operation

The Cheakamus project consists of a dam across the upper Cheakamus River that impounds Daisy Lake Reservoir (Figure A10-1). The reservoir is drafted in August to reduce fall flooding risk downstream of the dam, and again in April to provide storage for inflow from snowmelt. Flows are diverted by a man-made canal to Shadow Lake Reservoir where a tunnel and two penstocks convey water to the powerhouse on the Squamish River. The powerhouse discharges into an 1800 m long channel that enters the Squamish River about 21 km upstream of the Cheakamus confluence.

A10.2 Facility Summary

DAM	**Cheakamus**
Dependable capacity (MW)	155
Dam function	storage, diversion
Date constructed	1957
Date reconstructed	1981; 1988
Height (m)	29
Length (m)	680
RESERVOIR	**Daisy Lake**
Present area (ha)	395
Watershed area (km^2)	771
Elevation above sea level (m)	394
Normal drawdown range (m)	13.1
Mean depth (m)	10
Maximum depth (m)	15
Mean annual discharge (m^3/s)	23.3
DIVERSION	**to Squamish R.**
Structure type	tunnel (11km), penstock (440m)
Licensed flow (m^3/sec)	27
Fish flow release (m^3/sec)	5 (low water)
Mainstem length diminished Q (km)	26

A10.3 Fish Species and Natural Obstructions

Anadromous fish were not present in the reservoir area. Waterfalls beginning about 17 km up the Cheakamus River from the Squamish River confluence have blocked their passage (Lewis *et al.* 1996). All five salmon species and steelhead use river habitats below the falls. Daisy Lake Reservoir presently supports rainbow trout, Dolly Varden char, and kokanee (BCR Strategic Plan 2000).

A10.4 Summary of Potential for Anadromous Fish Passage

Anadromous fish were not present at the Cheakamus Dam site, and there is little opportunity to construct cost-effective passage structures past the falls and obstructions in the canyon. If adult fish were to be trapped and trucked above the dam each year, the diversion of large water volumes through the tunnel to the powerhouse would cause significant problems for juveniles migrating downstream and for adults homing upstream.

A10.5 Cheakamus River Literature Cited

Bridge-Coastal Restoration Strategic Plan. 2000. Cheakamus River Watershed (Chap.13). Vol.2: Watershed Plans. BC Ministry of Fisheries, Dept. Fisheries & Oceans, and BC Hydro. 17 p.

Lewis, A.F., G.J. Naito, S.E. Redden and BC Hydro Safety & Environment. 1996. Fish flow studies project: fish flow overview report. BCH Safety & Environment Rept. No. EA:95-06, 144 p.

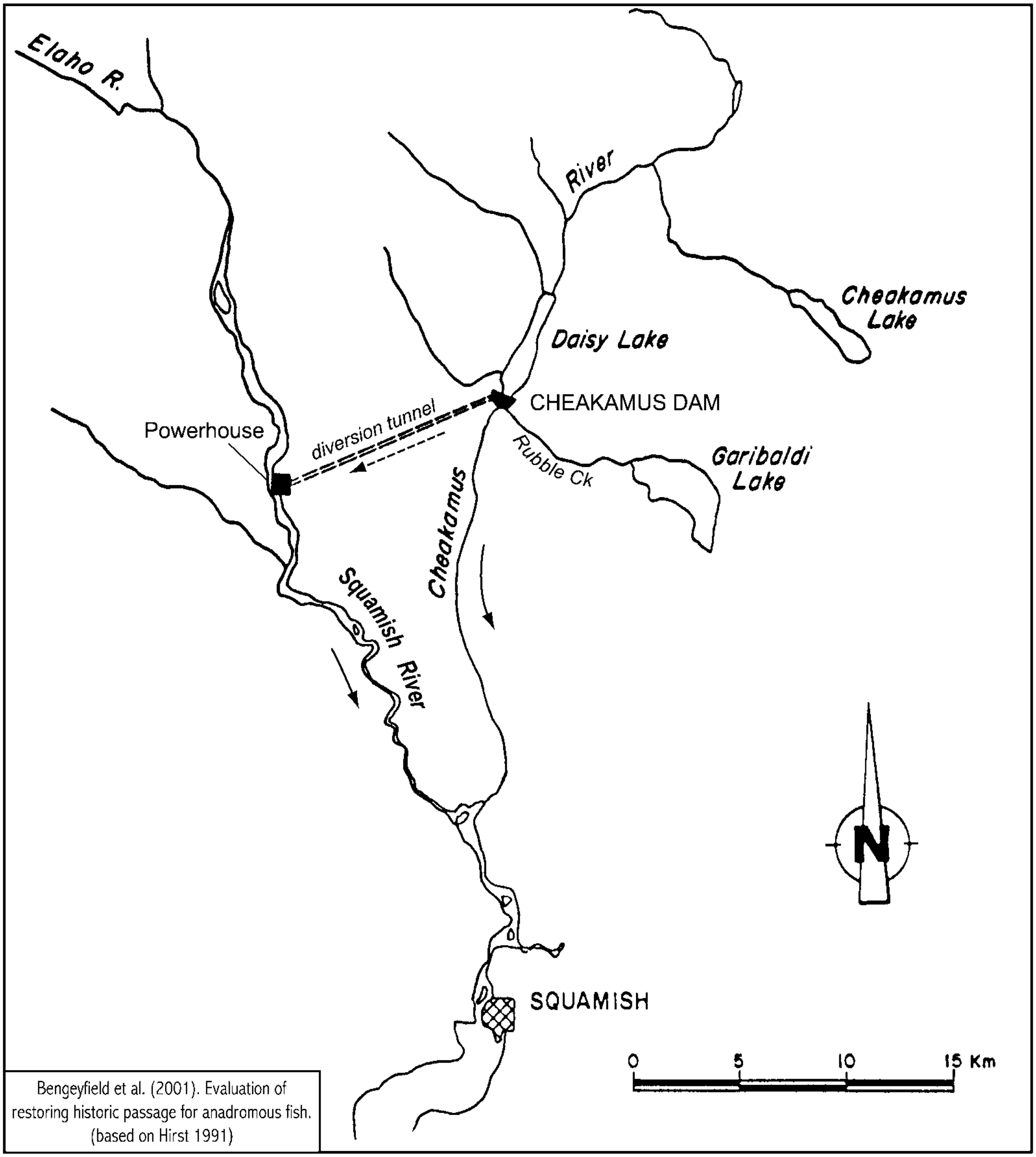

Figure A10-1. Location of Cheakamus Project.

Appendix A11

CLOWHOM DAM

A11.1 Project Operation

The Clowhom Project, commissioned in 1958 by the B.C. Electric Company, consists of a dam impounding Lower Clowhom Lake which joins Upper Clowhom Lake by a short channel and has one power plant 400 metres downstream of the dam (Figure A11-1). Prior to the existing development, B.C. Power Commission had installed a smaller plant consisting of a concrete dam, penstock and powerhouse in 1952 (Keller and Leslie 1996); the existing dam is just downstream of the older structure.

A11.2 Facility Summary

DAM	Clowhom
Dependable capacity (MW)	20
Dam function	storage, diversion
Date constructed	1952
Date reconstructed	1958
Height (m)	22
Length (m)	402
RESERVOIR	**Clowhom**
Present area (ha)	745
Watershed area (km^2)	390
Elevation above sea level (m)	30 (bathym)
Normal drawdown range (m)	11.3
Mean depth (m)	54
Maximum depth (m)	>100
Mean annual discharge 1984-2000 (m^3/s)	37.35
DIVERSION	**to powerhouse**
Structure type	penstock (300m)
Licensed flow (m^3/sec)	75
Fish flow release (m^3/sec)	0
Mainstem w/ diminished flows (km)	0.35

A11.3 Fish Species and Natural Obstructions

Archival information indicates the absence of anadromous fish in the Clowhom basin in the last century, at least in large or consistent numbers. A small secondary channel was reported to exist prior to initial dam construction in 1950 that apparently enabled coho salmon and steelhead to ascend the falls and possibly contained some spawning and rearing functions (BCR Strategic Plan 2000). However, there is also a report of a small tributary creek near the powerhouse that had small numbers of spawning salmon for a short distance upstream of tidewater.

An extensive sport fishery for rainbow and cutthroat trout existed in the original lakes from 1927 to 1956 (Keller and Leslie 1996). Kokanee were once abundant but have declined. The pre-impoundment lakes were judged to be unproductive due to their depth and the lack of benthic organisms and observable plankton (Smith and Larkin 1950). The upper Clowhom River has extensive spawning gravels (BCR Strategic Plan 2000). Most other reservoir tributaries are presently limited in habitat quality due to steep gradients, coarse substrates, obstructions, and low summer flows (Lewis *et al.* 1996). Some tributaries, *e.g.*, Red Tusk Creek, have been used as spawning habitat but species were not specified (Hirst 1991).

A11.4 Summary of Potential for Anadromous Fish Passage

Clowhom Falls was a significant obstacle that likely precluded access by anadromous stocks. Future construction of an adult fishway past these falls plus the dam, and a downstream screening and bypass facility for juveniles is not likely cost-efficient. Besides the capital and operational costs, biological constraints include potential impacts on resident stocks, reduced productivity caused by the drawdown regime, and the effects of forestry activities on tributary habitats in the upper watershed.

A11.5 Clowhom River Literature Cited

Bridge-Coastal Restoration Strategic Plan. 2000. Clowhom River Watershed (Chap.14). Vol.2: Watershed Plans. BC Ministry of Fisheries, Dept. Fisheries & Oceans, and BC Hydro. 14 p.

Hirst, S.M. 1991. Impacts of the operation of existing hydroelectric developments on fishery resources in British Columbia, Vol. 2. Inland fisheries. Can. Manuscript Rep. Fish. Aquat. Sci. 2093 v.2: 200 p.

Keller, B.C. and R.M. Leslie. 1996. *Bright Seas, Pioneer Spirits - the Sunshine Coast*. Horsdal & Schubart Publishers, Victoria, BC. 232 p.

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Smith, S.B. and P.A. Larkin. 1950. Report on the Clowhom lakes investigation. Unpubl. report, B.C. Game Branch, Vancouver, BC. 3 p.

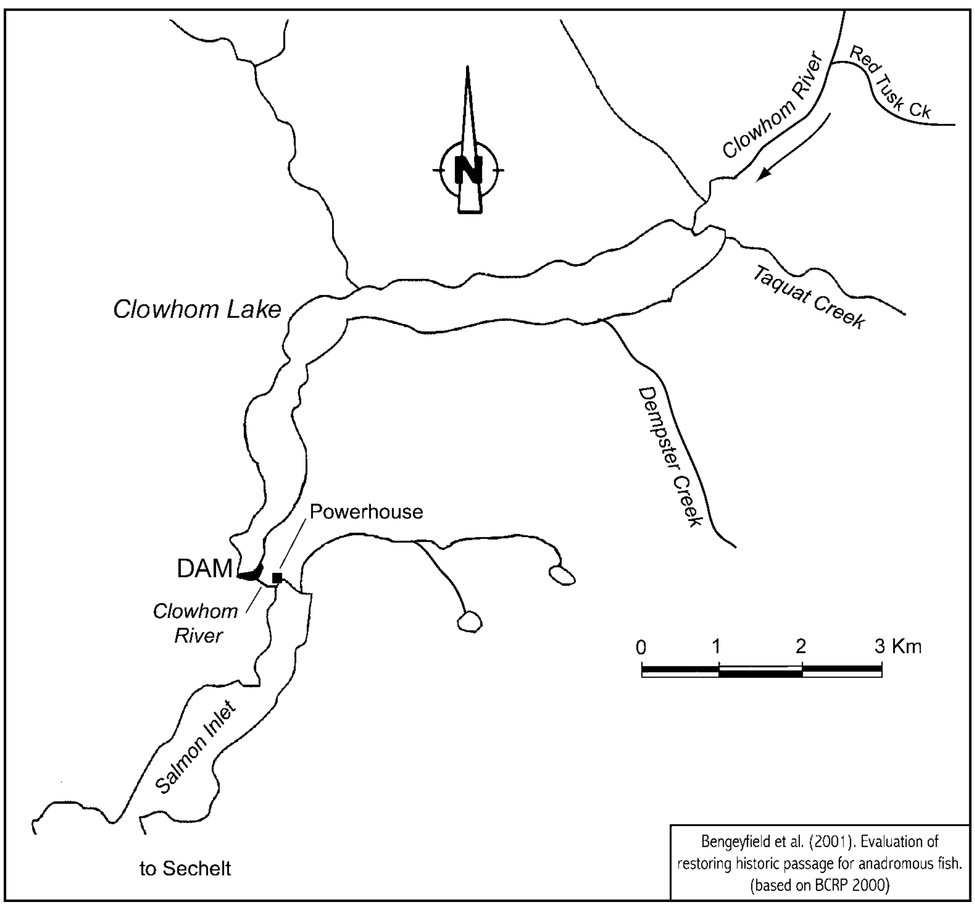

Figure A11-1. Location of Clowhom Project.

Appendix A12

FALLS RIVER DAM

A12.1 Project Operation

The Falls River Project was built in 1930 for the Northern B.C. Power Co. and acquired by B.C. Hydro in 1964. It consists of a dam located at the confluence of Big Falls Creek and the Ecstall River, two penstocks and a powerplant located at the base of Big Falls Creek (Figure A12-1). The reservoir undergoes rapid changes in level, spilling at anytime (BCR Strategic Plan 2000).

A12.2 Facility Summary

DAM	Falls River
Nameplate capacity (MW)	9.6
Dam function	storage, diversion
Date constructed	1930
Date reconstructed	1983; 1992
Height (m)	13
Length (m)	156
RESERVOIR	**Big Falls**
Present area (ha)	247
Orig. lake area (ha)	0
Watershed area (km^2)	248
Elevation above sea level (m)	90.3
Normal drawdown range (m)	2 -5
Maximum depth (m)	>10
Mean annual discharge (m^3/s)	
DIVERSION	**to powerhouse**
Structure type	penstock (220m)
Licensed flow (m^3/sec)	17
Fish flow release (m^3/sec)	1.3
Mainstem w/ diminished flow (km)	0.2

A12.3 Fish Species and Natural Obstructions

The 20+ m high falls stop anadromous fish passage about 200 m upstream of Big Falls Creek's confluence with the Ecstall River. The short section of stream has rocky bottom with some spawnable gravels in the deep pool at the tailrace outlet. Low numbers of coho, pink and chinook salmon spawn in the tailrace (DFO 1983). Hickey (1981) captured rainbow trout and Dolly Varden char and also noted chinook fry in the tail pond which is influenced by marine tides.

The cutthroat trout and Dolly Varden char in Big Falls Reservoir and Carthew Creek are not known to be a resource of special significance (Lewis *et al.* 1996). Threespine stickleback are present in Hayward Lake (FISS 2000).

A12.4 Summary of Potential for Anadromous Fish Passage

The Falls River Project has not impeded historic fish passage. The FISS database characterizes Big Falls Creek as having no enhancement potential due to its small size and impassable falls.

A12.5 Big Falls Creek Literature Cited

Bridge-Coastal Restoration Strategic Plan. 2000. Big Falls Creek Watershed (Chap.15). Vol.2: Watershed Plans. BC Ministry of Fisheries, Dept. Fisheries & Oceans, and BC Hydro. 11 p.

Dept. of Fisheries & Oceans. 1983. Catalogue of salmon streams and spawning escapements of Statistical Area 4 (Lower Skeena River) including coastal streams. Can. Data Rept. Fish. Aquatic Sci. No. 395.

FISS 2000. Fisheries inventory database. www.pisces.env.gov.bc.ca/FishWizard.asp

Hickey, D.G.1981. Salmon observations at Falls River hydroelectric project during 1981. Report by D.B. Lister and Associates Ltd. to B.C. Hydro. Vancouver, B.C. 27 p.

Lewis, A.F., G.J. Naito, S.E. Redden and BC Hydro Safety & Environment. 1996. Fish flow studies project: fish flow overview report. BCH Safety & Environment Rept. No. EA:95-06, 144 p.

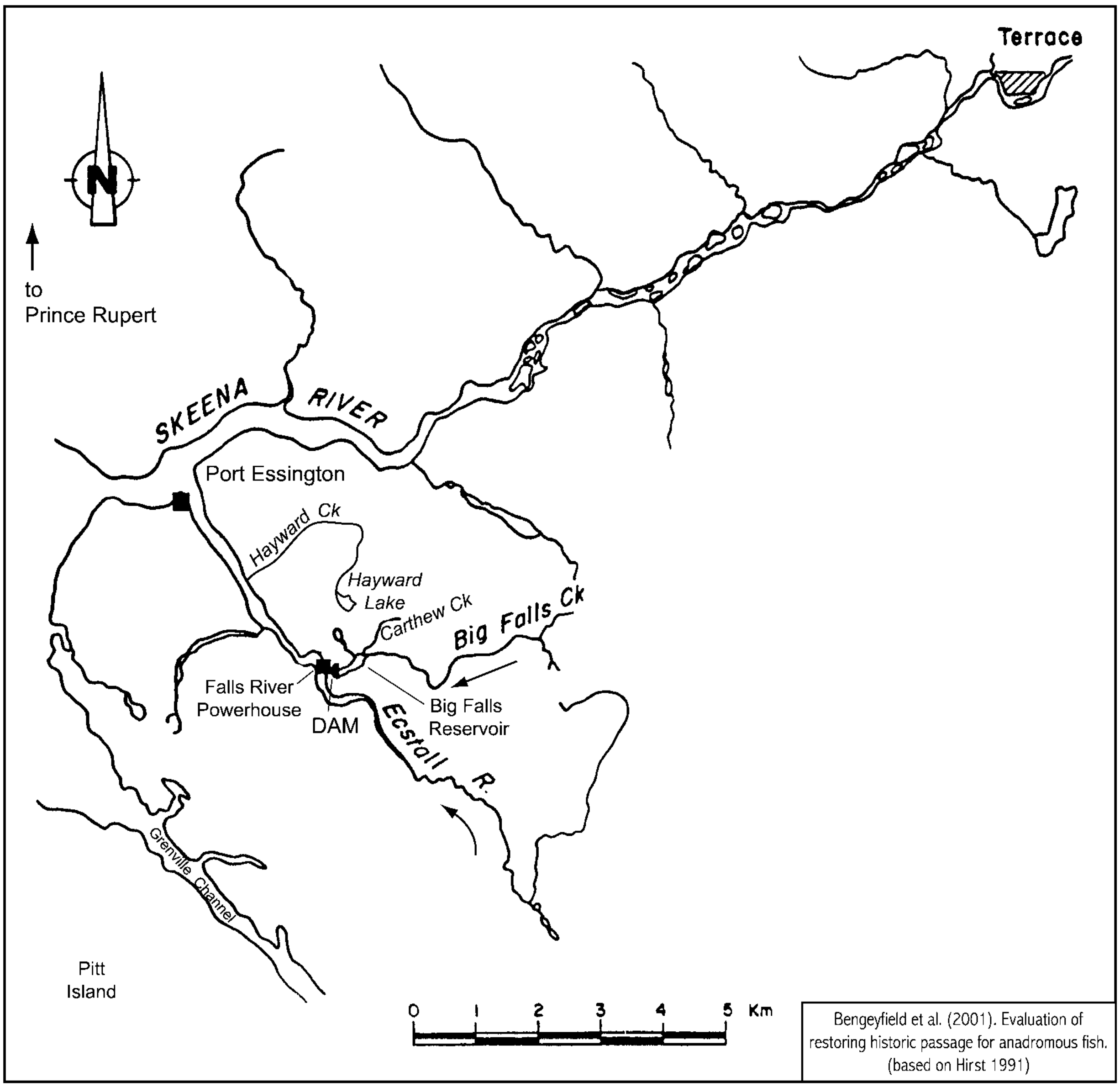

Figure A12-1. Falls River Project.

Appendix A13

CLAYTON FALLS DAM

A13.1 Fish Species and Natural Obstructions

Small numbers of pink and chum salmon spawn in the 200 m of channel between tidewater and the falls, including the tailrace area. The Clayton Falls system is a steep drainage with few natural habitats accessible to fish. Resident fish are apparently not present upstream of Clayton Falls (Lewis *et al.* 1996).

A13.2 Facility Summary

DAM	**Clayton Falls**
Dependable capacity (MW)	2.05
Dam function	diversion
Date constructed	1962
Height (m)	7
Length (m)	41
RESERVOIR	**headpond**
Present area (ha)	2
Watershed area (km^2)	93
Elevation above sea level (m)	78
Normal drawdown range (m)	4.1 (max)
Maximum depth (m)	
Mean annual discharge (m^3/s)	
DIVERSION	**to powerhouse**
Structure type	penstock (580m)
Licensed flow (m^3/sec)	1.3
Fish flow release (m^3/sec)	none
Mainstem w/ diminished flows (km)	0.5

A13.3 Project Operation

The Clayton Falls Project built by the B.C. Power Commission consists of a small diversion dam on Clayton Falls Creek 4 km west of Bella Coola. A pipeline draws water from a small headpond behind the dam to the generating station 100 m upstream of tidewater on North Bentinck Arm. The project is presently operated with relatively few fluctuations in flow (Lewis *et al.* 1996).

A13.4 Summary of Potential for Anadromous Fish Passage

There is no evidence of historical fish presence in the creek above the barrier falls (BCR Strategic Plan 2000), and provision of future passage is not considered viable in terms of available habitat upstream.

A13.5 Clayton Falls Literature Cited

Bridge-Coastal Restoration Strategic Plan. 2000. Clayton Falls Creek Watershed (Chap.16). Vol.2: Watershed Plans. BC Ministry of Fisheries, Dept. Fisheries & Oceans, and BC Hydro. 7 p.

Lewis, A.F., G.J. Naito, S.E. Redden and BC Hydro Safety & Environment. 1996. Fish flow studies project: fish flow overview report. BCH Safety & Environment Rept. No. EA:95-06, 144 p.

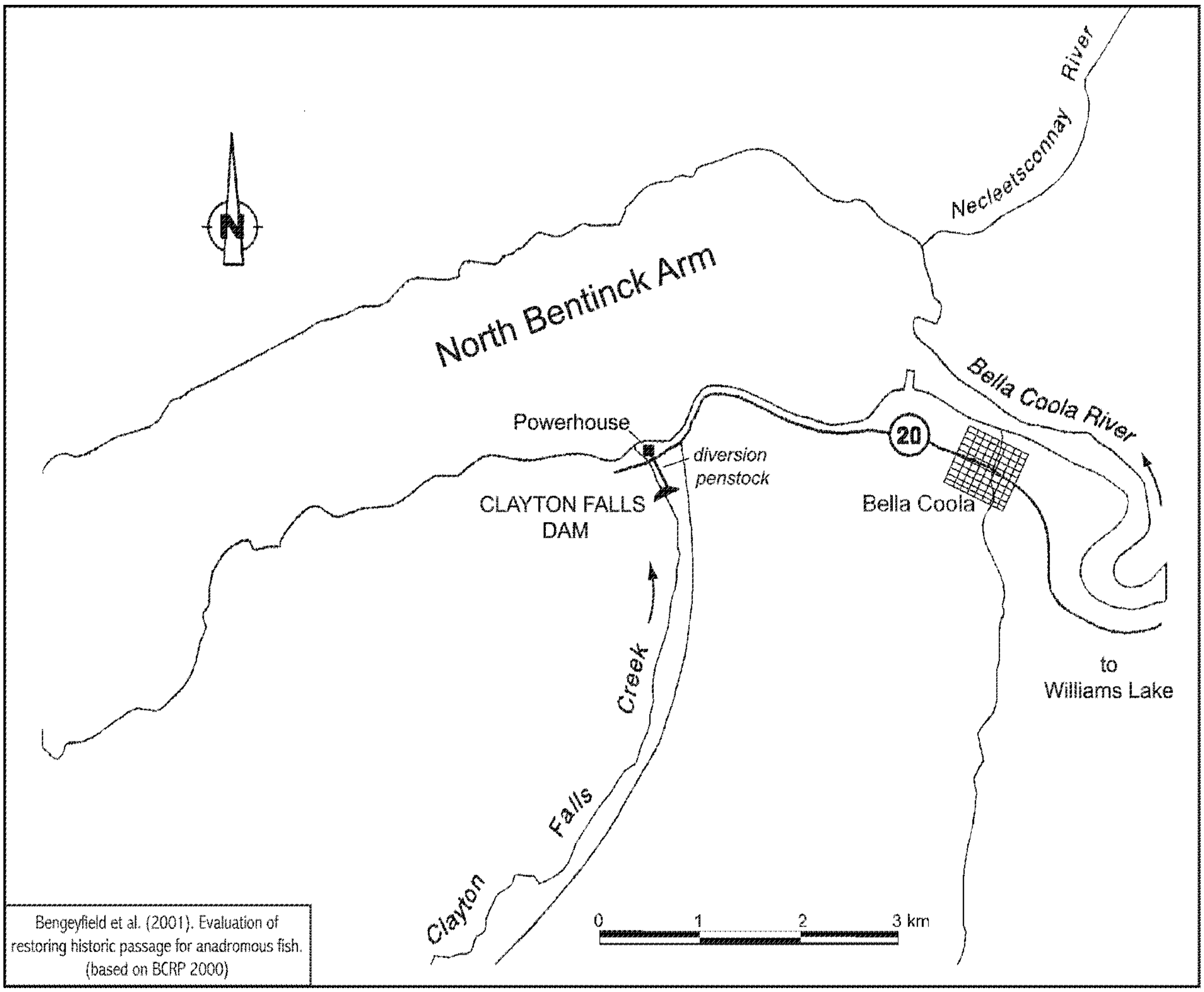

Figure A13-1. Location of Clayton Falls Project.

Appendix B

Facilities With Current Anadromous Fish Stocks

Appendix B1

PUNTLEDGE DIVERSION DAM

B1.1 Project Operation Summary

The Puntledge River project was first developed in 1912 by Wellington Collieries (Dunsmuir) Ltd. to supply electricity to coal mines on Vancouver Island. The project consists of a storage dam at the outlet of Comox Lake and a diversion dam downstream. Water is carried by an overland penstock to a powerhouse on the lower Puntledge River (Figure B1-1). The B.C. Power Commission redeveloped the dams and powerhouse in 1953-56 and increased Comox Lake storage.

Puntledge Diversion Dam sends flows to the powerhouse after they are released from Comox Dam; water is also spilled year round into the Puntledge River for fish purposes. At the present level of fish water releases, instream habitats in the river below Puntledge Diversion Dam are reduced in comparison to pre-project levels. Storage in Comox Reservoir is relatively limited, and spills have occurred in many years from rapid spring snowmelt or prolonged fall rains.

B1.2 Puntledge Diversion Dam Facility Statistics

DAM	**Puntledge**
Dependable capacity (MW)	18
Dam function	diversion
Date constructed	1912
Date reconstructed	1956
Height (m)	5.5
Length (m)	165
RESERVOIR	**headpond**
Present area (ha)	20
Orig. lake area (ha)	0
Watershed area (km^2)	473
Elevation above sea level (m)	130.2
Normal drawdown range (m)	min
Maximum depth (m)	5
Storage (million m^3)	min
Mean water retention time	<1 day
Mean annual discharge (m^3/s)	
DIVERSION	**to Puntledge River d/s**
Structure type	penstock
Licensed flow (m^3/sec)	32.5
Fish flow release (m^3/sec)	2.8-5.7
Mainstem length diminished (km)	6

* dashes (- -) mean not applicable

B1.3 Species & Natural Obstructions

The original anadromous stocks at Puntledge Diversion Dam in 1912 consisted of summer run chinook salmon, coho salmon and summer run steelhead. The principal spawning area for these groups was stated to be the 3-km section of river upstream of the dam, but likely included some tributaries to Comox Lake.

Downstream of the diversion dam, two sets of waterfalls—Stotan Falls and Nib Falls—were challenging partial barriers to historic upstream passage, particularly during low stream flows in late summer-early fall when most salmon stocks migrate to spawning habitats. Remedial work on these falls began in 1923 by Canadian Collieries (Walker and MacLeod 1970) and periodic improvements continued through 1977 (Hancock and Marshall 1985) so that now with the fish flow releases, the original three species and pink salmon can ascend to the dam.

Other species upstream of Puntledge Diversion Dam are rainbow and cutthroat trout, Dolly Varden, kokanee, lamprey *sp*., sculpin *sp.* and stickleback (Global Fisheries Consultants Ltd. 1992).

B1.4 Fish Passage Structures

The Puntledge Diversion Dam was the site of two early experiments to attempt guiding downstream migrants, one before and one after the 1957 project re-development and increased diversion licence. Brett and MacKinnon (1953) tested lights, sound and bubbles, and Ruggles and Ryan (1964) tested a prototype array of louver panels, in attempts to deflect juvenile fish within a generalized channel, but neither test was actually deployed at the entrance to the diversion canal. While some results were encouraging, neither technique was installed due to relative high costs *vs.* inconsistent benefits.

After the diversion was increased from 300 cfs to 980 cfs, smolt mortalities increased at the tailrace and were estimated during a 1955 field trial at 28-42%, depending on species and fish length (DFO records). In 1965 the fishway to the upstream spawning area was closed and a spawning channel for chinook salmon was substituted adjacent to the diversion dam so the fry could be shunted past the dam and avoid entrainment through the powerhouse, but fry production proved too low (Lister 1968). From 1989-94, BC Hydro began a six-year series of experiments that tested behavioral devices, electric field, barrier nets, and finally culminated in the successful installation of twin Eicher screens than provided a 90+% survival rate for chinook, coho, sockeye and steelhead smolts (*e.g.*, Bengeyfield and Smith 1989; Bengeyfield 1995).

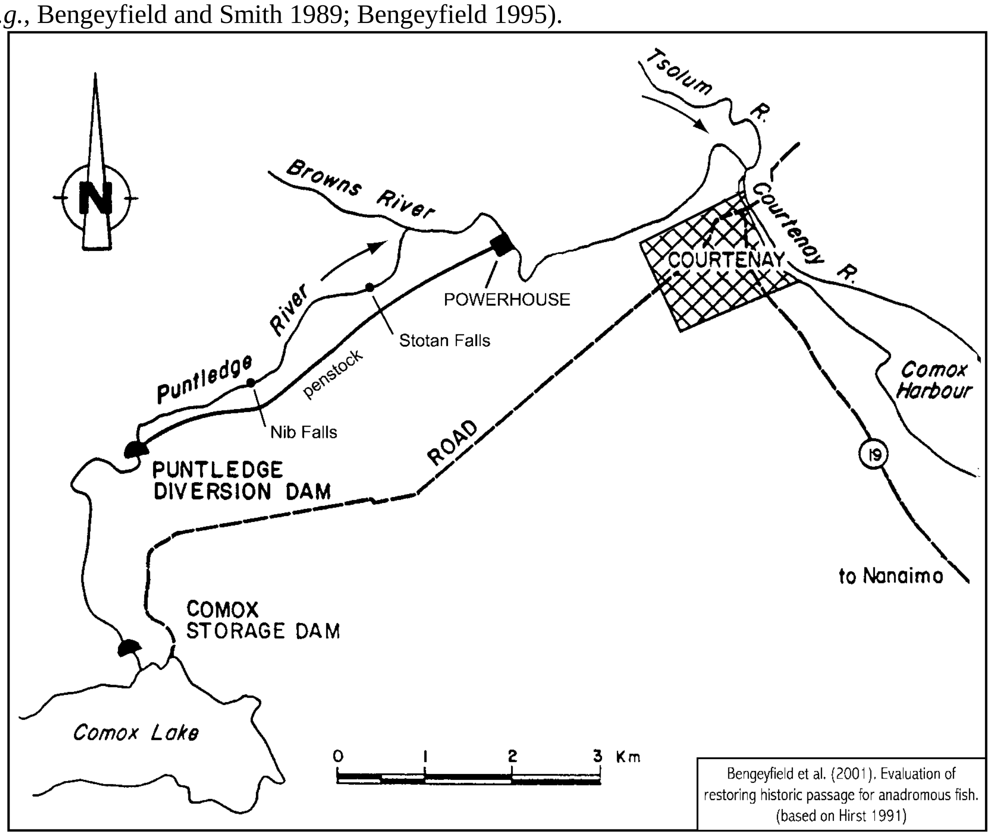

Figure B1-1. Puntledge Diversion Dam.

Upstream

The fishway at Puntledge Diversion Dam passes through the upper site of Puntledge Hatchery where adult salmon are detained for broodstock. Steelhead adults have been allowed to pass into the headpond since 1991. This structure is useful as a control point to limit non-historic species such as pink salmon that now ascend this far.

See Appendix E for further details on the existing structures.

Downstream

Eicher screens were installed in the diversion penstocks in 1993. Until that time, juveniles were entrained into the intakes except in years when spills carried some fish over the low dam to the river.

See Appendix E for details on existing structures.

B1.5 Puntledge Dam Literature Cited

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Bengeyfield, W. and H.A. Smith.1989. Evaluation of behavioural devices to divert coho salmon smolts from the penstock intakes at Puntledge Generating Station. Unpubl. rept. to BC Hydro by Global Fisheries Consultants Ltd., White Rock, BC. 27 p.

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Hancock, M.J. and D. E. Marshall. 1985. Puntledge River. Catalogue of salmon streams and spawning escapements of Statistical Area 14, Comox-Parksville. Can. Data Rep. Fish. Aquat. Sci. No. 504, 134 p

Lewis, A.F., G.J. Naito, S.E. Redden and BC Hydro Safety & Environment. 1996. Fish flow studies project: fish flow overview report. BCH Safety & Environment Rept. No. EA:95-06, 144 p.

Lister, D.B. 1968. Progress report on assessment of the Puntledge River spawning channel: June 1965 to May 1968. Memo. Report. Dept. Fisheries. Vancouver, B.C. 39 p.

Ruggles, C.P. and P. Ryan. 1964. An investigation of louvers as a method of guiding juvenile Pacific salmon. Can. Fish Culturist 33: 68 p.

Walker, C.E. and J.R. MacLeod. 1970. Puntledge River. *In:* Catalogue of salmon spawning streams and escapement populations, Statistical Area No. 14, Pacific Region. Dept. Fisheries and Forestry, Vancouver, p. 69-75

Appendix B2

COMOX LAKE DAM

B2.1 Project Operation Summary

See Section B1.1 (*Puntledge Diversion Dam*).

B2.2 Comox Dam Facility Statistics

DAM	**Comox**
Dependable capacity (MW)	- -
Dam function	storage
Date constructed	1912
Date reconstructed	1956; 1982
Height (m)	10.7
Length (m)	100
RESERVOIR	**Comox Lake**
Present area (ha)	2118
Orig. lake area (ha)	1868
Watershed area (km^2)	460
Elevation above sea level (m)	135
Normal drawdown range (m)	4.5
Mean depth (m)	61
Maximum depth (m)	100
Storage (million m^3)	106
Mean water retention time	no data
Mean annual discharge (m^3/s)	34-43
DIVERSION	**none**
Structure type	- -
Licensed flow (m^3/sec)	- -
Fish flow release (m^3/sec)	2.8-5.7

* dashes (- -) mean not applicable

B2.3 Species & Natural Obstructions

Historic chinook, coho and steelhead runs were known to pass Stotan and Nib falls and ascend to the river section above the diversion dam to the lake; hence the fishway at the original diversion dam. Judging from the present lake outlet site, the short rapids over bedrock shown in the original project drawings were almost certainly passable. The Federal Fisheries Department had no direct knowledge of anadromous fish in Comox Lake before the impounding dam was built, and Canadian Collieries (Dunsmuir) Limited claimed that local knowledge indicated the virtual absence of salmon for 30 years prior to 1919. The requirement for a fishway was discussed with the Inspector of Fisheries during a meeting at Nanaimo in early 1912 and the Company claimed that the Inspector was satisfied that the gates and log sluice provided in the impounding dam would also allow fish passage. When the Federal Fisheries Department became aware that the log sluiceway did not pass fish as planned, neither the Company nor the Agency could find a written statement to confirm this verbal agreement. After much correspondence about who should design and pay for the structure, the Agency served notice in January 1919 to the Company to install a proper fishway, and they persisted in field inspections and correspondence until the Company constructed a fish ladder in September 1922 (DFO correspondence files).

Soon after the timber crib fishway was added at Comox Dam, the Federal Fisheries Department attempted to start a sockeye run in Comox Lake by introducing 0.5-1 million eyed eggs from Rivers Inlet and Henderson Lake stocks each year from 1923-30, but the trial was unsuccessful.

The original fishway was replaced with a concrete version in 1946. A new fish ladder was incorporated into the new impoundment dam reconstructed in 1958. Concerns over losses of juvenile migrants to entrainment caused the agencies to close the fishway at the diversion dam in 1965. MELP modified the Comox Dam fishway for steelhead passage in 1991.

Since 1980 juvenile coho and sometimes chinook salmon from Puntledge Hatchery have been planted each year into Comox Lake and its tributaries. Steelhead adults are now allowed to pass the two dams and spawn naturally after a period of fry stocking. Steelhead adults were planted into Comox Creek, a Cruickshank R. tributary in 2001. Potential interactions between different species of outplanted hatchery fry were discussed by Bengeyfield (1995).

Cutthroat trout supported a local sport fishery in Comox Lake before 1912. Rainbow trout were planted in headwater lakes of the Cruickshank River (southwest end of Comox Reservoir) in 1930. Today cutthroat trout continue to produce large specimens. Dolly Varden occur in the upper headwater tributaries (Griffith 1995). It is not known whether kokanee were historically present before sockeye eggs were planted in 1923, but a small outmigration of kokanee smolts has been sampled in May through most of the 1990s.

Many reports have remarked on the large habitat capacity in the tributaries to Comox Lake (DFO correspondence 1920; Caw 1977; Brown *et al.* 1977; Griffith 1995).

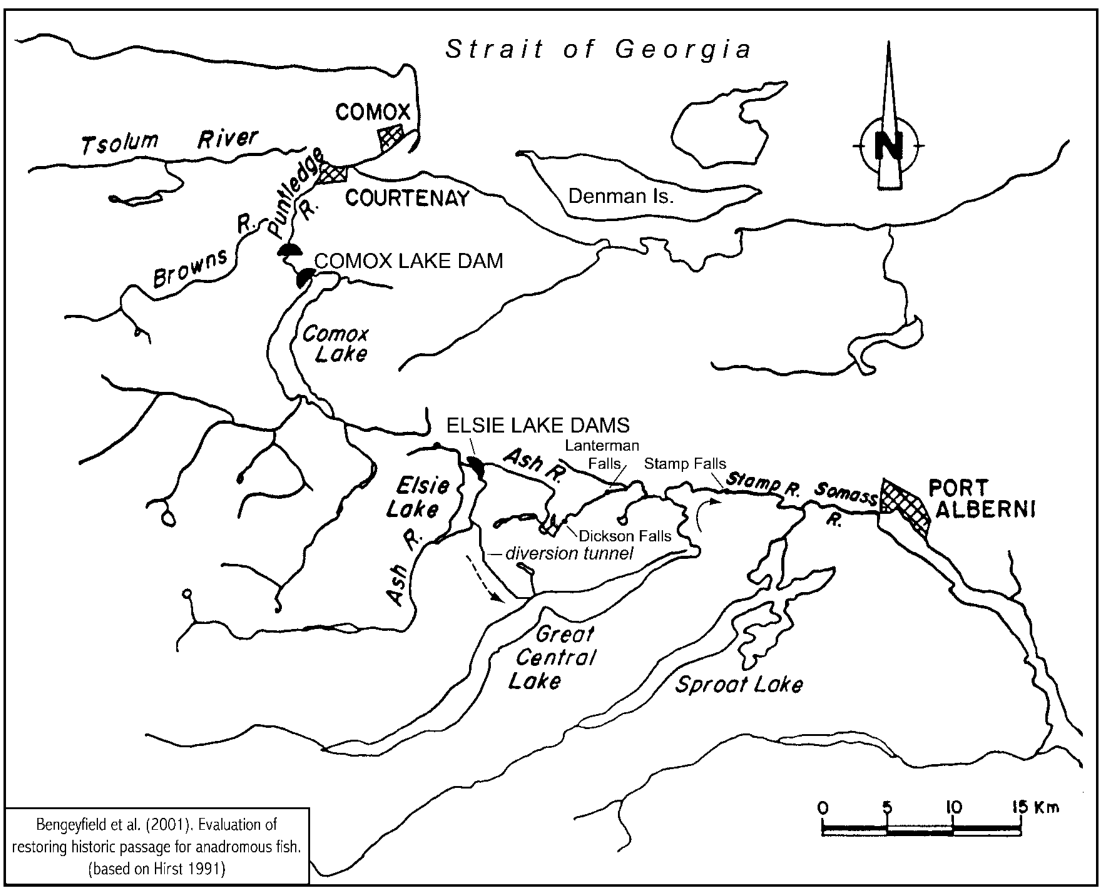

Figure B2-1. Location of Comox Dam.

B2.4 Fish Passage Structures

Upstream

The fish ladder at Comox Dam has been constructed in at least four different versions (1922, 1946, 1958, and 1991).

See Appendix E for details on existing structures.

Downstream

There are no special structures for downstream passage at Comox Dam. Fish migrate through the main gates at normal flows and at high flows, they pass over the spillway as well. The low head of Comox Dam has not caused obvious mortalities during smolt passage after 20 years of outplanting.

B2.5 Comox Dam Literature Cited

Bengeyfield, W. 1995. Puntledge River discussion paper on stocking strategies in the upper watershed. Global Fisheries Consulting Ltd. report to BC Hydro, 64 p.

Brown, R.F., V.D. Chahley and D.G. Demontier. 1977. Puntledge River. Preliminary catalogue of salmon streams and spawning escapements of Statistical Area 14 (Comox-Parksville). Fisheries and Environ. Canada, Fish. Mar. Serv., Pac. Region, PAC/D-77-12, 128 p.

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Hancock, M.J. and D. E. Marshall. 1985. Puntledge River. Catalogue of salmon streams and spawning escapements of Statistical Area 14, Comox-Parksville. Can. Data Rep. Fish. Aquat. Sci. No.504, 134 p.

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Walker, C.E. and J.R. MacLeod. 1970. Puntledge River. *In:* Catalogue of salmon spawning streams and escapement populations, Statistical Area No. 14, Pacific Region. Dept. Fisheries and Forestry, Vancouver, p. 69-75.

Appendix B3

SETON DAM

B3.1 Project Operation Summary

The Seton project, in service by 1956, consists of Seton Dam below the outlet of Seton Lake where water is diverted by canal and short penstock to the powerhouse on the Fraser River. Flows in Seton River are typically diminished by the powerhouse diversion except during spills. Cayoosh Dam diverts water from Cayoosh Creek via tunnel to Seton Lake (Figure B3-1).

Seton Lake has a total average inflow of about 117 m3/s of which 19 m3/s comes from the Seton basin, 16 m3/s is diverted from the Cayoosh Creek system, and 92 m3/s (78%) is diverted from the Bridge River basin (BC Hydro 1994). The seasonal flow regime of Seton Lake reservoir and Seton River is now dominated by the inflows from the Bridge River operations.

The Seton River basin is south of the Bridge River basin, separated by the Bendor Range and Mission Ridge. The Seton basin has no existing glaciers and is lower in mean elevation than the Bridge basin which has several glaciers. Anderson Lake, and to lesser degree Gates Lake, provide water storage within the Seton basin. Gates River, an important spawning ground for sockeye salmon, connects these two lakes and is 12 km in length. Anderson Lake drains into Seton Lake through the 2 km long Portage River, which supports spawning by several salmon species (Figure B3-2).

B3.2 Seton Dam Facility Statistics

DAM	**Seton**
Dependable capacity (MW)	42
Dam function	storage, diversion
Date operational	1956
Height (m)	7.6
Length (m)	130
RESERVOIR	**Seton Lake**
Present area (ha)	2530
Orig. lake area (ha)	2503
Watershed area (km^2)	1011
Elevation above sea level (m)	237
Normal drawdown range (m)	0.4
Mean depth (m)	85
Maximum depth (m)	150
Storage (million m^3)	9.4
Mean water retention time	no data
Mean annual discharge (m^3/s)	117 incl. diversions
DIVERSION	**to powerhouse on Fraser River**
Structure type	canal
Licensed flow (m^3/sec)	143
Fish flow release (m^3/sec)	5.7-11.3
Mainstem length diminished (km)	4.6

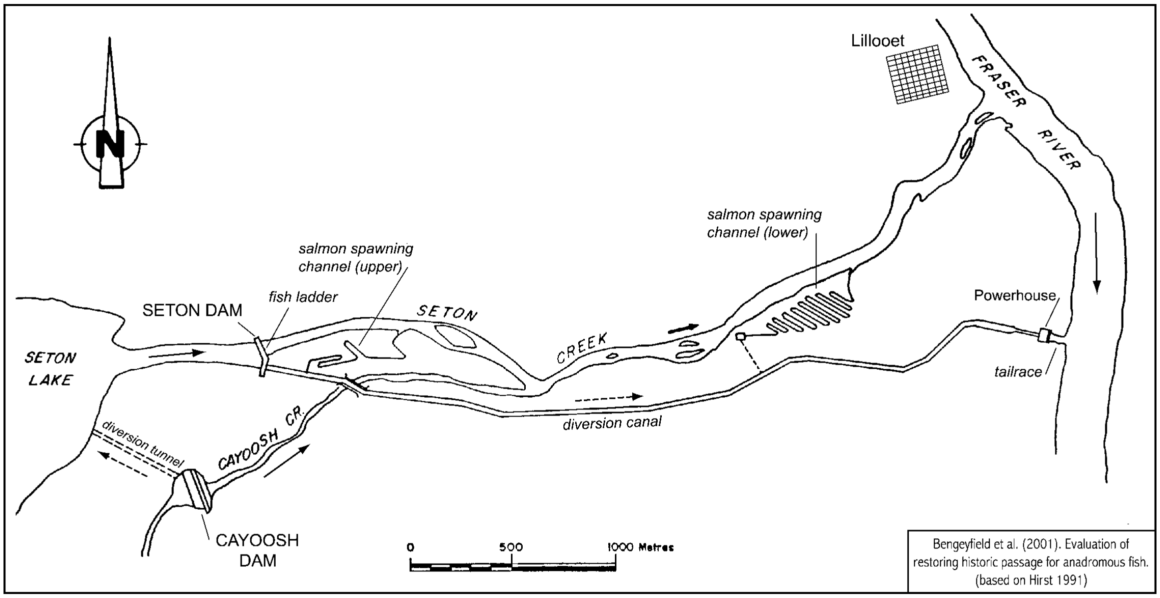

Figure B3-1. Seton Dam and Cayoosh Diversion.

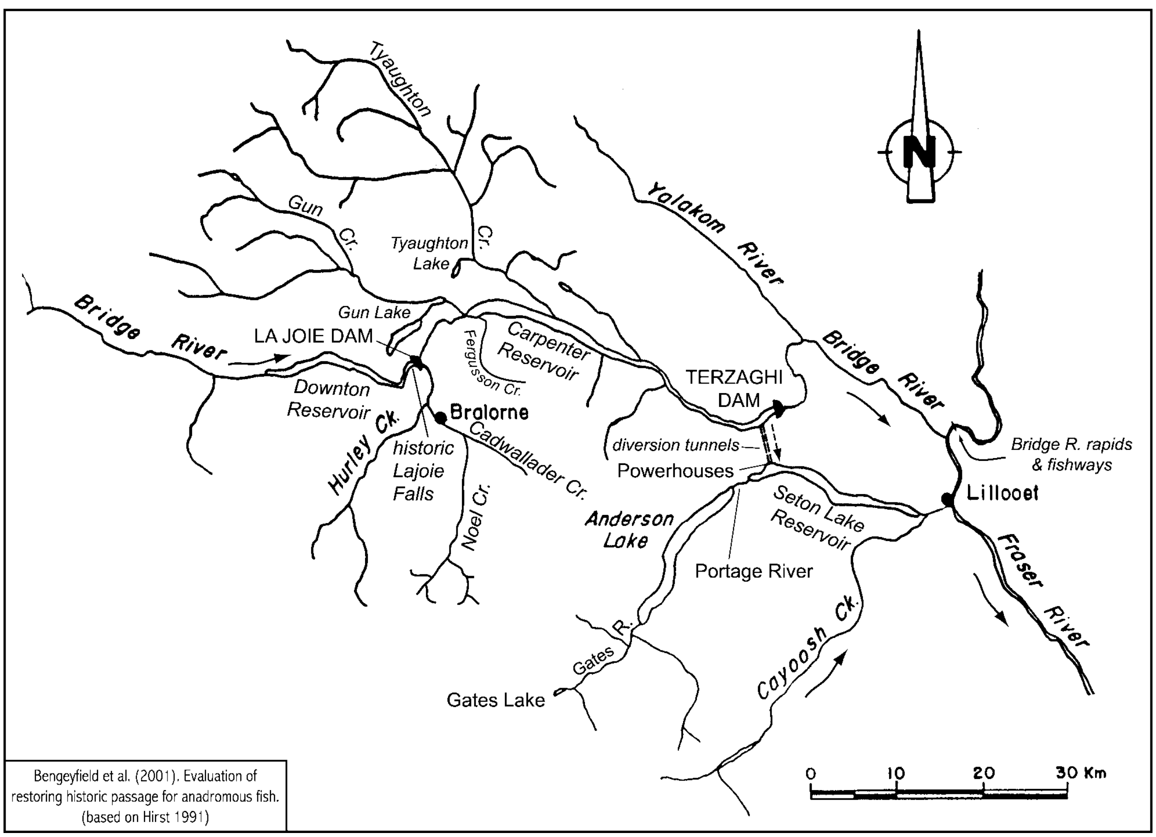

Figure B3-2. Bridge River Diversion to Seton Watershed.

B3.3 Species & Natural Obstructions

More detailed information on anadromous fish stocks in the Seton system can be found in Hirst (1991) and BCRP (2000). Anadromous stocks at Seton were affected by the notorious fish obstruction in Hells Gate Canyon in 1913 and 1914 well prior to any hydroelectric development. The large rockslides that slid into the Fraser River blocked the passage of nearly all returning adult salmon. Permanent fishways were finally completed on both riverbanks around Hells Gate between 1944 and 1947 (Roos 1991).

Declining escapements of sockeye to Seton River prompted the construction of the first sockeye hatchery in British Columbia in 1903 (Babcock 1904) near the present dam site, but the Provincial hatchery was not successful and closed about 1918 after Hells Gate. The hatchery operations have been considered by some to have exacerbated the decline in Seton stocks.

Seton Lake had anadromous runs of sockeye, pink, chinook, and coho salmon and steelhead prior to dam construction in 1956, and they exist in relatively strong numbers today. Rainbow trout, bull trout, Dolly Varden char, kokanee and mountain whitefish are the resident sportfish; white sturgeon may have been trapped in the lake by the dam. Babcock (1903) reported burbot and a unique form of kokanee called *oneesh* in Seton Lake.

Historic fish passage up Seton River was not hindered by natural barriers but two earlier dams or the hatchery fence across Seton River possibly affected upstream migration. One dam crossed the mouth of Seton Lake to retain log booms, and consisted of a 45 m long by 1.2 m high mound of boulders and rubble with two stoplog openings on the north side (Tubb 1938). A second dam, constructed by the Pacific Great Eastern Railway 100 m upstream of the confluence of Seton River and Cayoosh Creek, was present at least since 1932. It was 14 m long and 2 m high, with a 2.5 m wide fish ladder that was 6 m long with 3 step pools.

B3.4 Fish Passage Structures

Upstream

Fish passage structures for salmonids were incorporated into the dam structure but these would not be suitable for white sturgeon also reported in the lake.

See Appendix E for details on existing structures.

Downstream

Downstream passage structures were designed for the original Seton Dam. See Appendix E for details on existing structures.

The powerhouse tailrace discharges into a semicircular basin approximately 100 m x 75 m that was excavated in a gravel bench of the Fraser River about 1.5 km downstream of the Seton River confluence.

A field test of prototype louvers was begun in 1999 to guide migrants to these facilities (RL&L 1999).

B3.5 Seton Dam Literature Cited

Fretwell, M.R. 1989. Homing behaviour of adult sockeye salmon in response to a hydroelectric diversion of homestream waters at Seton Creek. Intl. Pacific Salmon Fisheries Commission. Vancouver, BC. Bull. No. XXV. 38 p.

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Tubb, J.A. 1938. Manuscript notes and sketches from a salmon spawning survey of Seton Creek. Pac. Salmon Comm. archive file 945.1-2, 15 p.

Appendix B4

SALMON RIVER DIVERSION DAM

B4.1 Project Operation Summary

The Salmon River Dam, completed in 1958, diverts part of the upper Salmon River and Paterson Creek via flume and channel for 14 km via Brewster, Gray, Whymper and Fry lakes and then into Lower Campbell Lake (Figure B4-1). The licensed diversion is 16 m^3/s but actual diversions have averaged about 11.3 m^3/s annually.

The upper Salmon basin drains 2000 m high mountains in Strathcona Provincial Park on Vancouver Island. Salmon River flows are typical of British Columbia coastal basins. High flows occur from May through July due to snowmelt. August and September are usually quite dry. Large storms separated by days or hours from October to March cause alternating periods of snow that accumulate, and heavy rains which cause immediate runoff.

B4.2 Salmon River Dam Facility Statistics

DAM	**Salmon Diversion**
Dependable capacity (MW)	- -
Dam function	diversion
Date constructed	1958
Height (m)	5
Length (m)	73
RESERVOIR	**headpond**
Present area (ha)	0.7
Watershed area (km^2)	269
Present elevation a.s.l. (m)	224
Normal drawdown range (m)	- -
Mean depth (m)	2
Maximum depth (m)	4
Storage (million m^3)	0
Mean water retention time	- -
Mean annual discharge (m^3/s)	14
DIVERSION	**to Lower Campbell L.**
Structure type	canal/channel
Licensed flow (m^3/sec)	15.7
Fish flow release (m^3/sec)	1.73
Mainstem diminished (km)	21

* dashes (- -) mean not applicable

B4.3 Species & Natural Obstructions

The Salmon Diversion Project is a special case where anadromous stocks were not present at the time of construction. When the diversion dam was built in 1958, historic anadromous stocks had been blocked by a 5 m high falls/obstruction located about 12 km downstream. The obstruction was a cluster of very large boulders that often retained a debris jam within the narrow steep-walled canyon about 38 km from tidewater . Remedial blasting by BC Fish & Wildlife Branch in 1975 and 1976 made this barrier passable (Ptolemy *et al.* 1977). Runs of steelhead and coho salmon have been started from fry releases in 1986 and 1987 respectively. Adult coho and steelhead apparently used the sluice gate to ascend past the dam (Perrin 1989) until a fish ladder was constructed in 1992. Resident stocks currently above the dam include kokanee, rainbow and cutthroat trout, Dolly Varden char, and sculpins (Hansen 1997).

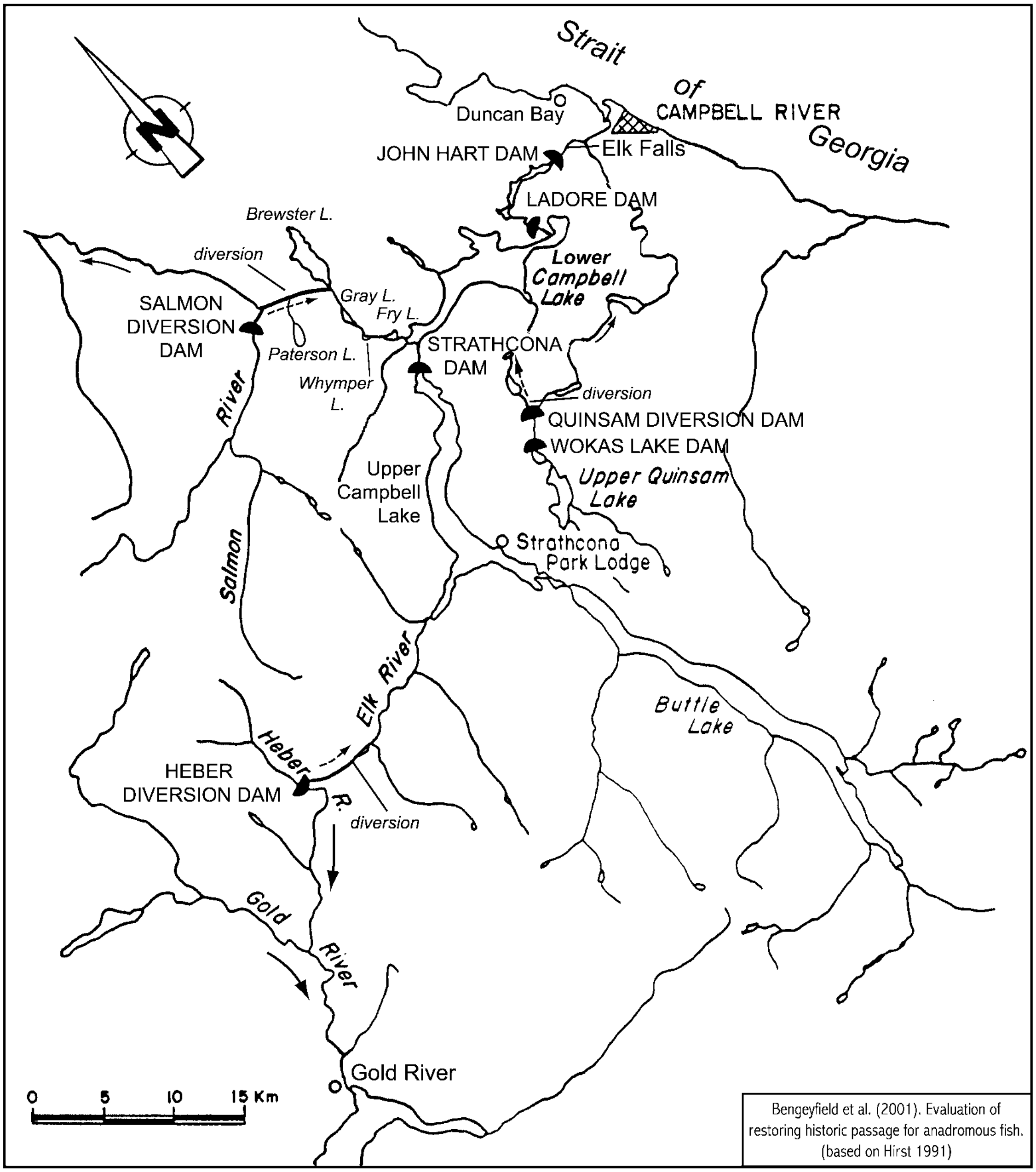

Figure B4-1. Location of Salmon River Diversion Project.

B4.4 Fish Passage Structures

Upstream Passage

A fishway was retrofitted at the Salmon Diversion Dam to accommodate the introduced runs of steelhead and coho salmon. The fishway was constructed in 1992 at the downstream end of the trimming weir adjacent to the left side of the radial gate structure. Sill elevation of the fishway is 220.79, and stoplog slots are provided (Lewis *et al.* 1996)

See Appendix E for details on existing structures.

Downstream Passage

History of the 'Bomford' screen was reported by Bomford and Lirette (1991).

See Appendix E for details on existing structures.

B4.5 Salmon Diversion Dam Literature Cited

Bomford, J.A. and M.G. Lirette. 1991. Design, operation and evaluation of an inverted, inclined outmigrant fish screen. American Fisheries Society Symposium 10: 228-236.

Hansen, L. 1997. Results of Fish Enumeration at the Salmon River Smolt Screen, April 1 - June 21, 1996. BC Hydro Power Facilities. Prepared for BC Conservation Foundation. 56 p.

Lewis, A.F., G.J. Naito, S.E. Redden and BC Hydro Safety & Environment. 1996. Fish flow studies project: fish flow overview report. BCH Safety & Environment Rept. No. EA:95-06, 144 p.

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Ptolemy, R A., J.C. Wightman and C.D. Tredger. 1977. A fisheries reconnaissance assessment of the Salmon River drainage, Vancouver Island, B.C. relative to enhancement opportunities. Memo. report. Fish and Wildlife Branch, BC Ministry of Recreation and Conservation. Victoria, B.C. 58 p.

Appendix C

Facilities That Excluded Anadromous Fish Stocks

Appendix C1

COQUITLAM DAM

C1.1 Project Operation

The Coquitlam-Buntzen project was designed and licensed to divert water out of Coquitlam Lake Reservoir via a 3.9 km tunnel to Buntzen Lake Reservoir where penstocks lead to two power-houses located on the marine shoreline of Indian Arm in Burrard Inlet (Figure C1-1). Buntzen Reservoir has little inflow of its own.

BC Hydro must reserve sufficient storage in Coquitlam Reservoir from May to September to meet domestic water demands of the Greater Vancouver Water District. The Greater Vancouver Water District has its 2.3 m diameter pipe intake located 300 m upstream of the dam on the east shore at an invert elevation of 132.65 m. The pipe is capable of carrying a maximum flow of 7.9 m^3/sec (Lewis *et al.* 1996). The typical annual drawdown of the reservoir is 12.8 m, nearly half of its 31 m maximum depth.

High inflows due to snowmelt occur from May to July, while August and September are usually dry, and high inflow from rain can occur from October to March (Lewis *et al.* 1996). The average annual reservoir inflow from 1960-98 was 22.5 m^3/sec while the maximum allowable diversion is 82 m^3/sec (BCRP 2000).

C1.2 Coquitlam Dam Facility Statistics

DAM	**Coquitlam**
Dependable capacity (MW)	- -
Dam function	storage, diversion
Date constructed	1904
Date operational	1905
Date reconstructed	1914, 1985
Height (m)	30
Length (m)	300
RESERVOIR	**Coquitlam**
Cleared/ not cleared	cleared
Present area (ha)	1198
Watershed area (km^2)	193
Present elevation a.s.l. (m)	155
Normal drawdown range (m)	12.8
Mean depth (m)	no data
Maximum depth (m)	31
Storage (million m^3)	202
Mean water retention time	no data
Mean annual discharge (m^3/s)	21.7-23
DIVERSION	**to BuntzenReservoir**
Structure type	tunnel (4km)
Licensed flow (m^3/sec)	82
Fish flow release (m^3/sec)	0.23-0.85
Mainstem length diminished (km)	14.5

* dashes (- -) mean not applicable

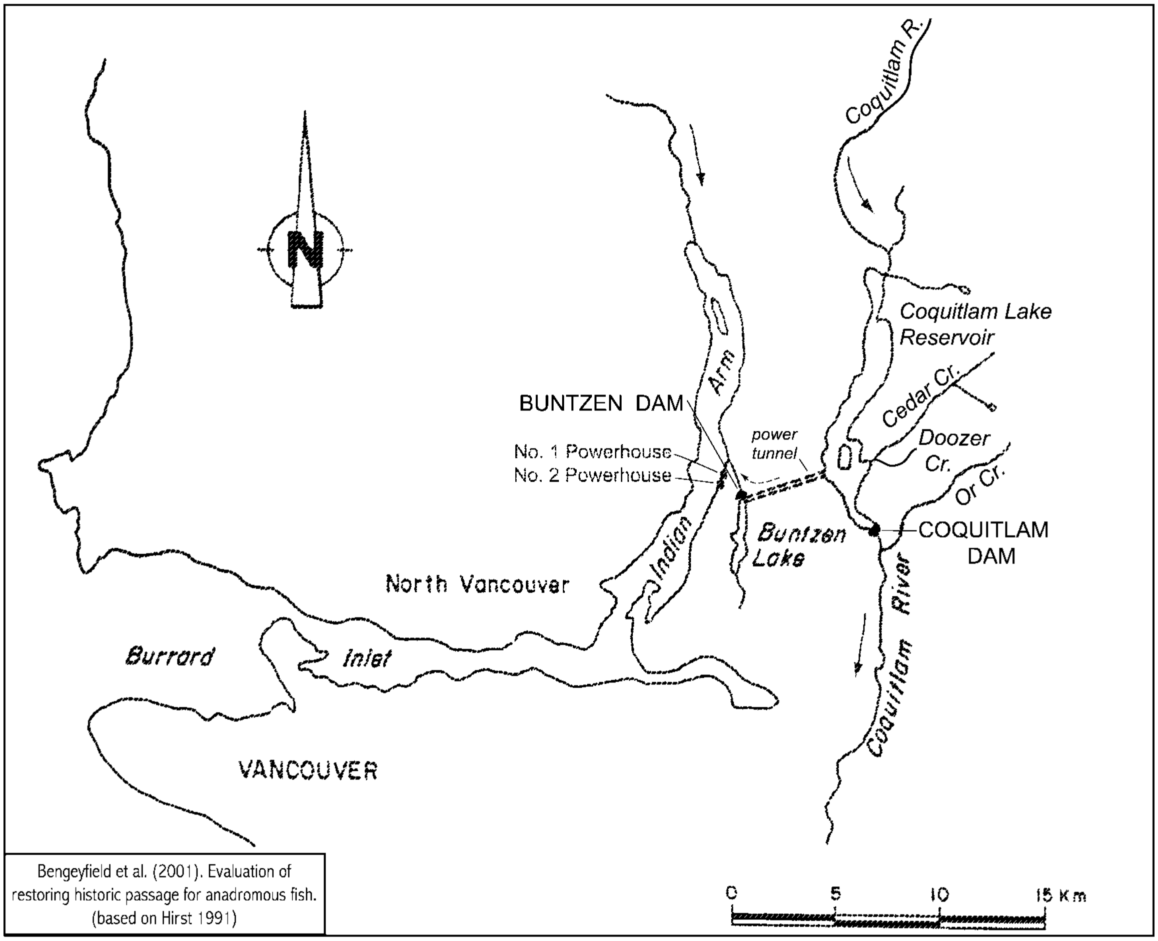

Figure C1-1. Coquitlam-Buntzen Diversion Project.

1.3 Species & Natural Obstructions

Prior to the hydroelectric development on the Coquitlam-Buntzen system in 1903, anadromous fish were able to ascend into Coquitlam Lake which provided spawning habitat for an early run (May) of sockeye salmon (Sword 1904). Estimates of historic escapement of sockeye to Coquitlam River are not available, and the run is now extinct. Coho salmon and likely steelhead and anadromous cutthroat also utilized tributary habitat upstream of the dam, and today they persist in the Coquitlam mainstem and tributaries downstream of the dam.

Upstream of the dam, rainbow trout and Dolly Varden (bull trout?) are listed by FISS (2001); no other fish species are reported. Cutthroat trout were reported by Acres (1999) when they conducted fish trapping in 36 stream reaches of upper tributaries to classify riparian zones for the Greater Vancouver Regional District (GVRD). Twelve reaches contained fish, and four other reaches were classified as potentially fish bearing because their gradient was less than 20 % and they were tributary to confirmed fish streams.

Downstream of the dam, the Coquitlam River provides spawning habitat for chum and coho salmon as well as steelhead and resident rainbow trout, cutthroat trout and Dolly Varden char. Pink salmon were present historically, and have been re-introduced as part of the Swoboda Channel installation. Chum salmon were thought not to ascend as far upstream as the dam. Recent estimates of escapement to Coquitlam River (downstream of the dam) have been compiled by DFO and are summarized in Table C1-1.

Table C1-1. Escapement of Pacific Salmon species to the Coquitlam River (FISS 2001).

Species	Ten Year Record	Mean Escapement of Ten Year Record	Max. Escapement of Ten Year Record	Year of Maximum Escapement
Chum	1988 - 1997	555	875	1972 (3,500 chum)
Coho	1987 - 1996	234	1000	1953 (1,500 coho)
Pink	1985 - 1993	25	25	1953 (3,500 pink)

C1.4 History of Fish Passage

The original 6 m high dam, constructed in 1903, included a fishway that was completed in the summer of 1905. The fish ladder was 3.6 m wide, consisted of baffle boards 1 m high and 2 m apart, and extended 4.9 m out from the face of the dam. Salmon did not use the initial fishway due to its steep slope and shallow water at the entrance until further alterations were made in summer 1906. The initial dam began leaking in 1906; repairs were made but significant leakage began again in 1908 (Koop 1994). The dam safety issue coincided with the opportunity to increase power capability at Buntzen.

The replacement dam was raised in 1908-11 to a height of 30 metres and no fishway was provided. The reasons for the waiving the fishway requirement were summarized in a letter from the Superintendent of Fisheries, Ottawa to the Inspector of Fisheries in New Westminster (Venning 1909):

- the proposed new dam was considered too high to pass salmon;
- the sockeye stock was thought to be commercially unimportant since the run timing was outside of commercial fishery openings, and coho were abundant and not highly valued;
- the public interest would be better served by the power provided by the dam; and
- Coquitlam Lake had been designated since 1892 and used since 1902 by the City of New Westminster as a domestic water supply, and public health concerns were raised when hundreds of salmon carcasses collected on the water intake (details from Koop 1994).

C1.5 Considerations for Anadromous Re-introduction

C1.5.1 Biological Aspects

Target Species [6]

Sockeye salmon were originally present in Coquitlam Lake, apparently in large numbers with 'thousands' of carcasses reported by the Superintendent of Waterworks (Koop 1994). This unique genetic stock of April-May run fish has become extinct. New populations of sockeye salmon are difficult to establish from egg transplants, and hatchery propagation of sockeye has never been very successful. Sockeye can be particular carriers of IHN (infectious hematopoietic necrosis) that will also infect chinook (Wood 1979). Sockeye are the only anadromous salmonid to spawn extensively in beach gravels along lake shorelines, particularly in areas with groundwater upwelling such as tributary fans and lake outlets. These spawning areas are susceptible to dewatering during reservoir drawdowns. Sockeye also spawn in tributary creeks, mainstem rivers, and side channels; the relative importance of each type of spawning habitat can vary between years. After emergence, juveniles typically rear through one summer and winter in a nursery lake where zooplankton abundance is high. Juveniles compete for food items with sticklebacks, kokanee, and another form called "residual" sockeye, which remains in freshwater to

[6] Groot and Margolis (1991) presented details of complex salmon life histories that can only be highlighted here. Steelhead stocks also exhibit great variation in life history (Withler 1966).

mature and reproduce (Burgner 1991). Sockeye smolts tend to lose scales easily from impingement, netting or handling.

Coho salmon were also originally present in Coquitlam Lake but likely were less abundant than sockeye. The downstream population is presumed to be the same genetic stock. Their preferred spawning habitats range from tiny creeks to medium-sized tributaries. Coho generally adapt to new colonization projects. Juvenile coho and sockeye typically spend at least one summer and winter in freshwater, but sockeye tend to rear in lakes while coho prefer low-velocity pools of natal streams, secondary channels, and off-channel ponds and swamps.

Steelhead are presumed to have been present in Coquitlam Lake tributaries prior to hydroelectric development. Genetic stock is presumed to exist in the remnant population downstream. Steelhead transplants may be less successful than those of other salmonids, perhaps due to the extended 2-3 year period required by juveniles for freshwater residency. Preferred spawning habitats range widely.

Habitat Capacity

The watershed of Coquitlam Reservoir has steep terrain. The reservoir flooded 194 hectares of land compared to 1004 ha of original lake. Until recently there was very little biophysical data available on the reservoir tributaries, possibly due to the long-standing policy of restricted public access imposed by the Greater Vancouver Regional District. The GVRD conducted a study of 36 stream reaches of the Coquitlam Lake tributaries to classify riparian zones (Acres 1999). Most channel sections were steep and few had low gradient (< 4%) that are accessible by fish from Coquitlam Lake. Apart from channel gradient, this report presented no other habitat data.

In October, 2000, BC Hydro made an assessment of fish access to 11 tributaries within the drawdown zone of Coquitlam Reservoir (unpubl. White Pine Resources Inc. data, 2000).

Although no work has been completed to quantify spawning habitat availability, it appears that suitable spawning habitat for anadromous salmonids upstream of Coquitlam Dam is limited.

<u>Mainstem Habitat Availability</u>

Approximately 1.3 km of mainstem channel habitat (3 ha) were flooded by the hydroelectric development (BCR Strategic Plan 2000). The amount of lost mainstem habitat due to impoundment is relatively low compared with other impoundments since the lake existed prior to the hydroelectric development. However, the lake did provide important spawning habitat for sockeye salmon. Presently, about 300 m of upper mainstem habitat remains accessible to fish between the reservoir and a complete barrier to fish passage (~ 10 m high falls, Figure C1-2). The section of river below the falls is about 5 % gradient with large bed materials and has little or no spawning potential (Figure C1-3).

<u>Tributary Habitat Availability</u>

At least 6 km of tributary habitats were flooded by the development (BCR Strategic Plan 2000). The October 2000 study examined tributaries within the drawdown zone of the reservoir and the lower 100-300 m sections above the reservoir at full pool, but did not estimate total accessible length (unpubl. White Pine Resources Inc. data, 2000). Measurements included wetted width, % gradient and % spawnable area, and stream flow was estimated (Table C.1-2). Of the 11 tributaries surveyed (including the upper Coquitlam River), Cedar Creek provides the most spawning habitat. Wetted width was measured at 23 m with a 1% gradient in the lower 200 m (Figure C1-4). Percent spawning in the lower 100 m was about 35 %, however, substrate compaction may reduce this estimate. Doozer Creek, a tributary to Cedar Creek, also provides some potential spawning habitat. The majority of the other larger tributaries surveyed had gradients greater than 5 % and had limited spawning potential (Table C.1-2). Smaller tributaries omitted in this assessment were high gradient, ephemeral drainages which provided little or no fish habitat during a dry autumn period.

Table C1-2. Assessment of fish access to tributaries in Coquitlam Lake during low reservoir levels, October 24 & 27, 2000.

(unpublished data from White Pine Resources Inc.)

Tributary	Critical El.[1]	Wetted Width (m)	% Gradient	% Spawnable	Approx. flow	Comments [2]
Upper Coq. River	none	20 - 25	5%	none	~ 300 cfs	No spawning potential in first 100 m
						Barrier at ~ 300 m u/s of reservoir
Flow Far Creek	none	8	7 - 9 %	5%	~12 cfs	Located at upper river/reservoir confluence
Cedar Creek	none	23	1%	~35 %	~ 60 cfs	Significant spawning gravels in lower 150 m of creek
						which is more suitable for large salmonids
Di Creek	none	10	5%	2%	~8 cfs	WW decrease to ~ 3m past 50 m u/s of confluence
Beaver Creek	none	5.5	10%	1 - 2 %	~ 15 cfs	Fish obstruction noted at 20 m u/s confluence (@ 10 %)
						which may be a barrier at lower flows
Root Creek	none	5	5%	10%	6 - 8 cfs	Some spawning potential in lower 100 m
Doozer Creek	none	5	4%	15%	~ 12 cfs	Doozer Creek confluence with Cedar Creek
(trib. to Cedar Cr.)						about 400 m u/s of reservoir
Meech Creek	see note	4	16 - 26 %	< 1%	~ 3 cfs	Critical El. - 11.5 m at 20 % gradient from reservoir
(Site CO-37)						elevation to top of obstruction (11:45 hrs, 27 Oct. 2000)
Unamed Creek	see note	2	20%	none	~ 0.5 cfs	Tributary to Meech Creek, same critical elevation.
(Site CO-43)						Obstruction noted just u/s of confluenec with Meech Cr.
						No fish habitat in this creek.
Unamed Creek	see note	2	> 20 %	none	< 1 cfs	Trib. to Meech Creek quite far u/s
(Site CO-35)						No fish habitat
Maple Creek	none	2	5 - 20 %	< 1%	~ 2 cfs	Channel width 10 - 15 m, evidence of periodic high-flow
						events. Little or no fish habitat.

1. Where no critical elevation was noted, there were no barriers to fish migration within the drawdown zone of the reservoir and none observed below the reservoir elevation at the time of the assessment.
2. Distances refer to the edge of reservoir at time of survey.

<u>Overview of Habitat Capacity</u>

There is a data deficiency in precise estimates of habitat capability that may require detailed field assessment; however, at an overview level, the prognosis appears poor for target species:

- Low sockeye spawning potential (drawdown exposes beaches and fans)
- Low sockeye rearing potential (high flushing rate of oligotrophic water)
- Low coho spawning potential (little tributary spawning area)
- Low coho rearing/overwintering potential (lack of low velocity stream and off-channel habitats; reservoir may compensate somewhat)
- Low steelhead spawning potential (little tributary spawning area)
- Moderate steelhead rearing potential (abundant boulder substrates in limited lower tributary reaches)

Interactions Between Species

From the limited trapping conducted in the tributaries, cutthroat and rainbow trout and Dolly Varden char were present in low densities. There may be some interaction between steelhead parr and resident rainbow trout parr if rearing habitat is limited.

Sockeye may introduce IHN virus to chinook using the system.

C1.5.2 Technical Feasibility

Appendix D discusses a range of structures, techniques and options that may be relevant for providing upstream and downstream fish passage at the Coquitlam facility. It is important to note that projects where downstream passage of juveniles has been successful are associated with reservoirs and facilities where juveniles have moved downstream through the reservoir to a location where large flows are either released through turbines or spillways, or to a location where smaller diversion flows are released from surface withdrawals. There is no precedent known for the successful bypass of fish from a reservoir where flow is withdrawn at depth from within the reservoir at a point distant from the spillway.

C1.5.3 Operational Aspects

Water is diverted from Coquitlam Lake through a 3.9 km long diversion tunnel to Buntzen Lake. Diversion flows are up to 34.5 m^3/s with one gate open and up to 39.0 m^3/s with both gates open and a reservoir elevation of about 155 m. Although there is a minimum fish flow requirement from the Coquitlam Dam (0.23 to 0.85 m^3/s, Lewis *et al* 1996), the majority of outmigrating juvenile salmonids are expected to orient to follow the comparatively higher diversion flows. The diversion intake is 3.2 km across the reservoir from the dam. Any fish surviving diversion from Coquitlam Lake would also be entrained through the Buntzen Generating Station (BGS) which discharges into the Indian Arm of Burrard Inlet. Surviving fish returning as adults may be attracted to the BGS discharge and then be unable to reach Coquitlam Lake unless it is possible to generate less during adult migration and increase flow releases at the dam. Such scenarios may be examined during the future development of the Coquitlam Water Use Plan.

If sockeye salmon were re-introduced upstream of Coquitlam Dam, reservoir operation must be considered. Maximum and minimum normal operating levels for Coquitlam Lake are 154.86 m and 140.23 m respectively. Their preference for spawning along beaches in the fall (particularly since tributary habitat seems limited), followed by a typical winter drawdown, is not favorable to reproductive success.

Re-introduction of sockeye salmon could conflict with metropolitan water quality standards, if sufficiently large numbers of post-spawning carcasses collected near the intakes as occurred historically.

C1.6 Summary Analysis of Passage Opportunity at Coquitlam

IMPEDIMENTS	COQUITLAM
Significant Dam Height	•
Interbasin Diversion Effects	♦
Significant Drawdown	●
Domestic Water Supply	●?
Upstream Habitat Capability	●?
Biological Interactions	•

• MINOR ● MAJOR

●? LIKELY MAJOR ♦ NOT VIABLE

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Appendix C2

ALOUETTE DAM

C2.1 Project Operation

The Alouette-Stave-Ruskin project provided the bulk of power used in the Lower Mainland prior to development of the Peace River hydro project. The Alouette Project consists of the dam at the south end of Alouette Lake Reservoir and a 1 km tunnel at the north end of the reservoir leading to the Alouette powerhouse on the shoreline of Stave Lake (Figure C2-1). Alouette Dam was constructed in 1926 (Burrard Power Co.) and was replaced by B.C. Hydro in 1984 with a modern earthfill structure. The spillway was rehabilitated in 1993. Most of the runoff from the South Alouette watershed is diverted into Stave Lake Reservoir, through Stave Falls generating plant to Hayward Reservoir and the Ruskin plant.

Alouette Lake is a steep-sided mountain reservoir. Reservoir impoundment raised the elevation of the original lake about 15 metres. Most of the annual 22 m^3/s inflow comes from two weather sequences: spring melting of the accumulated snowpack, and heavy fall rains from Pacific storms. Summer recreation demands, fish flow requirements in the Alouette mainstem, and low power demand tend to reduce flows through the diversion tunnel from June through August.

For maintenance of fish habitat in the South Alouette River, 0.7 m^3/s is released from the low level outlet of the dam. The fisheries agencies and the Alouette River Management Society have expressed concerned that the existing flow regime is insufficient to protect existing stocks (Lewis *et al.* 1996).

C2.2 Aloutte Dam Facility Statistics

DAM	**Alouette**
Nameplate capacity (MW)	9
Dependable capacity (MW)	9
Dam function	storage, diversion
Date constructed	1924-26
Date operational	1928
Date reconstructed	1984
Height (m)	21
Length (m)	315
RESERVOIR	**Alouette**
Cleared/ not cleared	
Present area (ha)	1580
Watershed area (km^2)	200
Present elevation a.s.l. (m)	117 (bathym)
Normal drawdown range (m)	9.5
Mean depth (m)	64
Maximum depth (m)	140
Storage (million m^3)	155
Mean water retention time	4.7 mo.
Mean annual discharge (m^3/s)	22
DIVERSION	**to powerhouse on Stave L.**
Structure type	tunnel (1km), penstock (31m)
Licensed flow (m^3/sec)	28.3
Fish flow release (m^3/sec)	0.7
Mainstem length diminished (km)	20

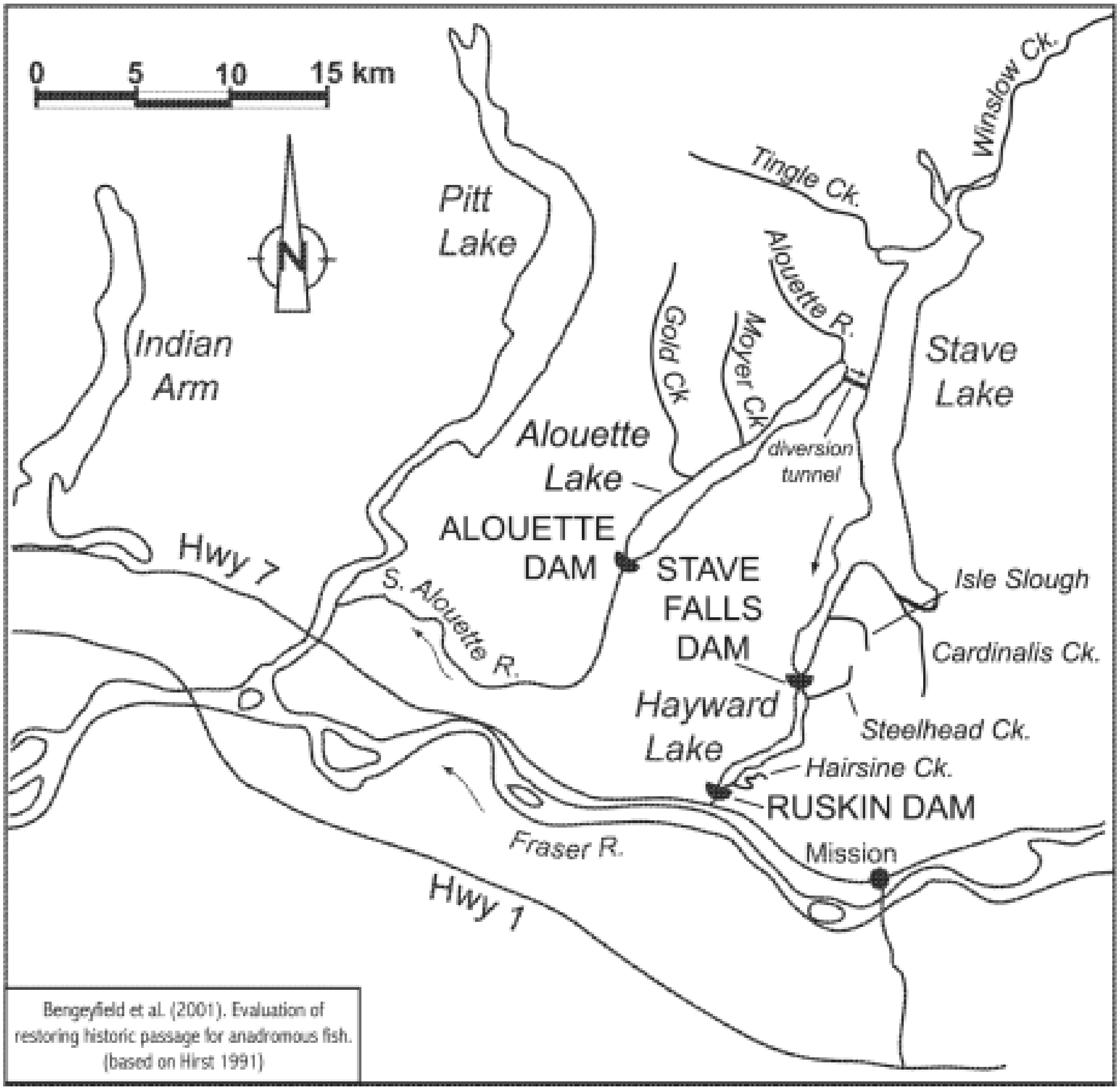

Figure C2-1. Alouette Reservoir Diversion.

C2.3 Species & Natural Obstructions

Prior to the construction of the Alouette Dam in 1926, anadromous salmonids had access to mainstem, tributary and lake habitats upstream of the two original Alouette lakes. Historically, habitats upstream of the dam were utilized by all species of salmon as well as steelhead and possibly anadromous cutthroat trout (IPSFC 1938).

The Alouette River supported an early run of sockeye salmon similar to that found in the Coquitlam River prior to its impoundment. Called “bastard” sockeye by gillnet fishermen at the time, they returned to the rivers in late spring. In 1927 Alouette Lake was first blocked to the ascent of salmon. In July, 1929 the South Alouette was nearly dry but about 2000 sockeye were noticed below a fall in the North Alouette River (IPSFC 1938). By the late 1930’s this stock had disappeared due to the lack of a fishway at Alouette Dam (Roos 1991).

A smaller stock of normal fall-run sockeye, and the Alouette chinook stock were also eliminated by the dam. Runs of pink and chum salmon were reported upstream of the lake, and we presume that coho salmon, steelhead and sea-run cutthroat trout were also present; all of these stocks have persisted by utilizing habitats downstream of the dam.

Recent estimates of escapement to the South Alouette River (downstream of the dam) have been compiled by DFO and are summarized in Table C2-1.

Table C2-1. Escapement of Pacific salmon species to the South Alouette River (FISS 2001).

Species	Ten Year Record	Mean Escapement of Ten Year Record	Max. Escapement of Ten Year Record	Year of Maximum Escapement
Chum	1988 - 1997	16,923	55,000	1997 (55,000)
Coho	1987 - 1996	597	1,600	1988 (1,600)
Pink	1988 - 1997	1,554	2,600	1985 (3,557)

The important spawning and rearing habitats that remain are in Gold Creek, Moyer Creek, and the upper Alouette River; most of the other tributaries are steep with erratic discharges. The majority of fish biomass in the reservoir is comprised of non-sport species, *e.g.*, northern squawfish, suckers, peamouth chub and redside shiners (Knight 1987). Lake trout were introduced in 1968 but failed to reproduce, partly a result of drawdown effects on spawning shoals (Knight 1987). The reservoir is oligotrophic with low levels of phosphorus and nitrogen and an absence of aquatic plants. A fertilization experiment was planned with levels based on the estimated historic presence of salmon carcasses (Wilson *et al.* 1999).

C2.4 History of Fish Passage

Alouette Dam blocked passage of upstream migrants, diverted virtually all flows to Stave Lake, and flooded much of the small amount of useable low-gradient tributary and mainstem habitats, particularly the lake outlet. When the dam was proposed in 1923, the Chief Inspector of Fisheries, in two letters to the Provincial Fisheries Department, stated that:

> "It is felt that the run of commercial fish to the Lillooet [Alouette] Lake is not of tremendous importance but I am obtaining further information in this connection." (August 21, 1923);
>
> and later, recognizing the correct name of Alouette Lake,
>
> "It now appears that the proposed operations will result in the building of a dam of approximately 40 feet in height at the outlet of Alouet [sic] Lake for the purpose of storing up the water which will be diverted by means of a tunnel to the Stave Lake. This will result in the cutting off of the source of supply of water for the Alouet [sic] River… and will eliminate this stream as a spawning area. Even should it be possible to place an adequate fishway in the proposed dam it is questionable if it would be of any value owing to the fact that the rise in the lake level would no doubt result in the loss of what spawning areas there are in the lake itself….. Under the circumstances it has been decided that no further action should be taken by this Department and that there should be no obstacle placed in the way of the proposed development.' (November 5, 1923).

C2.5 Considerations for Anadromous Re-introduction

C2.5.1 Biological Aspects

Target Species [7]

Sockeye salmon were originally abundant in Alouette Lake and had two separate stocks – the unusual April-June run and the normal fall run (IPSFC 1938). However, new populations of sockeye salmon are difficult to establish from egg transplants, and hatchery propagation of sockeye has never been very successful. Sockeye can be particular carriers of IHN (infectious hematopoietic necrosis) that will also infect chinook (Wood 1979). Sockeye are the only anadromous salmonid to spawn extensively in beach gravels along lake shorelines, particularly in areas with groundwater upwelling such as tributary fans and lake outlets. These spawning areas are susceptible to dewatering during reservoir drawdowns. However, sockeye also spawn in tributary creeks, mainstem rivers, and side channels; the relative importance of each type of spawning habitat can vary between years. After emergence, juveniles typically rear through one summer and winter in a nursery lake where zooplankton abundance is high. Juveniles compete for food items with sticklebacks, kokanee, and another form called "residual" sockeye, which remains in freshwater to mature and reproduce (Burgner 1991). Sockeye smolts tend to lose scales easily from impingement, netting or handling.

Chinook salmon were originally present in the lake prior to the dam (IPSFC 1938).

Coho salmon were also originally present in Alouette Lake but likely were less abundant than sockeye. The downstream population is presumed to be the same genetic stock. Their preferred spawning habitats range from tiny creeks to medium-sized tributaries. Coho generally adapt to new colonization projects. Juvenile coho and sockeye typically spend at least one summer and winter in freshwater, but sockeye tend to rear in lakes while coho prefer low-velocity pools of natal streams, secondary channels, and off-channel ponds and swamps.

Steelhead are presumed to have been present in Coquitlam Lake before development. Genetic stock is presumed to exist in the downstream population. Steelhead transplants may be less successful than those of other salmonids, perhaps due to the extended 2-3 year period required by juveniles for freshwater residency. Preferred spawning habitats range widely.

Habitat Capability

Mainstem Habitat Availability

The BCR Strategic Plan (2000) estimated that 0.3 km of mainstem channel (1 ha) were lost due to the development of the Alouette Dam. The amount of lost mainstem habitat due to impoundment is low since the lake existed prior to the hydroelectric development. However, it appears Alouette Lake may have provided important spawning and rearing habitat for both an early and late-run of sockeye salmon.

The upper Alouette River above the reservoir may contain some limited spawning and rearing habitat suitable for anadromous salmonids. However, Knight (1987) described the upper Alouette River as very flashy with boulder substrate and rapids as the main hydraulic habitat unit type. Bed loads were described as unstable with very small quantities of spawning habitat suitable for trout and kokanee. Although quantitative information on spawning and rearing habitats in the upper Alouette River was not available for review, it appears that spawning habitat suitable for anadromous salmonids may also be limited.

Tributary Habitat Availability

The BCR Strategic Plan (2000) estimated that approximately 4 km of tributary habitat was lost due to impoundment. Most of the post-impoundment tributary habitat upstream of Alouette Dam occurs in Gold Creek and Moyer Creek. The other tributaries have been described as steep with erratic discharges. Knight (1987) described Moyer Creek as very flashy with boulder substrate and predominated by rapid type hydraulic habitat units. Bed loads in Moyer Creek were also described as unstable with very small quantities of spawning habitat suitable for trout and kokanee.

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[7] Groot and Margolis (1991) presented details of complex salmon life histories that can only be highlighted here. Steelhead stocks also exhibit great variation in life history (Withler 1966).

Gold Creek, is the third significant tributary to Alouette Lake. This system is accessible to fish for a distance of 3.8 km upstream of the lake. The lower 0.7 km provides good rainbow trout parr habitat (Knight 1987). Griffith (1983) surveyed the accessible portion and divided it into 3 reaches. A description of the reach characteristics including a breakbown of hydraulic habitat unit types is shown in Table C2-2.

Table C2-2*. *Hydraulic habitat descriptions of Gold Creek.
Table adapted from Griffith (1983)

Reach Characteristic	**Reach 1 (d/s)**	**Reach 2**	**Reach 3 (u/s)**
Approximate Length	1400 m	700 m	1400 m
Mean width at low flows (~ 7 m^3/s)	17.5 m	14.0 m	15.5 m
% Rapid (> 2 % gradient)	18.6	47.0	12.8
% Rapid (< 2 % gradient)	59.7	42.9	16.4
% Riffle / Rapid	4.4	0	28.5
% Run	11.8	7.9	27.0
% Pool	5.5	2.2	15.3
Total % rapid (including riffle/rapid)	82.7	89.9	57.7

Rapids are the predominant hydraulic habitat types in all reaches. The mean gradient throughout all reaches was 2%. Griffith (1983) described spawning substrate to be lacking and stated that gravels tended to be large for the resident stocks. Small gravels represented about 5 to 10 % of the bed materials at most sample sites and were usually found in small pockets near the stream margins.

In general, the 3.8 km of accessible habitat in Gold Creek was judged to be very good for rearing parr and adult rainbow trout due to the abundance of large bed materials and suitable hydraulic habitat units. Rearing habitat for fry appeared to be very limited due to the lack of areas that provided low water velocities and good cover.

Based on a Habitat Quality Index production model (Binns 1982), Griffith (1983) estimated a standing stock potential of 3.0 g/m^2 for resident salmonids in Gold Creek. This model is based on dissolved nutrients (nitrate), flow and temperature and assumes adequate recruitment. Standing stock estimates in 1983 ranged from 1.3 to 3.7 g/m^2 for wild resident fish and 4.0 g/m^2 for hatchery fish (steelhead). During this 1983 survey, Gold Creek was considered to be at or near its carrying capacity for resident fish. The accessible portion of Gold Creek provides an abundance of rearing habitat in the boulder rapids for rainbow trout parr, however, fry and spawning habitat may be limited. Considering that this assessment focused on resident stocks, it is possible that anadromous salmonids may find more spawning habitat but that rearing habitat for fry and low productivity levels may still be limited.

Interactions Between Species

Re-introduced anadromous stocks to Alouette Reservoir could experience some predation and competition from resident populations depending on species. There may be some interaction between steelhead parr and resident rainbow trout parr if rearing habitat is limited. Sockeye may introduce IHN virus to chinook using the system.

C2.5.2 Technical Feasibility

Appendix D discusses structures, techniques and options that may be relevant for providing upstream and down-stream fish passage at the Alouette Reservoir. It is important to note that projects where downstream passage of juveniles has been successful are associated with reservoirs and facilities where juveniles have moved downstream through the reservoir to a location where large flows are either released through turbines or spillways, or to a location where smaller diversion flows are released from surface withdrawals. There is no precedent known for the successful bypass of fish from a reservoir where flow is withdrawn at depth from within the reservoir at a point distant from the spillway.

C2.5.3 Operational Aspects

Water is diverted from Alouette Lake through a 1.0 km long diversion tunnel to Stave Lake. Maximum diversion flows are 70 m^3/s with both the Alouette Generating Station (GS) and the adit gate open. Alouette GS discharges into Stave Lake and has a diversion capacity of 24 m^3/s (8 MW) alone. The minimum fish flow requirement of 0.6 m^3/s from the Alouette Dam (Lewis *et al.* 1996) is low compared to the diversion flows. Negative rheotaxis would likely orient the majority of outmigrating juvenile salmonids towards the much higher diversion flows. Juvenile migrants that survived diversion from Alouette Lake would subsequently be entrained through the Stave Falls GS and Ruskin GS which discharges into the Lower Stave River and eventually the Fraser River. Fish that survive passage through all three generating facilities may be falsely attracted to the Stave River system and not the Alouette system when returning as adults.

If sockeye salmon were re-introduced into Alouette Lake and if shore spawning was considered an important component of the spawning success, reservoir operation must also be considered. The normal operating range for Alouette Lake is 116.0 m to 125.5 m respectively. This drawdown is sufficient to limit benthic production and much of the littoral substrate above 121.25 m elevation has been described as barren (Lewis *et al* 1996). The drawdown would also likely impact shore spawning success of sockeye salmon unless reservoir levels were held constant throughout the spawning, incubation and emergence periods.

C2.6 Summary Analysis of Passage Opportunity at Alouette

IMPEDIMENTS	ALOUETTE
Significant Dam Height	
Interbasin Diversion Effects	♦
Significant Drawdown	•
Domestic Water Supply	
Upstream Habitat Capability	●?
Biological Interactions	•

• MINOR ● MAJOR

●? LIKELY MAJOR ♦ NOT VIABLE

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Appendix C3

RUSKIN DAM

C3.1 Project Operation

Ruskin Dam is the downstream most facility of the Alouette-Stave Falls-Ruskin system and is located on the Stave River approximately 3.5 km upstream of its confluence with the Fraser River (Figure C3-1). The dam impounds the 276 ha Hayward Reservoir. Ruskin Dam was completed in 1930, nineteen years after the Stave Falls and Blind Slough Spillway dams were completed upstream.

The Ruskin Generating Station contains three Francis turbines and has a nameplate generating capacity of 105.6 MW. Currently Ruskin Dam is required to release the following flows to protect the fishery resource downstream:

- a minimum flow of 38 m^3/s from 01 to 14 October;
- weekly block water releases (ranging from 38 m^3/s to 127 m^3/s depending on inflows) during the salmon spawning period (mid-October through November); and
- a minimum flow release equivalent to producing 10 MW (approximately 38 m^3/s) during the incubation and rearing periods (December to 15 May).

Ramping rates for flow reductions from the turbines must not be greater than 113.3 m^3/s per half hour. Flow reductions are particularly important during the period when emergent fry can become stranded in shallow peripheral habitats along the channel.

> Watershed inflow comes primarily from two weather patterns. In the fall, heavy rain from Pacific frontal systems produces large inflows. The annual peak short term inflows occur during this period, with daily flows fluctuating from trickles to potential flood levels. In the spring, the accumulated snowpack melts and provides steady high inflows.

Inflow into Hayward Reservoir includes the average annual inflow of about 111 m^3/s from Stave Falls Reservoir plus an additional 21 m^3/s from the Alouette diversion project. Stave Reservoir is at its highest levels during the fall and late spring due to high inflows. The storage reservoir is usually drawn down during winter to produce electricity and to accommodate spring snowmelt volume. Hayward Lake can fluctuate by 9.9 m daily but typical drawdowns range from 1-2 m. The typical operating range in elevation for Hayward Reservoir is between 33.00 m and 42.91 m elevation. Normal operation, however, maintains constant generation at Stave Falls while generation at Ruskin peaks with the daily power demand periods (morning and evening). There are currently no restrictions on the filling or drawdown rates for Hayward Reservoir.

C3.2 Ruskin Dam Facility Statistics

DAM	**Ruskin**
Nameplate capacity (MW)	106
Dependable capacity (MW)	100
Dam function	storage, diversion
Date operational	1930
Height (m)	59.4
Length (m)	125
RESERVOIR	**Hayward**
Cleared/ not cleared	nc
Present area (ha)	276
Watershed area (km^2)	953
Present elevation a.s.l. (m)	45
Normal drawdown range (m)	0.5-1(1.8)

Mean depth (m)	16
Maximum depth (m)	38
Storage (million m^3)	24
Mean water retention time	<3 days
Mean annual discharge (m^3/s)	132
DIVERSION	**to powerhouse**
Structure type	penstock (22-77m)
Licensed flow (m^3/sec)	357
Fish flow release (m^3/sec)	28-84
Mainstem w/ augmented flows (km)	2.8

C3.3 Species & Natural Obstructions

Currently, sport fish populations of rainbow and cutthroat trout and Dolly Varden char are generally low despite recent stocking efforts (Ramsay 1996). No kokanee were captured in the 1996 survey unlike previous sampling in 1985 and 1987. Hydroacoustic surveys in 1996 estimated the total fish population, including non-sport species, at between 13,600 to 51,600 individuals (Stables 1997). Non sport-fish species such as suckers, squawfish, sculpins and chub dominate the fish fauna in the reservoir. A 1985 gillnetting program in Hayward Lake (Grant and Balkwill 1986) produced kokanee, largescale sucker, squawfish, sculpins and peamouth chub. The total sport-fish catch per unit effort (CPUE) was 4.1 fish per $100/m^2/24$ hr period while the coarse fish CPUE was 72.6 fish per $100/m^2/24$ hr period. A 1987 lake survey resulted in a (CPUE) of 9.2 fish per $100/m^2/24$ hr period which was comprised mainly of suckers and chub with no sport-fish species present in the catch (Lewis *et al* 1996). Another gillnetting program was conducted in 1996 (Ramsay 1996). In this survey, very low numbers of rainbow trout (4) and cutthroat trout (3) were captured. Non sport-fish species included largescale sucker, northern squawfish and redside shiner.

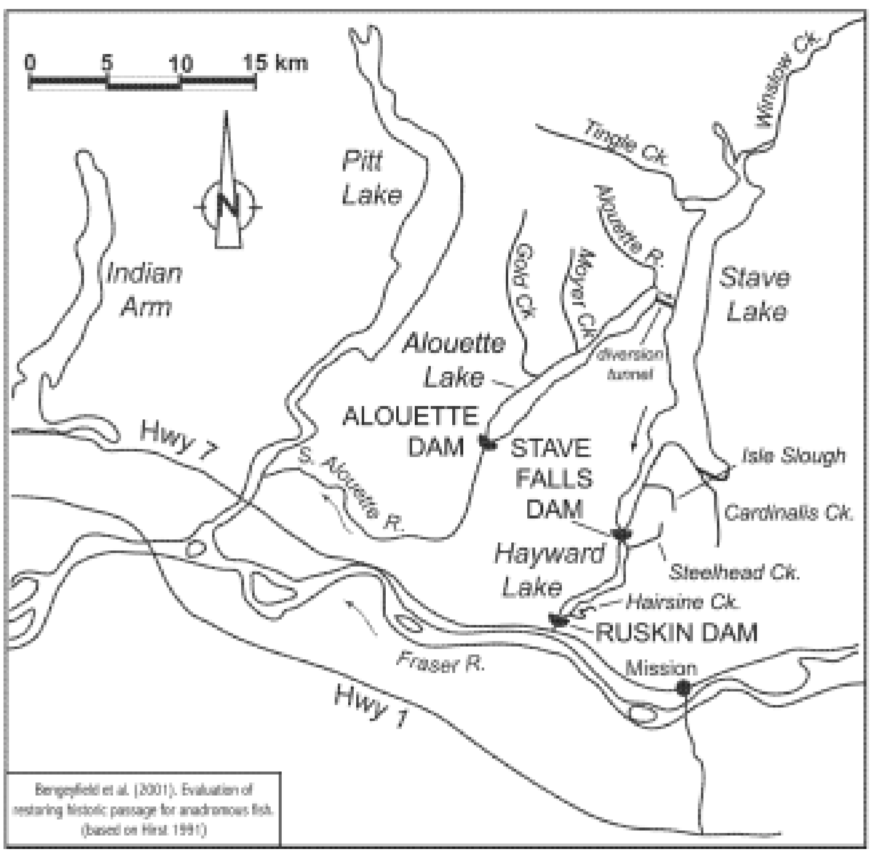

Figure C3-1. Ruskin Dam and Hayward Reservoir.

Downstream of Ruskin Dam

Andrew & Killick (1957) reported that only the lower 4.8 km of river (which would include 2 km above Ruskin Dam) were used by salmon to any extent. In 1935 there were counts of 100-300 coho, 500-1000 pink, 500-1000 chum and 50-100 steelhead. Smaller numbers of chinook and sockeye used this section.

This short reach crosses the Fraser River floodplain with low banks composed of sands and fine sediments. Water levels in this reach are influenced by tidal conditions and Fraser River discharge, as well as Ruskin operations. A 360 m spawning channel was constructed by DFO in 1991 on the left bank below the tailrace; it is mostly used by chum salmon (Wilson 1996).

In the Lower Stave River, chum, chinook, coho, sockeye and pink salmon have been present. Resident sport-fish species include rainbow trout, cutthroat trout, and mountain whitefish. Information on the escapement and spawning distribution of anadromous species prior to the hydroelectric development is scarce.

Presently, there is no fish passage upstream of Ruskin Dam. DFO has compiled escapement estimates of salmon species to the Lower Stave River (FISS 2001). Recent escapement to the Lower Stave River has been summarized in Table C3-1.

Table C3-1. Escapement of Pacific salmon species to the Lower Stave River (FISS 2001).

Species	Ten Year Record	Mean Escapement of Ten Year Record	Max. Escapement of Ten Year Record	Year of Max. Escapement
Chum	1990 – 1999	294,636	500,000	1998
Coho	1987 – 1996	100	100	1952
Chinook	1982 – 1991	10	10	1955
Pink	1988 – 1997	3	5	1957
Sockeye	1982 – 1991	0	0	1978

There is a considerable escapement of chum salmon to the lower Stave River and a much lower escapement of other salmon species. Sockeye have not been observed in the system since prior to 1982.

C3.4 History of Fish Passage

Prior to the impoundment of Hayward Lake by the Ruskin Dam, the lower Stave River was passable to anadromous fish species. Historically, all salmonid species utilized spawning habitat in the lower Stave River up to approximately 2 km upstream of the current Ruskin Dam location (Andrew and Killick 1957). Farther upstream was a series of rapids that extended about 4 km to an impassable barrier at the Stave Falls location. Some sections of these rapids were likely suitable for rearing by steelhead parr (BCRP 2000). The height of the Ruskin Dam (~60 m), along with the presence of a historic barrier to fish passage approximately 6 km upstream, were likely key factors for the decision not to provide fish passage during the development of the Ruskin Dam.

Ruskin Dam removed historic access to 2 km of mainstem spawning beds and rearing area for all species of salmon, steelhead, and possibly anadromous cutthroat trout (Andrew and Killick 1957).

The 6 km of original river channel flooded by Hayward Reservoir was described as a series of rapids that emptied onto the Fraser floodplain through a narrow granite gorge. The natural constriction at the site of Ruskin Dam was reported passable at high water. The lower 2 km of this reach apparently provided spawning habitats for all salmonid species (Andrew and Killick 1957), and portions of the upper section of rapids were likely suitable for rearing by steelhead parr (BCRP 2000).

C3.5 Considerations for Anadromous Re-introduction

C3.5.1 Biological Aspects

Target Species [8]

While steelhead and chinook, coho, pink and chum salmon are all historic species, the virtual lack of upstream habitat capability appears to preclude much further consideration of species attributes for re-introduction.

Habitat Capability

Mainstem Habitat Availability

There is essentially no mainstem habitat available upstream of Ruskin Dam since the Stave Falls Generating Station discharges directly into Hayward Reservoir. The Stave Falls spillway (Blind Slough) remains wetted between spills by seepage and may provide some rearing habitat for resident fish population in Hayward Lake. The Blind Slough is characterized by high gradient with primarily boulder and bedrock substrate. The lower section of Blind Slough may contain some gravels that are wetted and dewatered as reservoir levels fluctuate. No investigation has been completed to assess the potential fish habitat in Blind Slough, however, it is thought to be extremely limited. Since the generation capacity of Ruskin is greater than Stave Falls, spill events from Blind Slough are much more frequent compared to Ruskin. It is unlikely that fish could remain in Blind Slough during a substantial spill event.

Tributary Habitat Availability

Other than the Stave River (which enters Hayward Lake through the generating facility or Blind Slough spillway), there are eight small tributaries to Hayward Lake. Slaney (1994) completed an assessment of these tributaries and concluded that Hairsine Creek contained the most significant spawning and rearing habitat. Hairsine Creek is a low gradient system in a deeply incised channel that enters Hayward Lake near its south end. The creek continues to flow through the summer and contains both good cover and a variety of substrate types. Quantitative information on available habitat was not available for review.

Steelhead Creek flows into Hayward Lake near the north end. This system has a higher gradient and larger substrate with very low flows in the summer months. Slaney (1994) concluded that Steelhead Creek would have little importance to spawning or rearing fish. The majority of remaining tributaries are described as intermittent and would provide very little spawning and rearing habitat (Slaney 1994). Access to some of these tributaries is limited when the reservoir is drawn down. Again, quantitative information on available habitat was not available for review.

In terms of introducing anadromous fish species upstream of Ruskin Dam, it appears there would be insufficient spawning and rearing habitat to support these fish. Enhancement of Hayward Lake with non-anadromous species has occurred since 1936 with very little success. The lack of sport-fish captured in the gillnetting programs suggests the introduced fish (rainbow trout and steelhead) are either being consumed by coarse fish or they are moving out of the system (Slaney 1994). Although it would be unlikely that negative interactions between resident and anadromous populations would occur, it is also unlikely that there would be sufficient recruitment to support an anadromous population.

Interactions Between Species

Steelhead may compete with rainbow trout parr in the limited tributary habitat. Significant populations of non-salmonid predators (squawfish) and competitors (redside shiners) are present in Hayward Reservoir.

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[8] Groot and Margolis (1991) presented details of complex salmon life histories that can only be highlighted here. Steelhead stocks also exhibit great variation in life history (Withler 1966).

C3.5.2 Technical Feasibility

Triton (1994) presented conceptual plans and rationale for re-establishing fish passage at Ruskin Dam. Fish passage techniques and options relevant to Ruskin Dam have been updated in Appendix D.

C3.5.3 Operational Aspects

Hayward Reservoir operations preclude the establishment of significant resident populations due to lack of tributary habitat, access to tributary habitat, high flushing rate of oligotrophic water, and drawdown effects on local productivity (Triton 1994). Access to some tributaries in Hayward Lake is limited at reservoir elevations below the maximum (Slaney 1994). The normal operating range in elevation for Hayward Lake may range between 33.00 m and 42.91 m elevation. Reservoir elevations fluctuate daily depending on power generation. Since Hayward Lake has limited storage capacity and the Ruskin GS is operated as a peaking plant, it is unlikely that fluctuating reservoir levels could be avoided which may result in a further reduction of the limited tributary habitat. Considering the small amount of habitat to which access is restricted at lower reservoir elevations, it is unlikely that constraining reservoir operation to maintain tributary access would be a cost-effective alternative.

C3.6 Summary Analysis of Passage Opportunity at Ruskin

No further consideration is recommended for this system with regard to the introduction of anadromous fish species. A previous evaluation of providing fish passage was completed for both dams in the Stave River system (Triton 1994). They concluded that passage upstream of Stave Falls Dam was required as a viable project since very little habitat is available in Hayward Reservoir. Like Stave Reservoir upstream, Hayward appears to be limited by low overall productivity, a large population of non-sportfish predators (especially northern squawfish) and competitors, and limited spawning and fry rearing habitat.

IMPEDIMENTS	RUSKIN
Significant Dam Height	●
Interbasin Diversion Effects	
Significant Drawdown	
Domestic Water Supply	
Upstream Habitat Capability	♦
Biological Interactions	•

• MINOR ● MAJOR

●? LIKELY MAJOR ♦ NOT VIABLE

C.3.7 Ruskin Facility Literature Cited

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Appendix C4

TERZAGHI DAM

C4.1 Project Operation

The Bridge River project consists of La Joie Dam which impounds Downton Reservoir, and Terzaghi Dam which impounds Carpenter Reservoir. Water is diverted through tunnels and penstocks from Carpenter Reservoir to two powerhouses on Seton Lake Reservoir (Figure C4-1). About 80% of the total discharges through the Seton powerhouse originate from the Bridge River system via the major diversions into Seton Lake Reservoir.

The initial diversion dam, Mission Dam, was a 19 m high, 240 m long rockfill dam completed in 1948. Mission Dam was incorporated into the upstream toe of the new Terzaghi Dam which was completed in 1960 and renamed in 1965. La Joie Dam was constructed in 1948 by B.C. Electric Company and was redeveloped in 1957.

The Bridge River basin is located in the rainshadow of the southern coastal mountains about 200 km northeast of Vancouver. It lies immediately north of the Seton basin, separated by the Bendor Range and Mission Ridge. The headwater source of Bridge River is the Bridge Glacier in the Coast Mountain Range. The glacier comprises about 140 km^2 of the 998 km^2 watershed area above La Joie Dam. Tributaries to the Terzaghi sub-basin below La Joie Dam drain 2691 km^2. Elevations within the Bridge River basin range from 645 m to 2896 m, and the mean elevations for La Joie Dam and Terzaghi Dam local basins are 1900 and 1800 m respectively (BC Hydro 1991).

High inflows occur from May to August from snow and glacial melt. Inflow from September to April is usually low. Occasional heavy rainstorms from August to early October cause high inflow to the reservoirs which can result in spilling, on average about 1 year in 3. Natural lakes within the watershed, including Gun and Tyaughton, provide relatively insignificant storage (BCRP 2000).

Downton Reservoir has a total average inflow of 40 m^3/s (BC Hydro 1994). Additional inflow to Carpenter Reservoir is 51 m^3/s for a total diversion typically about 91 m^3/s into Seton Lake Reservoir. The licensed diversion flow from Bridge River is 147 m^3/s.

C4.2 Terzaghi Dam Facility Statistics

DAM	**Terzaghi**
Dependable capacity (MW)	480
Dam function	storage, diversion
Date constructed	1948
Date reconstructed	1960
Height (m)	60
Length (m)	366
RESERVOIR	**Carpenter**
Present area (ha)	4900
Orig. lake area (ha)	0
Watershed area (km^2)	2691
Present elevation a.s.l. (m)	609-651
Normal drawdown range (m)	44
Mean depth (m)	23
Maximum depth (m)	47
Storage (million m^3)	1011
Mean water retention time	3.8 mo
Mean annual discharge (m^3/s)	51

DIVERSION	to Seton Lake
Structure type	tunnel, penstock
Licensed flow (m³/sec)	150 (typical 91)
Fish flow release (m³/sec)	3
Mainstem length diminished (km)	34
Mainstem length augmented (km)	- -

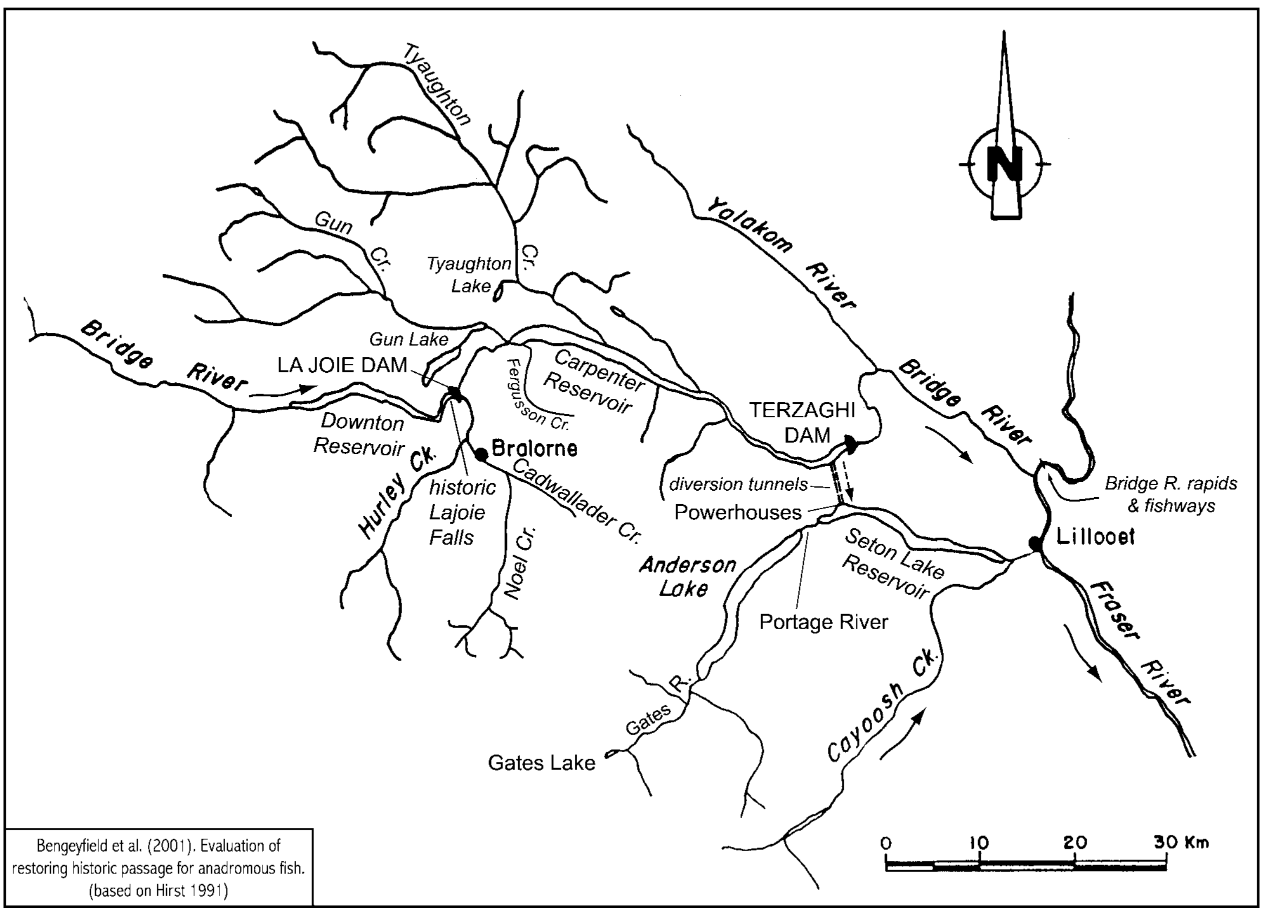
* dashes (- -) mean not applicable

C4.3 Species & Natural Obstructions

A more complete history of fish stocks upstream of Terzaghi Dam is presented in BCRP (2000). Prior to impoundment, the Bridge River was accessible to fish up to the location of LaJoie Dam where La Joie and Zoltique falls were located about 800 m apart on the Bridge River mainstem. La Joie Falls, downstream of Zoltique Falls, was reported to be about 50 feet vertical (Heyworth 1930) and apparently a barrier to upstream fish passage.

The section of Bridge River between Terzaghi and La Joie Dams (now Carpenter Reservoir) was accessible to anadromous salmonids. Sockeye and chinook salmon were reported to use this section of the Bridge River mainstem as well as Fergusson and Tyaughton Creeks. Runs of sockeye salmon in this area were described as very light (Atkinson 1947), although no estimates of historic escapement are available.

Chinook salmon escapement was estimated to range from 300 to 2000 fish in lower Tyaughton Creek between 1940–48 (BCRP 2000). Around the same period (1940–41), estimates of escapement to Fergusson Creek ranged from 1 to 300 fish. Fergusson Creek was reported as being seriously impacted by placer mining in 1942 (BCRP



2000).

Figure C4-1. Carpenter Reservoir Diversion to Seton Lake.

Cartwright (1978) concluded that coho salmon likely used habitat upstream of Terzaghi Dam based on their current presence in the lower Bridge River and the abundance of suitable habitat in the low gradient, meandering mainstem that existed prior to impoundment (BCRP 2000). Today, the sportfish species found in Carpenter Reservoir are kokanee (stocked), bull trout and rainbow trout.

Presently, there is no fish passage structures at Terzaghi Dam. Recent estimates of escapement to the lower Bridge River (downstream of Terzaghi Dam) have been compiled by DFO and are summarized in Table C4-1.

Table C4-1*. *Escapement of Pacific salmon species to the lower Bridge River (FISS 2000).

Species	Ten Year Record	Mean Escapement of Ten Year Record	Max. Escapement of Ten Year Record	Year of Maximum Escapement
Chinook	1989 - 1998	899	1,968	1997
Coho	1989 - 1998	406	900	1993
Pink	1988 - 1997	144164	184327	1991
Sockeye	1985 - 1994	374	1050	1981

C4.4 History of Fish Passage

On May 5, 1920, the Bridge River Power Company Limited, later BC Electric, published its application to store 3,500 acre-feet of water above LaJoie Falls and divert that water from Bridge into Seton Lake Reservoir. "Neither the Department of Fisheries nor John Pease Babcock, the provincial Deputy Commissioner of Fisheries, thought this would affect the salmon run up Bridge River." (O'Donnell 1988). This quote was footnoted: "Correspondence, reports and photographs dealing with the effects of the hydroelectric project on salmon spawning in Bridge River are on file at the National Archives Canada, RG 23, Volume 843, Files 719-9-101 (1-3)". We have not been able to access these files.

Other original correspondence, however, indicates that within 5 days, the Chief Inspector of Fisheries in New Westminster was aware of the application and on May 20, 1920, the Resident Fisheries Engineer advised the Comptroller of Water Rights in Victoria that "…this stream flows through a valuable sockeye spawning area and it will be necessary that the Company doing the work take adequate steps to protect this variety of salmon in any construction work that they may do." This statement was apparently a misunderstanding between the location of the Bridge River Rapids on the Fraser River, which had been causing considerable blockage of sockeye, and the Bridge River itself. Meanwhile a site meeting was arranged with the Company and the Inspector of Fisheries reported to the Chief Inspector on July 23 that:

> "... As you are aware this dam site is on the South fork of the Bridge River[9] , and this particular branch of the stream it appears has never been at any time important from a Salmon fisheries standpoint. I am informed that there are above this point [Yalakom confluence] Steelhead and several species of trout, all of which appear to be native to this stream between this point and LaJoie Falls. … My opinion is that this branch of the Bridge River is not of sufficient importance from a Salmon fisheries standpoint, to prevent the development of this Company's undertaking, nor to require them to construct a fishway in their proposed dam. I would therefore recommend accordingly."

[9] TheYalakom River was then called the North fork of the Bridge River.

The water license was apparently granted shortly thereafter. Nearly 14 years later, in February 1934, another notice of application for water rights by Bridge River Power Company was made to store 350,000 acre feet of water at a dam at LaJoie Falls. On February 27, 1934, a letter from the District Supervisor to the Chief Inspector, Federal Fisheries Department, repeated that 'no salmon ascend to this point and the trout are non-migratory' (IPSFC nd). This suggested that the building of the dam was not considered to have a significant negative impact.

C4.5 Considerations for Anadromous Re-introduction

C4.5.1 Biological Aspects

Target Species [10]

The historic target stocks suitable for re-introduction appear to be chinook, coho, and steelhead. Remnants of these stocks appear to have persisted downstream of the dam and in the Yalakom River.

Sockeye were observed in some years as far upstream as Fergusson Creek. At times very large numbers of sockeye ascended the river but these infrequent occurrences were likely associated with the obstruction in the Fraser River upstream of the Bridge confluence. The International Pacific Salmon Fisheries Commission apparently did not explore the potential for sockeye runs in Bridge River due to the absence of large nursery lakes, although some sockeye stocks are succeessful without nearby lakes (*e.g.* Iskut-Stikine). Sockeye salmon have not been considered a potential stock for re-introduction for reasons discussed in the Coquitlam section C1.5.1.

Habitat Capability

Suitable spawning habitat for anadromous salmonids upstream of Terzaghi Dam appears to be limited with the exceptions of the larger tributaries of Tyaughton Creek, Hurley River, and Cadwallader Creek[11]. Triton (1992) stated that the loss of spawning habitat as a result of impoundment possibly limits the recruitment of resident sportfish populations in Carpenter Reservoir. It appears that sufficient spawning habitat may exist to support a viable population of anadromous salmonids without additional habitat enhancement efforts. However, if the final analysis for Carpenter Reservoir warrants, a more detailed study would be necesssary to examine these streams for suitable temperature and nutrient regimes and other important characteristics.

Mainstem Habitat Availability

The BCR Strategic Plan (2000) estimated that 92 km of mainstem channel (761 ha) were impounded by Carpenter Reservoir. There is still about 2 to 3 km (depending on reservoir elevation) of mainstem river habitat between the upstream end of Carpenter Reservoir and La Joie Dam. This section of river is described as an unconfined and heavily braided channel with an extremely low potential for rearing and spawning for resident stocks (Triton 1992).

Tributary Habitat Availability

The length of tributary habitat lost due to impoundment of Carpenter Reservoir was estimated at 55 km (BCR Strategic Plan 2000). Triton (1992) reported that 56 tributaries (excluding Cadwallader Creek, Hurley and Bridge Rivers) flow into Carpenter Reservoir. Triton summarized the finding of a kokanee habitat survey completed in 1973 by the BC Fish and Wildlife Branch. These tributaries had increasing gradient from the confluence with Carpenter Reservoir upstream to the headwaters, with many waterfalls or steep rapids within 2 km of the confluence. Many of these waterfalls and rapids were judged to be barriers to upstream migration by kokanee. The tributaries also had limited spawning substrate for kokanee and few holding pools. Surveys for 19 of the tributaries to Carpenter Reservoir are summarized in Table C4-2 as adapted from Triton (1992). Presumably, these 19 tributaries were selected as those having the most potential spawning and rearing habitat, yet many were still limited by high gradients, barriers near the downstream extent and limited availability of spawning substrate. The lower gradient sections of these tributaries, which may have provided most of the suitable spawning and rearing habitat, were inundated after impoundment.

Tyaughton Creek

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[10] Groot and Margolis (1991) presented details of complex salmon life histories that can only be highlighted here. Steelhead stocks also exhibit great variation in life history (Withler 1966).

[11] We were unable to review the recent biophysical report by R.P. Griffith for BC Hydro that apparently determined current fish densities and carrying capacity of the smaller Carpenter Lake tributaries.

From the tributaries shown in Table C4-2, Tyaughton Creek appears to have the most spawning potential. Based on the 1973 data, there appears to be approximately 10 km of accessible habitat downstream of the barrier (assessed for kokanee) which is located 250 m downstream of Tyaughton Lake. The average gradient was 1% and although the abundance of spawning substrate was rated as sparse, the spawning potential was rated as excellent (Triton 1992).

Hurley River

Griffith (1997) conducted a biophysical survey of habitat for resident stocks in the Hurley River and its major tributary, Cadwallader Creek which are the largest systems between the two Bridge River dams. From its confluence with the Bridge River, the lower 1.2 km of the Hurley River was dominated by glides over cobble substrate. High turbidity due to glacial till ranged from 48.7 to 212 mg/L during the 1995 investigation, and precluded a thorough assessment of substrate; however, gravels were estimated to be fairly abundant but highly compacted based on observations made of shallow water areas and exposed bars (Griffith 1997).

Beyond 1.2 km upstream of the confluence, there is a 7 km narrowly confined section dominated by increased gradient (3%), abundant rapids and large bed materials. Presence of gravel substrate in this section of the mainstem was low and the spawning potential (for resident species) was described as limited (Griffith 1997). There is a barrier to upstream migration located at the top of this reach which precludes access to 13+ km of low gradient (< 0.5%) mainstem habitat with a 35 m channel width dominated by cobble and gravel bed materials. Beyond that, the Hurley River extends another 18+ km with a channel width of approximately 25 m, gradient of 1 to 2% and hydraulic habitat types predominated by glide and riffle (Griffith 1997).

Cadwallader Creek

Cadwallader Creek is the major tributary to the Hurley River. The two systems join about 7.5 km upstream of the Bridge River. The lower 8 km of Cadwallader Creek (Reach 1) has an average channel width of 25 m and about 3 % gradient with large boulder bed materials. This substrate would provide good cover for trout parr and adults. Spawning potential in this reach was poor in the lower sections of this reach and improved marginally in the upper sections of Reach 1 (Griffith 1997). Two remnant dams from previous mining operations are barriers to fish passage and are located 5.5 km and 8.0 km upstream of the Hurley River confluence. The lower dam was intact and was a complete barrier to fish passage at the time of the assessment (1995) while the upstream wooden crib dam is only partially intact and may be passable at some flows. Noel Creek is the major tributary to the Cadwallader. Its confluence is downstream of the first barrier dam on the Cadwallader, but there is a barrier falls located 400 m upstream of its confluence.

Habitats in the Hurley River and Cadwallader Creek drainages that are downstream of the present barriers to fish passage are shown in Table C4-3. These sites represent the habitat that would be currently accessible to anadromous fish if they were present. Significant amounts of additional fish habitat would be available if the two barriers in Cadwallader Creek and one barrier in Hurley River were remediated.

Table C4-3. Summary of habitats accessible to fish in the Hurley River and Cadwallader Creek drainages (from Griffith 1997)

Survey Site	Reach	Length (km)	Gradient (%)	Channel Width (m)	Hydraulic Habitat Types (% of wetted area)				
					Pool	Riffle	Glide	Rapids	Cascades
Hurley River									
1	1	1.2	1.5	50	10	20	60	10	0
2	2	7	3	30	5	15	30	45	5
3	2	--	1	40	15	5	50	30	0
Cadwallader									
8	1	8	3	25	10	25	35	30	0
9	1	--	3	18	15	20	30	35	0

Table C4-2. Carpenter Lake tributary surveys, July 31 to August 5, 1973. Ministry of Environment, Fish and Wildlife.

Table adapted from Triton (1992).

Stream	Average Gradient[1]	Max width at mouth (m)	Barriers Present	Barrier Type	Location of Barrier (Distance upstream)	Spawning Substrate	Pools Present	Spawning Potential
Nosebag	7 to 9°	3	yes	40 m falls/rapids	120 m u/s	sparse	no	fair
Keary	3 to 6°	3	yes	20 m falls	500 m u/s	sparse	no	good
				2 m falls	50 m u/s			
Tommy	2 to 6°	5	partial	1m falls/rapids	throughout	intermittant	yes	excellent
Bobb	9 to 15°	2.5	yes	1 m falls/rapids	throughout	sparse	no	fair
William	7 to 12°	3	yes	2 m falls	25 m u/s	intermittant	yes	fair
Truax	3 to 14°	5	yes	5 m falls	60 m u/s	intermittant	yes	good
Girl	6 to 13°	1	yes	series of falls	1000 m u/s	sparse	yes	good
MacDonald	3 to 7°	2	yes	0.25 m falls	500 m u/s	abundant	yes	good
Pipeleine	2 to 9°	3	yes	2.5 m falls	500 m u/s	moderate	yes	excellent
Gun	1 to 3°	16	partial	rapids	throughout	sparse	no	excellent
Tyaughton	1°	15	yes	10 m falls	250 m d/s Tyaughtaon Lk	sparse	yes	excellent
Marshall	n/o	14	yes	20 m falls	100 m u/s	abundant	yes	good
Jones	3.5 to 7°	8	yes	2 m falls	500 m u/s	abundant	yes	good
Bighorne	3 to >25°	0.75	yes	continuous falls	250 m u/s	abundant	no	good
Fell	>25°	1	yes	continuous falls	throughout	no	no	good
Cedarvale	0.5 to >25°	2.5	yes	culvert	mouth	abundant	no	good
				16 m falls	200 m u/s			
Sebring	5°	1.5	yes	15 m falls	400 m u/s	abundant	yes	good
Viera	12 to 15°	4	yes	0.5 m falls	50 m u/s	abundant	no	fair

1. All measurements are ground estimates and all slopes measured over 20 m.

Interactions Between Species

In terms of the re-introduction of anadromous salmonids, there would likely be few negative interactions with resident populations in these two systems due to the very low densities of resident fish. Fish densities in the Hurley River mainstem were low (0.01 to 0.05 fish /m^2) and no fish were captured in the upper half of the system. Fish captured in the lower portions were likely migratory fish from Carpenter Reservoir (Griffith 1997). Generally, this system is very unproductive probably due to the high turbidity, cold temperatures, and low nutrients levels. Fish densities in the Cadwallader Creek were somewhat higher than the Hurley River but still relatively low (0.01 to 0.16 fish / m^2) (Griffith 1997). Some positive benefits to system productivity could accrue from decomposition of carcasses of an anadromous run.

C.4.5.2 Technical Feasibility

Fish passage techniques and options relevant to Terzaghi Dam are presented in Appendix D. It is important to note that projects where downstream passage of juveniles has been successful are associated with reservoirs and facilities where juveniles have moved downstream through the reservoir to a location where large flows are either released through turbines or spillways, or to a location where smaller diversion flows are released from surface withdrawals. There is no precedent known for the successful bypass of fish from a reservoir where flow is withdrawn at depth from within the reservoir at a point distant from the spillway.

C.4.5.3 Operational Aspects

Depending on the location of the prospective natal streams in Carpenter Reservoir, migrating fry may experience some delay in finding or orienting to its points of discharge. A very large portion of Bridge River water, approximately 153 m^3/s, is diverted out of Carpenter Reservoir through two 5 km long diversion tunnels to the Seton Lake watershed. The diversion intakes are located 4 km away from Terzaghi Dam. Although a minimum fish flow of 3 m^3/sec is now released from Terzaghi Dam to the lower Bridge River, the outmigrating juvenile salmonids in the reservoir would be generally attracted to the much larger diversion flows on a roughly proportional basis. Passage through the Pelton turbines after the rapid elevation drop to Seton Lake would likely incur high rates of mortality. Survivors would incur some additional mortality to pass the Seton facilities.

A further major problem would arise if a large percentage of returning adults were attracted to and delayed at the Seton tailrace due to its large component of Carpenter Reservoir water. A worse outcome would be if they later moved up the Seton River over Seton Dam to the Bridge powerplants' tailraces in Seton Lake. Assuming that some fish might try to return to the Fraser River, their pathway option to descend Seton Dam would be limited to the adult fishway; entrainment through the Seton powerplant is typically precluded by the adult fish screens on the intake gates to the power canal. Such delays and resulting attrition would be expected to significantly reduce the numbers of spawners that eventually find the small flow of Bridge River itself and then ascend a challenging fishway over Terzaghi Dam to reach Carpenter Reservoir and finally their natal tributaries.

C.4.6 Summary Analysis of Passage Opportunities at Terzaghi

IMPEDIMENTS	TERZAGHI
Significant Dam Height	●
Interbasin Diversion Effects	◆
Significant Drawdown	●

Domestic Water Supply	
Upstream Habitat Capability	•
Biological Interactions	•

• MINOR ● MAJOR

●? LIKELY MAJOR ♦ NOT VIABLE

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Appendix C5

WILSEY (SHUSWAP FALLS) DAM

C5.1 Project Operation

The plans for a power project at Shuswap Falls had been initially developed in 1912 by the Couteau Power Company based in Vancouver, B.C. The Shuswap Falls generating station, Wilsey Dam and Peers Dam were constructed and owned by West Canadian Hydroelectric Corporation and went into service in 1929. The Shuswap Falls project was acquired by the B.C. Power Commission (predecessor of B.C. Hydro) in 1945. The project consists of impounded storage in Sugar Lake controlled by Sugar Lake (Peers) Dam (Appendix A9), and power generation from Wilsey Dam at Shuswap Falls 31 km downstream (Figure C5-1).

The Middle Shuswap basin is located in the western ranges of the Monashee Mountains. Sugar Lake is normally fully drafted by the end of March. The Shuswap River begins to rise in April after the winter months of decreased flow, and usually peaks in late May or early June. The runoff regime is dominated by melting of the large winter snowpack. A small amount of glaciation within the watershed does not contribute significantly to the flow regime. Rainfall is a minor contributor to the volume of the annual flow, but can produce large peak flows that lead to spilling between June and August (BCH 1994). The storage capacity of Sugar Lake Reservoir is about 11% of mean annual inflow. Between 1990-99, 53% of annual inflow was used for generation. Reservoir operation tends to attenuate the onset of spring freshet flow peaks and elevates winter flows from December through February (Lister 1990).

BC Hydro is currently undergoing a Water Use Plan process which will review and recommend a revised instream flow strategy. For protection of fish resources downstream of Wilsey Dam, the current minimum flow release is 15 m^3/s, except between September 15 and November 15 when 22.7 m^3/s is required.

C5.2 Wilsey Dam Facility Statistics

DAM	**Wilsey**
Dependable capacity (MW)	5
Dam function	diversion
Date constructed	1928
Date operational	1929
Height (m)	30
Length (m)	40
RESERVOIR	**headpond**
Present area (ha)	7
Orig. lake area (ha)	0
Watershed area (km^2)	1969
Present elevation a.s.l. (m)	444.5
Normal drawdown range (m)	3
Mean depth (m)	no data
Maximum depth (m)	30
Storage (m^3)	45,000
Mean water retention time	<1 day
Mean annual discharge (m^3/s)	50
DIVERSION	**to powerhouse**
Structure type	penstocks (140m)
Licensed flow (m^3/sec)	31
Fish flow release (m^3/sec)	15-22.7
Mainstem length diminished (km)	0.14

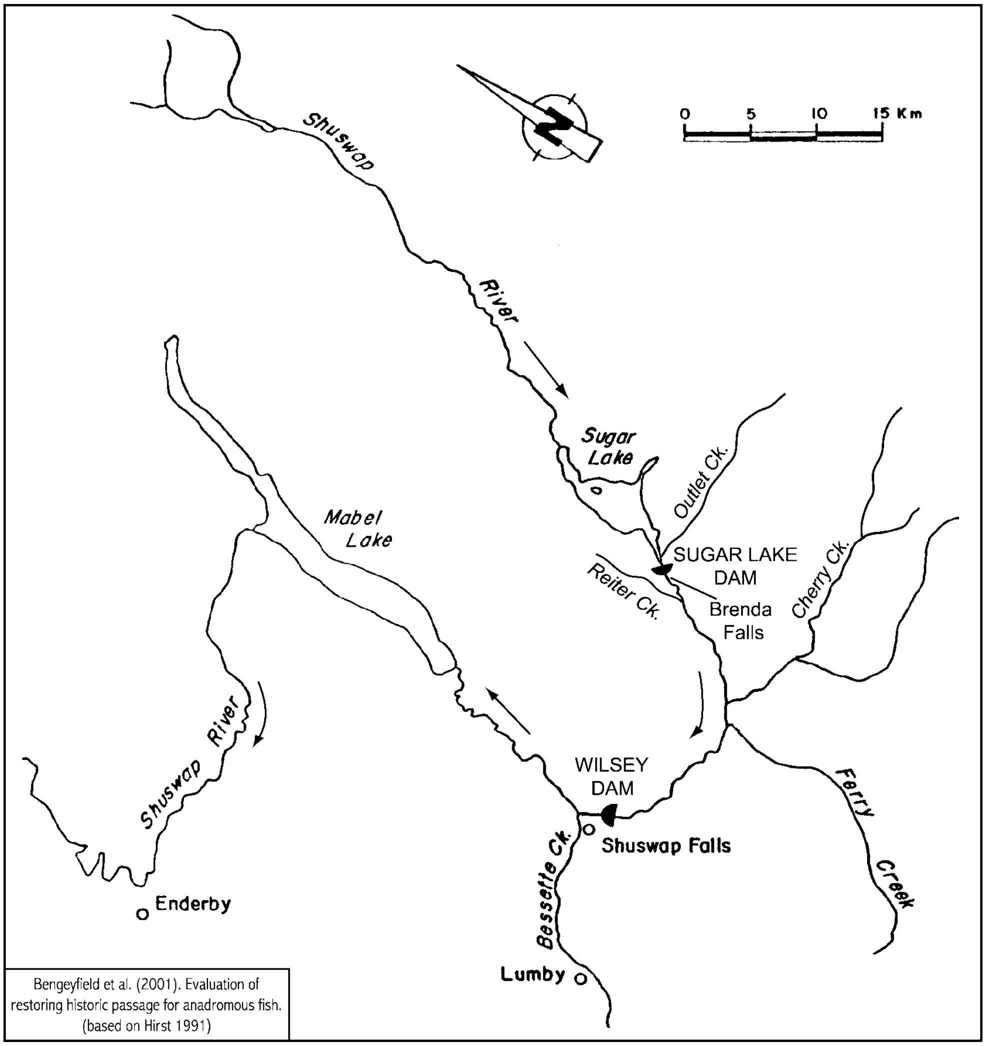

Figure C5-1. Location of Wilsey Dam.

C5.3 Species & Natural Obstructions

Historically, the Middle Shuswap River below Shuswap Falls produced chinook, coho, sockeye and pink salmon. Resident sport-fish species include rainbow and cutthroat trout, bull trout and mountain whitefish.

Information on the escapement and spawning distribution of anadromous species prior to the hydroelectric development is scarce. The original Shuswap Falls were described as a succession of short drops totalling 12.2 m over a distance of 61 m in a narrow rocky canyon. Chinook salmon spawned upstream of Shuswap Falls prior to the construction of Wilsey Dam (Fee and Jong 1984, Griffith 1979), and it is likely that coho did as well. Farther upstream, Brenda Falls below Sugar Lake is believed to have blocked anadromous fish passage prior to the development of Sugar Lake Dam (Fee and Jong 1984), although there have been anecdotal reports of sockeye in Sugar Lake (Babcock 1903; IPSFC 1977; French 1995). That sockeye did not have a substantive population above Shuswap Falls is consistent with IPSFC's assessment of the Fraser basin (1945) which rated Mabel Lake downstream as "non-productive" for sockeye salmon; however, occasional sockeye may have spawned above Wilsey Dam and reared in Mabel Lake.

ARC Environmental Ltd. (2001) summarized the escapement and run timing of salmon species utilizing the Middle Shuswap River (Table C5-1).

Table C5-1. Escapement of Pacific Salmon species to the Middle Shuswap River (ARC Environmental Ltd. 2001).

Species	Mean Escapement	Range in Escapement	Arrival Timing	Years Recorded
Sockeye	14,483	0 – 96,451	mid Oct. - early Nov.	1990 - 1999
Chinook	3922	2441 - 5000	early Oct. - mid Nov.	1990 - 1999
Coho	422	20 - 1200	Oct. - mid Dec.	1986 - 1995
Kokanee	59,350*	33,900 – 108,000	Late Sept. – late Oct.	1990 - 1999

* Mean is based on 4 years data: 1991, '93, '94, '99

Griffith (1979) and Fee and Jong (1984) conducted fish and fish habitat studies upstream of Wilsey Dam. Both studies found relatively large numbers of rainbow trout and mountain whitefish and low numbers of 'Dolly Varden' (bull trout). Non sport-fish species captured upstream of the Wilsey Dam (Griffith 1979) were slimy sculpins (*Cottus cognatus*), longnose dace (*Rhinichthys cataractae*), longnose suckers (*Catostomus catostomus*) and redside shiners (*Richardsonius balteatus*).

C5.4 History of Fish Passage

In February 1913, the Couteau Power Company submitted an application to the Chief Inspector of Dominion Fisheries in New Westminster to waive the fishway requirement at their proposed Shuswap Falls dam. The application included two photos of the pre-project river, a pre-project hydrograph, and a map of the river with a note of 38 foot sheer falls at Sugar Lake outlet (Mackenzie 1913). The latter point was possibly made to show that Sugar Lake in the upper system was not a sockeye-producing lake, the principal species of interest in that era. Mackenzie, a Vancouver lawyer for the Company, argued the lack of a commercial river fishery, the inaccessibility of the river to sportsmen, the "sheer falls of 38 feet"[12] at the outlet of Sugar Lake, the proposed dam height of 70 feet, and the added financial burden to the project. He estimated the fish ladder would cost $20,000 to $25,000.

The Kamloops fishery officer, H. Shotton , was sent to the area in March 1913 and relayed various notes from local residents about fish presence and good spawning grounds above the 'lower' (Shuswap) falls and their opinions as to the necessity of a fish ladder at Shuswap Falls. In April, Shotton (1913) recommended to the Chief Inspector that a fishway be required at this dam. In May 1913, Chief Inspector F.H. Cunningham passed these notes to the Provincial Commissioner of Fisheries J.P. Babcock for his comment, adding that "I am very strongly of the opinion no effective fish ladder could be constructed in a dam of this height". Within two months, a large rock slide at Hells Gate blocked fish access up the Fraser River Canyon; this event and a worse slide in February 1914 subsequently reduced the abundance of salmon to the Shuswap system. The early devastating effects of Hells Gate may have caused the agencies to question whether the upper Fraser stocks could be restored. Babcock replied to Cunningham's letter a year later in May 1914. Babcock stated he had visited the Shuswap Falls site in October 1913 and had seen no fish, and was "of the opinion that the area of spawning grounds above the falls is not of sufficient consequences[sic] to oppose the construction of a dam there or the necessity upon the construction of a fishway, in the event that the dam is placed there".

[12] Correspondence at the time indicated confusion about locations and heights of the various falls and rapids between Shuswap Falls and Sugar Lake. Mackenzie's note about a 38 foot sheer falls at the outlet of Sugar Lake was erroneous; the project surveyor told Shotton (1913) that the upper [Brenda] falls had a sheer drop of 10 feet at most, and that the rapids section had a total fall of 38 feet in a distance of 1100 feet.

The Couteau power project proposal was revived by the West Candian Hydro Electric Company who prepared a conceptual engineering plan of the proposed Wilsey Dam circa 1920 that showed a short fish ladder leading into the lower end of the spillway channel. The fishway was not built, however when the dam was constructed in 1928. The Canada Fisheries Branch Annual Report for 1928-29 stated:

> "Shuswap River Falls – Investigation was made into the feasibility of providing a fishway for a dam seventy feet in height at this point. As a result of these investigations it was ascertained that the passage of salmon could not be assured and under the circumstances it was recommended that the construction of a fishway was not required." (p. 219).

C5.5 Considerations for Anadromous Re-introduction

C5.5.1 Biological Aspects

Target Species

Chinook salmon is the principal target species considered for a re-introduction initiative. Athough blocked from using upstream habitats for 70 years, the chinook stock has persisted in the river downstream of Wilsey Dam. The Shuswap Falls Hatchery began enhancing the Middle Shuswap chinook stock in 1985 after earlier escapements dropped to 500 fish per year (D. Lofthouse, DFO Support Biologist, 2001). In recent years, 2000-4000 fish now return to the point where a small local fishery has been opened between Mabel Lake and the dam. The peak return timing of these runs is typically August-September.

In 1977, DFO tested the feasibility of re-introducing chinook above the dam by releasing 75 adult chinook salmon. Additional chinook releases in 1993 and 1995 both resulted in wild fry that reared in the river above the dam (Triton 1994; 1995).

Coho salmon is also a target species for upstream passage. Shuswap Hatchery produces two 'stocks' of coho—Middle Shuswap and Bessette Creek (D. Lofthouse, DFO Support Biologist, 2001). Both stocks have peak returns in late October. More information on the biology of these stocks should be obtained if a detailed feasibility study on passage is undertaken [13].

Habitat Capability

The headpond behind Wilsey Dam has backwatered about 3.7 km of the incised river channel for an area about 7 ha (Lewis *et al.* 1996). Non-hydro impacts in the watershed on re-introduced fish include effects of logging, agriculture, and road construction.

<u>Mainstem Habitat Availability</u>

Provision of fish passage at Wilsey Dam would allow access to approximately 15 km of useable mainstem river habitat (total 31 km) that is currently not available to anadromous species.

Griffith (1979) divided the middle Shuswap River above Wilsey Dam into 3 reaches. From upstream to downstream the reaches are; 1) Brenda Falls to Cherry Creek (15.2 km) , 2) Cherry Creek to a small chute located 3.7 km upstream of Shuswap Falls (13.1 km), and 3) the chute to Shuswap Falls (3.7 km). Mean gradients for reaches 1, 2 and 3 are 0.63 %, 0.28 % and 0.16 % respectively. Table C5-2 has been adapted from Griffith (1979) and details the gradient breakdown of the upper Middle Shuswap River.

[13] Groot and Margolis (1991) presented details of complex salmon life histories that can only be highlighted here.

Table C5-2. Gradient breakdown (0.2 % intervals) of the upper Middle Shuswap River.
(adapted from Griffith 1979)

	Length (km) of section / reach within gradient interval					Mean
Section / Reach	0 - 0.2 %	0.21 - 0.40 %	0.41 - 0.60 %	0.61 - 0.80 %	0.81 - 1.0 %	Gradient
Shuswap Mainstem (Shuswap Falls to Brenda Falls)	6.08	9.14	8.95	4.61	3.20	0.44
Reach 1 (Brenda Falls to Cherry Creek	0	1.83	5.56	4.61	3.20	0.63
Reach 2 (Cherry Creek to the chute)	3.68	6.06	3.39	0	0	0.28
Reach 3 (Chute to Shuswap Falls)	2.40	1.26	0	0	0	0.16

Reach 1 is characterized by moderately high gradient, with large substrate (62% is greater than 10 cm, Fee and Jong 1984) and predominated by riffle (53%) and run (31%) habitat types. Griffith (1979) described this reach as having abundant, good quality rearing habitat for rainbow trout. During an assessment completed in the fall of 1978 (Griffith 1979), this reach was underutilized by rainbow trout but was heavily used by mountain whitefish. Griffith concluded that rainbow trout populations may have been limited by recruitment due to a lack of quality spawning habitat for this species throughout this reach. Mountain whitefish, on the other hand, were much more plentiful in the fall of 1978 and may benefit from the larger substrate size since they are broadcast spawners of demersal eggs. Fee and Jong (1984) found similar species composition and distribution, however, the relative abundance of rainbow trout was estimated to be 12 times greater than the 1979 sampling.

Although the substrate in Reaches 2 and 3 are dominated by gravels, Griffith (1979) concluded that spawning habitat in these two reaches was limited for rainbow trout. The majority of the substrate in these reaches ranged from 5 to 10 cm in size and was considered too large for the resident trout populations. Smaller substrates were present in some areas within theses two reaches but were associated with areas of lower gradient and water velocities and were often impregnated with sand resulting in moderate to high consolidation. As a result, these areas were also considered to be unproductive spawning habitat for rainbow trout. It is unknown how much variation occurs due to substrate shifting during freshet.

In terms of chinook salmon spawning and rearing habitat, it appears that Reach 1 would be unproductive for the life history requirements of this species. The lower two reaches (Reaches 2 and 3), however, appear to provide an abundance of spawning habitat for the larger anadromous species. It also appears that there would be adequate rearing habitat to sustain a viable population of chinook salmon. For example, Griffith (1979) calculated a standing crop estimate of 2,393 kg total biomass of juvenile chinook in Reach 2 based on an escapement of 1000 adult females. This corresponded to a mean biomass density estimate of 2.85 g/m^2 compared with the actual range of 0.11 to 1.02 g/m^2 found for Reach 2 during the 1978 investigation. Based on the rearing habitat available, and assuming food is not limiting, this reach could likely support a biomass density of approximately 5.0 g/m^2.

Tributary Habitat Availability

There are several tributaries to the Middle Shuswap River between Wilsey Dam and Sugar Lake. These tributaries provide spawning and rearing habitat to resident fish species and potentially could provide habitat for adult and juvenile anadromous species. The available habitat in these tributaries was assessed by Griffith (1979) as well as Fee and Jong (1984).

Cherry Creek is the largest tributary to Shuswap River upstream of Wilsey Dam. The creek is approximately 40 km long with several tributaries of its own. Griffith (1979) described the lower 4 km of the tributary as having riffle/glide/rapid habitat types with a good diversity and abundance of rainbow trout habitat. Spawning habitat in the lower 4 km was described as of relatively good quality and abundant. Fee and Jong (1984) stated that the gradients above 12 km upstream of the confluence with Shuswap River is suboptimal for salmon rearing. The usable area in this section, based on velocities of less than 0.4 m/s, was estimated at 50 %. However, their conclusion was that habitats were generally not suitable for salmon production.

Ferry Creek is the second largest tributary to the middle Shuswap River upstream of Wilsey Dam. Gradient in this system is in excess of 3 to 4 % and provides only limited suitable spawning substrate in the lower 200 m upstream of the confluence (Griffith 1979). It appears there would be little production value for this system for chinook salmon, however, further work would be required to verify this.

Reiter Creek is located about 6 km downstream of Sugar Lake and is approximately 9 km in length. The lower 1 km of Reiter Creek is 3 to 4 % gradient after which the gradient increases significantly to 14 % and greater. This creek contains small amounts of poor quality gravel in the lowest 200 m and spawning habitat is very limited above that point (Griffith 1979).

There are several other small tributaries to the Shuswap River upstream of Wilsey Dam. Although these creeks may have some viable spawning habitat and likely provide rearing habitat for juvenile rainbow trout, it is unlikely they would contribute significantly to salmon production if they were introduced to this section of the middle Shuswap River. Many of the remaining tributaries are about 3 to 8 km long with gradients that are in excess of 20 % within the first km upstream of its confluence with the middle Shuswap River.

Although many of the tributaries discussed may provide productive spawning and rearing habitat for rainbow trout and other resident species, their value for chinook salmon would likely be very limited. Fee and Jong (1984) found that the mainstem Middle Shuswap River is better suited than the tributaries for chinook production. This assessment included mainstem and tributaries above and below Wilsey Dam. Further work would likely be required on the larger tributaries upstream of Wilsey Dam (Cherry Creek, Ferry Creek) to determine their potential to provide chinook salmon habitat.

Interactions Between Species

In terms of introducing chinook to areas above Wilsey Dam, it appears that, based on studies conducted in 1978 and 1983, there may be sufficient suitable habitat to support a viable population. However, implication between the introduced species and current fish populations needs to be addressed. The Ministry of Environment has expressed some concerns about effects of salmon transplants on resident salmonids (Jantz 1995). Griffith (1979) discussed the potential impact of chinook salmon on rainbow trout and concluded that there would be little interaction between the two species and a significant negative effect on the rainbow trout population would be unlikely. Interaction between the two species is limited due to a size separation created by differential emergence timing and by habitat requirements.

The highest densities of rainbow trout were found in Reach 1 (most upstream reach), and in Cherry Creek (Griffith 1979, Fee and Jong 1984). Reach 1 is characterized by higher gradient, larger substrate and higher water velocities which are habitat characteristics preferred by rainbow trout. Low densities of rainbow trout were found in the lower two reaches which are characterized by lower gradient and water velocities as well as smaller substrate. These habitat characteristics are more suitable to rearing juvenile chinook. Since juvenile chinook have been introduced upstream of Wilsey Dam intermittently over the years, some of the assumptions with respect to the species interactions have been verified in the field. Griffith (1979) captured rainbow trout and chinook salmon together in only 2 of 11 electrofishing sites both of which were associated with complex organic habitats (log jams) in Reach 2. No chinook were captured in Reach 1. Similar results were reported by Fee and Jong (1984).

The conclusion that introducing chinook to habitat upstream of Wilsey Dam would not result in the decline of existing populations was qualified with the assumption that food was not limiting to the current resident fish populations. If food was limiting and juvenile chinook were introduced to the system, an increase in competition for the food resource would likely result in declining densities within the resident populations. Further work to determine benthic invertebrate production was recommended prior to the introduction of anadromous species.

C5.5.2 Technical Feasibility

Fish passage techniques and options relevant to Wilsey Dam are presented in Appendix D. See discussion in the main report.

C5.5.3 Operational Considerations

Releases from Sugar Lake Dam, operation of the Wilsey headpond and power generation requirements all can potentially affect fish populations in the middle Shuswap River. Extremely high flows released from Sugar Lake Dam have the potential to displace fish from preferred habitat while extreme low flows can reduce the amount of preferred habitat within a given reach. Flow fluctuation from Peers Dam may result in rapid stage changes in the river which potentially strand fish by dewatering peripheral habitat. Fielden and Slaney (1994) assessed the fisheries implications of summer flow ramping in the middle Shuswap River. They concluded that there would be a low risk of stranding in Reach 3 (just upstream of Wilsey Dam) and that the stranding potential in the upper 2 reaches (1 and 2) would be low and limited to the coarse substrate in the margins. The highest potential for stranding was found in the first reach downstream of Wilsey dam which is low gradient and contains numerous side channels which become isolated from the mainstem at low flows.

Wilsey headpond operation will potentially affect the survival of outmigrating juvenile chinook. If there is no spill and the generating station is operating during peak outmigration, entrainment through the turbines may cause mortality. Turbine mortality has not been addressed at this station and turbine mortality rates vary significantly from one facility to the next. If turbine mortality at this station is considered unacceptable, use of barrier nets, halting generation and spilling water during periods of peak outmigration may need to be considered.

C5.6 Summary Analysis of Passage Opportunities at Wilsey

IMPEDIMENTS	WILSEY
Significant Dam Height	•
Interbasin Diversion Effects	
Significant Drawdown	
Domestic Water Supply	
Upstream Habitat Capability	
Biological Interactions	•

• MINOR ● MAJOR

●? LIKELY MAJOR ♦ NOT VIABLE

Information Deficiencies

Some further work is recommended to fill data gaps found as a result of this evaluation and to verify that the finding of Griffith (1979) and Fee and Jong (1984) are still accurate.

- A tributary assessment in the larger tributaries (Cherry and Ferry Creeks) may be required to assess more fully their potential to provide spawning and rearing habitat for chinook salmon.
- A standing crop estimate would allow a comparison with fish densities found in the 1978 and 1983 work.
- An assessment of habitat types and substrates using the same sample sites as previously used would allow a comparison with the older work. For example, this would determine if sedimentation has reduced the quantity and quality of available spawning habitat in Reaches 2 and 3. The Water Use Plan presently being developed will assist in defining the relationship between operations and habitat.
- A study to determine benthic invertebrate production between the two dams would help to determine whether food is limiting the carrying capacity of the system.
- A literature study or field investigation into turbine mortality would aid in determining if operating constraints are required as a results of anadromous introduction.

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Appendix D

Summary Table of Facilities With Historic Anadromous Fish Stocks

Appendix D: Summary Table of Facilities With Historic Anadromous Fish Stocks

Part 1. Facilities With Current Anadromous Fish Stocks

	Current Anadromous Fish Presence			
Dam Description & Operations	**Puntledge Diversion**	**Comox Lake**	**Salmon Diversion**	**Seton**
year of completion	1912	1912	1958	1956
nominal height (m)	5.5	10.7	5.0	7.6
max height to water level (m)	5.5	10.7	12.73	13.46
material	concrete	concrete	timber crib	concrete
downstream face	vertical	vertical	angled	vertical
nameplate capacity (MW)	27	--	--	42
dependable capacity (MW)	18	--	--	42
Average annual generation (GWhr, data:1984-2000)	155.9	--	--	336.4
licensed flow (m3/s)	32.5	--	16	102
present fish flow release (m3/s)	5.7	5.7	1.73	5.6 - 11.3
normal drawdown range (m)	--	5	--	0.37
months with low elevations	--	Sep to Nov, Feb to May	--	--
depth of intake (m) (varies w/ reservoir level)	surface	below gate	surface	surface
Anad. Fish Stocks above Dam	**SK sockeye, CH chinook, CO coho, PK pink, CM chum, ST steelhead**			
Historic at construction:	CN, CO, ST	CN, CO, ST	none	SK, CN, CO, PK, ST
At present: wild	ST	ST	ST, CO	SK, CN, CO, PK, ST
hatchery outplants	CO, CN	CO, CN	ST & CO	none
adult transplants	occas. CO	occas. CO	none	none
spawning channel	none	none	none	SK - Gates Cr.
Target Stocks for Passage	historic group	historic group	ST, CO	historic group
Present Status of Source Stocks:	depressed	depressed	?	CN,CO,ST - low
Years Dam Blocked Access	1912 construction;	1912-22 all spp.;	1975-92 ST	none
	1965-96 all spp.;	1965-96 all spp.;		
	1997-2000 all salmon	1997-2000 all salmon		
Upstream principal migration period	June-October	June-October	October-March	July-Dec; Mar-Apr
Downstream principal migration period	April-July	April-July	April-July	April-July
Passage Impediments D/S				
name/type	Stotan Falls	Puntledge Diversion Dam	5m falls 12 km d/s	none
name/type	Nib Falls	--	--	--
low fish flow releases	yes	--	yes	--
citation	*Marshall 1973*	*Bengeyfield 1995*	*Ptolemy et al. 1977*	--
Existing Passage Facilities	Year of installation			
UPSTREAM	1912	1922	1992	1956
Fishway type	pool & weir	pool & weir	pool & slot	vertical slot
length (m)	35 (ST ladder)	67	31	107
total elevation drop (m)	2.13	5.5	2.25	8.22
#steps	5	19	7	32
max. jump (m)	0.3	0 (submerged orifice)	0 (slot)	0 (slot)
DOWNSTREAM	yes	yes	yes	yes
Screen Eicher	1993	--	--	--
Bomford	--	--	1986	--
Louvers	--	--	--	1999
Adult ladder	1912	1922	1992	1956

Fish siphon	--	--	--	1956
Fish sluiceway	--	--	--	1956
Radial gate	--	1912	--	1956
Spilling	1912	1912	1958	1956
km from diversion intake to dam	side by side	n/a	side by side	side by side
Instream Habitats Above Dam				
km mainstem lost to reservoir	1	1	0	0.5
km mainstem avail. u/s	not relevant	not relevant	not relevant	not relevant
km tributary lost to reservoir	<0.5	2.1	0	0
km tributary avail. u/s	not relevant	not relevant	not relevant	not relevant
status of habitat data u/s	v.good	v.good	fair	fair
	GFCL '92	*Griffith '95*		
	Griffith 2000			
NON-HYDRO ISSUES				
Municipal Water Source	Courtenay	Courtenay		
OVERALL ASSESSMENT :	1. DFO does not allow spawners	1. Fishway may have problems	1. Screen needs renovation?	1. Fish counter blocks large
	upstream because critical low	operating at different reservoir		chinook passage
	popn has limited mating	levels		2. Juvenile bypass is being
	opportunities and want to			tested with louvers
	maximize genetic diversity.			

Appendix E

Characterization of Existing Fish Passage Facilities:

Comox Dam, Puntledge Dam, Salmon River Diversion Dam and Seton Dam.

Hay & Company Consultants Inc.

BC HYDRO AND POWER AUTHORITY

CHARACTERIZATION OF EXISTING FISH PASSAGE FACILITIES: COMOX DAM, PUNTLEDGE DAM, SALMON RIVER DIVERSION DAM AND SETON DAM

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1 INTRODUCTION

Hay & Company Consultants was invited by BC Hydro to submit a proposal to assess existing fish passage facilities at four BC Hydro dams. This proposal was accepted by Ms. Helen Hamilton Harding, EIT and Ms. Cynthia Powell, Project Manager for BC Hydro on February 6, 2001. The final scope of work was agreed at a meeting on February 12 attended by BC Hydro, Duncan Hay and Bill Bengeyfield of Global Fisheries Consultants Ltd.

The modified scope of work consists of providing concise descriptions of the existing fish passage facilities, primarily in tables and drawings, for the following four BC Hydro dams:

- Comox Dam
- Puntledge Dam
- Salmon River Diversion Dam
- Seton Dam

2 COMOX DAM FISH PASSAGE FACILITIES

Comox Dam is located on Puntledge River 300 m downstream of Comox Lake and upstream of Puntledge Dam and the City of Courtenay. The dam regulates flow for the Puntledge Project downstream. The dam was constructed in 1912 and modified in 1957/1958, 1982 and 1989. The present fishway was constructed in 1957/1958.

Adult fish migrating upstream pass Comox Dam via the pool fish ladder located between the spillway and sluiceway. Water flows from pool to pool over a stop log sill and through an orifice. Fish can travel upstream either by swimming through the orifice or by jumping over the waterfall at the stop logs. The pools provide a resting area for the migrating fish. Flow in the ladder is controlled by varying the height of stop logs at the upstream end of the fish ladder. The downstream end of the fish ladder is not supplemented with extra flow for fish attraction.

Juvenile fish travelling from Comox Lake to the Puntledge River below can pass the dam through the two-bay gated sluiceway, over the spillway or down the fish ladder. Generally the majority of the flow (and juvenile fish) are passed through the sluiceway. No studies have been conducted to estimate fish mortality during downstream migration; however it has never been identified as a problem.

For a general facilities arrangement plan, see Figure 2.1. The following sections provide details of the upstream and downstream fish passage facilities at Comox Dam (BC Hydro, 1989, 1991a, 1998, 2000c).

2.1 Upstream Passage

▪ Upstream fish passage facilities	Concrete fish ladder (pool type); see Figure 2.1 & 2.2.
▪ Length	67 m (1.82m wide inside)
▪ Total elevation drop	0.91 m drop in ladder invert elevation (129.84 m to 128.93 m). Up to 5.49 m drop in water surface elevation.
▪ Number of steps	Maximum of 19 steps (19 baffles) Some baffles become submerged at various flow scenarios.
▪ Overall slope	0.014 m/m based on the ladder invert
▪ Ladder configuration	0.61 m high baffles with an alternating 0.30 m by 0.30 m orifice. Stop logs are set in slots above the baffles. The number of stop logs varies. In order to operate properly, additional stop logs must be inserted at the upstream baffle of the ladder when Comox Lake is above elevation 135.33 m.
▪ Average flow in the fish ladder	0.3 to 0.4 m^3/s
▪ Method of flow control at inlet	Stop log height variation at the upstream end
▪ Supplementary flow (guide to fish ladder) at fish ladder entrance	No supplementary flow or guides
▪ Minimum normal water surface elevation (upstream)	131.0 m
▪ Maximum normal water surface elevation (upstream)	April 1 to September 30: 135.33 m October 1 to March 31: 134.42 m The lake level is adjusted by stepwise increases or decreases between seasons to provide gradual transitions.

2.2 Downstream Passage

▪ Downstream fish passage facilities	Primary downstream passage: Sluice gates. Generally all flow is through the sluice gates. Secondary downstream passage: spillway and the fish ladder.
▪ Sluice gate entrance	2 gates 4.27 m wide, 7.32 m high
▪ Total elevation drop	Spillway crest to river bed below 8.14 m (135.33 m to 127.19 m). Sluice gate sill to river bed below 0.93 m (128.93 m to approx. 128 m).
▪ Minimum flow	15.57 m^3/s
▪ Optimal flow	35 m^3/s (above 35 m^3/s, the flow is for management of reservoir levels)
▪ Normal maximum flow range	80 to 100 m^3/s
▪ Large flow range (not common)	100 to 200 m^3/s
▪ Very large flow range (very rare)	200 to 280 m^3/s

3 PUNTLEDGE DAM FISH PASSAGE FACILITIES

Puntledge Dam is located on the Puntledge River downstream of Comox Dam and upstream of the City of Courtenay. The dam was constructed in 1912 and modified in 1954 and 1957. In 1965 the Department of Fisheries and Oceans constructed a spawning channel and replaced the existing fish ladder with two new ladders. A rearing channel was constructed parallel to the spawning channel in 1975. The spawning and rearing channels have since been modified for additional rearing and for holding of pre-spawning adults. For a general facilities arrangement plan, see Figure 3.1.

The fish ladders are pool ladders for upstream migration of fish, see Figures 3.2, 3.3. The fish ladders are very similar to the ladder at Comox Dam. Stop logs at the upstream end of each ladder control flow in the fish ladders. The pumpstation at the upstream end of the spawning channel provides flow for the spawning channel fish ladder. Fish water release conduits that discharge at the downstream end of the fish ladders provide supplemental flow to attract upstream migrating fish. The conduit flows are controlled by gate valves and the outflow is diffused through a grating in the invert at the base of the fish ladders. Salmon travelling upstream leave the spawning channel fish ladder and enter an artificial spawning channel. Steelhead migrating upstream travel up the Steelhead bypass fish ladder and exit to the Puntledge River. The spawning channel fish ladder is blocked with a screen at the downstream end during steelhead migration. The Steelhead bypass is blocked during salmon migration.

The majority of salmonids migrating upstream are diverted to the main hatchery facility downstream of the powerhouse. Some of the juvenile fish are transported from the hatchery to the rearing channel and spawning channel at the dam for rearing, however most are transported to Comox Lake (upstream of Puntledge and Comox Dams) and released to rear normally.

To reduce juvenile mortality during downstream passage, the twin penstocks were relocated and replaced in 1993 with penstocks equipped with Eicher fish screens, fish bypass pipes and an evaluation facility. It was estimated that 60% of the juvenile migrants were killed when travelling downstream though the turbines prior to the construction of the screens. When travelling downstream via the intake channel the fish enter the power intakes, travel down the penstocks and are diverted by the screens and funnelled into the fish bypass pipes, which deliver them back to Puntledge River, see Figure 3.4.

In 1993 and 1994, the two Eicher screens were evaluated independently for mortality effects on downstream migrants (Bengeyfield 1994,1995). Samples of fish were collected at an evaluation facility to monitor their condition and population size. A sample of 15% of the flow was taken at the facility where fish were diverted by wolf traps into collection tanks. The fish were then released from the facility through a fish bypass pipe back to Puntledge River. The evaluation facility is considered optional and its use may be discontinued when the performance of the screens has been demonstrated. In the first year of operation of the Eicher fish screens the mortality of downstream migrating fish was documented to be less than 1%.

The primary route of downstream fish passage is via the fish screens and fish bypass pipes. Occasionally, water flows over the spillway, which provides another means of downstream migration. Salmonids reared in the artificial rearing channels migrate down the spawning channel fish ladder. The Steelhead bypass fish ladder is generally blocked off when not in use for upstream migration and is not a route for downstream migration.

The following sections provide details of the upstream and downstream fish passage facilities at Puntledge Dam (BC Hydro, 1991, 1998, 2000b; Matthews & Taylor, 1995; McLean, 2001).

3.1 Upstream Passage

▪ Upstream fish passage facilities	Two concrete fish ladders (pool type). One leads to the spawning channel (spawning channel fish ladder) and one leads to the Puntledge River upstream (Steelhead bypass fish ladder). See Figure 3.2 & 3.3.
▪ Length	41.76 m (21.34 m of the length is sloped)
▪ Total elevation drop	2.13 m (ladder invert)
▪ Number of steps and baffles	9 steps (including 8 baffles and upstream stop logs) - spawning channel fish ladder 5 steps (including 4 baffles and upstream stop logs) - Steelhead bypass fish ladder
▪ Elevation change per step	0.30 m (ladder invert)
▪ Overall slope	0.1 m / m (ladder invert)
▪ Ladder configuration	There are 0.46 m tall baffles with an alternating 0.46 m tall by 0.30 m wide orifices. In the spawning channel fish ladder, which leads to the spawning channel, there are three 0.25 m high stop logs that are set in slots above the baffles. In the Steelhead bypass fish ladder two 0.25 m high stop logs are set in slots above the baffles. Stop logs at the upstream ends of both ladders control the flows in the ladders. See Figures 3.2 & 3.3.
▪ Flow in spawning channel and fish ladders (for fisheries interests)	June 10 to September 30: Spawning channel receives 2.8 m^3/s, of which 0.78 m^3/s goes down the spawning channel fish ladder and 2.02 m^3/s goes down the fish water release conduit. August 31 to June 10: Spawning channel flow may be reduced by the amount passing through the Steelhead ladder to a minimum of 1.42 m^3/s. The spawning channel fish ladder is blocked with a screen during steelhead migration.

	A maximum of 2.83 m^3/s is allowed for fish conservation in the spawning channel.
▪ Minimum flow downstream of the diversion dam (for fisheries interests)	5.7 m^3/s
▪ Method of flow control at inlet	Spawning channel fish ladder: Flow is fed from a pumpstation (3 pumps) via spawning channel to the spawning channel fish ladder; see Figure 3.1 & 3.2. Flow at the upstream end of the fish ladder is controlled by stop logs.
	Steelhead bypass fish ladder: Flow from Puntledge River upstream is diverted into the Steelhead bypass fish ladder; see Figure 3.1 & 3.2. Flow at the upstream end of the fish ladder is controlled by stop logs.
▪ Fish water release conduits	One fish water release conduit flows from the spawning channel at the upstream end of the spawning channel ladder and exits at the downstream end of the fish ladder.
	A second fish water release conduit flows from Puntledge River at the upstream end of the Steelhead bypass ladder and exits at the downstream end of the fish ladder.
▪ Supplementary flow (guide to fish ladder) at fish ladder entrance	Water is diffused through the invert grating at the outlets of the fish water release conduits to attract fish to the downstream end of the fish ladders; see Figure 3.1
▪ Depth in each cell	Spawning channel fish ladder: At least 1.22 m plus the water depth above the stop logs.
	Steelhead bypass fish ladder: At least 0.97 m plus the water depth above the stop logs.
▪ Artificial channel length	Spawning channel (also used for rearing):

	approximately 260 m
	Rearing channel: approximately 180 m

3.2 Downstream Passage

▪ Downstream fish passage facilities	Primary downstream passage: Eicher screens in the intake penstocks (2), which divert and return juvenile fish to Puntledge River via fish bypass pipes. See Figure 3.4. Secondary downstream passage: Some downstream migration also possible over the spillway and the log sluice. Salmonids reared in the artificial channels migrate down the spawning channel fish ladder.
▪ Normal operating level	130.15 m
▪ Total elevation drop	0.30 m from the inlet to the outlet of the fish bypass pipe that goes directly to the river. 2.50 m from the inlet to the outlet of the fish bypass pipe d/s of the evaluation facility. Approximately 5.7 m from the spillway crest to the lowest point of the riverbed downstream. Approximately 2.7 m from the log sluice crest to the lowest point of the riverbed downstream.
▪ Fish screen angle and direction	16.5 degrees to the horizontal. The screen angles up in the direction of the flow.
▪ Maximum screen opening	2.5 mm
▪ Penstock diameter at the screens	3.12 m
▪ Minimum flow in penstocks	8 m^3/s
▪ Maximum flow in penstocks	30 m^3/s

▪ Minimum flow in fish bypass pipes	1.41 m^3/s total flow in the fish bypass pipes (2), 0.705 m^3/s each.
▪ Flow maintenance schedule below Puntledege generating station (for fisheries interests)	June 10 to September 30: Minimum flow of 15.6 m^3/s September 1 to September 30: Any flow increase must be maintained until September 30 October 1 to June 9: Minimum flow of 20.5 m^3/s when Comox Lake is at or above 133.8 m on September 1 October 1 to November 30: Minimum flow beween 15.6 m^3/s and 20.5 m^3/s when Comox Lake is below 133.8 m on September 1 Minor variations in the dates listed above are acceptable to accommodate timing of fish runs, Comox Lake levels and inflow conditions.
▪ Velocity	2.44 m/s in the fish bypass pipes. 1.83 m/s approach velocity towards the screen (1.77 m/s parallel to the screen; and 0.549 m/s perpendicular to the screen). Maximum approach velocity to wolf traps in the evaluation facility 1.53 m/s.
▪ Diameter of the fish bypass pipes	0.61m

4 SALMON RIVER DIVERSION DAM FISH PASSAGE FACILITIES

Salmon River Diversion Dam is located on the Salmon River west of Campbell River. The dam was constructed in 1957/58. No fish passage facilities were required at the time of construction of the dam due to the presence of a barrier downstream of the site. The Ministry of Environment blasted the barrier in 1977. Stocking of the upper watershed began in 1986.

The Department of Fisheries and Oceans constructed a fish ladder in 1992 adjacent to the canal and just upstream of the radial gate structure. The fish ladder is a pool ladder to allow upstream migration for fish. Water flows from pool to pool through an orifice. A sluice gate at the upstream end of the ladder controls the flow in the fish ladder. Fish can travel upstream by swimming through the orifices between pools.

In 1986 BC Ministry of Environment constructed a fish screen in the diversion canal, which guides fish migrating downstream to a bypass pipe leading back to the Salmon River. The estimated passage efficiency was 80% based on limited data (Bomford and Lirette, 1991). Modifications were made to the screens in 1995 and 1999 to improve the passage efficiency. The fish screen is located 400 m downstream of the canal headwaters. The smolts are swept down along the screen to a series of flow vanes, which guide the fish to an exiting well, fish trap and fish bypass pipe that discharges to the Salmon River. The fish screen is the primary facility for downstream fish migration, however passage is also possible down the sluiceway, over the spillway, and over the trimming weir.

For a general facilities arrangement plan, see Figure 4.1. The following sections provide details of the upstream and downstream fish passage facilities at Salmon River Diversion Dam (BC Hydro, 2000, 2000d; Hay & Company, 1999; Veary, 2001).

4.1 Upstream Passage

- Upstream fish passage facilities — Concrete ladder (pool type); see Figure 4.2.
- Length — 30.9 m
- Total elevation drop — 2.25 m drop from 220.75 m to 218.50 m (ladder invert)
- Number of orifices — 7 orifices and one sluice gate.
- Elevation change per step — 0.27 m is typical, however there is some variance (ladder invert)
- Overall slope — 0.073
- Ladder configuration — Each pool is separated from the next by a pair of vertical concrete walls offset by 400 mm from each other. A 1.25 m orifice is created between the two walls by embedded metalwork that joins them. A 1.25 m nosing extends upstream perpendicular to the longer wall. See Figure 4.2

▪ Minimum flow in the fish ladder	0 m^3/s
▪ Maximum flow in the fish ladder	3.25 m^3/s at a water depth in the diversion of 1.15 m. Note: The flow can potentially be greater than 3.25 m^3/s. The depth in the diversion can be greater than 1.15 m under the current dam operation guidelines, however the rating curve does not extend beyond 1.15 m. See Figure 4.3.
▪ Method of flow control at inlet	Sluice gate at baffle between Pool 1 and the forebay
▪ Supplementary flow (guide to fish ladder) at fish ladder entrance	None

4.2 Downstream Passage

▪ Downstream fish passage facilities	Primary downstream passage: Fish screen 400 m downstream of the canal headwaters. The screen diverts fish back to Salmon River, Secondary downstream passage: sluiceway (2.6 m high by 3.2 m wide) to Salmon River, spillway crest to Salmon River, and side weir flow over the trimming weir. See Figures 4.4 and 4.5.
▪ Minimum normal flow released to the Salmon River	The dam must provide 1.73 m^3/s to Salmon River, if available. If the upstream inflow is less than 1.73 m^3/s then the diversion canal is closed.
▪ Entrance to canal and fish screen	Fish enter the canal through an intake structure and flow through a radial gate structure (3.96 m high x 6.71 m wide) before being carried further downstream to the screen.
▪ Normal operating level	There is no normal operating level as the Salmon Diversion Dam is "run of river".
▪ Maximum normal elevation of the reservoir	223.72 m

▪ Total elevation drop	Spillway: 5.09 m from 224.18 m to 219.09 (invert) Sluiceway: 2.27 m from 221.36 m to 219.09 m (Invert) Diversion pipe (diverts juvenile fish to the Salmon River): 2.7 m
▪ Screen details	The screen is angled at 7.44 degrees to the horizontal. The screen angles down in the direction of the flow. The downstream section at the bottom of the screen has vanes to guide fish laterally to the fish diversion pipe (at a different angle than the upstream section of the screen). See Figure 4.5.
▪ Screen opening	The screen opening amount decreases towards the vanes from an 80% open screen to 7, 6 and 5 mm wedge wire screens, 72, 69 and 65% open respectively.
▪ Fish bypass pipe flow	Generally between 0.15 m^3/s and 0.85 m^3/s
▪ Minimum flow in diversion canal	0 m^3/s
▪ Ramp down procedures	No less than four hours are taken to ramp down to fisheries flows.
▪ Diversion canal capacity	42.5 m^3/s
▪ Maximum allowable flow in diversion canal when the fish screen is in place	16 to 23 m^3/s (testing underway). Note that the diversion flows are reduced during smolt downstream migration (April 1 to June 30) to ensure effective fish screen operation.
▪ Water level	Water level not to exceed 2 m depth in the canal (corresponds to 16 m^3/s) during smolt migration (April 1 to June 30). Note that subsequent to the 1999 modifications, experiments have been conducted with water depths up to 2.4 m, which corresponds to 23 m^3/s in the canal.

▪ Maximum screen velocity	The maximum velocity normal to the screens is less than 0.3 m/s.
▪ Diameter of the fish diversion pipe	457 mm

5 SETON DAM FISH PASSAGE FACILITIES

Seton Dam is located on Seton Creek approximately 200 km northeast of Vancouver. The dam was constructed in 1956, approximately 850 m downstream of the natural outlet of Seton Lake. Water is conveyed via a canal and penstock to the powerhouse at the Fraser River. Inflow to Seton Lake is supplemented by two tunnels from Carpenter Lake (Bridge River) and one from Cayoosh Creek. For a site plan and a general facilities arrangement plan, see Figures 5.1 and 5.2 respectively.

A fish ladder to allow for upstream fish migration is located adjacent to the fish water release at the dam headwaters. The fish ladder is a vertical slot pool ladder, which allows for operation through a larger range of flows than do weir/orifice pool ladders. The fish swim through the vertical slots and rest in the pools between. The flow in the ladder is controlled by stop logs at the upstream end and supplementary flow is provided at the base from the fish water release. The release is operated with the gate in the undershot (open at the bottom) position during upstream migration and the water discharges at the downstream entrance of the fish ladder through deflector vanes in the concrete guide. This supplementary flow is intended to attract fish to the entrance of the fish ladder. The ladder is equipped with a removable electronic fish counter.

The Department of Fisheries and Oceans maintains two artificial spawning channels below the dam, which are fed by siphons from Seton Canal during the migration and incubation periods. Operating rules for the fisheries flows that are released to the spawning channels are outlined in the sections below.

Juvenile fish migrating downstream can travel through the fish water release, fish ladder, turbine (Francis), siphon (five in total) spillway and radial gate spillway. The turbine, fish water release and Siphon 1 are the primary downstream fish passage routes. In absence of fish diversion efforts, passage through the various facilities tends to be proportional to the flow; therefore, historically the turbine has been the predominant downstream fish passage route. Mortality estimates of fish passage through the fish water release gate, siphon spillway and radial gate is about 2% or less and 17% for passage through the turbine. In 1999, temporary louvers were installed at the dam to divert fish from the canal intake and hence the turbine. It has been estimated that the louvers divert about 50% of the smolts away from the canal intake, however tests are still in progress.

The louvers deflect migrating juvenile fish away from the canal (and turbine) to the preferred primary passages (the fish water release and Siphon 1) and the secondary passages (Siphons 2 through 5 and the radial gate). The fish not diverted by the louvers are carried down the canal to the turbine.

The louvers are a removable line of parallel vertical slats supported by metal guides and floats at an angle to the flow. The louvers partially block the flow from the water surface to a depth of 2.4 m, where the majority of the juvenile fish migrate. The fish are diverted away from the canal intake by both the sweep velocity, which carries them along the louvers and by being discouraged from swimming through the louvers.

The fish water release is located between the siphons and the fish ladder. The flow is controlled at the upstream end by a release gate. Flow at the outlet can either be set to flow over (overshot position) or under (undershot position) the downstream control gate. The downstream gate is operated in the overshot position during downstream migration to reduce mortality.

The five siphons are located just to the north of the fish water release. Siphon 1 is the primary siphon and is primed before the other siphons are used. A large baffle block is located just downstream of the siphons to dissipate energy. The radial gate is operated after all the siphons have been primed and only if required during downstream migration. It also has a large baffle block located just downstream.

The following sections provide details of the upstream and downstream fish passage facilities at Seton Dam (BC Hydro, 1990, 1997, 1998a, 2000a; Groves & Sled, 2000; Prigione, 2001).

5.1 Upstream Passage

▪ Upstream fish passage facilities	Vertical slot fish ladder; see Figure 5.3.
▪ Length	106.7 m
▪ Total fish ladder elevation drop	8.22 m from 233.89 m to 225.67 m (ladder invert)
▪ Number of vertical slots	32
▪ Elevation change per pool	0.23 m is typical, however there is some variance (ladder invert)
▪ Overall slope	0.075
▪ Configuration	Stilling pools 3.05 m x 2.44 m with vertical slots between, vertical walls with nose returns and offset

	opposing vertical walls. See Figure 5.3.
▪ Minimum flow	0.85 m^3/s
▪ Maximum flow	Approximately 1.3 m^3/s at an upstream water level of 236.33 m. See Figure 5.4.
▪ Method of flow control at inlet	Stop logs
▪ Supplementary flow (guide to fish ladder) at fish ladder entrance	The fish water release control gate can be operated in the undershot position to attract the adult fish to the ladder entrance. See Figure 5.5
▪ Artificial spawning channels	The upper and lower Pink Salmon spawning channels are located below the dam and fed by siphons from Seton Canal.
▪ Operation constraints during specific species migration	Adult salmon upstream passage (July 20 to November 15): The fish water release gate is set to the undershot position to attract fish to the fish ladder entrance. The minimum Seton Dam discharge is 11.32 m^3/s, which includes 0.85 m^3/s in the ladder. During Sockeye migration (July 20 to August 31) the plant is shut down or operated at greater than 35 MW. This is intended to deter fish from entering the draft tube. To reduce injuries to fish, air is injected in to the draft tube during plant shutdowns to lower the water surface to 179 m. The flow through the radial gate is restricted to 28 m^3/s except when all siphons are operating. To facilitate upstream migration, the maximum dilution ratio of Cayoosh to Seton water is: 20% Cayoosh for the Gates Creek Run and 10% for the Portage Creek Run. During Pink Salmon migration (September 15 to October 25 in odd years): fish screens are installed at the upper end of the power canal. During spawning and incubation periods (September 15 odd years to May 31 even years) the total Seton Dam spill is limited to 57 m^3/s. The Seton Canal cannot be

	drained while salmon eggs and fry are present in the DFO operated spawning channels unless other sources of water are provided. During the incubation period (November 15 odd years to May 31 even years) at least half of the flow of the spawning period is maintained in the spawning channels. During approximately September 15 to October 29, odd years, a winter incubation flow greater than 5.7 m^3/s is required when Seton Dam discharge is in excess of the 11.3 m^3/s minimum

5.2 Downstream Passage

▪ Downstream fish passage facilities	Behavioural device: Louvers, which divert fish away from the canal intake and turbine to Siphon 1 and fish water release (testing phase). Primary downstream passage: Siphon 1, fish water release (with a sluice gate on downstream side) and Francis turbine. Secondary downstream passage: fish ladder, Siphons 2 through 5 and radial gate spillway (used as last resort spills during d/s migration).
▪ Normal operating level	The reservoir fluctuates daily.
▪ Minimum normal elevation of Seton Lake	235.96 m
▪ Maximum normal elevation of Seton Lake	236.33 m (OMS Manual)
▪ Flow through the radial gate spillway when forebay at 236.33 m elevation	248 m^3/s
▪ Flow in the siphons when forebay at 236.33 m elevation	Siphon 1: 23 m^3/s; Siphons 2 to 5: 28.0 m^3/s each; Total: 135 m^3/s (approximate flows)

▪ Flow in the fish water release when forebay at 236.33 m elevation	Approximately 14 m^3/s
▪ Maximum flow in canal when forebay at 236.33 m elevation	Approximately 147 m^3/s
▪ Average fish water release flow	5.66 m^3/s
▪ Total elevation drop	Fish water release: 5.63 m from 231.30 m to 225.67 m (invert) Siphon Spillways: No. 1: 6.6 m from 236.03 m to 229.43 (invert) m at outlet and 10.36 m to 225.67 m (invert) at the base; No. 2 to 5: 6.93 m from 236.1 m to 229.17 (invert) m at outlet and 8.61 m to 227.5 m (invert) at the base. A large energy dissipator baffle is located just downstream. Radial Gate Spillway: 5.26 m from 230.92 m to 225.66 m. A large energy dissipator baffle is located just downstream.
▪ Louver details	The louvers are a test design with a 2 to 3-year design life. They are in place during April 1 to June 30. The louvers are constructed of polypropylene and are supported by steel guides on timber floats. The louvers are 2.4 m high, 64 mm wide. They are spaced at 75mm centres. The net surface area perpendicular to the flow is 77 m^2. The louver boom has an effective span of 150 m and is angled at 1:4 with respect to the flow direction (in plan). The upstream attachment is at the log boom anchor block and the downstream attachment is between the fish water release and the fish ladder. See Figure 5.6.
▪ Ramp up procedures	15 minute time lapse between each siphon and radial gate flow increase. Siphon 1 is primed first followed by Siphons 2 through 5. The radial gate is opened after all siphons are operating and the gate is opened in 14 m^3/s steps

	every 15 minutes. All 5 siphons are in operation at 122 m^3/s. All 5 siphons are open and the radial gate is partially open at 136 m^3/s
▪ Ramp down procedures	A stepped decrease in spill releases is required. For flows above 169.9 m^3/s the steps do not exceed 25% reduction over a one hour period. For flows between 169.9 m^3/s and 56.6 m^3/s the siphons can be de-primed one per hour. For flows below 56.6 m^3/s ramping down is done with the radial gate. The ramp down rate should be 1 hour at an interval of 1.42 m^3/s until 28.32 m^3/s is reached then the flow is ramped down at 5.66 m^3/s per hour for flows below 28.32 m^3/s.
▪ Specific species migration – operation constraints (selections from the BC Hydro S.O.O. 4P-39)	Sockeye smolt downstream passage (April 1 to June 30): The fish water gate is set to the overshot position. A minimum of 5.66 m^3/s release must be maintained including 0.85 m^3/s in the ladder and 1.13 m^3/s in the upper spawning channel. The fish water release and all five siphons must be used before the radial gate is used. During periods of low inflow the discharge from the lake is maintained constant to utilize the lake's normal operating range of 235.96 to 236.33 m. The turbine is operated between 35 and 44 MW. When possible, changes to the dam and/or turbine discharge are implemented during the period of 04:00 to 16:00 hours.

This report has been prepared by:

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Appendix F

Fish Passage at Dams:
An Overview of Technical and Engineering Aspects

Hay & Company Consultants Inc.

BC HYDRO AND POWER AUTHORITY

FISH PASSAGE AT DAMS
AN OVERVIEW OF TECHNICAL AND ENGINEERING ASPECTS

BCHP.010A

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1 INTRODUCTION

Measures have been undertaken with varying degrees of success to pass migratory fish past natural barriers and dams. Fish passage around natural barriers has often been undertaken to give access to additional spawning and rearing habitat. Effective fish passage around dams is necessary to protect or recover migratory fish stocks. For anadromous fish, passage is required in the upstream direction for adults returning to spawn and in the downstream direction for the migration of juveniles to the ocean.

This report provides an overview of concepts and technical considerations for the passage of anadromous fish, considering both upstream and downstream passage facilities and techniques presently in use or under development. Although the selection, design and performance of passage facilities for a particular site is influenced by site-specific characteristics, this report is intended to give a framework whereby particular passage concepts can be included, or discarded, for additional consideration for a particular site.

2 GENERAL CONSIDERATIONS

A basic consideration to address in considering the passage of fish around a dam, particularly for the re-introduction of fish stock, is the question of whether the stock can be maintained in the system, even with highly effective fish passage facilities. Sustainability is highly dependent upon the fecundity of returning adults, availability of spawning and rearing areas, egg to fry survival, water quality, and predation pressure. The incremental loss of fish during fish passage past a dam could be small in relation to losses incurred at other times in the life cycle of the stock. The bypass efficiency at the dam is only one of several factors in determining the sustainability of the stock. In this regard, it may be possible to accept lower bypass efficiency for a single dam in a system than the bypass efficiency required for multiple dams where injury and mortality could be compounded at each dam to the point where sustainability of the stock is imperiled.

In general there has been good success in moving adults upstream past natural barriers and allowing juveniles to move downstream through the turbulent waters of rapids or falls which are impassable for the adults (Odeh, 1999). The challenge is quite different at dams. For although there has been good success in moving adults upstream past dams, a different set of hydraulic conditions is encountered by the juveniles in the reservoir and at the dam as compared to a natural system. Slow moving water in a long reservoir may not be sufficient to identify an outward migration route for the juveniles. This is more likely to be a problem for high head dams (over 30 m) than for lower dams. Testing of the migratory response of juveniles to a reservoir by radio or acoustic tracking of individual fish would be an appropriate pre-design strategy.

Outmigration is often delayed at a dam, particularly if flow is withdrawn to the turbines from depth within the reservoir. Although likely species and age dependent, juveniles are reluctant to sound to deeply located intakes. Ice and trash sluices at dams on the Columbia River, which draw water from the surface, have been shown to pass a high percentage of juveniles relative to the amount of flow released. The penchant for salmonids to be surface oriented, coupled with the desire to decrease outmigration delays, has led to the testing and development of fish bypasses at Columbia River Dams that draw flow from the surface of the reservoir.

The size and behavioural characteristics of the various species of salmonids vary. Swimming speeds vary for both adults and juveniles, which influences the hydraulic design of fish passage components. The response to stimuli, ability to avoid predation, resistance to scale loss, and other factors, which may affect the success of sustaining a stock, require consideration. It is necessary early in any study plan for the re-introduction of anadramous fish to identify which species will be targeted for re-introduction.

3 UPSTREAM PASSAGE

Upstream passage facilities consist of the following types of fishways: fish ladders, fish locks or lifts, and trap and haul arrangements. While there is some tendency for regional preferences for the type of facility to use, in that European practice tends to use locks and lifts more than in North America, the factors to consider in the selection of a particular upstream passage facility include:

- target species,
- migration timing and number of fish expected to be passed,
- height of the dam,
- local topography and accessibility,
- distance between the powerhouse intakes and outlets,
- instream flow characteristics related to fish migration routes and location of entrances to passage or trapping facilities,
- likelihood of spill during the migration season,
- forebay and tailwater fluctuations during migration periods,
- need, availability and cost of auxiliary fish attraction flows,
- maintenance and operational requirements, and
- capital, maintenance and operating costs.

3.1 Fish Ladders

Fish ladders have been used extensively for effective passage and the technology for the application of these structures is well advanced. Where ladder entrances can be located near attraction flow, fish ladders are often the preferred design for upstream passage at low to medium head dams, or natural barriers, because of reliability, low operation costs, ease of enumeration of returning adults, and limited, if any, handling of the fish.

Ladders are designed to provide hydraulic conditions that match the target species swimming abilities. Characteristics and features of typical fish ladders are presented below together with comments on where each concept is best applied. Detailed design of these ladders generally focuses upon entrance and exit locations, required capacity and routing.

3.1.1 Denil Ladder

Through laboratory testing and field experimentation in the early 1900's, G. Denil developed the fish ladder concept that bears his name. It uses a series of U-shaped baffles within a flume, Figure 3.1, to create a velocity regime near the flume boundaries that is passable by upstream migrants. A variation of the Denil fish ladder, called the Alaska Steeppass was developed in the early 1960's using a different configuration of baffles. Clay (1995) suggests a value of 750 fish per hour would be a suitable design value to use in assessing the adequacy of a single Denil ladder at a project. Additional passage could be accomplished by additional ladders.

The maximum practical dimensions of a Denil ladder are in the order of 1.2 m wide and 1.75 m deep. The flows in the fishways are normally in the order of 0.5 to 1.0 m^3/s. The minimum depth of flow should be about 0.6 m. Clay (1995) gives the dimensions for Denil ladders as suggested by Larinier relating baffle dimensions, spacing and height to the width of the ladder. The ladders are normally constructed at a slope of between 16 to 20%, although they have been constructed on slopes as steep as 25% (Katopodis, 1981).

Whereas Denil ladders are ideal for passage of low obstructions, where the passage can be made in a single run or for a run into a fish trap, they have also been used for passage of dams. In this case it is necessary to incorporate resting pools between runs of the Denil ladder. Generally the maximum vertical rise should be 3 to 4 m between pools.

The advantage of the Denil type ladders is simplicity and ease of construction. Disadvantages include their application where there is a large fluctuation in forebay levels, unless specific hydraulic designs are developed at the exit of the ladder, and the need to keep both debris and heavy sediments from entering the ladder.

3.1.2 Pool Ladders

A series of stepped pools from the tailrace to the forebay of the dam is a common and widely used means of upstream fish passage, Figure 3.1. Energy is dissipated by high velocity flow from one pool to the next with the maximum velocity being set less than the burst swimming speed of the target species. The pools offer a place of rest for the fish while dissipating flow energy. Pools are sized so as not to be excessively turbulent and to provide an adequate volume of water for the number of fish expected to be within a pool during the peak of migration.

The passage of water from one pool to the next may be accomplished by passing the flow over weirs or through vertical slots or orifices. There are several types of internal arrangements within the pools each with particular hydraulic characteristics and applicability to specific situations. The weir type ladders are subject to larger variations in discharge than the slot and orifice types when there is a variation in upstream water levels. Therefore the slot and orifice ladders are generally more suited to sites with variable water levels. This can be offset however by the use of gated ports at the fish ladder exit that supplies flow to lower pools in the ladder as the forebay level drops.

The drop in water level from pool to pool for adult salmon is usually in the range of 0.23 to 0.30 m with the lower value being more suitable for the slower swimming chum and pink salmon. Velocities are normally kept below 2.4 m/s but are often in the order of 1.2 m/s in association with a water level differential of 0.3 m. The flow over weirs is usually in the order of 0.4 m^3/s per m of weir width. Some weirs incorporate notches to reduce the volume of flow required, Figure 3.1. It is often desirable to increase the flow at the bottom of the fish ladder to more effectively attract fish to the ladder entrance. This is accomplished through either gravity fed flow from the forebay or pumping of flow from the tailrace. This auxiliary flow may be introduced within the lower pools or be kept separate from the ladder and be discharged through ports designed to maximize attraction to the ladder entrance.

The depth of the pools is normally less than 3 m. Pools are sized on the number of fish expected to occupy the pools during the peak of migration. It would be reasonable to assume that a 2 m deep by 1.2 m wide and 2.5 m long pool could accommodate a peak of about 800 salmon per hour. Experience has shown that fish tend to hold longer in the lower than upper pools in the ladder.

Some of the early pool ladders built were constructed at slopes of 1:16 to 1:20. More recently it is common to design the ladders on an average slope of 1:10. Generally pool-type ladders have been considered the most economical means of fish passage for dams less than 40 m high. Some have thought that ladders that exceed this height may induce unacceptable levels of stress in the returning adults. Care needs to be taken that flow in the ladder is not heated to unacceptable levels due to the residence time in a long ladder. However, a ladder on the North Fork Dam located on the Clakamas River in Oregon, which is 60 m in height and about 2.7 km in length, has operated satisfactorily since operation began in 1958.

Long straight sections of the ladder are preferable to frequent turns and switch backs. Corners in turns should be rounded to minimize the proclivity for fish to jump at sharp corners.

Siting of the ladder entrance and exit is very site specific. If the entrance is located near a spillway that is likely to operate during migration, it is best located near a shear line that the adult salmon would follow on the boundary of the spill flow. Care should be taken not to locate an entrance in a back eddy that is strong enough to mask the attraction flow from the ladder. The exit should be located away from the spillway, if possible, to minimize the risk of adult fish being caught if spill releases. Often adjacent to a bank where there is downstream flow offers a good exit location.

3.2 Fish Locks

Although experimental fish locks and elevators were tried as early as the 1920's, they were not developed into a practical method of fish passage until the late 1940's. The first of these modern locks was designed by J. Borland and constructed in Ireland. Subsequent installations have been referred to as Borland locks, Figure 3.2. It consists of a top and bottom chamber connected with a sloping chamber. Water released through the top gate flows through the bottom chamber into the tailrace to attract upstream migrants. At a predetermined cycle time, or when sufficient fish have entered the bottom chamber, the downstream gate is closed, the upstream gate is opened, and the lock fills with water. The fish then swim up the shaft and into the forebay.

Borland locks have been designed for dams as high as 60 m, the Orrin Dam in Scotland being an example of a high head dam that uses the Borland lock. Most of the fish locks in use today are located in Europe. Some were constructed at dams on the Columbia River but are not in use today because ladders are more efficient in passing the large runs of salmon seen on the Columbia River.

In Russia fish locks have been designed to pass species other than salmon and have features not included in the Borland lock. The Tzymlyanskij fish lock on the Don River was designed with a vertical shaft and provides auxiliary attraction water, a device to crowd fish into the lock and a vertical lifting basket to insure that the fish ascend the lock into the forebay. The fish crowding features overcome the principal disadvantage of the Borland lock where some fish tend to hold in the lock and not exit quickly to the forebay. The Volzhskaya Dam on the Volga River is similar to the Tzymlyanskij lock but has two locks side by side so one lock is always attracting fish as the other lock is passing fish over the dam. The twin locks increase the fish passage rate over that of a single Borland lock.

3.3 Fish Lifts

As a design concept, fish lifts fall between the operation of a fish lock and the trap and haul concept discussed in the following section. Figures 3.3 and 3.4 are schematics showing fish lift concepts.

Although it is no longer in operation, a fish lift was constructed and operated at the Round Butte Development on the Deschutes River in Oregon. It consisted of an aerial tram system that lifted fish 112 m from the tailrace into the forebay.

Fish enter the lifts from the tailrace led by attraction water flowing out of the lower entrance. When sufficient fish have entered the lift a ‘crowder’ forces the fish into a hopper that is then raised from the tailrace to the forebay.

The advantages of fish lifts are that they can be utilized at high head dams where fish ladders would be impractical, and that fish are moved more quickly than through a single Borland-type lock. Another advantage is that, apart from the flow required for attraction, there is limited use of water in the system and it can be designed to accommodate a wide range of fish species. Lifts have an advantage over ladders where there are large fluctuations in forebay and tailwater levels but have the disadvantages of being labour intensive and having lower fish passage rates.

3.4 Trap and Haul

Trap and haul systems have been used as both temporary and permanent systems for bypassing fish around dams both during and after construction. Fish are led to an area where they are crowded into a hopper, which is then lifted and emptied into a tanker truck that hauls the fish upstream for release into the forebay.

As for ladders and lifts, a flow release is required to attract the migrating adults to an area where they can be trapped. There are several systems used to trap the fish and crowd them into a hopper. One is shown on Figure 3.5 where the attraction flow is released from a diffusion chamber that is screened on the bottom. When sufficient fish have entered the chamber they are moved by a brailing system into the hopper. At other locations, such as at the Hells Canyon Dam on the Snake River, fish are attracted to a short length of fish ladder. As they move across the top of the ladder they pass over a grate that separates the smaller non-targeted species from the larger salmonids. The grate section also serves as a trap and shunts the larger fish into a hopper where they are lifted to the transport truck.

A typical trap and haul system has operated successfully on the South Fork of the Skykomish River in Washington by the Washington Department of Fish and Wildlife to bypass fish around three falls. It is currently used to transport up to 24,000 fish each year using a 1,000 gallon tanker truck that hauls up to 150 fish per trip, depending upon the species of fish being transported. Bell (1990) suggests transportation tanks should be sized to accommodate 0.06 kg to 0.16 kg of fish per litre of water with the value dependent upon the size of fish and haul distance.

The advantage of a trap and haul system is that there is considerable latitude in the choice of the best site for the trap location. The system has economic advantages for bypassing at high head dams, particularly where the migration run is small and manageable by trap and haul, due to a low capital cost in comparison to other systems. Disadvantages of the system include the limited run size that could be readily handled, the labour intensive nature of the operation, and the potential for added stress on the fish being transported and discharged from the haul truck.

4 DOWNSTREAM PASSAGE

The success in passing juvenile salmonids from natal streams to downstream of a reservoir and dam varies widely. At some locations, such as the Baker River project in Washington, described later, there has been good success. At other locations, such as at the Brownlee Dam on the Snake River, Idaho, where a large screen curtain was installed in conjunction with some fish bypass barges at the time of construction in 1958, there has been very little, if any, success leading to bypass facilities being removed or abandoned.

In general, downstream passage is accomplished through the use of one or more of the following: surface collectors, surface spills, screen diversions, and turbine passage, often in conjunction with a behavioural device to guide the fish and increase turbine bypass efficiencies. A description with examples of each of these passage routes is presented below. Surface collectors and screen diversions normally require conduits to transport the fish from the point of collection to the tailrace, unless fish are placed in barges or trucks for hauling downstream. For the Howard Hanson Dam on the Green River, Washington, consideration is being given to using a lock to move outmigrants from the forebay to the tailrace of the dam.

It is important to note that projects where downstream passage of juveniles has been achieved are associated with reservoirs and facilities where juveniles have moved downstream through the reservoir to a location where large flows are either released through turbines or spillways, or to a location where smaller diversion flows are released from surface withdrawals. There is no precedent known for the successful bypass of fish from a reservoir where flow is withdrawn at depth from within the reservoir at a point distant from the spillway.

It is also important to note that there is no universal and widely applied design for routing outmigrants around turbines at dams. There are options to consider but no ready-made solutions, and many of the options available are either untested or in the process of being tested at various projects. The failure of some bypass designs and the uncertainty associated with others has led some projects to extensive field testing as part of design development and implementation. Costs associated with field testing can be considerable, as presented in Section 5.0 of this report.

General factors to consider in the assessment and application of downstream passage options include:

- target species and age class;
- period of outmigration;
- location and depth of the major flow releases from the reservoir;
- reservoir hydraulics from the natal streams and in close proximity to the outlets;
- distribution of outmigrants in the reservoir, both vertically and horizontally in the water column;
- likelihood of spill requirements during the period of outmigration;
- range of forebay and tailrace water levels during outmigration;
- turbine type; and
- spillway type and head.

More specific factors to consider include:

- fish behavioural characteristics such as schooling (sockeye), and swimming speeds;
- use and advantages of behavioural guidance devices;
- reduction of migration delays;
- energy dissipation in delivering flow and fish from the forebay to tailrace;
- predation at the point of release in the tailrace;
- minimizing injury at screens, or in highly turbulent flows;
- handling of debris; and
- capital and operating costs.

4.1 Spillways and Surface Collection

Juvenile salmonids, being capable of surviving in high velocities and turbulent waters, have been passed successfully through spillways with low rates of mortality. Obviously the risk of injury and mortality increases with increased spillway heads, but mortality rates of less than 2% are not uncommon at dams up to 30 m in height. During recent tests for the Rocky Reach project on the Columbia River, there was no mortality of fish entering a still pool with flow at 15 m/s. Tests at Rock Island Dam on the Columbia River, in which juvenile salmonids were released into flow at similar velocities that impacted a concrete sill 3 m below the water surface, resulted in no mortality.

Dams with various spill routes may present an opportunity to test and select the route that is most cost effective in bypassing fish without injury. A siphon spillway is used to bypass sockeye outmigrants at Seton Dam, British Columbia.

One advantage to bypassing fish through spill releases is that a bypass route is generally available to all species and age classes. The disadvantages of spill releases are associated with the cost of released water, the possibility of increasing levels of dissolved gas in the tailrace and, unless spill volumes are high, imposing a delay on the outmigrations. Surface collection and bypass systems are designed to reduce the volume of water required to achieve effective fish passage.

As the name implies, surface collection systems focus on providing a bypass route for fish near the surface of the reservoir. Some of these systems seek to accommodate the reluctance of juveniles to sound to deep outlets. The degree to which juvenile salmonids are reluctant to sound and have the ability to resist being drawn to depth with flows is likely dependent upon the species and size of the salmonids. Experience on the Columbia River would indicate that Chinook and Steelhead smolts perhaps have the volitional ability to find surface bypass routes. Chinook fry and Sockeye tend to be more widely distributed in the water column, with Sockeye tending to show schooling behaviour rather than moving on an individual bypass route. For those fish that are widely distributed in the water column it is necessary to guide these fish to a surface bypass through screening or other behavioural guidance devices. Although tests using light, sound and electrical fields have been conducted to guide fish, the most effective behavioural guidance systems appear to be screens or solid structures.

Surface bypass systems consist of a bypass entrance, which withdraws flow from the reservoir, a channel which normally leads to a point where fish in the system are trapped by velocities that preclude their return upstream, and a system to deliver the fish to the tailrace. Some refer to flow withdrawn at the entrance as the ‘attraction’ flow. It is questionable whether fish are ‘attracted’ to this flow in the same way that returning adults are attracted to a velocity at the entrance to a fishway. For juveniles it appears more important in design to ensure that fish are not detracted from the entrance by encountering areas of flow deceleration, unsteadiness or turbulence.

To date there has been no rigorous basis developed upon which to decide how much flow is required at a surface bypass entrance, nor how many entrances should be placed in the reservoir. The bypass flow for the fish attraction barge at Lower Baker Dam is about 4.5 m^3/s, whereas the bypass flow at Rocky Reach Dam is 170 m^3/s, reflecting the differences between the size of the runs and powerhouse flows at these projects. Both facilities are described below.

Lower Baker Dam was constructed in 1927 on the Baker River, Washington. It is an 87 m high, concrete, semi-gravity, arch dam impounding a 21 km long reservoir. It operated initially by passing sockeye fry through Francis turbines and over the spillways, which led to a large reduction in fish runs. Subsequently, through testing and development in the field, a system has been developed that bypasses Sockeye fry and maintains a run of about 8000 returning adults.

The system includes a fish attraction barge, an exclusionary net and a fish trap barge, from which the fry are placed in a truck for transport to the tailrace. The fish attraction barge, shown on Figure 4.1, is 10.9 m wide and 21 m long. It is positioned at the apex of an exclusionary net that extends from the surface to the bottom of the reservoir some 30 m upstream of the two power intakes. The net is suspended from an inflated hose and buoys. Two primary pumps and one secondary pump draw flow through a 3.7 m wide by 2.7 m deep entrance. The entrance flow is dewatered through a louver as fish and flow are carried to a 0.9 m wide flume and into a hopper. From the hopper fish are transported through a 25 mm diameter flexible pipe to a floating fish trap, from which they are loaded into a transport truck then released below the dam.

As mentioned earlier, a similar system installed at the Brownlee Dam on the Snake River was not successful, possibly due to the greater length of the Brownlee reservoir (93 km), greater in-reservoir predation, and the fact the exclusionary net at Brownlee did not reach the bottom of the reservoir.

As previously noted, observations at dams on the Columbia and Snake Rivers have indicated a relatively high percentage of Chinook, Sockeye and Steelhead smolts utilize ice and trash sluiceways, when they have been opened during the outmigration season. This has been observed at Ice Harbour, The Dalles, Bonneville and Wanapum Dams. Fish drawn to the forebay by powerhouse or spillway releases appear to prefer exiting the forebay through the surface-oriented sluiceways rather than sounding to the turbine intakes.

Outmigrant fish bypass at the Wells Dam, Columbia River, has been highly successful because the unique design of this dam permits flow to be drawn from above the power intakes and discharged to the tailrace. Wells Dam is a hydrocombine where the powerhouse and spillway are integrated into one structure, with the spillway intakes drawing flow from above the power intakes and discharging flow downstream above the draft tubes. Five bypass entrances are evenly spaced across the dam, each being associated with two turbine units. Each bypass draws a flow equal to about 10% of a single turbine flow. The velocity at the bypass entrance is about 0.2 m/s. Approximately 90% of outmigrants pass Wells Dam through controlled spillway openings.

The success of downstream fish passage at Wells Dam has led to field testing of surface collectors at other projects on the Snake and Columbia Rivers, where openings of similar dimensions and with similar entrance velocities have been placed above turbine intakes. The success has varied. Tests at Wanapum Dam did not produce fish passage results as high as expected, whereas results at Rocky Reach Dam have encouraged the owner to proceed to design and construct a surface bypass system which will be fully operational in 2002-03.
A plan view of the Rocky Reach Dam surface collection bypass is shown on Figure 4.2. The surface bypass is located adjacent to the most downstream of 11 turbine units. The forebay of the powerhouse narrows towards the downstream units, such that fish entering the area tend to be concentrated in the

region of the bypass. Historically, prior to the testing of surface collector designs, approximately 80% of fish passing the dam went through Units 1 to 3.

The entrance to the surface bypass is 17.4 m deep and 12.2 m wide. It is split into two halves to facilitate dewatering the intake flow and provide the possibility for moving one of the two intakes upstream at a later date, if considered desirable. Each of the two intakes will draw 85 m^3/s. The majority of this flow is dewatered through screens, drawn by pumps located in the forebay. Approximately 3.4 m^3/s is carried past the dewatering screens, over a weir that traps the fish, and is discharged together with the fish into the tailrace downstream of the dam. The system is to be initially operated in conjunction with intake diversion screens in the intakes of turbine units 1 and 2. Prototype testing indicated the system is more efficient in bypassing juvenile Chinook and Steelhead than Sockeye.

A surface collector bypass is also being developed and tested at Lower Granite Dam on the Snake River. A 100-m long floating structure, 18 m high and 6 m wide extends from the spillway to in front of three of the six turbine unit intakes. It has three fish bypass entrances with multiple sliding doors which are used to vary and test entrance configurations. In 1998 an 335 m long floating behavioural guidance structure was added to the system to guide fish toward the surface collector bypass. The guidance structure, shown in Figure 4.3, extends from the water surface to depths of up to 24 m in the reservoir.

4.2 Surface Spill

In order to achieve fish survival goals, some projects on the Snake and Columbia Rivers have been required to bypass fish through spillways during the period of juvenile salmonid outmigration. Based on the apparent effectiveness of bypassing fish through ice and trash sluiceways, some dam owners have been testing and utilizing modifications to existing spillways to bypass fish with flow drawn from the upper levels of the water column in order to bypass fish with a smaller total flow release.

At Rock Island Dam on the Columbia River, leafs of vertical lift gates have been modified to incorporate a notch in the upper leaf to pass flows ranging from 50 m^3/s to 70 m^3/s per notch. Two designs were tested, one with a notch 3.4 m wide and 4.3 m deep, and one with a notch 9.1 m wide and 2.1 m deep. Tests to date suggest the narrower notch is more effective in bypassing fish. At present nine of the 32 gates at Rock Island equipped with notched gates are used to bypass juvenile salmonids at a total discharge of about 575 m^3/s. The notched gates are distributed across the spillway, based on locations selected from model tests and field observations.

At Wanapum Dam on the Columbia River, tests were conducted on one of twelve taintor gates where a notched bulkhead was placed upstream of the taintor gate to discharge surface oriented flow, Figure 4.4. The bypass flow and water level downstream of the bulkhead were controlled by the amount of taintor gate opening. Testing was discontinued after fish injury was noted and before the bypass efficiency of the opening could be determined. It is not known whether fish injury resulted from the level of turbulence in the downwell behind the bulkhead, or by fish striking the lip and seal of the taintor gate.

Along similar lines, the U.S. Corps of Engineers is testing a removable spillway weir by at the Lower Granite Dam on the Snake River. This structure will sit on the crest and ogee of the spillway, essentially raising the level of the crest to reduce the flow of the spillway when the gate is fully open. Flow over the removable weir will be surface oriented.

The potential advantage of surface spill bypasses is that the same number of fish can be passed as through conventional spillways but at much reduced rates of flow. That is, the rate of passage per unit of flow appears to be higher for surface than deep releases. Disadvantages of the surface spill approach are that it is very site dependent and still under development at projects where it is being tested.

Other issues associated with surface spill are the generation of elevated levels of dissolved gas and the potential for fish injury. Both the measures for the abatement of elevated gas levels and risk of fish injury are very dependent upon the spillway configuration and flow velocities. Tests conducted for the fish bypass outfall at Rocky Reach Dam showed no injury or mortality of juvenile salmonids entering a tailrace pool with flow at a velocity of 14.9 m/s.

4.3 Screens

Screens have been successfully used to divert juvenile salmonids from a mainstream of flow into other passages and facilities where they are bypassed around dams. Three basic types of screens are in use: those used at the intake of the reservoir outlet; those used in penstocks such as the Eicher and Modular Inclined screens; and those used within turbine intake passages. The type of material used for the screen depends upon the application and can vary from flexible mesh used for nets to wedge wire screens, which were developed to facilitate the shedding of debris. The size of openings in the screen material is dependent upon the size of juveniles targeted for diversion. Generally openings of 1.75 mm, or less, would be suitable for all sizes of juveniles, increasing to about 6.3 mm if only smolts are targeted.

A critical hydraulic parameter for the design and injury-free operation of screens is the velocity of the flow approaching normal to the face of the screen. A common design criterion is to maintain the velocity normal to the screen at less than 0.12 m/s, but the need for meeting this criterion is dependent upon the size and species of outmigrants, and the flow velocity parallel to the screens. Power intake diversion screens with a normal velocity of less than 0.9 m/s have been successful is diverting Chinook and Steelhead smolts, when the ratio of the tangential to normal velocities has been greater than one. Eicher screens have been used successfully with normal velocities in the range of 1.2 m/s. The distribution of flow through the screen should be as uniform as possible to avoid setting up circulation cells on the screen and local areas of high velocity, where debris may concentrate or fish would have an increased risk of impingement.

An Eicher screen is an elliptical wedge-wire screen designed to divert fish within closed penstock systems. The screen inclines upward at about 16 degrees to guide fish into a bypass channel located at the top of the penstock, Figure 4.5. The screen is pivoted to facilitate cleaning by reversing the position of the screen and backflushing the screen face. Eicher screens have been installed at the T.W. Sullivan plant, Willamette River, Oregon; the Elwha Dam in Washington; and at the Puntledge hydroelectric facility in British Columbia.

Modular Inclined Screens (MIS), Figure 4.6, are similar to Eicher screens, being based upon the same concept of high approach velocities, strong tangential velocities along the screen face, and short times of exposure of the fish to the screen. A module consists of an entrance with trash racks, dewatering stop logs, an inclined wedge-wire screen set at an angle of 10 to 20 degrees to the flow, and a fish bypass conduit. Modules are designed to be closed systems and operate at flow approach velocities of 0.6 to 3.0 m/s, depending upon the size of the targeted species. A MIS system was tested at the Green Island hydroelectric station in New York in the fall of 1995 and 1996 and showed good fish bypass survival. A large-scale application of the MIS is yet to be implemented, although inclined screen systems with similar characteristics to MIS systems have been used to pass fish from canals.

The primary advantages of the Eicher and MIS systems are they can be used to screen all the flow in the diversion and are insensitive to forebay levels. A disadvantage of these systems is the limited flow capacity, being in the order of 15 to 20 m^3/s per screen, requiring multiple units to accommodate most hydropower plants. Inclined screen systems that are not enclosed present the design challenge of accommodating fluctuations in water levels.

Intake diversion screens have been installed at Snake and Columbia River hydroelectric projects since the late 1970's. The system consists of two sets of screens, a screen that diverts fish from the turbine intake up a gatewell, and a vertical screen that dewaters the gatewell flow and diverts the fish to a collection channel or bypass pipe, Figure 4.7. The diversion screen usually occupies the upper third to half of the intake at a slope of about 50 degrees. Two types of diversion screens have been used, a travelling screen and a fixed screen. The travelling screen is usually a fabric mesh, which rotates on a frame past a screen cleaner. The fixed screens are usually fabricated with stainless steel wedge-wire bars and rely on removal for cleaning, or a mechanical cleaner that is deployed to travel down and up the screen. The vertical barrier screens use either perforated plate or wedge-wire bars.

As mentioned earlier, the flow velocities normal and tangential to the screens are important parameters with respect to safe fish passage. The vertical barrier screens are usually designed with normal velocities of 0.12 m/s, whereas the diversion screen is designed for normal velocities in the order of 0.9 m/s. Hydraulic model studies are often used to determine how best to vary the porosity of the screens to achieve uniform flow through the screens.

Intake diversion screens are expensive to develop and install. Considerable retrofitting of gatewells and trashracks are often necessary to provide flow passages for bypassed fish and to handle trash at the intakes. Also, diversion screens have been most successful for bypassing smolts rather than fry. Incidents of high scale losses on sockeye and mortality of fry have occurred, being associated with the design values used for velocities normal to the screen face. There is insufficient space available within normal turbine intakes to provide enough screen area to develop normal velocities more suited to the diversion of fry.

The handling of debris and cleaning of screens is an important consideration for any fish bypass screen system. Trashracks are normally located upstream of screens to keep large debris from the screens, but the openings in the trashracks need to be sufficiently large so as not to impede fish passage. As a result, small debris and organic material frequently impinge on diversion screens and need to be removed to preclude injury to fish and unacceptably high head losses across the screens. Backflushing systems, such as incorporated in the design of Eicher and MI screens, are helpful but do not totally eliminate the need for inspection and manual cleaning.

4.4 Turbines

Mortality of fish that pass through turbines is due to direct or indirect effects. Direct effects are associated with the turbine passage, such as being struck by a turbine blade, whereas indirect effects are largely due to predation on fish that are made vulnerable by being disoriented after passage through the turbine. Data on mortality rates often do not separate the direct and indirect effects.

Bell (1990) reported that turbines could cause 15% mortality. Based on a review of nine hydroelectric projects on the Snake and Columbia River, Voith Hydro indicate the average rate of direct mortality ranged from 0% to 16% through large Kaplan units.

The type of unit, setting of unit, head, tolerances and size of fish affects the rate of mortality. Kaplan runners are most often used for low heads up to 30 m and Francis runners, Figure 4.8, for heads between 30 and 300 m. Ruggles (1980) suggests that mortality rates are higher in the Francis units than the Kaplan units due to higher runner speeds and small clearances at the wicket gates. Greater head is also likely a factor.

There is research and development actively underway to reduce the mortality rate of fish passing through Kaplan turbines. These modifications include modifying the spherical hub and discharge ring to eliminate gaps at the edges of the blades over the full range of blade angles, and modification to the blade design to minimize or eliminate cavitation. Consideration is also being given to the effect a particular flow path through the turbine has on the rate of mortality, with the view to the potential of guiding fish to a particular position of the turbine intake as a means of reducing the rate of mortality. In general smaller fish are subject to a lower rate of mortality than larger fish.

There has also been a recent development of a turbine concept designed to pass fish with little, or no, mortality. Alden Research Laboratory and Northern Research and Engineering Corporation have developed a turbine runner based on a screw-type impeller, Figure 4.9, which although not installed at a hydropower plant may be suitable for heads up to 30 m. Laboratory tests on turbine efficiency and fish passage on a 1.2 m diameter prototype are planned for the year 2001.

A prudent first step in assessing fish bypass at a hydropower facility would be to undertake tests to determine the rate of mortality likely to be experienced on a target species and age class on passing through the turbines at the plant. This could be followed by an assessment of whether modifications to the units could be undertaken to achieve an acceptable level of mortality, together with an assessment of the measures to minimize indirect mortality in the tailrace area.

5 COSTS

Costs associated with a fish passage project can generally be broken down into the following main categories:

- biological studies;
- engineering studies;
- design, tendering and construction management;
- prototype testing and evaluation;
- capital cost of construction;
- operation and maintenance.

Both biological and engineering feasibility require assessment. Biological studies may range from basin wide investigations to assess the availability of suitable habitat, to tracking the movement of juveniles and monitoring swimming behaviour during outmigration. Engineering studies would often include geotechnical assessments of foundation conditions and hydrotechnical investigations may be required using physical or numerical models to address particular design issues. Field testing of prototype concepts is often prudent prior to committing to large capital expenditures, especially if developing designs for downstream passage of juveniles.

Design would normally move through three stages of development, starting at a conceptual level and then progressing through preliminary to final designs, where often the feasibility of the project is assessed with a preliminary design in hand. There are administrative costs incurred with implementing projects that are associated with the preparation of contract documents, tender award and monitoring of the construction.

The cost of design, tendering and construction management is usually estimated as a percentage of the capital cost of project. Although the percentage would normally decrease with the size of the project, for budgeting purposes a cost of 15% of the estimated project cost is suggested, not including special studies and investigations discussed below.

The cost of biological studies and special geotechnical or hydrotechnical investigations would likely be a function of the size of the project. They could be in the range of 7 to 10% of capital cost for biological studies (possibly over multiple years) and 12 to 20% for engineering investigations.

The cost of field testing fish passage concepts during design development is difficult to estimate. It could be assumed there would be no cost associated with this for developing an upstream passage design, but a cost should be included for field testing downstream passage designs. These could include testing of changes to turbine designs or prototype testing of screen systems, behavioural guidance systems or surface collectors.

Capital cost estimates can only be developed for a particular site. Operation and maintenance costs should be amortized over the life of the facilities and added to the estimated capital cost to make direct comparisons between various passage options.

There are no known lifts in operation used for moving upstream migrants from the tailrace of a dam to the forebay. In a very limited way, lifts are used as part of a trap and haul operation. However, extending the lift from the 5 to 10 m required to take fish from a holding area to a tanker truck, to the height required to take fish over the dam, appears to exist only as a concept that has not been engineered with costs for application to a specific site.

The estimated cost of a trap and haul facility includes the cost of a small fish ladder, an attraction flow pump and piping, a brailing system, site preparation and a tanker truck. For rivers with large fish runs it is unlikely a single trap and haul facility would have sufficient fish passage capacity. Although it is unlikely to be practical, the cost of two trap and haul facilities could be included for the medium height and high dams with large flows.

The estimated cost of spilling water for bypassing fish could be developed on a site-specific basis by:

- estimating what spill flow would be required to pass fish;
- estimating the period of time spill passage would be required;
- assigning a dollar value to the water released for fish passage on an annual basis; and,

- calculating a present net value of the water released over an expected life of the dam or alternative bypass structures.

The estimated cost of surface collection systems should include the capital cost of work in the forebay to collect the fish, the cost of any behavioural guidance devices, the capital cost of transporting fish to the tailrace, and the cost of water use. The cost of surface collection systems is very site-specific.

The cost of turbine intake screens is estimated to be similar to the cost of forebay screening for flows above 450 m^3/s, but twice the cost for smaller flows due to the work within the dam that is necessary for the collection and transport of fish screened within a power intake. Screening to full depth in a reservoir is expected to be the same order of magnitude of cost as screening all of the power intakes.

The cost of retrofitting turbines to improve fish passage will be site-specific depending upon the type of unit and water passage configuration.

In summary, the capital, maintenance and operating costs of fish passage facilities vary widely, depending upon the targeted species, run size, passage efficiency required, height of dam, flows, water level fluctuations and other site-specific factors such as topography and geology. Cost estimates should be developed on a site-specific basis and updated, as necessary, as design progresses from a conceptual to final design.

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Hay & Company Consultants Inc.

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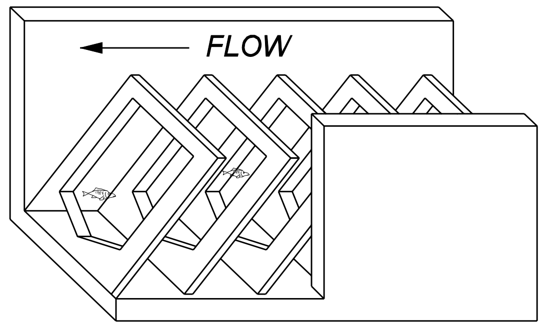
FIGURES



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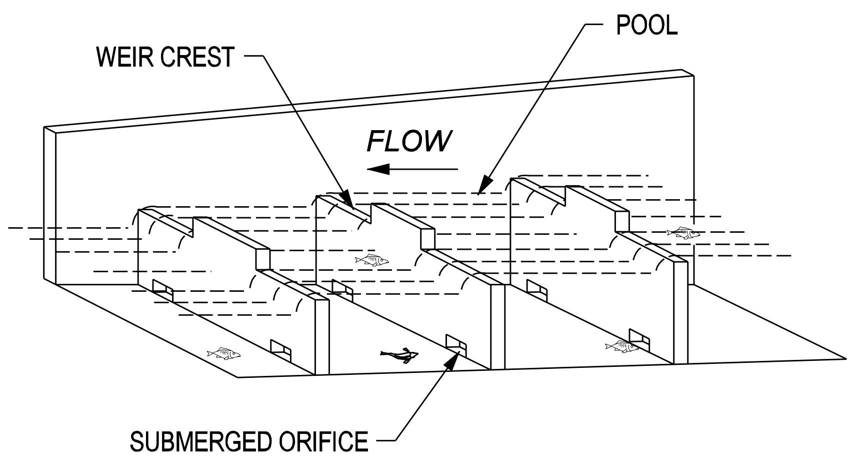

POOL TYPE

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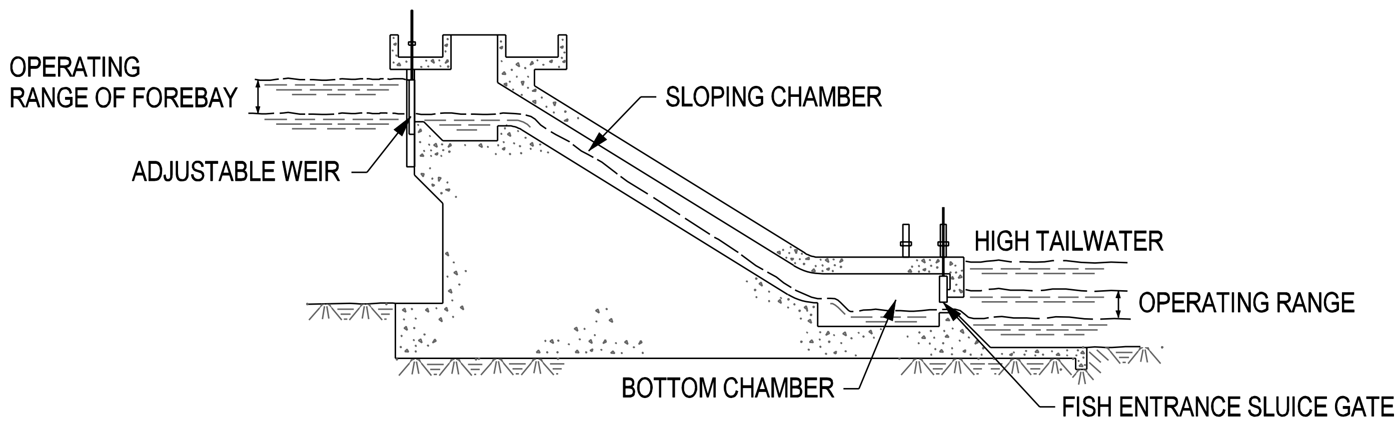
BC HYDRO AND POWER AUTHORITY

FISH PASSAGE AT DAMS

FISH LADDERS

FIG. 3.1

CAD FILE ; BCHP10 / BCHP10FIGS.DGN / 2001 MAR 23



BORLAND LOCK

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BC HYDRO AND POWER AUTHORITY

FISH PASSAGE AT DAMS

FISH LOCKS

FIG. 3.2

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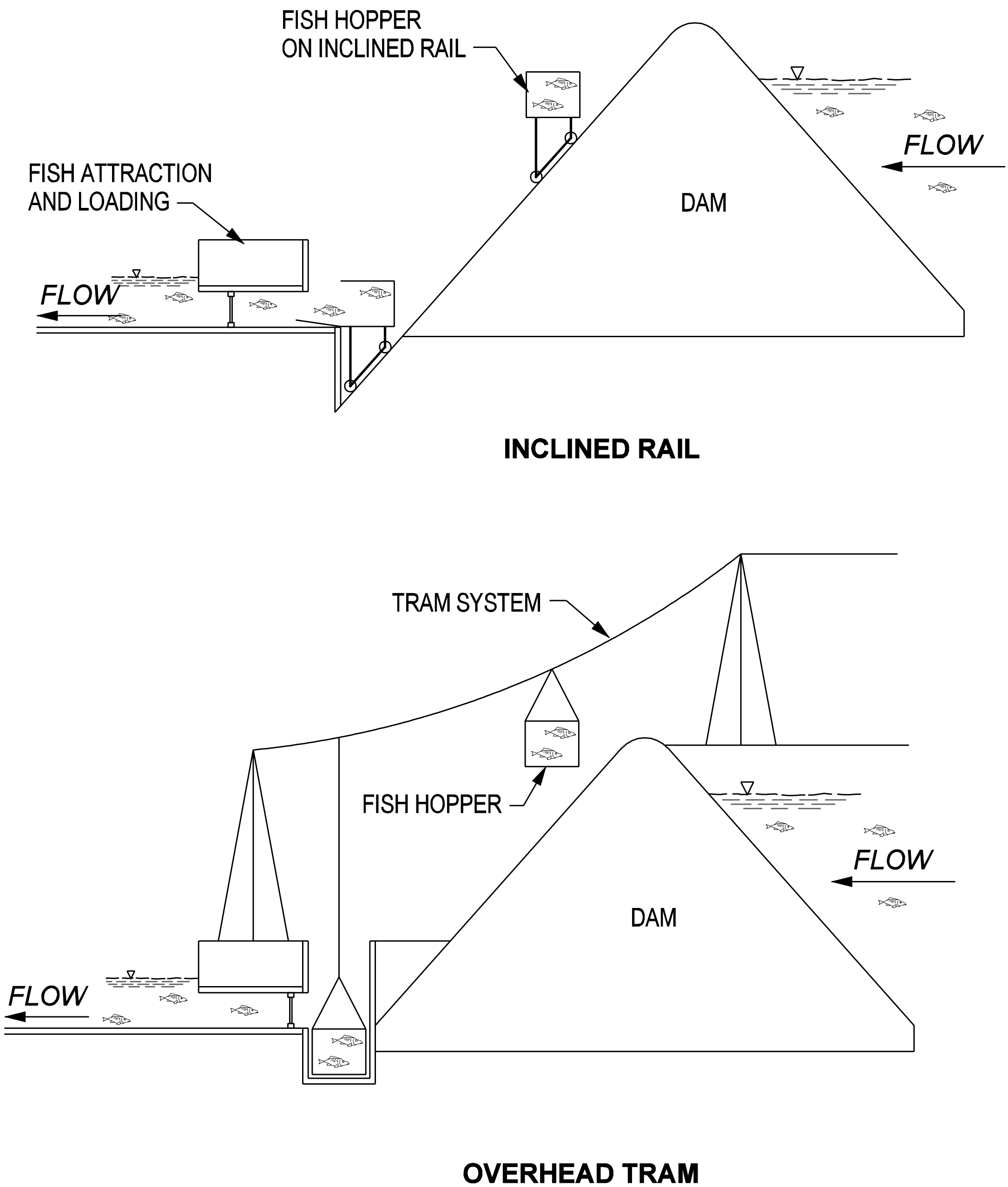

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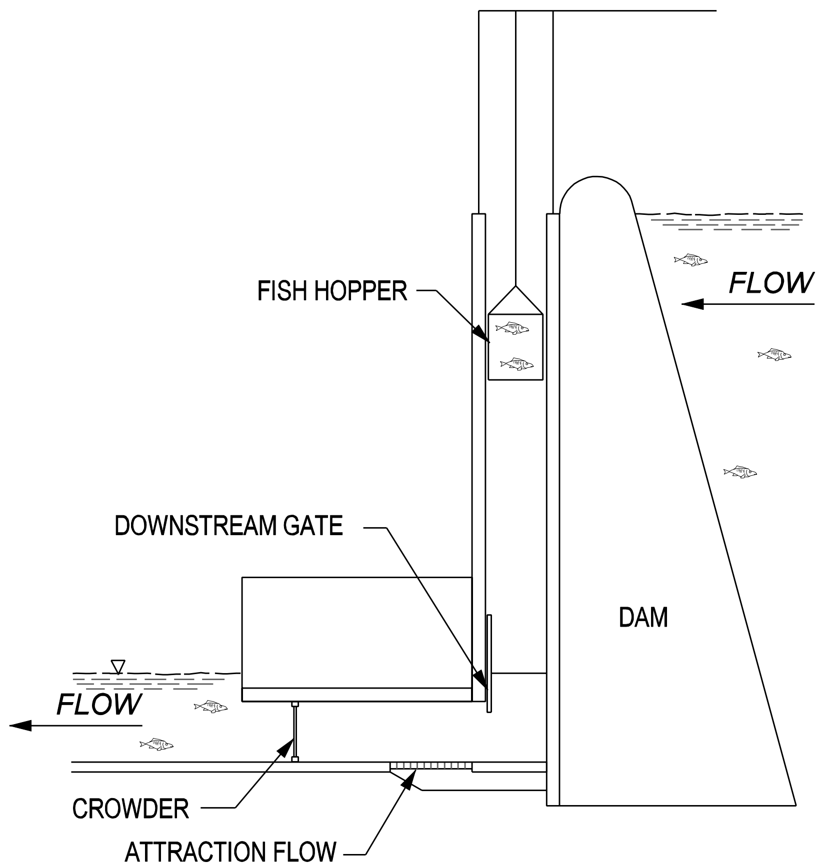
BC HYDRO AND POWER AUTHORITY

FISH PASSAGE AT DAMS

INCLINED RAIL AND OVERHEAD TRAM FISH LIFTS

FIG. 3.3

CAD FILE ; BCHP10 / BCHP10FIGS.DGN / 2001 MAR 23



VERTICAL SHAFT

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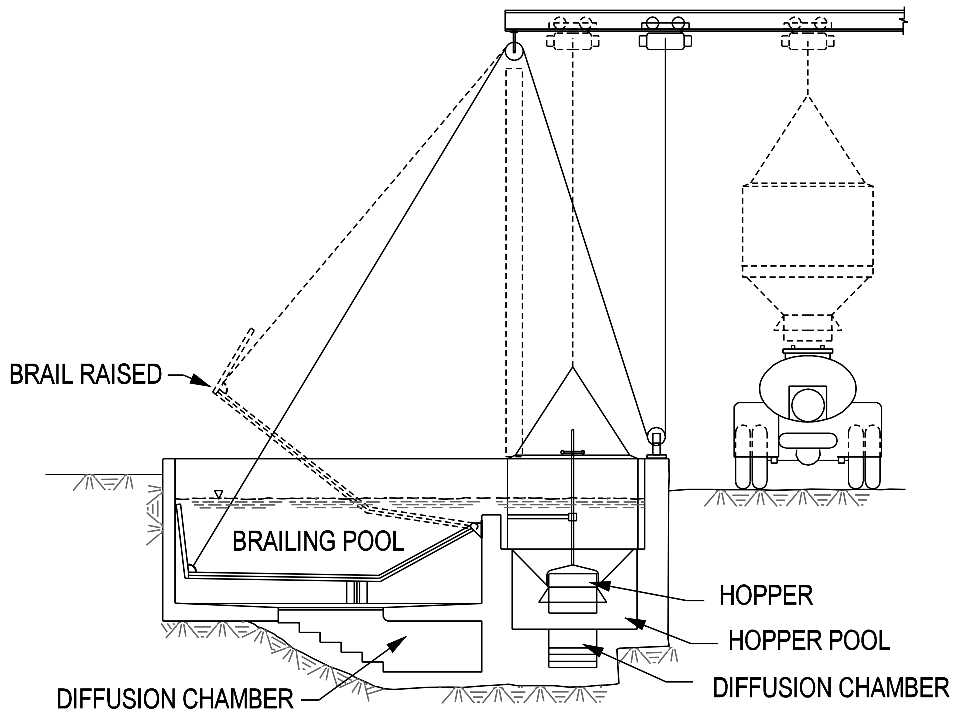
BC HYDRO AND POWER AUTHORITY

FISH PASSAGE AT DAMS

FISH LIFT

FIG. 3.4

CAD FILE ; BCHP10 / BCHP10FIGS.DGN / 2001 MAR 23



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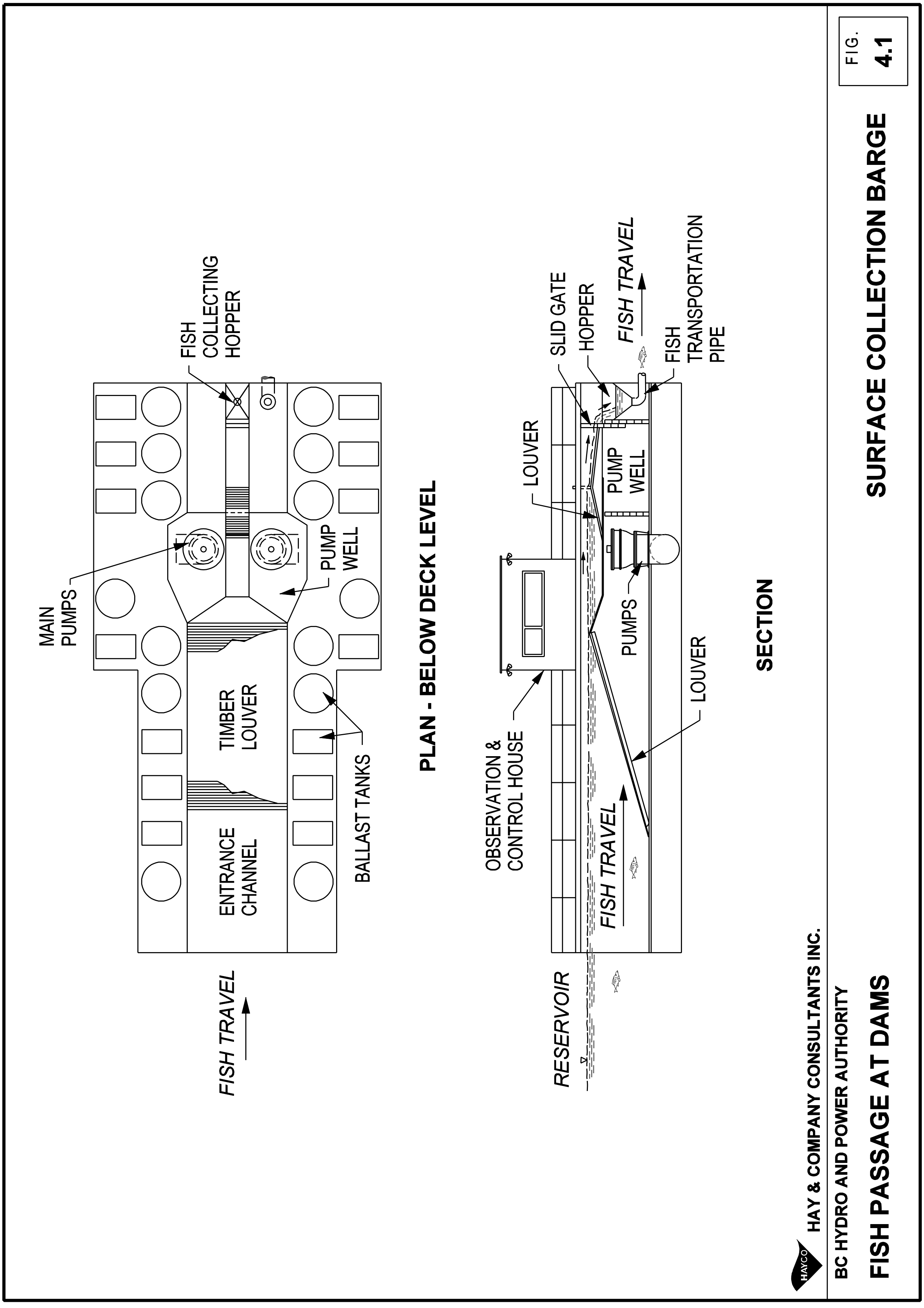
BC HYDRO AND POWER AUTHORITY

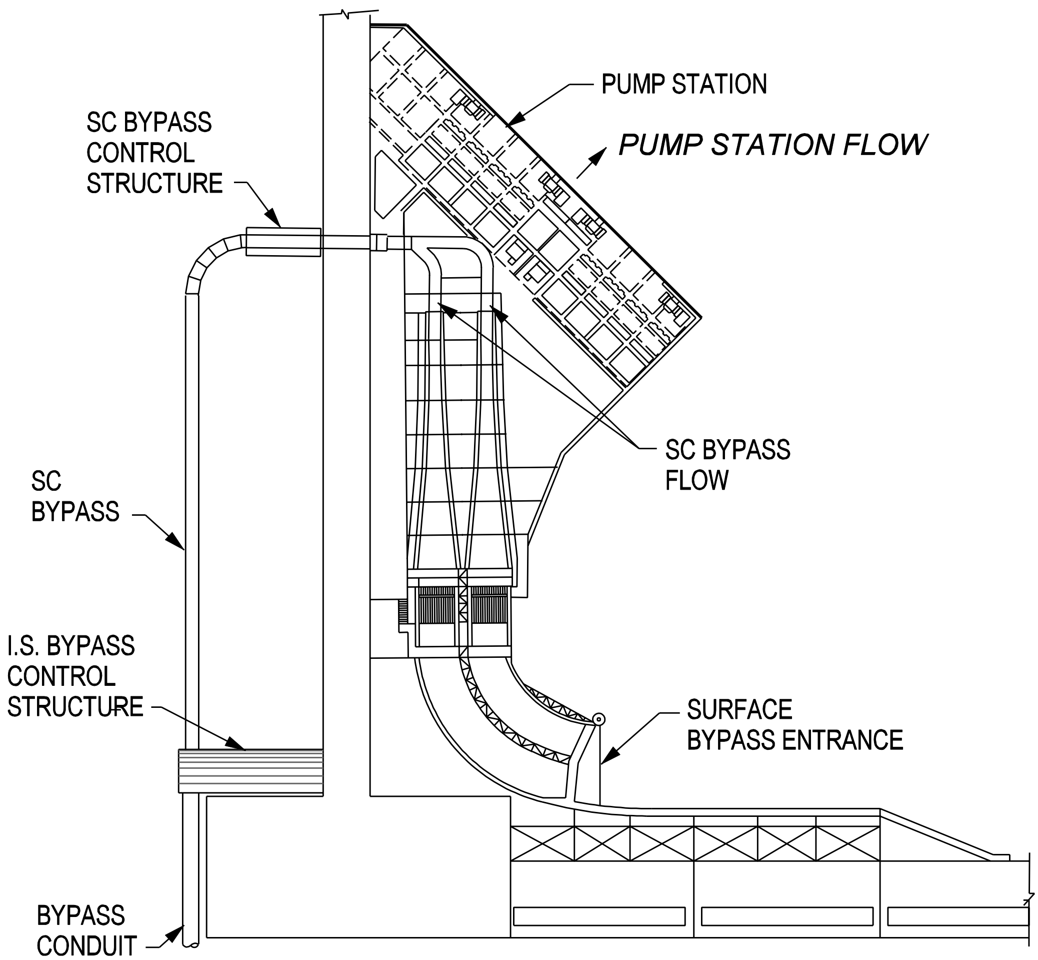
FISH PASSAGE AT DAMS

TRAP AND HAUL

FIG. **3.5**

CAD FILE ; BCHP10 / BCHP10FIGS.DGN / 2001 MAR 23


FISH COLLECTING HOPPER
MAIN PUMPS
PUMP WELL
TIMBER LOUVER
BALLAST TANKS
ENTRANCE CHANNEL
FISH TRAVEL
PLAN - BELOW DECK LEVEL
SLID GATE
HOPPER
FISH TRAVEL
FISH TRANSPORTATION PIPE
LOUVER
PUMP WELL
PUMPS
LOUVER
OBSERVATION & CONTROL HOUSE
FISH TRAVEL
RESERVOIR
SECTION
HAY & COMPANY CONSULTANTS INC.
BC HYDRO AND POWER AUTHORITY
FISH PASSAGE AT DAMS
SURFACE COLLECTION BARGE
FIG. 4.1
CAD FILE ; BCHP10 / BCHP10FIGS.DGN / 2001 MAR 23



PLAN

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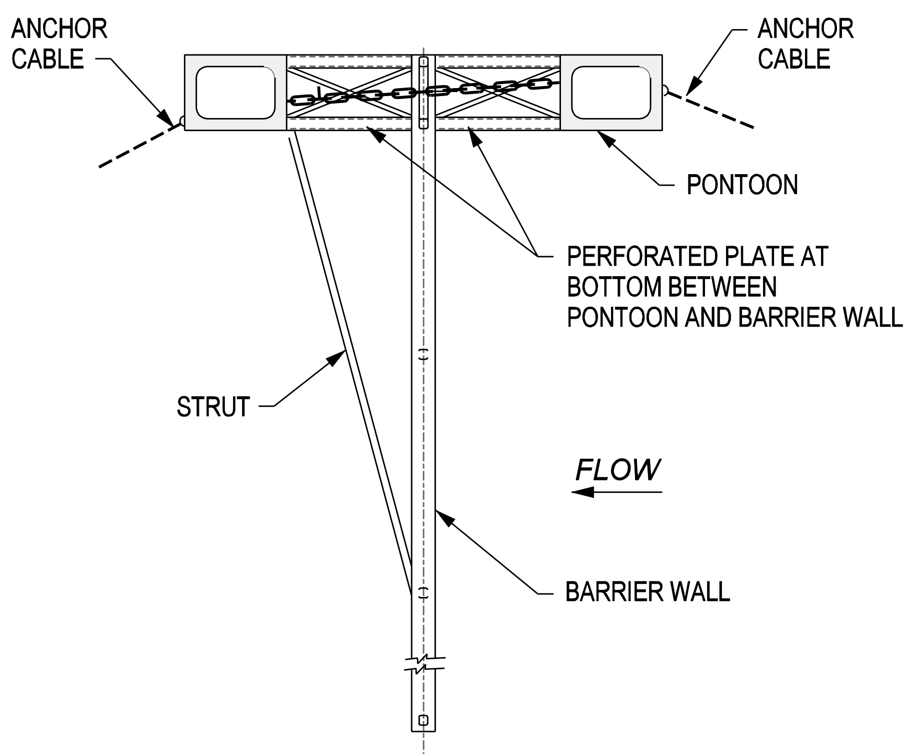
BC HYDRO AND POWER AUTHORITY

FISH PASSAGE AT DAMS

SURFACE COLLECTION BYPASS

FIG. 4.2

CAD FILE ; BCHP10 / BCHP10FIGS.DGN / 2001 MAR 23



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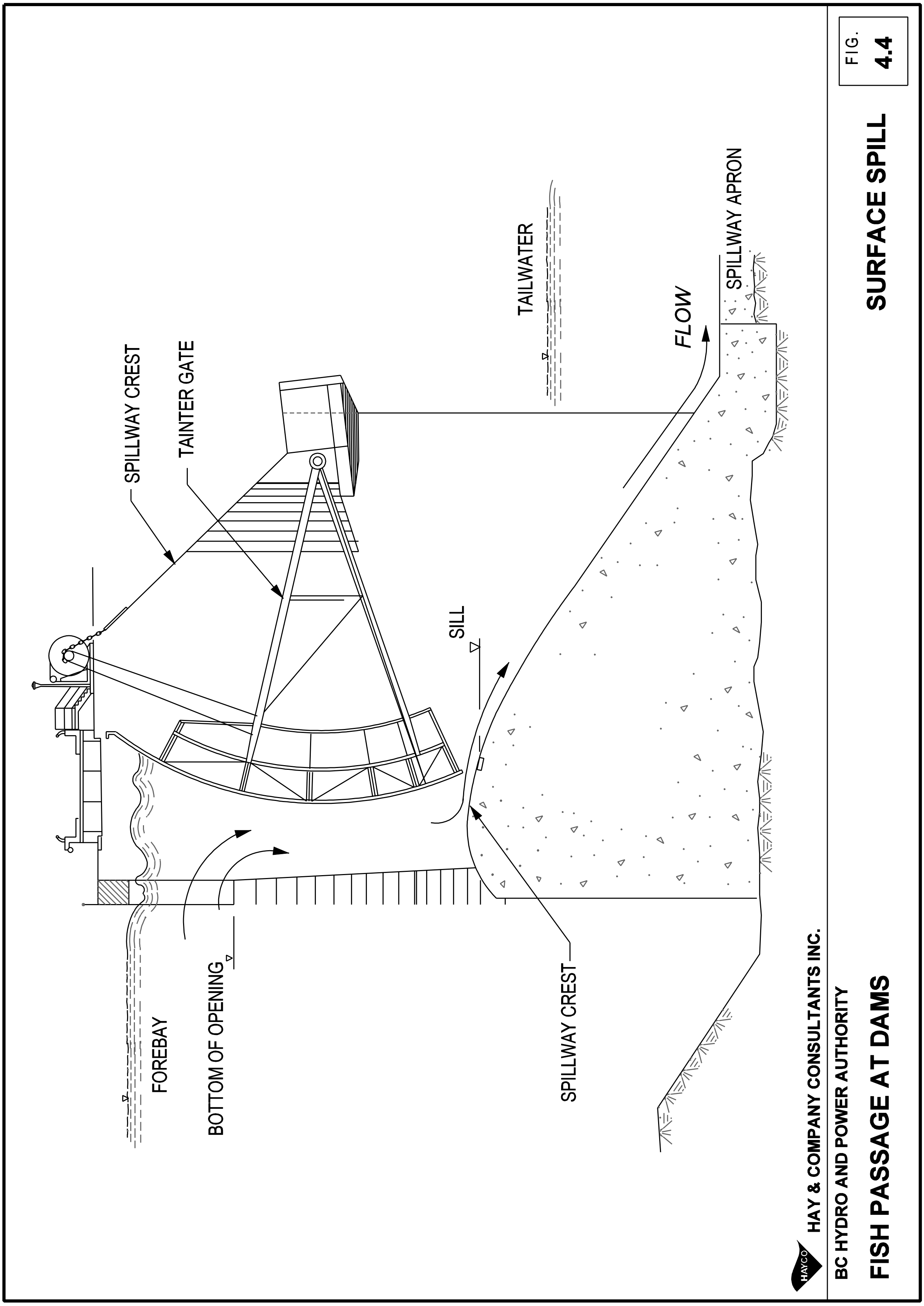
BC HYDRO AND POWER AUTHORITY

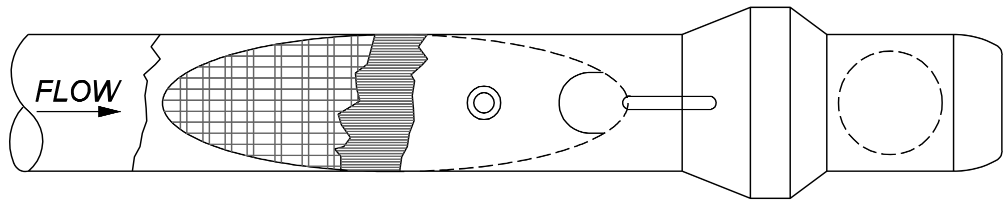
FISH PASSAGE AT DAMS

FISH GUIDANCE STRUCTURE

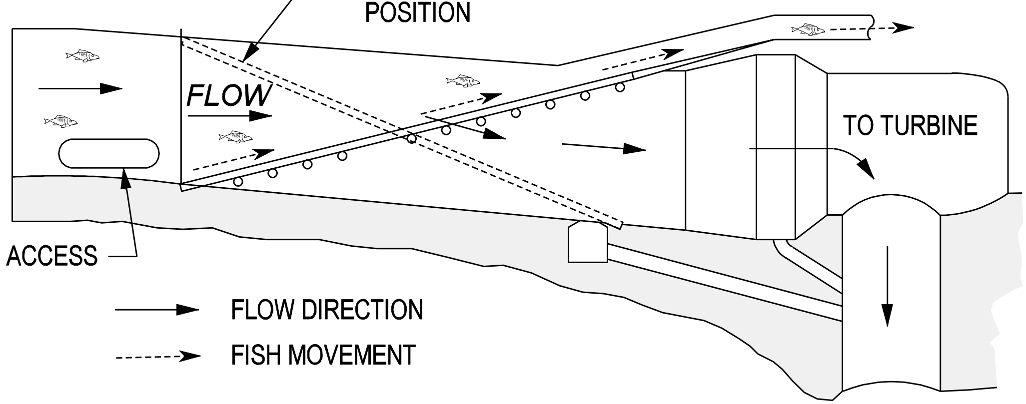
FIG. 4.3

CAD FILE ; BCHP10 / BCHP10FIGS.DGN / 2001 MAR 23


SPILLWAY CREST
TAINTER GATE
TAILWATER
SPILLWAY APRON
FLOW
SILL
FOREBAY
BOTTOM OF OPENING
SPILLWAY CREST
HAYCO
HAY & COMPANY CONSULTANTS INC.
BC HYDRO AND POWER AUTHORITY
FISH PASSAGE AT DAMS
SURFACE SPILL
FIG.
4.4
CAD FILE ; BCHP10 / BCHP10FIGS.DGN / 2001 MAR 23



TOP VIEW



SECTIONAL VIEW

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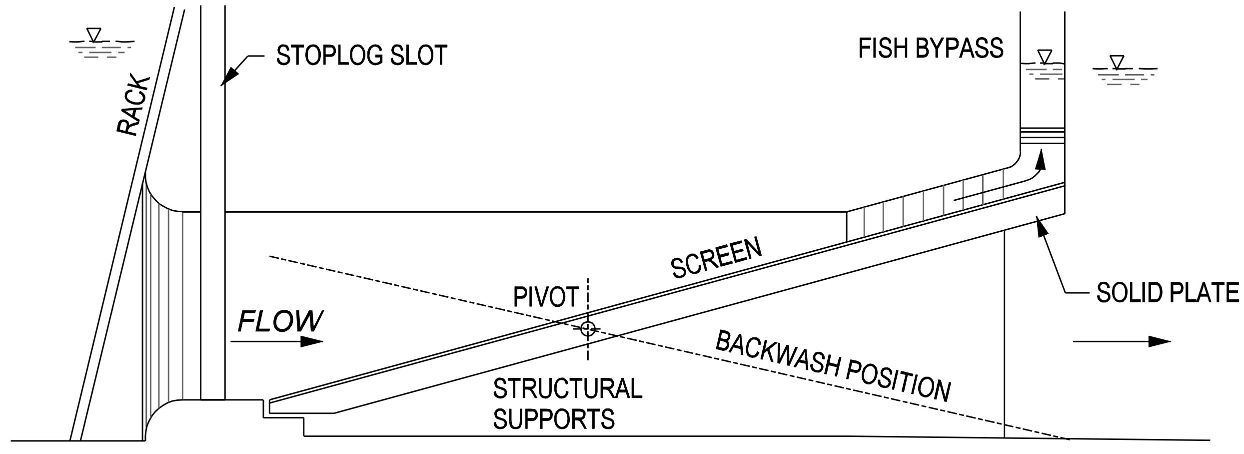
BC HYDRO AND POWER AUTHORITY

FISH PASSAGE AT DAMS

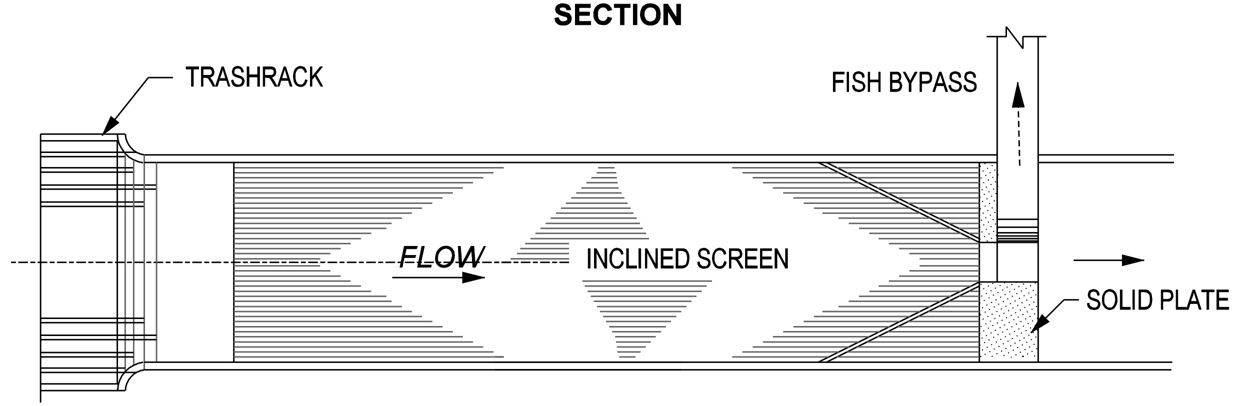
EICHER SCREEN

FIG. 4.5

CAD FILE ; BCHP10 / BCHP10FIGS.DGN / 2001 MAR 23



SECTION



PLAN

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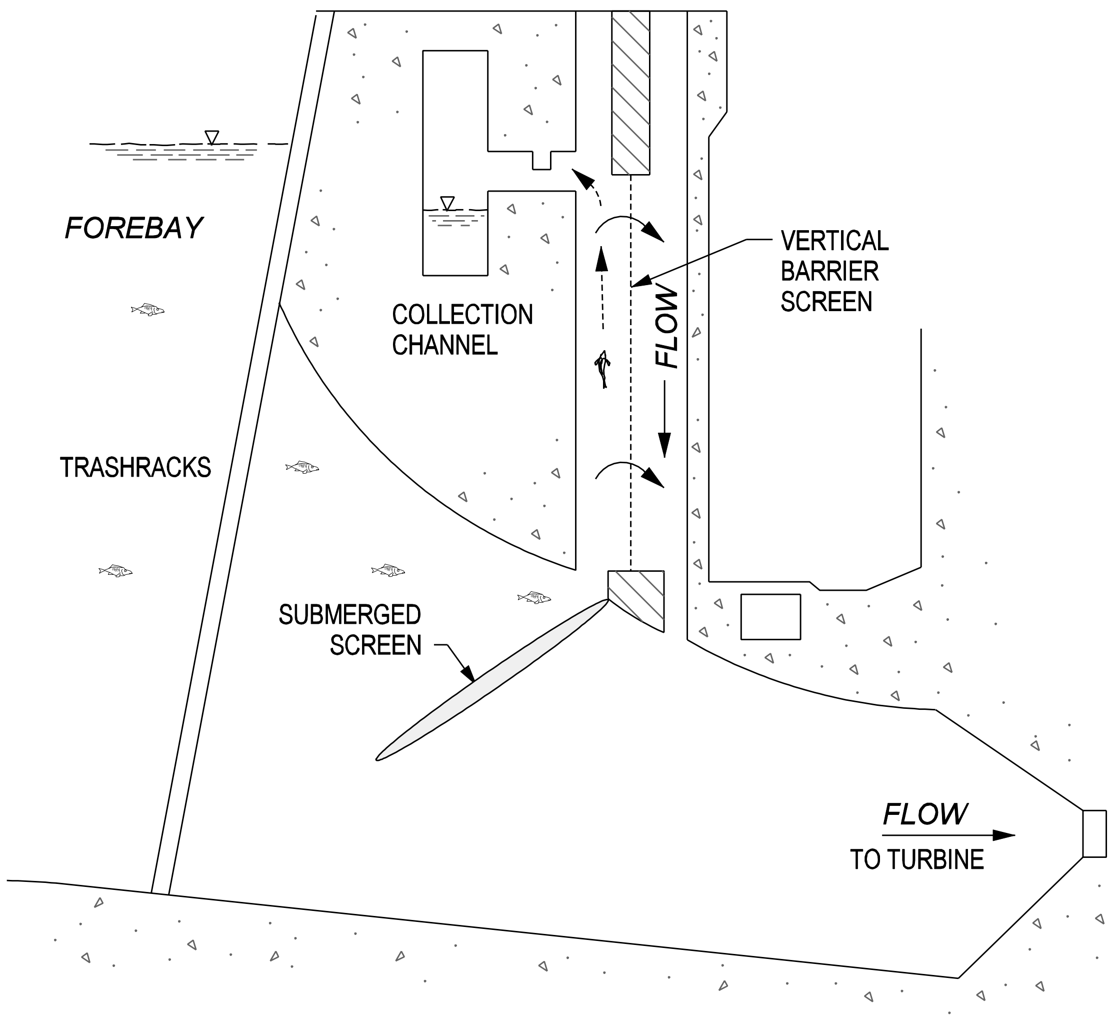
BC HYDRO AND POWER AUTHORITY

FISH PASSAGE AT DAMS

MODULAR INCLINED SCREEN

FIG. 4.6

CAD FILE ; BCHP10 / BCHP10FIGS.DGN / 2001 MAR 23



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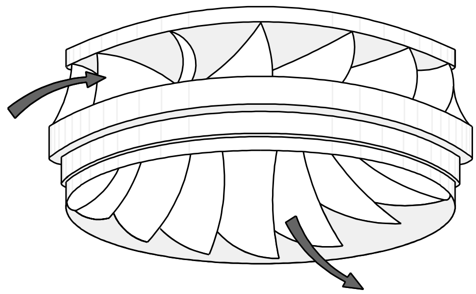
BC HYDRO AND POWER AUTHORITY

FISH PASSAGE AT DAMS

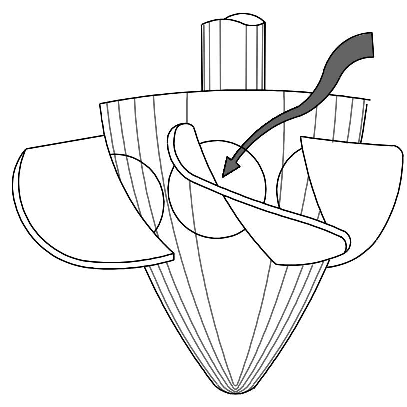
INTAKE SCREEN

FIG. 4.7

CAD FILE ; BCHP10 / BCHP10FIGS.DGN / 2001 MAR 23



FRANCIS



KAPLAN

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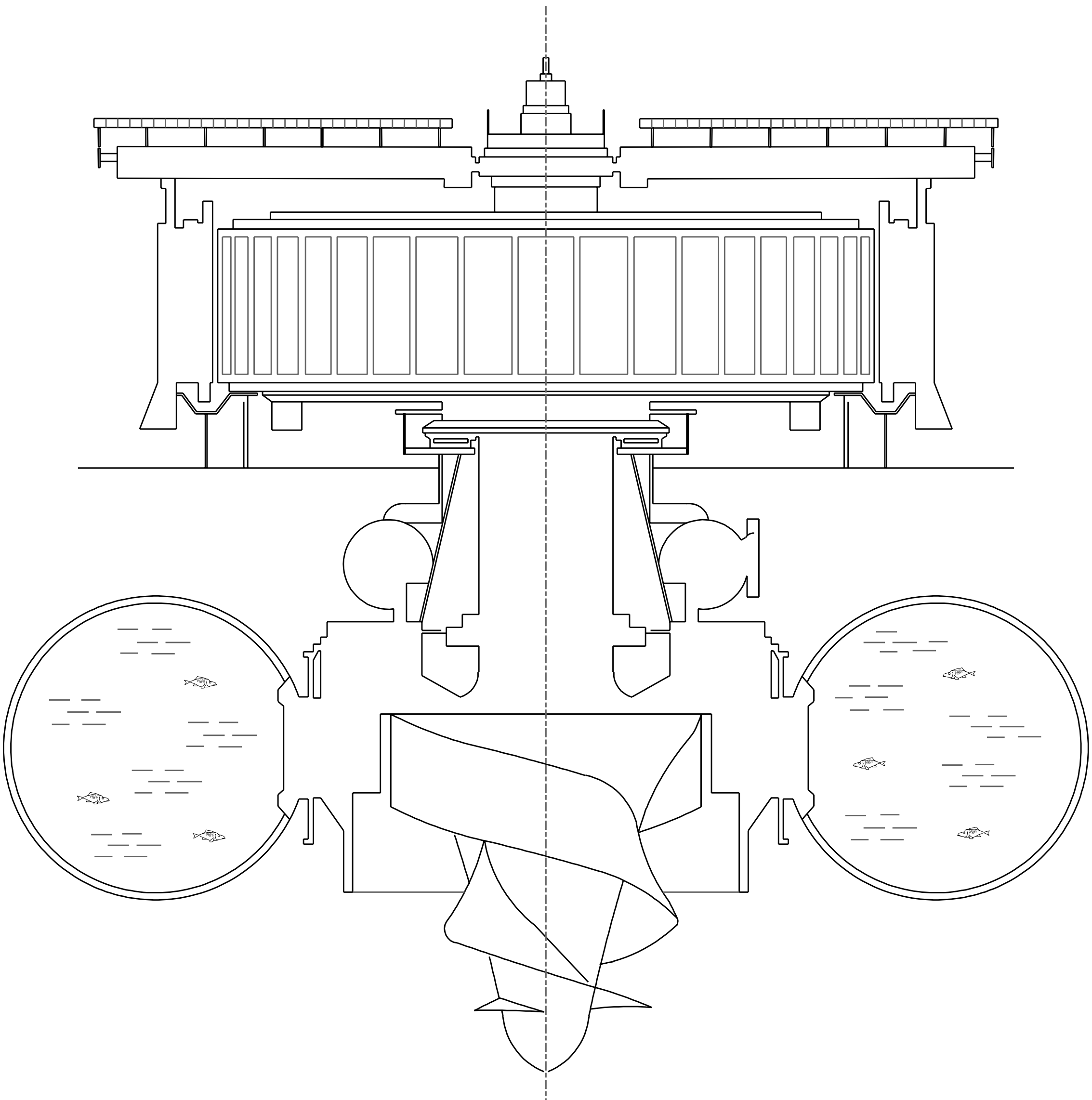
BC HYDRO AND POWER AUTHORITY

FISH PASSAGE AT DAMS

FRANCIS AND KAPLAN TURBINES

FIG. 4.8

CAD FILE ; BCHP10 / BCHP10FIGS.DGN / 2001 MAR 23



ARL / NREC FISH FRIENDLY HYDROTURBINE

HAY & COMPANY CONSULTANTS INC.

BC HYDRO AND POWER AUTHORITY

FISH PASSAGE AT DAMS

ARL / NREC FRIENDLY HYDROTURBINE

FIG. 4.9

CAD FILE ; BCHP10 / BCHP10FIGS.DGN / 2001 MAR 23

Fish Passage Decision Framework for BC Hydro Facilities

Purpose - To establish a process which will determine how BC Hydro will address fish passage issues at BC Hydro facilities.

Background - The development of some of the BC Hydro dams in certain coastal rivers resulted in a blockage to migratory fish. The result often meant the elimination or the reduction of specific salmon runs in the rivers. Proposals for fish passage have been initiated by public and First Nation groups, with Fisheries Agencies support, on several of the coastal BC Hydro facilities. The rationale for fish passage is to re-establish selected species of fish to the portions of the watershed they historically utilized.

BC Hydro Statement of Strategic Intent - BC Hydro's long term goal, stewardship ethic and environmental policy establish the commitment to minimizing our impacts, and where possible, restoring the environment. The *Fish Passage Decision Framework* will ensure that fish passage decisions are based on a Triple Bottom Line approach, with sound defensible criteria.

Fish Passage Decision Framework for BC Hydro Facilities

The construction of several of BC Hydro hydro-electric facilities resulted in a blockage to fish that previously used the portion of the watershed above the dam. Fish passage is required to re-establish selected species of fish to portions of the watershed that they historically utilized. There have been several fish passage proposals, involving the construction of fish ladders at hydro-electric facilities.

The Compensation Programs were established by BC Hydro as a mechanism to help address footprint impacts. The Compensation Programs finance technically sound proposals to restore habitat in the watersheds impacted by the hydro-electric facilities.

While the blockage of fish passage is defined as a footprint impact, there is insufficient funding in the Compensation Programs to take on the expensive proposals. As a result, BC Hydro is proposing the establishment of a formalized approach to help analyze the issue and to ultimately make decisions to address fish passage at the BC Hydro level. The following "Decision Framework" provides a formalized approach aimed at ensuring Triple Bottom Line (TBL) decision making and is applied to fish passage proposals.

Fish passage proposals to date have only involved salmon species. Resident species may be considered at a future date or as required under regulatory requirements such as the Species at Risk Act or recovery planning initiatives.

<u>Compensation Program Role</u>:

Step 1 - Preliminary Screening

To determine whether a fish passage proposal for a specific watershed addresses a footprint impact, the following screening question will be asked:

> *"Did the facility block passage of a fish stock at the time of construction?"*

Proposals that satisfy this condition will proceed to Step 2.

Step 2 – Stakeholder and FN Engagement - Strategic Watershed Prioritization

Each of the Compensation Programs has strategic plans (BCRP Strategic Watershed Plans; PWFWCP Strategic Implementation Plans; CBFWCP Dam Impact Assessments). These are developed in consultation with the Compensation Program infrastructure (Board, Planning Committee, Steering Committee, and Technical Committees), BC Hydro, First Nations, DFO, MOE, and other stakeholders through a series of consensus building workshops. The planning process establishes priority restoration opportunities for each watershed.

Fish passage opportunities are ranked by the strategic planning processes. Ranking is based on Provincial and Federal agency species objectives and on preliminary biological and technical feasibility criteria.

Step 3 - Environmental Feasibility Studies

In order to assess the potential for success for a fish passage proposal, initial environmental feasibility studies must be undertaken. The Compensation Program will fund the studies at their discretion and consistent with their mandate. The environmental feasibility of each fish passage proposal must include the following assessments:

- Target species are available in the watershed in sufficient numbers to support rebuilding a sustainable population. If the target species is not available and a donor stock transplant is proposed, a thorough risk assessment related to suitability of the donor stock and impact on the donor stock must be undertaken.

- Potential ecological and disease impacts to native species.
- Existence of high quality spawning and rearing habitat below the dam.
- Other physical impediments downstream that may restrict fish migration to the dam.
- Sufficient spawning and rearing habitat above the barrier to support the target fish population numbers established in the Watershed Plan, or the known potential to restore sufficient habitat. Feasibility studies must be undertaken to assess this potential.

The results from the environmental feasibility studies will be provided to the Fisheries Agencies (DFO & MOE) for decision in circumstances requiring their approval. Once the analysis indicates the fish passage proposal meets the above criteria and is supported by the Fisheries Agencies as a high priority, the proposal will be reviewed by the Program's Technical Committee and recommendations will be forwarded to the Compensation Program management structure.

Step 4 – Preliminary Technical Feasibility Consideration

If infrastructure is part of the proposal, an inquiry should be made to BCH Engineering about the feasibility of the fish passage. At this stage, the technical feasibility assessment will be undertaken by BC Hydro at a cursory level only. More detailed analysis and assessment will be carried out in step 6 if determined appropriate.

Step 5 – Compensation Program Endorsement

Based on the priority ratings and the completion of the required process, the Compensation Programs will recommend BC Hydro consider the proposal.

<u>BC Hydro Role</u>:

Step 6 – TBL Driven Business Case Development

The Triple Bottom Line (TBL) decision making approach will follow a structured approach to explicitly integrate environmental, social and financial objectives. The process will provide a rating from high to low for fish passage proposals.

(a) Environmental Assessment: in consultation with the Compensation Programs and Technical Committee, BC Hydro will further assess the environmental feasibility if required.

(b) Financial/Technical Assessment: options to provide fish passage will be analyzed to ensure technical feasibility for the proposed river system.

- Dam structure integrity must be maintained; therefore designs for upstream and downstream passage facilities must undergo an engineering review.
- The fish passage proposal must be able to operate within the current Water Use Plan (WUP) operating parameters for the facility. If not, the proposal will be deferred until the scheduled WUP review takes place.
- Designs and costs for additional structures, such as screens to reduce potential juvenile migrant fish mortality, must be considered.

(c) Social Benefits Assessment – fish passage at the proposed site will be considered with respect to added societal value. Considerations may include:

- Intrinsic values – there is demonstrated evidence that the intrinsic value of the watershed will be positively impacted by the proposal (i.e. improved ecosystem biodiversity).
- Cultural – First Nation have identified the importance of returning fish providing food, ceremonial, spiritual values.
- Socio-economic – there is demonstrated evidence that there will be an increase in tourism, recreation, jobs and / or a new or enhanced fishery

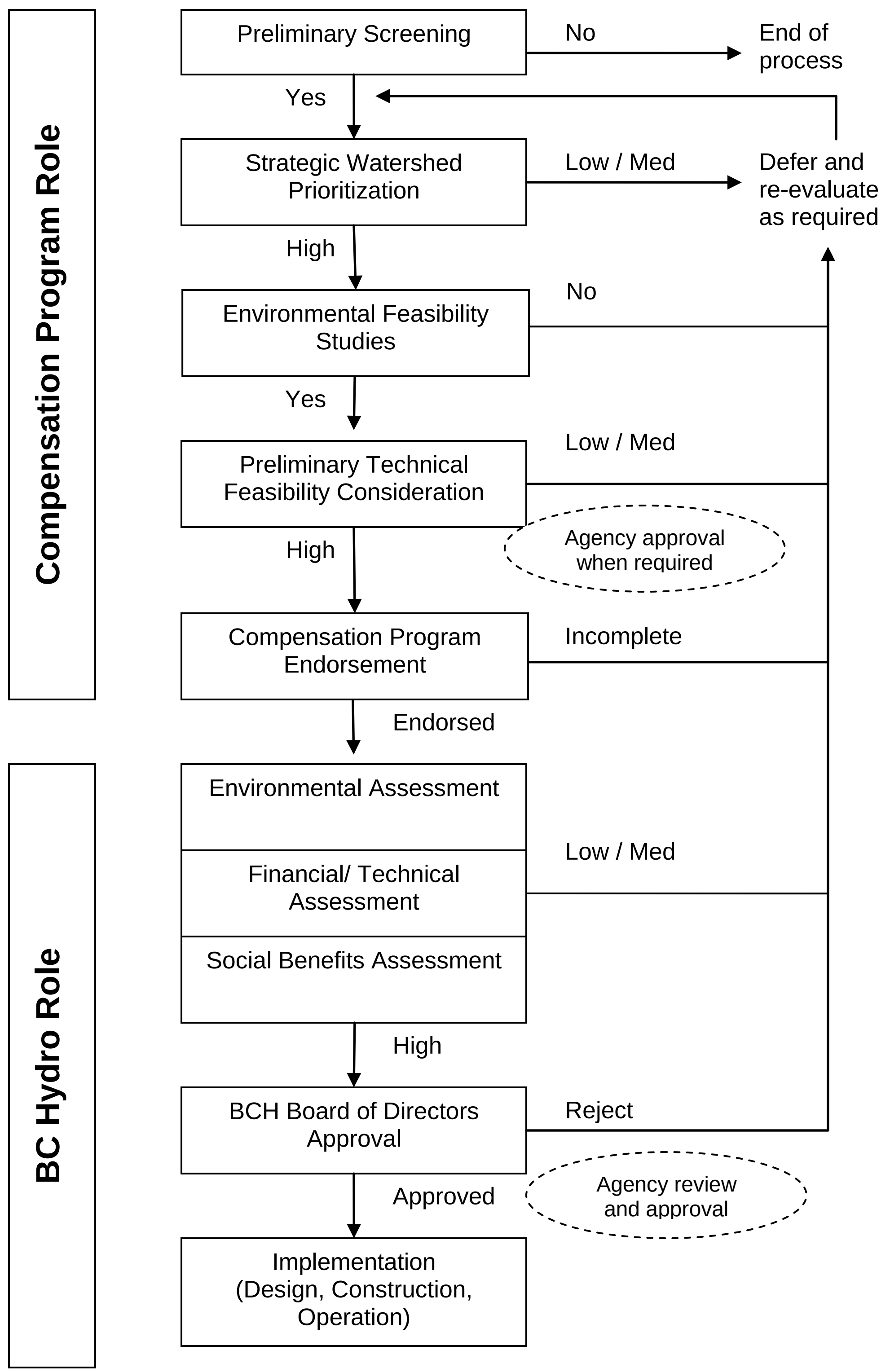
The proposal will move to step 7 if the evaluation of the above indicates it has a high potential for success.

Step 7 –BCH Board of Directors Approval

The proposed fish passage project will need to be evaluated with respect to BC Hydro's economic and business practices and must fit within BC Hydro's long term capital plan. The business case may include a detailed trade-off analysis and will include a detailed design.

If accepted by the BC Hydro Board of Directors, BC Hydro will be responsible for the management of design and construction of the passage facility. Regulatory Agency review and approval will be required. BC Hydro will be responsible for ongoing operation and maintenance of the passage facility.

Fish Passage Decision Framework for BC Hydro Facilities



30.0 Reference: Dam Safety-Ruskin Dam
Exhibit B-7, BCUC 1.93.1, Attachment 4, p. 324
Spillway Shotcrete Assessment

2.30.1 Please state which of the 7 Options was chosen by BC Hydro for Implementation or describe where the preferred Option can be found in the Application.

RESPONSE:

Option 5 was selected as the preferred option. The spillway shotcrete work is described in Exhibit B-1, Table 2-1 (Spillway Resurfacing) and Appendix H-1, page 135 of 345.

30.0 Reference: Dam Safety-Ruskin Dam
Exhibit B-7, BCUC 1.93.1, Attachment 4, p. 324
Spillway Shotcrete Assessment

2.30.1.1 Please reference where the direct and fully loaded costs are stated in the Application or provide same.

RESPONSE:

Table 2-1 of Exhibit B-1 confirms that the Spillway face work is part of the overall Upper Dam Work. BC Hydro confirms that the costs of the Spillway face work are included in Table 2-4 of Exhibit B-1. The breakdown of Table 2-4 cost estimates (Expected and Authorized Amounts) is set out in Exhibit B-7-1, BC Hydro's Confidential response to BCUC IR 1.40.1 under the line captioned "Spillway Resurfacing".

31.0 Reference: Manual Gate Operation
Exhibit B-7, BCUC 1.70.2
Exhibit B-7, BCUC 1.93.1, Attachment 4, page 73 of 406

"The existing gates are radial type (tainter) gates which are actuated by a sprocket/chain system. The gates were originally designed to be opened by a mobile cart which was rolled into place on the road deck and attached to the sprocket/chain drive system. Approximately ten years ago permanent hoist motors and gearboxes were installed for each gate under the road. These motors are at risk of being submerged during major flood events." (Exhibit B-7, BCUC 1.93.1, Attachment 4, page 73 of 406)

2.31.1 Is it possible to open the gates using a mobile system similar to the original if the existing motors become inoperable?

RESPONSE:

Yes, this might be possible. A new mobile system would need to be designed and an assessment made of the existence and condition of the gear box input stems. Such a system, even if viable, would solve only one of many problems with the existing gates and hoists that will be addressed by the Upper Dam Work.

31.0 Reference: Manual Gate Operation
Exhibit B-7, BCUC 1.70.2
Exhibit B-7, BCUC 1.93.1, Attachment 4, page 73 of 406

"The existing gates are radial type (tainter) gates which are actuated by a sprocket/chain system. The gates were originally designed to be opened by a mobile cart which was rolled into place on the road deck and attached to the sprocket/chain drive system. Approximately ten years ago permanent hoist motors and gearboxes were installed for each gate under the road. These motors are at risk of being submerged during major flood events." (Exhibit B-7, BCUC 1.93.1, Attachment 4, page 73 of 406)

2.31.1.1 Is it possible to drive the gears with a portable drill motor or could this feature be added?

RESPONSE:

The rationale for the Spillway Gate work is to improve the existing spillway gate structure to meet the MDE, which is the seismic criterion that the B.C. Comptroller of Water Rights (CWR) expects through the Dam Safety Regulation which results from the Very High Consequence category for the Ruskin Facility. Meeting the MDE requires more than the improvement of the mechanical systems that operate the spillway gates.

It might be possible to drive the gears with a portable drill motor provided an associated gear box feeding into the existing gate hoist mechanism could be designed and built.

32.0 Reference: Incremental Energy
Exhibit B-1, Section 3.4.2,
Powerhouse Two versus Three Unit Configuration, p. 3-48
Exhibit B-7, BCUC 1.2.1, Attachment 1, page 28 of 44

"The annual energy is higher by 18.6 GWh in the three-unit alternative, and the value of energy is higher by $3.6 million using the TDF firm energy price from the Clean Power Call."

"The optimized load duration curves for Ruskin show that the plant is operating with three units for about 6% of the time (Figure 3). Generation from the third unit is in the order of 10 GW.h per annum with a value in the order of $0.5 million."

2.32.1 Please provide the analysis which quantifies that the total and incremental annual average energy from the third unit.

RESPONSE:

The Ruskin Facility is a part of the Stave River System consisting of three cascading, connected generating facilities. Being a part of a larger system, the Ruskin Facility is not operated in isolation. It is operated to allow the optimal power generation for the entire system.

BC Hydro modelled the operation of the Stave River System with 2- and 3-unit Ruskin Facility scenarios. As stated in Exhibit B-1, page 3-48, the expected average energy generation from the entire Stave River System with a two-unit Ruskin Facility is 736.7 GWh/year, while the expected average energy generation of the entire Stave River System with a three unit Ruskin Facility is 755.3 GWh/year. The expected incremental energy from Ruskin Facility Unit 3 (U3) is 18.6 GWh/year. This is the amount of U3 incremental energy used for justifying U3.

The data presented in Exhibit B-7, BCUC IR 1.2.1, Attachment 1, page 28 of 44, which indicates incremental U3 energy of 10 GWh per annum predates the analysis presented in Exhibit B-1, page 3-48.

32.0 Reference: Incremental Energy
Exhibit B-1, Section 3.4.2,
Powerhouse Two versus Three Unit Configuration, p. 3-48
Exhibit B-7, BCUC 1.2.1, Attachment 1, page 28 of 44

"The annual energy is higher by 18.6 GWh in the three-unit alternative, and the value of energy is higher by $3.6 million using the TDF firm energy price from the Clean Power Call."

"The optimized load duration curves for Ruskin show that the plant is operating with three units for about 6% of the time (Figure 3). Generation from the third unit is in the order of 10 GW.h per annum with a value in the order of $0.5 million."

2.32.2 Please provide the annual amount of firm energy and non-firm energy associated with the third unit.

RESPONSE:

BC Hydro Firm Energy Load Carrying Capability analysis is calculated across the entire BC Hydro system and is analysed at the plant level. The firm energy contribution of U3 is prorated based upon its average energy contribution. The contribution of U3 to firm energy is 88 per cent of its incremental contribution to average energy. The U3 contribution to firm energy is 16.4 GWh (= 0.88 * 18.6).

Please refer to BC Hydro's response to BCUC IR 2.32.1 for details on U3 incremental energy contribution and to Exhibit B-1, page 1-1, footnote 3; section 2.1.3; and page 3-48, footnote 41 for details on the percentage of firm vs. average energy of the Ruskin Facility.

33.0 Reference: Project Costs
Exhibit B-1, Chapter 3, Section 3.4.2
Powerhouse – Two versus Three Unit Configuration;
Table 3-12

"The annual energy is higher by 18.6 GWh in the three-unit alternative, and the value of energy is higher by $3.6 million…" and

"Due to the need for flow continuity at the Ruskin Facility, the consequences of a coincident outage in a two unit facility would likely be a spill…"

2.33.1 BC Hydro explains that the incremental cost for installing the third turbine and generator at the completion date is $41.7 million compared to $52.4 million for the two unit alternative. Please advise whether both estimates include all loadings. If not, recalculate Table 3-12 showing the NPV of the benefit of the three versus the two unit alternative including loadings.

RESPONSE:

BC Hydro notes an error in Table 3-12 of Exhibit B-1: the line captioned "NPV (Two Unit Alternative)" is the NPV of the value of the incremental energy available from a three-unit Powerhouse compared to that from a two-unit Powerhouse over a fifty year term, assuming that the energy value is flat in real terms. The value shown is not related to the cost or incremental cost to install either two or three units in the Powerhouse.

The amount of $41.7 million shown in Table 3-12 of Exhibit B-1 as the incremental cost of installing the third unit is stated in 2010$ and as set out at page 3-45, lines 22 to 24, of Exhibit B-1 includes the time-value of money to the in service date, assuming that all costs are incurred at the beginning of the installation period for the third unit. In fact, since costs will be incurred during the installation period this value slightly overstates the IDC cost to the in service date. Loading for Capital Overhead is not applied to these costs: at an overhead rate of 16.41 per cent this loading would be $6.85 million. Including the Capital Overhead loading as a part of the incremental capital cost of installing the third unit would reduce the NPV of the decision to install a third unit by that amount, or from $10.7 million to $3.8 million. BC Hydro reiterates the irrelevance of loaded cost figures in evaluating projects or project alternatives.

33.0 Reference: Project Costs
Exhibit B-1, Chapter 3, Section 3.4.2
Powerhouse – Two versus Three Unit Configuration;
Table 3-12

"The annual energy is higher by 18.6 GWh in the three-unit alternative, and the value of energy is higher by $3.6 million…" and

"Due to the need for flow continuity at the Ruskin Facility, the consequences of a coincident outage in a two unit facility would likely be a spill…"

2.33.2 Please define what BC Hydro considers to be incremental costs.

RESPONSE:

An incremental cost is one that would not be incurred in the absence of a particular decision or course of action. If a decision or action both incurs costs and allows savings or avoids other costs, the incremental cost is the cost net of the savings or avoided costs.

33.0 Reference: Project Costs
Exhibit B-1, Chapter 3, Section 3.4.2
Powerhouse – Two versus Three Unit Configuration; Table 3-12

"The annual energy is higher by 18.6 GWh in the three-unit alternative, and the value of energy is higher by $3.6 million…" and

"Due to the need for flow continuity at the Ruskin Facility, the consequences of a coincident outage in a two unit facility would likely be a spill…"

2.33.3 Please provide a table of the direct and fully loaded costs to supply and install the following items associated with the third unit: Intake entry modifications, operating gate, stop-logs and hoists; penstock and tunnel rehabilitation; new generator and runner; NDT of reused parts; turbine overhaul (embedded parts, new wicket gates and rehabilitation of bushings etc); static exciter; digital governor; cooling water system; protection and controls; draft tube repairs, stoplogs/bulkheads and monorail extension; unit and transformer fire protection; raw water, unit transformer and oil spill containment; unit circuit breaker and LV bus; 60 kV cable connection to switchyard; avoided larger size of switchyard and associated First Nations accommodation costs (if appropriate); and station service connections. Note the costs should be comparable to one third of the figures associated with the gensets as supplied in BC Hydro's Confidential response to BCUC 1.40.1 on p. 2 and since this IR is asking for an estimate, a response of "BC Hydro did not prepare an estimate" is not considered acceptable (please use the figures provided in the Application or supplied elsewhere in Exhibit B-7, BCUC IR 1 responses).

RESPONSE:

The requested information is provided as Confidential Attachment 1 to this IR response.

In accordance with section 42 of the ATA and the Confidential Practice Directive, BC Hydro respectfully requests that Attachment 1 to BC Hydro's response to BCUC IR 2.33.3 be kept confidential. Attachment 1 is filed in confidence because it contains commercially sensitive information, and in particular the anticipated cost of certain items of equipment and construction related to the supply and installation of turbines, generators and ancillary equipment, which will prejudice BC Hydro in its negotiations with contractors and suppliers and could result in a material financial loss to BC Hydro and its ratepayers. BC Hydro has consistently treated such information as confidential.

CONFIDENTIAL ATTACHMENT

FILED WITH BCUC ONLY

33.0 Reference: Project Costs
Exhibit B-1, Chapter 3, Section 3.4.2
Powerhouse – Two versus Three Unit Configuration;
Table 3-12

"The annual energy is higher by 18.6 GWh in the three-unit alternative, and the value of energy is higher by $3.6 million…" and

"Due to the need for flow continuity at the Ruskin Facility, the consequences of a coincident outage in a two unit facility would likely be a spill…"

2.33.3.1 Please identify which of the above costs BC Hydro considers as incremental costs in a separate column in the above table.

RESPONSE:

BC Hydro assumes that all of the costs shown in Confidential Attachment 1 to BC Hydro's response to BCUC IR 2.33.3 are incremental, up to the line labelled "Total Construction Cost Expected (Unloaded)" indicating a total cost of $43.19 million, including contingency. This cost is reflected in the calculation of the incremental cost and benefit of installing the third unit shown in Table 3-12 of Exhibit B-1 as follows:

	($ 000) (in 2010$)	
Cost to Install Unit 3 (BCUC IR 2.33.3)		43,188.9
Avoided costs to remove Unit 3 from Service (from B&V Alternative A)		
Isolate Unit 3	1,623.9	
Drain & Prep	103.9	
Remove Unit 3	871.6	
Backfill & Cap	367.0	
Total Avoided Costs		(2,966.4)
Incremental Cost to install Unit 3		40,222.5

As set out at lines 22 to 24 of page 3-45 of Exhibit B-1, BC Hydro made the assumption that all these costs are incurred when the third unit is taken out of service. To determine the cost to the Unit 3 In-Service Date (ISD), this cost is compounded at BC Hydro's real discount rate from the out of service date until the ISD, resulting in a cost of $41.7 million at ISD.

33.0 Reference: Project Costs
Exhibit B-1, Chapter 3, Section 3.4.2
Powerhouse – Two versus Three Unit Configuration; Table 3-12

"The annual energy is higher by 18.6 GWh in the three-unit alternative, and the value of energy is higher by $3.6 million…" and

"Due to the need for flow continuity at the Ruskin Facility, the consequences of a coincident outage in a two unit facility would likely be a spill…"

2.33.4 Please discuss the NPV merits of completing the entire powerhouse structural upgrades and opting not to perform any other third unit upgrades until the unit fails beyond repair. The discussion should recognize that spare components will be available from the two units that will be replaced and also consider that the third unit need only run during periods of spill (which should be less frequent due to the larger replacement units). The option of keeping the stator dry utilizing waste heat from an operating unit may merit further investigation to prolong the life of the winding.

RESPONSE:

As noted in Confidential Attachment 1 of BC Hydro's response to BCUC IR 2.33.3 the incremental cost of replacing U3 is $35.9 million (in 2010$) before contingencies.
BC Hydro assumes that in "opting not to perform any other third unit upgrades" they would still undertake the intake structure, draft tube, and tunnel rehabilitation included in that figure and required for safety and seismic withstand reasons. These items come to a cost of $9.65 million, before contingencies, and after IDC, the costs to the ISD the amount deferred would be:

	($ 000)
U3 Installation Cost (BCUC IR 2.33.3.3)	**43,189**
Intake, Draft Tube and Penstock	**(9,648)**
Contingency on above (20%)	**(1,930)**
Amount deferred	**31,611**
Value at ISD	**32,794**

Deferring this replacement would produce approximately $1.82 million in time-value of money savings for each year of the deferral, declining slightly over time. BC Hydro notes that the benefit of the third unit is not only in avoiding spill, but also includes energy shaping, so the third unit will be required to run more often than would be required if it was run only to meet high discharge requirements. Please refer to BC Hydro's response to CEABC IR 2.4.4 for details of the Ruskin Facility dispatch levels over the past

ten years, which indicated that all three units are frequently dispatched. As set out in Exhibit B-7-2, BC Hydro's response to CECBC IR 1.19.1, adding U3's dependable capacity allows BC Hydro to shape the output of the Ruskin Facility's clean and renewable electricity into periods when customers have the greatest need and during time of other system contingencies. There are few clean or renewable resources that have been offered to BC Hydro in recent power acquisition processes that have the ability to shape output. Please also refer to BC Hydro's response to BCUC IR 2.29.6.1 and in particular 4 c-d in that response.

It is reasonable to assume that most of these benefits (spill avoidance and energy shaping) can be captured either with the existing U3 or a new unit, although the benefits would be slightly higher with the new unit due to its higher efficiency. This assumption ignores the current condition of U3.

BC Hydro does not anticipate significant maintenance or reliability benefits from retention of components taken from the other two units. As set out in Exhibit B-7-2, BC Hydro's response to AMPC IR 1.5.2, the most likely failure mode for the three existing units is a generator stator failure. There is no means to remove the windings from the existing stators without damaging them to the point that they could not be placed back into service. As well, the stators and stator frames were not designed to be lifted, so it is not possible to rely on a stator kept intact from either of the existing units and held to replace the U3 stator after a failure.

Mechanical components in the U1 and U2 turbines and governors are worn after 70 years in service, and will be of limited value in repairing a mechanical failure. All exciters are in poor condition, but could be retained as spares and used to replace a failed exciter on U3.

Against the time-value of money savings, deferring the replacement of U3 would also incur costs. The most obvious cost is that a future replacement will require a second mobilization and demobilization for the installation. In addition, during the extended operating period maintenance costs for the existing U3 may be higher than anticipated for the new unit installed in the Project. The timing of the replacement, and therefore the market conditions and the supplier's order backlog at the time of that replacement, cannot be predicted. BC Hydro believes that this would make it impossible to contract for the replacement unit with the successful turbine/generator supplier for the revised Project scope (a two unit supply and install contract with an optional third unit) at an acceptable cost. Therefore, on replacement of U3 at some unspecified future date, BC Hydro will either bear the cost exposure to a single-source contract for a turbine/generator to match those installed under the reduced Project scope contemplated in this IR, or face the cost of multiple designs in a small three-unit powerhouse and the increase in future spares stocking and maintenance costs. In addition, BC Hydro will be required to procure a new turbine generator, associated ancillaries and completion work. The cost of this additional procurement process is about $0.5 million. Finally, undertaking a smaller project to replace a single unit will lead

to lower construction productivity and lost economies of scale. This cost could be about $1.0 million.

Whether U3 is or is not sole-sourced, the supply contract may duplicate the cost of engineering, design, and equipment testing incurred in the Project – (it is not possible to avoid it if it is not sole-sourced), and also no way to put pressure on a sole-source supplier not to price it in to their bid. Finally, if the U3 replacement occurs after U3 has run to failure then the Ruskin Facility will be running with two units until the replacement is completed. A reasonable estimate if the replacement unit is not sole-sourced is that approval, and procurement will require six months; design and testing one year; manufacturing an additional year; and installation six months, for a total of three years from the time of the failure to return to service – during this time BC Hydro will lose the energy shaping benefits of the third unit.

The anticipated cost for the future replacement of the third unit will be:

	($ 000)
Deferred costs, as above	**31,611**
Additional Mob/De-Mob	**340**
Lost Shaping Benefit (3 years x $3.27 million)	**9,802**
Additional Procurement Costs	**500**
Lost Construction Productivity	**1,000**
Future costs	**43,253**
Value at ISD	**44,872**

The “break-even” duration for the deferral is 5.5 years, and a deferral of any shorter duration will represent an economic cost, rather than a benefit. This calculation ignores the possibly higher maintenance costs during the operating period, the cost risk on a sole-sourced contract, and the possible duplication of engineering, design, and testing costs. This break even duration includes the three years after a failure required for the procurement and installation of a new unit, so the calculation implies that U3 would have to continue in service until roughly May 2020, or nine years from now, to make deferral an economically attractive alternative.

This IR presupposes that BC Hydro would run U3 to failure. Consequences of that failure are difficult to predict but could include worker safety issues, environmental issues associated with oil contamination and debris, possible damage to other generating units and the loss of capacity in the LM until U3 is replaced. As set out in Table 3-2 of Exhibit B-1, there is a capacity shortfall beginning in F2017. Furthermore, please refer to BC Hydro’s response to CEABC IR 2.11.1, which explains that the LM is capacity constrained. In particular that IR response sets out the restrictions governing Burrard describes deliverability risk with respect to Demand Side Management and identifies the uncertainty with respect to the ILM project.

33.0 Reference: Project Costs
Exhibit B-1, Chapter 3, Section 3.4.2
Powerhouse – Two versus Three Unit Configuration;
Table 3-12

"The annual energy is higher by 18.6 GWh in the three-unit alternative, and the value of energy is higher by $3.6 million…" and

"Due to the need for flow continuity at the Ruskin Facility, the consequences of a coincident outage in a two unit facility would likely be a spill…"

2.33.5 Did the increase of 18.6 GWh account for the larger units that would be installed by the Project (40 MW/unit or larger vs. the present 35 MW/unit)? If not, please provide the appropriate GWh revised figure and resultant NPV benefit of the Three Unit vs. Two Unit Alternative in Table 3-12.

RESPONSE:

The calculations shown in section 3.4.2 of Exhibit B-1 were based on a comparison of three new units to two new units, and in each case assumed the same 40 MW capacity for each unit.

33.0 Reference: Project Costs
Exhibit B-1, Chapter 3, Section 3.4.2
Powerhouse – Two versus Three Unit Configuration; Table 3-12

"The annual energy is higher by 18.6 GWh in the three-unit alternative, and the value of energy is higher by $3.6 million…" and

"Due to the need for flow continuity at the Ruskin Facility, the consequences of a coincident outage in a two unit facility would likely be a spill…"

2.33.6 Please discuss the viability of installing an inflatable rubber dam at the highway or railway bridge to avoid fish stranding either for the construction or post construction periods.

RESPONSE:

BC Hydro interprets this question to be related to the use of an inflatable dam in the event that turbine flow is interrupted due to a plant outage or failure of a generating unit. BC Hydro is of the view that such a structure could not be permitted, and if permitted and built, would not be effective.

The Stave River at Lougheed Highway or Canadian Pacific Railway bridges is between 120 and 130 m wide. The channel bottom is at elevation -5.6 m and to prevent outflow of the lower Stave River the crest of a weir would have to be at approximately elevation +2 m, indicating a gate height of nearly 8 m. BC Hydro assumes, without doing any detailed design, that a 6 m diameter air bladder would be sufficient to elevate the required gates.

This structure would have to be anchored to the channel bottom, requiring either underwater construction or placement of coffer dams to allow work in the dry. It is likely that either alternative would give rise to a possible HADD, in turn requiring an authorization from DFO under the *Fisheries Act*. It is inevitable that the structure would impose a barrier to navigation on the lower Stave River, which has historically been used for log booming and tug and barge operations, thereby requiring authorization by Transport Canada under the *Navigable Waters Protection Act*.

Either of the authorization for a HADD or interference with navigation would require a review under CEAA, and related engagement, consultation, mitigation and compensation activities and costs. In BC Hydro's view, it is unlikely that either of the approvals would be granted when there are clear alternatives available (in the Project or any of the Decommissioning Alternatives) which do not create a HADD or interfere with navigation.

Further, as set out in BC Hydro's response to AMPC IR 2.9.8, the response time after an interruption in flow at the Ruskin Facility is less than 10 minutes. Inflation of a rubber bladder of the required volume would require an air supply capable of delivering from

340 to 425 m^3 per minute – a daunting task when an industrial installation supplying less than a tenth of that volume is considered to be very large – making it likely that the rubber dam will not inflate rapidly enough to prevent the dewatering of the lower Stave River. BC Hydro concludes that the installation described is impractical, and does not represent a feasible solution.

33.0 Reference: Project Costs
Exhibit B-1, Chapter 3, Section 3.4.2
Powerhouse – Two versus Three Unit Configuration;
Table 3-12

"The annual energy is higher by 18.6 GWh in the three-unit alternative, and the value of energy is higher by $3.6 million…" and

"Due to the need for flow continuity at the Ruskin Facility, the consequences of a coincident outage in a two unit facility would likely be a spill…"

2.33.7 Please discuss the subject of adding pumped storage to Ruskin.

RESPONSE:

It is BC Hydro's view that it would not be feasible to add pumped storage at the Ruskin Facility. While BC Hydro has not undertaken any specific studies on pumped storage at this facility, building pumped storage requires two reservoirs and the Lower Stave River would be a very unlikely lower reservoir as maintenance of water elevation is a critical environmental concern at this location.

34.0 Reference: Two Unit versus Three Unit Configuration
Exhibit B-7-2, BCOAPO 1.9.1, p. 1

"Based on average daily discharge, there was only one year between 1986 and 2009, inclusive (i.e., 1 in 26 years, or 3.85 per cent of that time period), in which two units could handle all of the total discharge from the Ruskin Facility (Powerhouse and spillway combined) during the year. Due to flow variations within a year, the number of years where all flow could be handled by a given number of units may be less informative than the number of days that the required discharge could be handled by that number of units. During that same period, the total daily discharge from the Ruskin Facility (Powerhouse and spillway combined) could be handled by two units for 90.0 per cent of those days, and by three units for 97.8 per cent of those days."

2.34.1 Did the above response to the original IR account for larger units being installed by the Project? If not, please update the response considering replacing only two units and not the third unit.

RESPONSE:

The increase in unit capacity is due to increases in turbine efficiency, and is not accompanied by higher discharge flows, so Exhibit B-7-2, BC Hydro's response to BCOAPO IR 1.9.1 is unchanged whether considering the existing or proposed units.

35.0 Reference: Project Justification
Exhibit AMPC, IR 1.4.1, p. 2
Maintenance Practices
Exhibit B-7-1, IR 1.93.1 Attachment 5 , p. 108
MWH Report

"BC Hydro concludes pursuant to its Equipment Health Ratings (EHRs) that major Powerhouse equipment and ancillaries have reached "poor" or "unsatisfactory" equipment health ratings."

"According to long-term maintenance staff, the draft tube stoplogs have not been installed for over 30 years."

2.35.1 Please explain why maintenance in the draft tubes has not been performed and these assets have been allowed to deteriorate to "poor" or "unsatisfactory" asset for over 30 years.

RESPONSE:

BC Hydro does not have an EHR assessment methodology specifically for draft tubes; rather, for EHR assessment purposes, the draft tube is considered part of the turbine. The latest EHR assessments show that the condition of all three turbines (which includes the turbine inlet valve, scroll case, wicket gates, servomotors, runner, turbine bearing and draft tube) is "unsatisfactory", independent of the current condition of the draft tubes.

The draft tube stoplog hoist has not been in service for a number of years. Without the hoist, the draft tube stoplogs cannot be installed, and the ability to perform maintenance on the draft tube is limited. However, divers were used to inspect the draft tube in 1994 which confirmed, at that time, there were no significant concerns with the condition of the draft tubes. Given the age, condition, and anticipated re-development of the Powerhouse, an investment to repair the stoplog hoist and address any concerns with the condition of the draft tubes was judged not to be the best use of limited maintenance resources.

35.0 Reference: Project Justification
Exhibit AMPC, IR 1.4.1, p. 2
Maintenance Practices
Exhibit B-7-1, IR 1.93.1 Attachment 5 , p. 108
MWH Report

"BC Hydro concludes pursuant to its Equipment Health Ratings (EHRs) that major Powerhouse equipment and ancillaries have reached "poor" or "unsatisfactory" equipment health ratings."

"According to long-term maintenance staff, the draft tube stoplogs have not been installed for over 30 years."

2.35.1.1 Please explain if maintenance on the lower section of the runners has also not been performed for over 30 years and what effect this has had on the life of these assets.

RESPONSE:

At the Ruskin Facility, unlike at many BC Hydro generating stations, the tailrace elevation is lower than the runner elevation for a significant portion of the year. At such times it is possible to inspect and maintain the runner, including the lower section of the runner, without installing the draft tube stoplogs and draining the draft tube. Maintenance of the runners has been performed approximately every four to six years.

35.0 Reference: Project Justification
Exhibit AMPC, IR 1.4.1, p. 2
Maintenance Practices
Exhibit B-7-1, IR 1.93.1 Attachment 5 , p. 108
MWH Report

"BC Hydro concludes pursuant to its Equipment Health Ratings (EHRs) that major Powerhouse equipment and ancillaries have reached "poor" or "unsatisfactory" equipment health ratings."

"According to long-term maintenance staff, the draft tube stoplogs have not been installed for over 30 years."

2.35.1.2 Please explain why the Project has provision for new draft tube stop logs when the current practice is not to isolate this section of the water passage.

RESPONSE:

Current practices are judged to be the best use of maintenance resources for the Ruskin Facility given its advanced age, and the anticipated Powerhouse re-development/replacement. Current practices do not allow for access to the draft tubes for inspection or maintenance; and limit access to the turbines and water passages during periods of low tailwater *and* reduced generation.

However, following re-development/replacement of the Powerhouse, this practice would no longer be acceptable, and draft tube stop logs would be required to enable recommended inspections and maintenance of the draft tube, and provide increased flexibility to perform maintenance on the runner. Ensuring provision of a safe work environment for plant operating staff at all times of the year dictates the need for draft tube gates. Additionally, the Project Scope includes the installation of a draft tube and tunnel dewatering system to be integrated into the draft tube gates. This provision drastically improves the reliability and efficiency of unit maintenance from current practices which rely on gravity drainage and an improvised pumping system to dewater the tunnel.

35.0 Reference: Project Justification
Exhibit AMPC, IR 1.4.1, p. 2
Maintenance Practices
Exhibit B-7-1, IR 1.93.1 Attachment 5 , p. 108
MWH Report

"BC Hydro concludes pursuant to its Equipment Health Ratings (EHRs) that major Powerhouse equipment and ancillaries have reached "poor" or "unsatisfactory" equipment health ratings."

"According to long-term maintenance staff, the draft tube stoplogs have not been installed for over 30 years."

2.35.1.2.1 Please discuss the merits of installing the most robust turbine and draft tube components, not including new stop log isolation facilities and continuing to maintain the facility as per current practice. Please comment if these replacements would last for the anticipated remaining life of the Ruskin facility (40 or 50 years). Please provide an estimate of the NPV of the avoided costs.

RESPONSE:

A cost estimate has not been developed for installation of "the most robust turbine and draft tube components". Nonetheless, based on market soundings prior to the implementation of Revelstoke Unit 5, it is expected that the full lifecycle cost of "the most robust" possible turbine and draft tube with no tailrace isolation facilities would be significantly higher than the draft tube modification and repair, tailrace isolation facilities and turbine proposed as part of the Project. Therefore, it is considered that there would be no merit to installing "the most robust turbine and draft tube components, not including new tailrace isolation facilities".

35.0 Reference: Project Justification
Exhibit AMPC, IR 1.4.1, p. 2
Maintenance Practices
Exhibit B-7-1, IR 1.93.1 Attachment 5 , p. 108
MWH Report

"BC Hydro concludes pursuant to its Equipment Health Ratings (EHRs) that major Powerhouse equipment and ancillaries have reached "poor" or "unsatisfactory" equipment health ratings."

"According to long-term maintenance staff, the draft tube stoplogs have not been installed for over 30 years."

2.35.1.2.2 Please discuss if not providing draft tube maintenance gates is a standard practice in BC Hydro (such as LaDore GS for around 40 years) and describe any material negative consequences of this strategy on the life of the asset(s).

RESPONSE:

Standard practice for BC Hydro is to provide draft tube maintenance gates or stoplogs. The decision to not include draft tube maintenance gates would only be undertaken by exception, after significant engineering analysis of the specific facility and the impact on the overall lifecycle cost. The lack of draft tube gates (or stoplogs) would typically negatively impact the ability to undertake inspections and maintenance of the draft tube, and in most cases the runner. It is not possible to safely operate without regular runner inspections and maintenance.

35.0 Reference: Project Justification
Exhibit AMPC, IR 1.4.1, p. 2
Maintenance Practices
Exhibit B-7-1, IR 1.93.1 Attachment 5 , p. 108
MWH Report

"BC Hydro concludes pursuant to its Equipment Health Ratings (EHRs) that major Powerhouse equipment and ancillaries have reached "poor" or "unsatisfactory" equipment health ratings."

"According to long-term maintenance staff, the draft tube stoplogs have not been installed for over 30 years."

2.35.1.3 Please discuss if this strategy is in keeping with RCM (Reliability Centered Maintenance) principles.

RESPONSE:

In general, BC Hydro adopts Reliability Generated Maintenance (RCM) principles to develop maintenance programs. However, additional factors, such as remaining in-service life, may also be considered to minimize total lifecycle cost. This is the case when equipment is near, or at, end of life. Given the current condition, age and anticipated re-development/replacement of the Powerhouse, maintenance has reduced where possible to minimize total lifecycle cost.

35.0 Reference: Project Justification
Exhibit AMPC, IR 1.4.1, p. 2
Maintenance Practices
Exhibit B-7-1, IR 1.93.1 Attachment 5 , p. 108
MWH Report

"BC Hydro concludes pursuant to its Equipment Health Ratings (EHRs) that major Powerhouse equipment and ancillaries have reached "poor" or "unsatisfactory" equipment health ratings."

"According to long-term maintenance staff, the draft tube stoplogs have not been installed for over 30 years."

2.35.1.4 If "the draft tube stoplogs have not been installed for over 30 years" can BC Hydro assure the ratepayers that these new facilities once installed will, in fact, be maintained and utilized at periods supposedly less than once in 30 years.

RESPONSE:

Following the re-development/replacement of the Powerhouse, it is BC Hydro's intention to utilize the draft tube stoplogs to perform recommended inspections and maintenance of the draft tube and, as needed, the turbine.

36.0 Reference: Alternative Means of Carrying Out the Project
Exhibit B-1, Section 3.4.3, p. 50
Spillway Gates

2.36.1 Please confirm that Option 3 is the proposed option and describe if stoplogs and slots in the new road are to be incorporated, or if modifications to the temporary construction bulkhead will be utilized for gate isolation or if some other means will be employed.

RESPONSE:

Yes, Option 3 is the proposed option.

Yes, stoplogs and slots are to be incorporated in the Dam Crossing. This solution was chosen over using the temporary construction bulkhead.

36.0 Reference: Alternative Means of Carrying Out the Project
Exhibit B-1, Section 3.4.3, p. 50
Spillway Gates

2.36.1.1 Please discuss if a gantry crane will be provided to install/remove the spillway maintenance gates/stoplogs or if a rented mobile crane will be utilized.

RESPONSE:

Yes, a gantry crane will be provided to install and remove spillway stoplogs. The gantry crane is planned to serve multiple functions, including servicing the pier control rooms, cleaning intake trash racks and servicing the intake gates.

36.0 Reference: Alternative Means of Carrying Out the Project
Exhibit B-1, Section 3.4.3, p. 50
Spillway Gates

2.36.1.1.1 If a rented mobile crane has been chosen, please explain why the dam roadway needs to be widened to two lanes when a mobile crane cannot be wider than a single lane to travel on the highway (without a permit).

RESPONSE:

As set out in the response to BCUC IR 2.36.1.1, BC Hydro has chosen a gantry crane as part of the Project scope. Both a gantry or a mobile crane will require that the Dam Crossing be widened to at least two lanes. A mobile crane requires a width of more than two lanes with its stabilizing outriggers fully extended. A mobile crane has its outriggers retracted for highway travel in one lane.

37.0 Reference: Alternatives to the Proposed Project
Exhibit B-7, BCUC 1.95.1

2.37.1 Please comment on the feasibility of a revised Alternative A with the following characteristics:

i) Right Abutment seismic upgrades as in the proposed Project
ii) Left Abutment seismic upgrades as in the proposed Project
iii) Eliminate intake gates from Project scope and retain turbine inlet valves.
iv) Two new spillway gates and associated piers, rehabilitate remaining gates and stabilize remaining piers.
v) Powerhouse crane, superstructure, and substructure seismic upgrades as in the proposed Project
vi) Replace two units, with associated control, draft tube rehabs, new transformers and auxillary systems as in the proposed Project (retain old equipment for replacements on remaining unit – and operate as run to failure)
vii) Retain switchyard on Powerhouse roof
viii) install new access from east side of powerhouse and abandon bridge.

Please explain the constraints, if any, that would prevent the above-described project alternative from operating at the original reservoir level and any lost energy and revenue that would result if the reservoir could not be returned to the normal operating level. Please discuss the reliability in relation to public safety for the revised alternative.

RESPONSE:

Of the scope items listed in the above IR, items i, ii, and v are as described in the current Project scope, and require no comment. With respect to the other adjustments to the Project scope, BC Hydro makes the following observations:

iii) Eliminate intake gates from Project scope and retain turbine inlet valves:

As set out in Exhibit B-7, BC Hydro's response to BCUC IR 1.3.1, the existing TIV cannot be certified for Single Device Isolation, and therefore cannot be relied on to allow work on the turbine or generator without an additional isolation point. In addition, TIVs cannot close against flow, meaning that a TIV cannot be relied on for emergency situations where the turbine wicket gates cannot control flow.
BC Hydro believes that this is an unacceptable design for a generating station. A TIV requires a positive energy source to close, and cannot be operated passively,

like an inlet gate which will close largely under its own weight even if power is unavailable. BC Hydro sees this as a positive design feature for inlet gates. Finally, and also as described in BC Hydro's response to BCUC IR 1.3.1, removal of the existing TIVs will reduce penstock hydraulic losses and improve worker safety by improving access to the scroll case and turbine pit.

iv) Two new spillway gates and associated piers, rehabilitate remaining gates and stabilize remaining piers.

As set out in Exhibit B-7, BC Hydro's response to BCUC IR 1.95.1, BC Hydro investigated the alternative of strengthening the existing piers by re-anchoring and found that it was not feasible, and could not bring the piers to a condition where they could be relied on to not fail in a seismic event with ground accelerations below those expected in the MDE. BC Hydro also investigated strengthening the existing piers by adding concrete to the lateral surfaces, and concluded that uncertainties in the strength of the bond between old and new concrete meant that this was not a viable solution. It is unclear what impact either approach would have on gate geometry and the resulting need for replacement or modification of the existing gates.

Please also refer to Exhibit B-7, BC Hydro's response to BCUC IR 1.84.1, and to BC Hydro's response to BCUC IR 2.58.6 for a discussion of why 'hybrid' alternatives involving partial replacement of piers or gates have been rejected. As set out in BC Hydro's response to BCUC IR 2.66.1, BC Hydro does not believe that a response that leaves the Dam unable to withstand the MDE is acceptable.

vi) Replace two units, with associated control, draft tube rehabs, new transformers and auxillary systems as in the proposed Project (retain old equipment for replacements on remaining unit – and operate as run to failure).

Please refer to BC Hydro's response to BCUC IR 2.33.4 for the reasons why running Unit 3 to failure is not a cost-effective alternative.

vii) Retain switchyard on Powerhouse roof

The Ruskin Facility could continue to operate with the Switchyard located on the roof, but this would not address the worker safety issues, particularly LOA, with the Switchyard, as set out in Exhibit B-7, BC Hydro's response to BCUC IR 1.8.1 and BC Hydro's response to AMPC IR 2.10.4. For purposes of responding to this IR, BC Hydro has conservatively assumed that the entire cost of the Switchyard could be avoided. The alternative would reduce the cost of the Project by the cost of the Switchyard relocation, or approximately $19.4 million to $22.2 million (Expected and Authorized Amounts, respectively), or approximately $10.5 to $12.0 million in NPV terms, increasing the NPV of the Project by a like

amount. In fact, some costs to address LOA would likely be incurred, reducing the benefit.

viii) Install new access from east side of powerhouse and abandon bridge.

For purposes of Project construction, BC Hydro proposes to access the site both from the east and west side of the Powerhouse. Limiting access solely to the east side for purposes of Project construction is not feasible. Please refer to BC Hydro's response to BCUC IR 2.56.2.

BC Hydro is of the view that the revised Alternative A as described in this IR is not a feasible solution, and therefore would not be undertaken by BC Hydro. Specifically, item iv) contemplates BC Hydro undertaking work that would leave the dam unable to meet the MDE. In essence, this IR calls for BC Hydro to disregard seismic criterion. BC Hydro is not prepared to follow that course of action; please refer to BC Hydro's response to BCUC IR 2.66.1. The development of Alternatives to the Project took approximately 1½ years, which is understandable given the significant engineering and other work that is required to develop feasible alternatives. First BC Hydro began to develop these alternatives in-house. BC Hydro then retained B&V in April 2010 to further develop feasible alternatives to the Project including Decommissioning Alternative A; please refer to Exhibit B-7, BC Hydro's response to BCUC IR 1.51.0 for the reasons why BC Hydro retained B&V. Decommissioning Alternative A through E represent the full range of feasible alternatives to the Project. Accordingly, the best description of the alternative contemplated in this IR, if BC Hydro elects to continue to operate the Ruskin Facility, is the description of Decommissioning Alternative A provided in Exhibit B-1, section 3.3.1.2, page 3-20, lines 1-24.

37.0 Reference: Alternatives to the Proposed Project
Exhibit B-7, BCUC 1.95.1

2.37.2 Please provide a cost estimate in a Table format of the above described project that would enable a comparison to be made with the proposed project and Alternative A. **Note**: this IR asks BC Hydro to prepare an estimate, hence a response of "BC Hydro has not prepared an estimate" will be considered unacceptable.

RESPONSE:

BC Hydro respectfully declines to provide a cost estimate for the alternative advanced in BCUC IR 2.37.1 for the following reasons:

- **The alternative is not a feasible solution and therefore cannot assist the BCUC with respect to the decision of whether or not to issue a CPCN for the Project;**
- **Even if such an alternative was feasible, it would take several months of engineering design and estimating work to develop an estimate comparable to the estimates for the Project and Alternatives A to E.**

37.0 Reference: Alternatives to the Proposed Project
Exhibit B-7, BCUC 1.95.1

2.37.3 Please provide an NPV analysis in a Table format of the above described project that would enable a comparison to be made with the proposed project and Alternative A.

RESPONSE:

BC Hydro has not provided the requested NPV analysis for the reasons set out in its responses to BCUC IRs 2.37.1 and 2.37.2.

38.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 1
First Nations Consultation

"A map provided to BC Hydro by the Matsqui, which is different from the map [in] Exhibit B-1 in that the Matsqui assert that their traditional territories stretch further to the north of the Fraser River."

2.38.1 Please confirm when the Matsqui provided this map to BC Hydro.

RESPONSE:

The map provided to BC Hydro by Matsqui First Nation (Matsqui) has been filed as Exhibit B-7, Attachment 4 to BC Hydro's response to BCUC IR 1.14.1 (Attachment 4 Map).

Matsqui provided the Attachment 4 Map to BC Hydro in relation to the ILM project on February 20, 2009. The following month, the Environmental Assessment Office (EAO) identified Matsqui as a potentially affected First Nation on the Project and provided them with a copy of the Ruskin Project Description, a copy of which is found at Appendix H-4 of Exhibit B-1, pages 9 of 115 to 112 of 115.

The Matsqui provided the Attachment 4 Map to BC Hydro in relation to the Ruskin Project on March 31, 2011.

Please also refer to BC Hydro's response to BCOAPO IR 2.2.1.

39.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, pp. 1-2
Bouchard and Kennedy Reports

2.39.1 Why was the 2008 Report not shared with the Kwantlen until March 25, 2011 and with the Matsqui until March 31, 2011?

RESPONSE:

Per the Supreme Court of Canada's decision in *Haida Nation v. British Columbia (Ministry of Forests) and Weyerhaeuser* [2004] S.C.R. 511 (*Haida*), the content of the duty to consult varies with the circumstances. The law does not require that a preliminary strength of claim (SOC) assessment be provided to a First Nation. BC Hydro will address this legal issue further in argument.

BC Hydro makes its decisions on the sharing of relevant information, including preliminary SOC information, on a case by case basis and in accordance with the scope of the duty to consult. Additionally, BC Hydro notes that a premature sharing of a SOC assessment with a First Nation can be unproductive, prejudice a consultation process and consequently affect ratepayers.

BC Hydro did not provide Kwantlen with a copy of the report entitled "An Evaluation of First Nations' Aboriginal Rights and Title in the Vicinity of the Ruskin Dam" (the 2008 Report) prior to March 25, 2011 because:

- **Through BC Hydro's prior experience in the Stave River Water Use Plan process, BC Hydro understood that Kwantlen has the strongest claim relative to other First Nations in the Project area. Please refer to Exhibit B-7-2, BC Hydro's response to BCOAPO IR 1.13.1. This was confirmed through interactions with Sto:lo Nation and Sto:lo Tribal Council in March and May 2007 respectively. Please refer to Exhibit B-1, page 4-11, lines 17 to 20 and page 4-12, lines 5 to 7;**

- **BC Hydro approached consultation with Kwantlen consistent with consultation at the deeper end of the *Haida* spectrum; and**

- **SOC issues, as they relate to the consultation process being conducted by the parties, were not raised by Kwantlen during the consultation process prior to Kwantlen's intervention in the BCUC Project proceeding, and because SOC issues had not been an impediment to consultation on the Project.**

Matsqui responded to BC Hydro regarding the Project for the first time at the workshop on February 28, 2011. BC Hydro immediately engaged with Matsqui to

provide capacity funding for Matsqui's review of the Project CPCN Application. On March 31, 2011, BC Hydro provided Matsqui with its research on Matsqui's claim to the Project area ("An Examination of Matsqui Traditional Territory, A Literature Review" dated March 28, 2011, referred to as the 2011 Report). BC Hydro also provided Matsqui with a copy of the 2008 Report for additional context only, given that the 2008 Report does not mention a potential Matsqui claim in the project area.

39.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, pp. 1-2
Bouchard and Kennedy Reports

2.39.2 Please report the comments, written, verbal or otherwise delivered, that the Kwantlen and the Matsqui have given BC Hydro in relation to these Reports.

RESPONSE:

Kwantlen has provided no feedback on these Reports to date. However, as noted in Exhibit C3-4, Kwantlen intends to file evidence regarding issues related to traditional use and strength of claim on June 24, 2011.

BC Hydro and Kwantlen have continued to meet, but on May 27, 2011 Kwantlen informed BC Hydro that they wish to set aside Project-related discussions, and do not want BC Hydro to present an IBA offer concerning the Project, until Kwantlen receive a response from the Province of British Columbia (the Province) with regard to the Province's participation in an Agreement in Principle.

Matsqui provided a letter to BC Hydro on April 18, 2011, a copy of which is filed as Attachment 1 to BC Hydro's response to BCUC IR 1.27.1. BC Hydro responded to that letter on May 12, 2011. A copy of BC Hydro's response letter is included as Attachment 1 to this IR response.

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Chris Heard
Aboriginal Relations and Negotiations
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May 12, 2011

Mr. Stanley Morgan
Aboriginal Rights Officer
Matsqui First Nation
PO Box 10
Matsqui, BC V4X 3R2

Dear Mr. Morgan:

Re: Ruskin Dam and Powerhouse Upgrade Project (the "Project")

I write in response to your letter which I received by email on April 18, 2011.

In addition to the information provided in my emails of April 21, 2011 where I provided a copy of BC Hydro's response to British Columbia Utilities Commission (**BCUC**) Information Request (**IR**) 1.27.1 (BC Hydro provided the BCUC with a copy of your letter as Attachment 1 to BC Hydro's response to BCUC IR 1.27.1) and a copy of BC Hydro's consultation log with the Matsqui First Nation (**Matsqui**) on the Project to date, and April 28, 2011 where I provided a copy of the latest version of the Summary of Environmental Information, Assessment and Mitigation report for the Project, this letter and its related attachments are intended to provide you with responses to concerns that you have raised. We address the concerns in the order in which they appear in your letter.

Map

Please note that there was no mention of a "recent" map in BC Hydro's response to BCUC IR 1.14.1. Please also note that we have provided the BCUC with the map that you have provided to us; it was provided as Attachment 4 to BC Hydro's response to BCUC IR 1.14.1. A copy of BC Hydro's response to BCUC IR 1.14.1, together with all four attachments, is found as Attachment 1 to this letter.

Matsqui Strength of Claim (SOC)

BC Hydro's preliminary assessment of the Matsqui's SOC in the Project area relied on known and available historical and ethnographic evidence gathered by Bouchard & Kennedy Research Consultants. BC Hydro also has reviewed the information that Matsqui provided concerning the Interior to Lower Mainland (**ILM**) project with respect to traditional use and strength of claim (*Final Report – Matsqui First Nation Traditional Use Study for the BC Hydro Interior to Lower Mainland Reinforcement Project – Matsqui, B.C., August 2009*). As is apparent from BC Hydro's response to BCUC IR 1.14.1, BC Hydro made the BCUC aware of

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the Environmental Assessment Office's (**EAO**) finding of Matsqui SOC in respect of the ILM project by providing the BCUC with a copy of the EAO's ILM Project Assessment Report. We look forward to receiving any additional information specific to the Matsqui historic use and occupation in the Ruskin Project area. It would also be helpful to BC Hydro to understand whether the nature of Matsqui's use and occupation; whether it was exclusive to Matsqui, or part of a collective Sto:lo claim.

Potential Project Impacts

With regard to the potential impacts of the proposed Project, as noted in section 4.2.2 of BC Hydro's application for a Certificate of Public Convenience and Necessity (the **Application**), BC Hydro submitted evidence that the incremental impacts of the proposed Project will have minimal adverse impacts on First Nations for the following reasons:

- Project impacts are confined to the construction period, anticipated to occur between 2012 and 2017, and construction will take place primarily within the existing Ruskin Facility footprint. As described in section 2.8.3.2 of the Application, there will be no change to the Powerhouse footprint and the Upper Dam Work footprint change is limited to the relocation of Hayward Street (one road width). While the proposed relocated switchyard would result in a new footprint of approximately 50 m x 100 m, the switchyard would be sited on previously disturbed land.

- The Project will not result in water flow changes outside of normal operational variation in Hayward Lake Reservoir or the Stave River, with the Ruskin Facility continuing to operate within the conditions specified in the existing Conditional Water Licenses (**CWLs**) and the Stave River Water Use Plan.

- The Project-related drawdowns of Hayward Lake Reservoir would occur only during construction and reservoir levels during the drawdowns will remain within the conditions specified in the CWLs.

- The Project does not extend beyond the boundaries of BC Hydro currently owned property.

- The Project is not expected to cause any impact on the current status of archaeological resources as confirmed by an archaeological impact assessment of the Project area.

- The Project will be constructed pursuant to BC Hydro Environment Management Plans, which address potential environmental risks related to construction activities (e.g., sediment containment, hazardous materials spill containment, spill response procedures). Refer to section 5.3.8 of the Application for details concerning proposed mitigation measures.

- As described in section 2.8.3.2 of the Application, the Project is not expected to result in significant adverse environmental effects (including fisheries impacts), taking into account the implementation of recommended mitigation measures, including working closely with Kwantlen over the course of their environmental review.

Please also refer to BC Hydro's response to BCUC IR 1.15.1.1, which among other things contains a table with all environmental studies provided to Kwantlen First Nation which may be

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of interest, and to BC Hydro's response to Kwantlen IR 1.7.2 (enclosed as Attachment 2) for Project-related mitigation measures.

BC Hydro Selection of Project as Preferred Alternative

Information regarding the two de-rating and three decommissioning alternatives was provided to Matsqui in the Summary of Information on December 15, 2009. BC Hydro received no response from Matsqui in relation to the alternatives set out in that document.

As noted in BC Hydro's response to BCUC IR 1.27.1 previously provided to Matsqui, the Project as the preferred alternative was not selected by BC Hydro's Board of Directors (**Board**), and the two de-rating and 3 decommissioning alternatives were not rejected by the Board, until February 17, 2011. Refer to BC Hydro's responses to Kwantlen IR 1.3.1 and to BCUC IR 1.97.0, which are found as Attachment 3 to this letter.

As is apparent from these responses, your assertion that BC Hydro had chosen the Project over the two de-rating and three decommissioning alternatives prior to BC Hydro's application to the EAO to voluntarily opt-in to the B.C. *Environmental Assessment Act* (***BCEAA***) process in early 2009 is not correct. The reasons for BC Hydro's application to the EAO to voluntarily opt-in to the *BCEAA* are set out in BC Hydro's response to Kwantlen IR 1.1.1; the *BCEAA* process would provide more certainty, guidance, and timelines for the assessment of the potential environmental and social impacts of the Project (see Attachment 4 to this letter).

With regard to your point about removing the Dam entirely, BC Hydro submitted evidence that this alternative may not be acceptable to regulators given the little additional environmental benefits and relatively higher costs compared to decommissioning alternative D, whereby the Dam is left in place with a notch to provide flow as was done when BC Hydro decommissioned the Coursier Dam, or as compared to the two de-rating alternatives. Decommissioning requires not only environmental assessment-related approval(s) but also BCUC permission pursuant to section 41 of the *Utilities Commission Act*. In this regard, please refer to BC Hydro's response to BCUC IR 1.14.6, provided as Attachment 5 to this letter. It is also important to keep in mind that replacing the power generation lost from the Ruskin facility to meet energy self-sufficiency obligations under the *Clean Energy Act* would likely require the construction of other facilities, which can have significant new environmental concerns.

Please refer to Attachment 6 and Attachment 7 of this letter for further discussion on the alternatives for the Project. These minimal cost studies by Black and Veatch which examines the probable construction costs of the two de-rating and three decommissioning alternatives (Attachment 6), and Hemmera, which examines the minimal mitigation and other environmentally-related costs of these alternatives (Attachment 7) will provide information which was used as an input into the recent February 2011 choice for the Project as the preferred alternative. I have also provided a copy of BC Hydro's response to BCUC IR 1.14.6 as Attachment 5 and Kwantlen IR 1.2.1 as Attachment 5 to this letter. These responses will provide information on consultations around alternatives with First Nations. I also direct your attention to Section 3.3.1 of the Application and Appendix G-1 to the Application which provides further information including a description of lost energy and capacity.

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Project Drivers

As noted in BC Hydro's response to BCUC IR 1.27.1 previously provided to you, the Project is driven by safety and seismic concerns, and not an "increased demand for energy" as indicated in your letter. Please also refer to BC Hydro's response to BCSEA IR 1.4.1 (Attachment 8 to this letter) for further information on the Project drivers.

Project Costs

The Expected and Authorized Amounts for Project are set out in section 2.4 of the Application. There are no discrepancies between the Authorized Amount approved by the Board on 17 February 2011 and the costs of the Project set out in section 2.4 of the Application. The Authorized Amount is $856.9 million; refer to Table 2-4, page 2-31 of the Application.

Costs for consultation with First Nations on the Project were included in the Authorized Amount and were estimated based on the potential adverse impacts of the Project on First Nations interests and BC Hydro's experience consulting with First Nations. Consultation related costs were provided to the BCUC on a confidential basis as part of BC Hydro's responses to BCUC IR 1.14.3.1 and 1.14.4.

Accommodation costs were not included in the Authorized Amount; BC Hydro provided the BCUC with its estimate of First Nation accommodation-related costs for the Project as part of its confidential response to BCUC IR 1.14.5. However, as explained in BC Hydro's response to BCOAPO IR 1.14.2, accommodation-related costs are likely to be similar for the two de-rating alternatives, and perhaps higher for the three decommissioning alternatives. Copies of BC Hydro's responses to BCOAPO IRs 1.14.1 and 1.14.2 are found as Attachment 9 to this letter.

Revenue Sharing

Attachment 10 to this letter is a document *(Project-related Benefits for First Nations)* that reflects the direction that the Province (of British Columbia) has given to BC Hydro regarding revenue sharing. To date, the Province (or the BCUC) has not authorized the sharing of BC Hydro revenues with First Nations and as such, BC Hydro is not considering revenue sharing with First Nations as part of the Project.

Capacity Funding

To date, BC Hydro has provided $10,000 for Matsqui to review the Application and related documents to determine and provide BC Hydro with information on how the Project's incremental impacts will affect Matsqui. In light of the concerns that you have raised with regard to alternatives and strength of claim, BC Hydro is prepared to provide an additional $5,000 in funding for this purpose and will forward a cheque in that amount. Should Matsqui's review produce information that causes BC Hydro to reconsider the Matsqui's SOC or shows the Project's potential to impact the rights and/or title of Matsqui, BC Hydro would be willing to enter into further discussions at that time.

BC hydro
FOR GENERATIONS

If you have any questions or concerns, please contact me directly at chris.heard@bchydro.com or at 604-528-1558.

Sincerely,

Chris Heard
Sr. Coordinator, Consultation and Negotiations
Aboriginal Relations and Negotiations

cc: Bram Rogachevsky

40.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 2 and Attachment 1, pp. 27, 31
Preliminary Assessment of Kwantlen SOC

"BC Hydro's preliminary SOC assessment is that the Kwantlen have, on balance, a reasonable *prima facie* Aboriginal rights (including title) claim in the Project area... 'Reasonable' implies that the claim is not a weak claim but the available information may not be sufficient to conclude that a claim is a 'strong *prima facie'* claim." (BCUC 1.1.4.1, p. 2)

"By the 1850s, the Kwantlen were so entrenched in a village situated upstream from the second Fort Langley site that one of the rivers had become known in English as the Kwantlen River…subsequent ethnographic work, as reviewed above, associated this term with the village situated at the mouth of the Stave River, as well as the Stave River, itself, and the Stave River people." (Attachment 1, p. 27)

"…the Kwantlen people occupied the Stave River in the historic period, at least by the 1830s, after the demise of the original residents, the Skayuks." (Attachment 1, p. 31)

2.40.1 Why does BC Hydro consider the Kwantlen to have a reasonable claim to the Project area when the Bouchard and Kennedy Report found that the Kwantlen occupied the Stave River area at least by the 1830s?

RESPONSE:

The amount and scope of ethnographic historic information regarding the Project area is considered to be low.

The SOC assessment required under *Haida* is a preliminary assessment, to be carried out as part of the commitment to a meaningful process of consultation. While it is BC Hydro's view that, based on a preliminary assessment, Kwantlen have a reasonable *prima facie* claim of Aboriginal rights (including title) in the Project area, BC Hydro believes that it has in fact carried out consultation which is consistent with consultation at the deeper end of the *Haida* spectrum. As noted in Exhibit B-7, BC Hydro's response to BCUC IR 1.23.3 and BC Hydro's response to BCUC IR 2.42.4, BC Hydro, through its capacity funding agreement, has funded and continues to fund a Traditional Use Study (TUS). To date, Kwantlen has not yet produced the TUS as part of the BC Hydro/Kwantlen consultation process.

From the evidence that are available, what appears is that a group known as the "S'hai-yuks" were associated with the Stave River. This group, distinct from Kwantlen, appear to have been wiped out by small pox in the 1770s. It also appears that Kwantlen

migrated east from the New Westminster area and became the dominant group in the area.

However, although there appears to have been a Kwantlen village upstream of Fort Langley, historical records provide no definitive location at the Stave River. In particular:

- **The 1827-1830 Fort Langley journals do not mention the location of a Kwantlen village on the Stave River, even though it appears that wood parties were being sent up the river to harvest pine for staves (2008 Report, found at Exhibit B-1, Attachment 1 to BC Hydro's response to BCUC IR 1.14.1, pages 11 to 12 of 54);**

- **Anthropologist Wilson Duff considered Kanaka Creek to be the site where Kwantlen principally settled after they moved upstream from New Westminster, before then settling at McMillan Island (2008 Report, page 27 of 54);**

- **Fort Langley journals record encountering Kwantlen along the Fraser River in the general vicinity of the Pitt River (2008 Report, page 10 of 54);**

- **John Work observed one lodge and noted another Kwantlen lodge during the Hudson Bay Company expedition in December 1824 up the Salmon River (lead by James McMillan): the first was observed as the party left the Salmon River near an island two miles upstream for the Salmon River trail, which is in the vicinity of McMillan Island; the second (from which a party of 51 Kwantlen travelled to visit the party) appears to be in the vicinity of Hatzic Slough, which is east of the Stave River (2008 Report, page 9 of 54); and**

- **"Thus, it is certainly possible that people resided in the Stave Lake area [in the winter] in the early historic period, and they were possibly doing so to avoid the Lekwiltok [raids to capture slaves], but no direct evidence has been found. The Fort Langley journals do not mention the existence of such a village, but by the 1830s… [due to disease and warfare]…the Kwantlen appear to have been focused in at two winter villages, one situated in the New Westminster area, and the other situated upstream from Fort Langley." (2008 Report, page 19 of 54). This is evidence of some form of occupation, although it is not known whether this occupation was episodic, or regular.**

41.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3 and Attachment 1, p. 31, and *Delgamuukw v. British Columbia* [1997] 3 S.C.R. 1010, para. 143
Preliminary Assessment of Kwantlen SOC

"The information BC Hydro has reviewed raises some question as to whether or not the Kwantlen had "exclusive pre-sovereignty occupation" (that is, on or before 1846) of the Project area sufficient to establish a claim of Aboriginal title." (BCUC 1.14.1, p. 3)

"…the Kwantlen people occupied the Stave River in the historic period, at least by the 1830s, after the demise of the original residents, the Skayuks." (Attachment 1, p. 31)

"In order to make out a claim for aboriginal title, the aboriginal group asserting title must satisfy the following criteria: (i) the land must have been occupied prior to sovereignty, (ii) if present occupation is relied on as proof of occupation pre-sovereignty, there must be a continuity between present and pre-sovereignty occupation, and (iii) at sovereignty, that occupation must have been exclusive." (*Delgamuukw*, para. 143)

2.41.1 Please point to specific evidence that supports BC Hydro's statement that its review of information raises some question as to whether or not the Kwantlen had exclusive pre-sovereignty occupation of the Project area sufficient to establish a claim of Aboriginal title.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.40.1 regarding Kwantlen occupation of the Project area.

It is BC Hydro's conclusion that there is insufficient evidence to conclude whether Kwantlen had or did not have exclusive occupation of the Project area on or before 1846. Ethnographic information indicates that the Stave River area was originally occupied by the Skayuks people, who were wiped out by small pox in the 1770s. Ethnographers theorize that Kwantlen association with Skayuks and Stave River may be based on traders' mistakenly referring to a number of groups on the Fraser River's north bank collectively as Kwantlen (including the Hatzic, Skayuks, Nicomen, Brownsville and Coquitlam). A second theory is that Kwantlen expanded their territory east from their village in the New Westminster area and absorbed areas once occupied by the then-extinct groups (2008 Report, page 17 of 54). In either case, as per BC Hydro's response to BCUC IR 2.40.1, the extent to which Skayuks villages or any up river sites were ever occupied and effectively controlled by Kwantlen is unknown at the stage, given the lack of ethnographic information (2008 Report, page 38 of 54).

41.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3 and Attachment 1, p. 31, and
***Delgamuukw v. British Columbia* [1997] 3 S.C.R. 1010, para. 143**
Preliminary Assessment of Kwantlen SOC

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2.41.1.1 Please discuss BC Hydro's statement given that the 2008 Bouchard and Kennedy Report found that the Kwantlen occupied the Stave River at least by the 1830s.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.41.1.

41.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3 and Attachment 1, p. 31, and
***Delgamuukw v. British Columbia* [1997] 3 S.C.R. 1010, para. 143**
Preliminary Assessment of Kwantlen SOC

"The information BC Hydro has reviewed raises some question as to whether or not the Kwantlen had "exclusive pre-sovereignty occupation" (that is, on or before 1846) of the Project area sufficient to establish a claim of Aboriginal title." (BCUC 1.14.1, p. 3)

"…the Kwantlen people occupied the Stave River in the historic period, at least by the 1830s, after the demise of the original residents, the Skayuks." (Attachment 1, p. 31)

"In order to make out a claim for aboriginal title, the aboriginal group asserting title must satisfy the following criteria: (i) the land must have been occupied prior to sovereignty, (ii) if present occupation is relied on as proof of occupation pre-sovereignty, there must be a continuity between present and pre-sovereignty occupation, and (iii) at sovereignty, that occupation must have been exclusive." (*Delgamuukw*, para. 143)

2.41.1.2 Please discuss BC Hydro's statement in relation to the test for Aboriginal title as set out in *Delgamuukw*. Please reference any other case law BC Hydro relied on to make its statement above.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.41.1.

41.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3 and Attachment 1, p. 31, and
***Delgamuukw v. British Columbia* [1997] 3 S.C.R. 1010, para. 143**
Preliminary Assessment of Kwantlen SOC

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"…the Kwantlen people occupied the Stave River in the historic period, at least by the 1830s, after the demise of the original residents, the Skayuks." (Attachment 1, p. 31)

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2.41.2 Is it BC Hydro's conclusion that the Kwantlen did not have exclusive occupation of the Stave River area on or before 1846? If so, please specify the evidence to support this conclusion.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.41.1.

42.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3, and
BCUC IR 1.14.1, Attachment 1, p. 37
Preliminary Assessment of Kwantlen SOC

"In respect of Aboriginal rights, such as fishing and traditional activities, the evidence suggests that the Kwantlen probably have a reasonable prima facie Aboriginal rights claim in the Stave River area. However, it is difficult to determine the precise scope and nature of any Aboriginal rights because there is limited information relating to traditional use in the Stave River area".
(BCUC 1.14.1, p. 3)

"According to Duncan McLaren's 2003 Master's thesis, two Traditional Use Studies have been prepared relating to the Stave River area: one of these TUS studies was by T.H. Dandurand *et al.* (1996); and the other was by Ann Stevenson (1996).126 The first was prepared for BC Hydro, the Stó:lō Nation and the Kwantlen First Nation, while the second was prepared for the Stó:lō Nation and the Kwantlen First Nation." (Attachment 1, p. 37)

2.42.1 Please explain how limited information relating to traditional use in the Stave River exists when two traditional use studies have been done in the area.

RESPONSE:

BC Hydro's conclusion as to the level of information relating to traditional use in the Stave River area is based on the conclusion of Bouchard and Kennedy from an ethnographer's perspective (2008 Report, page 37 of 54):

> **"Very little information has been found relating to the traditional use of the Stave River area, despite examining several collections of field notes, manuscripts and publications, including the following:**

- **Wilson Duff's fieldnotes of 1949-1950, as well as his 1952 publication;**
- **Diamond Jenness's fieldnotes and manuscripts of 1934-36 and als his 1955 publication;**
- **Marian Wesley Smith and her students' 1935-1945 fieldnotes and manuscripts;**
- **Fort Langley journals of 1827-1830;**

- **Duncan McLaren's 2003 Master's thesis on the archaeology of the Stave watershed;**

- **Local historian Charles Miller's 1981 book *Valley of the Stave;***

- **The 2001 *Sto:lo Historical Atlas* edited by Keith Carlson;**

- **Documents concerning Indian Reserve establishment".**

Bouchard and Kennedy also noted in the 2006 Report, page 37 of 54 that Duncan McLaren, whose master's thesis on the archaeology of the Stave watershed contains a summary of the information in the two TUS studies, also came to a similar conclusion:

> **"Due to the impacts of epidemic diseases in the Stave River area, there are few specific historical or ethnographic records of the traditional use or knowledge of the Stave Watershed with the exception of a recently-compiled traditional use study (Dandurand et al. 1996)".**

BC Hydro has a copy of the 1996 TUS by T.H. Dandurand et al. (1996 TUS)
BC Hydro notes that while the 1996 TUS identifies traditional uses, it does not necessarily provide supporting evidence of the use, of the intensity or significance of the use, nor evidence associating Kwantlen with the use.

42.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3, and
BCUC IR 1.14.1, Attachment 1, p. 37
Preliminary Assessment of Kwantlen SOC

"In respect of Aboriginal rights, such as fishing and traditional activities, the evidence suggests that the Kwantlen probably have a reasonable prima facie Aboriginal rights claim in the Stave River area. However, it is difficult to determine the precise scope and nature of any Aboriginal rights because there is limited information relating to traditional use in the Stave River area".
(BCUC 1.14.1, p. 3)

"According to Duncan McLaren's 2003 Master's thesis, two Traditional Use Studies have been prepared relating to the Stave River area: one of these TUS studies was by T.H. Dandurand *et al.* (1996); and the other was by Ann Stevenson (1996).126 The first was prepared for BC Hydro, the Stó:lō Nation and the Kwantlen First Nation, while the second was prepared for the Stó:lō Nation and the Kwantlen First Nation." (Attachment 1, p. 37)

2.42.1.1 Section 6 of the 2008 Kennedy and Bouchard Report identifies traditional uses such as fisheries, hunting and trapping, plant foods, large cedars, travel routes and others. Please explain how there is limited information relating to traditional use in the Stave River area given these identified traditional uses.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.42.1.

42.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3, and
BCUC IR 1.14.1, Attachment 1, p. 37
Preliminary Assessment of Kwantlen SOC

"In respect of Aboriginal rights, such as fishing and traditional activities, the evidence suggests that the Kwantlen probably have a reasonable prima facie Aboriginal rights claim in the Stave River area. However, it is difficult to determine the precise scope and nature of any Aboriginal rights because there is limited information relating to traditional use in the Stave River area".
(BCUC 1.14.1, p. 3)

"According to Duncan McLaren's 2003 Master's thesis, two Traditional Use Studies have been prepared relating to the Stave River area: one of these TUS studies was by T.H. Dandurand *et al.* (1996); and the other was by Ann Stevenson (1996).126 The first was prepared for BC Hydro, the Stó:lō Nation and the Kwantlen First Nation, while the second was prepared for the Stó:lō Nation and the Kwantlen First Nation." (Attachment 1, p. 37)

2.42.2 Did BC Hydro review its previously prepared TUS in its preliminary assessments of strength of claim?

RESPONSE:

BC Hydro did not review the 1996 TUS at the time of its preliminary SOC assessment reflected in Exhibit B-7, BC Hydro's response to BCUC IR 1.14.1. However, Bouchard and Kennedy did review this TUS information, as it is summarized in Duncan McLaren's 2003 master's thesis. Bouchard and Kennedy also reviewed Charles Miller's 1981 book *Valley of the Stave*, on which the 1996 TUS heavily relied. Both these sources were considered by Bouchard and Kennedy along with all other readily available evidence in preparing the 2008 Report.

BC Hydro subsequently reviewed the 1996 TUS and, for the reasons set out in BC Hydro's response to BCUC IR 2.42.1, the 1996 TUS does not change BC Hydro's preliminary SOC assessment.

42.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3, and
BCUC IR 1.14.1, Attachment 1, p. 37
Preliminary Assessment of Kwantlen SOC

"In respect of Aboriginal rights, such as fishing and traditional activities, the evidence suggests that the Kwantlen probably have a reasonable prima facie Aboriginal rights claim in the Stave River area. However, it is difficult to determine the precise scope and nature of any Aboriginal rights because there is limited information relating to traditional use in the Stave River area".
(BCUC 1.14.1, p. 3)

"According to Duncan McLaren's 2003 Master's thesis, two Traditional Use Studies have been prepared relating to the Stave River area: one of these TUS studies was by T.H. Dandurand *et al.* (1996); and the other was by Ann Stevenson (1996).126 The first was prepared for BC Hydro, the Stó:lō Nation and the Kwantlen First Nation, while the second was prepared for the Stó:lō Nation and the Kwantlen First Nation." (Attachment 1, p. 37)

2.42.3 What Kwantlen traditional uses did the 1996 TUS indentify?

RESPONSE:

BC Hydro notes that the 1996 TUS states that "due to the short time line, there are limitations to the study." BC Hydro also notes that the 1996 TUS makes certain presumptions, does not provide information on the witnesses and how they came to have the knowledge, does not include evidence for some of the uses, does not include evidence of the intensity or significance of the use, and does not include evidence associating Kwantlen with the use:

- **Archaeological Resources – The 1996 TUS identifies four provincially registered sites. BC Hydro notes that the ethnicity of the people who used the sites cannot generally be determined archaeologically;**

- **Burial grounds (along the Stave Falls area, the length of the lower Stave River, and at Ruskin Prairie) – BC Hydro notes that the two witnesses do not specify these to be Kwantlen sites, nor does the 1996 TUS provide information as to how the witnesses came to this knowledge. The 1996 TUS also states that burial mounds date to 1,000 to 1,500 years ago, which would predate Kwantlen migration to the area;**

- **Large shell heap and fish trap or weir (below the first canyon), consistent with a location fishing location used by Kwantlen fishers – BC Hydro notes that the ethnicity of the people who used the sites cannot generally be**

determined archaeologically. The age of the shell heap and fish trap is undated. The report notes traps as old as 4,600 years old in Kwantlen territory;

- **Stave Falls as an important trading centre – BC Hydro notes this general statement is attributed to a witness without any other details or evidence, nor any information as to how the witness came to this knowledge. It appears that aside from this general statement, the 1996 TUS appears to make this conclusion based on the report of a trail and travel corridor on the west side of the Stave River, and reports that that there was fishing and hunting in the area;**

- **Hunting for deer, elk, and grouse between Ruskin and Stave Falls – BC Hydro notes that this general statement is attributed to a witness without any other detail from the witness. The report also cites a local historian's mention of hunting and trapping at Stave Lake. The 1996 TUS concludes that the Stave area was also a training ground for hunters, without any supporting evidence;**

- **Stave River fishing camps and villages– BC Hydro notes that the report identifies long houses on the west side of Stave Lake and families residing on what is now Hayward Lake. The 1996 TUS does not reconcile the fact of permanent villages all along the Stave River with the presence of additional establishment of summer fishing camps. The 1996 TUS does not provide information as to how the witness came to this knowledge. BC Hydro also notes that the salmon run on the Stave River is a fall/winter run;**

- **Berry gathering - The report cites a witness stating that his family and other people collected blueberries, blackberries, cranberries and crab apples at the Stave River. BC Hydro notes that the 1996 TUS provides no details as time period for the use.**

42.0 Reference: First Nations Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3, and
BCUC IR 1.14.1, Attachment 1, p. 37
Preliminary Assessment of Kwantlen SOC

"In respect of Aboriginal rights, such as fishing and traditional activities, the evidence suggests that the Kwantlen probably have a reasonable prima facie Aboriginal rights claim in the Stave River area. However, it is difficult to determine the precise scope and nature of any Aboriginal rights because there is limited information relating to traditional use in the Stave River area".
(BCUC 1.14.1, p. 3)

"According to Duncan McLaren's 2003 Master's thesis, two Traditional Use Studies have been prepared relating to the Stave River area: one of these TUS studies was by T.H. Dandurand *et al.* (1996); and the other was by Ann Stevenson (1996).126 The first was prepared for BC Hydro, the Stó:lō Nation and the Kwantlen First Nation, while the second was prepared for the Stó:lō Nation and the Kwantlen First Nation." (Attachment 1, p. 37)

2.42.4 Has BC Hydro received traditional use information from the interim TUS reports funded through the Kwantlen CFA?

RESPONSE:

Kwantlen has acknowledged that they did not meet their commitments under the Capacity Funding Agreement to provide interim TUS reporting (May 31, 2010, and December 15, 2010), but have recently indicated that the field work for the study is complete and that the information is being formatted for presentation. Kwantlen also stated that some of their traditional use information would be filed in this proceeding as part of their evidence on June 24, 2011.

43.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3
Preliminary Assessment of Kwantlen SOC

"In the ILM EAO Report, the EAO considered the Kwantlen's SOC in the context of Nodes Q to T of the ILM preferred project route, which is to the north of the Project area. In that context, the EAO concluded:

'The Kwantlen First Nation's main present-day community is within about three kilometres of the proposed Project alignment at Nodes Q to T. Since their ancestors appear to have occupied this area of the proposed Project alignment along the Fraser River at sovereignty, EAO considers that the Kwantlen First Nation's prima facie case for aboriginal rights (such as fishing, hunting and gathering listed above) and title in this segment of the proposed Project alignment is strong'."

2.43.1 Please confirm that the ILM Project alignment at Nodes Q to T includes the Stave River area.

RESPONSE:

BC Hydro is not clear what is meant by the reference in this IR to "the Stave River area." The Interior-to-Lower Mainland Transmission Project (ILM Project) preferred alignment from Node Q to Node T is approximately 42 km in length and crosses the southern tip of Stave Lake at Node S, near Stave Falls Generating Station. Please also refer to BC Hydro's response to BCUC IR 2.43.3.

43.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3
Preliminary Assessment of Kwantlen SOC

"In the ILM EAO Report, the EAO considered the Kwantlen's SOC in the context of Nodes Q to T of the ILM preferred project route, which is to the north of the Project area. In that context, the EAO concluded:

'The Kwantlen First Nation's main present-day community is within about three kilometres of the proposed Project alignment at Nodes Q to T. Since their ancestors appear to have occupied this area of the proposed Project alignment along the Fraser River at sovereignty, EAO considers that the Kwantlen First Nation's prima facie case for aboriginal rights (such as fishing, hunting and gathering listed above) and title in this segment of the proposed Project alignment is strong'."

2.43.2 Please file Appendix E to the ILM EAO Report which contains a description of the ILM Route Alignment Segments.

RESPONSE:

Appendix E of the ILM Project Assessment Report, prepared by the EAO and dated May 12, 2009, is provided as Attachment 1 to this IR response.

Appendix E – Preferred Alignment Route Segments

Segment	Name	Length (km)	Alignment	Terrain
[A-B]	NIC Substation – Kingsvale	50.3	Parallel to 5L82	Easy/ Medium Terrain
[B-C]	Kingsvale – Uztlius Creek	20.2	Parallel to 5L82	Medium Terrain
[C-C1]	Uztlius Creek – 5L82 Structure 44/3	2.2	Parallel to 5L82	Medium Terrain
[C1-C2]	5L82 Structure 44/3 – Spius	8.1	New Alignment	Rough Terrain
[C2-C3]	Spius – Stoyoma	3.5	New Alignment	Medium Terrain
[C3-D]	Stoyoma – North Anderson	6.1	New Alignment	Medium/Rough Terrain
[D-E]	North Anderson – East Anderson	4.6	Parallel to 5L41	Medium Terrain
[E-F]	East Anderson – South Anderson	2.8	Parallel to 5L41	Medium Terrain
[F-F1]	South Anderson – 5L82 Structure 60/6	6.9	Parallel to 5L81/82	Medium/Rough Terrain
[F1-G1]	5L82 Structure 60/6 Spuzzum Creek	5.6	New Alignment	Rough Terrain
[G1-H]	Spuzzum Creek – Sawmill Creek	5.6	New Alignment	Medium Terrain
[H-J1]	Sawmill Creek – All Hallows Creek	5.9	New Alignment	Medium Terrain
[J1 - L]	All Hallows Creek – Emory	13.8	New Alignment	Medium Terrain
[L-N]	Emory – Upper Emory	6.5	Parallel to 5L41	Medium Terrain
[N-O]	Upper Emory - Ruby Creek	7.4	Parallel to 5L82	Medium Terrain
[O-O1]	Ruby Creek - Hicks Lake	9.9	Parallel to 5L82	Medium Terrain
[O1-P]	Hicks Lake - Bear Mountain	5.0	Parallel to 5L82	Medium Terrain
[P Q]	Bear Mountain West Norrish	30.5	Parallel to 5L82	Medium Terrain
[Q-R]	West Norrish – Hatzic Prairie	9.8	Parallel to 5L82	Medium/Rough Terrain
[R-S]	Hatzic Prairie – Stave Lake	10.7	Parallel to 5L82	Medium Terrain
[S-T]	Stave Lake - Pitt Polder	22.6	Parallel to 5L82	Medium Terrain
[T-U]	Pitt Polder - Burke Mountain	8.7	Parallel to 5L82	Medium Terrain
[U-V]	Burke Mountain – Meridian Substation	8.3	Parallel to 5L82	Medium Terrain

43.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 3
Preliminary Assessment of Kwantlen SOC

"In the ILM EAO Report, the EAO considered the Kwantlen's SOC in the context of Nodes Q to T of the ILM preferred project route, which is to the north of the Project area. In that context, the EAO concluded:

'The Kwantlen First Nation's main present-day community is within about three kilometres of the proposed Project alignment at Nodes Q to T. Since their ancestors appear to have occupied this area of the proposed Project alignment along the Fraser River at sovereignty, EAO considers that the Kwantlen First Nation's prima facie case for aboriginal rights (such as fishing, hunting and gathering listed above) and title in this segment of the proposed Project alignment is strong'."

2.43.3 If the EAO concluded the Kwantlen have a strong *prima facie* case for rights and title in the Stave River area, why does BC Hydro conclude the Kwantlen have a reasonable claim? Please reference specific differences or different pieces of information used by the EAO and BC Hydro to make these conclusions.

RESPONSE:

BC Hydro notes that the EAO ILM Project Assessment Report states that Kwantlen did not provide any information on traditional uses of the land in the ILM Project vicinity. The EAO states that it therefore used other available information to determine Kwantlen's *prima facie* case for aboriginal rights and title, but does not cite the evidence on which that determination was made.

With respect to the evidence that BC Hydro reviewed in arriving at its preliminary SOC assessment, please refer to BC Hydro's response to BCUC IRs 2.40.1, 2.41.1, 2.42.1, 2.42.2 and 2.42.3.

44.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, Attachment 1, p. 1
2008 Bouchard and Kennedy Report

"The evidence supports the conclusion that Kwantlen people established and maintained a village site and more temporarily-occupied settlements in the Stave River area after all or most of the original Aboriginal occupants, the 'Skayuks' died, as a result of the first smallpox epidemics of the 1770s…these data indicate that below Stave Falls was an area of intensive Aboriginal use, while the area above the falls appears to have been occupied on a seasonal basis for specific activities. The area was particularly prized for its timber, especially for the cedar used for constructing canoes."

2.44.1 Please confirm that the conclusion regarding the Kwantlen's occupation of the Stave River area is that of the Report authors, Bouchard and Kennedy, and was made based on a review of the ethnographic evidence recounted in Sections 2.0 - 4.0 of the Report. If this is correct, did BC Hydro come to the same conclusion after its review of the same ethnographic evidence in the Report?

RESPONSE:

Confirmed.

BC Hydro's conclusions are set out in Exhibit B-7, BC Hydro's response to BCUC IR 1.14.1, and BC Hydro's responses to BCUC IR 2.40.1, the BCUC IR 2.41 series and the BCUC IR 2.42 series.

44.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, Attachment 1, p. 1
2008 Bouchard and Kennedy Report

"The evidence supports the conclusion that Kwantlen people established and maintained a village site and more temporarily-occupied settlements in the Stave River area after all or most of the original Aboriginal occupants, the 'Skayuks' died, as a result of the first smallpox epidemics of the 1770s…these data indicate that below Stave Falls was an area of intensive Aboriginal use, while the area above the falls appears to have been occupied on a seasonal basis for specific activities. The area was particularly prized for its timber, especially for the cedar used for constructing canoes."

2.44.2 Was the village site established and maintained by the Kwantlen in the Stave River area occupied year-round or seasonally after the 1830s? Was the area below Stave Falls an area of intensive Aboriginal use by many different First Nations peoples or by the Kwantlen as of the 1830s?

RESPONSE:

BC Hydro's view is while that there appears to have been a Kwantlen village upstream of Fort Langley, historical records provide no definitive location at the Stave River. Please refer to BC Hydro's response to BCUC IR 2.40.1.

Regarding the use of the area below Stave Falls, BC Hydro notes that there is very little TUS information, and that the 1996 TUS does not provide evidence of intensity of use. Please refer to BC Hydro's response to BCUC IR 2.42.3.

44.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, Attachment 1, p. 1
2008 Bouchard and Kennedy Report

"The evidence supports the conclusion that Kwantlen people established and maintained a village site and more temporarily-occupied settlements in the Stave River area after all or most of the original Aboriginal occupants, the 'Skayuks' died, as a result of the first smallpox epidemics of the 1770s…these data indicate that below Stave Falls was an area of intensive Aboriginal use, while the area above the falls appears to have been occupied on a seasonal basis for specific activities. The area was particularly prized for its timber, especially for the cedar used for constructing canoes."

2.44.3 Was the area below or above Stave Falls particularly prized for its timber? By whom was it prized? The Kwantlen or other Aboriginal groups?

RESPONSE:

The Stave River area appears to have been prized for its western white pine by Hudson's Bay Company for use as stave materials (2008 Report, page 12 of 54). There is evidence during the setting aside of the three Indian Reserves on the lower Stave River in 1879 that Kwantlen wanted agricultural land, but if that could not be obtained, that Kwantlen would like timber land (2008 Report, page 51 of 54). It appears that Indian Reserve No. 4 on the Stave River was set aside as a timber reserve because of the value of the timber (2008 Report, page 42 of 54).

45.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.1, p. 5
Preliminary Assessment of Matsqui SOC

"The 2011 Kennedy Report and the 2008 Bouchard & Kennedy Report conclude that the various descriptions in the historical literature reflect the Matsqui's presence exclusively on the southern side of the Fraser River and seasonal use of mid-channel islands some distance east from the Stave River".

2.45.1 Did the Matsqui use the Stave River area seasonally or at all?

RESPONSE:

Based on the 2011 Report, BC Hydro's view is that:

- **There is no evidence indicating Matsqui's use of the Stave River area; and**
- **There is evidence that Matsqui's use and territory was limited by the south bank of the Fraser River and Matsqui Island.**

46.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.7, p. 2
BC Hydro Board Decision

2.46.1 What specific information on the impacts to Aboriginal rights and title did the BC Hydro Board of Directors have when making its decision on the Preferred Alternative?

RESPONSE:

This response addresses BCUC IRs 2.46.1, 2.46.2 and 2.46.3.

The Executive Summary and the Alternatives Analysis Table listed in Exhibit B-7, BC Hydro's response to BCUC IR 1.97.0 were the two documents provided to the BC Hydro Board of Directors (Board) for purposes of the February 17, 2011 decision. However, there were many other inputs which went into this Board decision, as follows:

- **IBA Mandate - The Chief Executive Officer (CEO), who attended the February 17, 2011 Board meeting, approved the IBA mandate for the Project on November 4, 2010 after a briefing by the Director of Aboriginal Relations and Negotiations. BC Hydro provided the BCUC with its IBA mandate estimate in Exhibit B-7-1, BC Hydro's confidential response to BCUC IR 1.14.5. Please also refer to BC Hydro's response to BCUC IR 2.24.1 and to BC Hydro's confidential responses to the Confidential BCUC IR 2.2 series;**
- **Executive Review of Alternatives, Project Scope/Costs - The CEO and the Executive Vice President of Generation, who were present at the February 2011 Board meeting for discussion and the answering of questions, as well as other members of the Executive Team, reviewed materials at the following meetings:**
  - **December 14, 2010 - The Decommissioning Alternatives;**
  - **January 17, 2011 - Project costs, schedule, procurement and scope.**

  In addition, at a January 28, 2011 meeting the CEO and Executive Vice President of Generation reviewed Powerhouse and Switchyard safety hazards materials. A copy of these presentation materials is provided as Attachment 1 to BC Hydro's response to AMPC IR 2.10.7; and
- **Board Capital Committee Meeting – At a meeting on February 14, 2011, Management provided an overview of the condition of the Dam and Powerhouse, including the public safety and worker safety risks, and the five Decommissioning Alternatives, followed by a discussion, and a question and answer session.**

46.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.7, p. 2
BC Hydro Board Decision

2.46.2 Were the Application Executive Summary and Alternatives Analysis Table listed in BC Hydro's response to BCUC IR 1.97, the only two documents the Board reviewed before making their February 17, 2011 decision? If not, please provide a copy of the other documents.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.46.1.

46.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.7, p. 2
BC Hydro Board Decision

2.46.3 Did the BC Hydro Board consider other information, such as in-person presentations, to make its February 17, 2011 decision?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.46.1.

47.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.27.1, Attachment 1
Consultation with the Matsqui

"In particular, BC Hydro has been engaged in consultation with Matsqui with respect to the ILM Project. As you note, the EAO found a medium strength of claim in the areas."

2.47.1 To the best of BC Hydro's knowledge, why have the Matsqui not registered as interveners in this Commission proceeding?

RESPONSE:

BC Hydro provided Matsqui with the following:

- **A copy of the Application (Exhibit B-1);**
- **An invitation to attend BC Hydro's Workshop held on February 28, 2011, which Matsqui's counsel attended;**
- **A copy of the Order and the Notice of Application and Written Public Hearing (Exhibit B-6); and**
- **Copies of the Bouchard & Kennedy Research Consultants reports referenced in Exhibit B-7, BC Hydro's response to BCUC IR 1.27.1, and a draft redacted response to BCUC IR 1.14.1.**

BC Hydro also provided Matsqui with funding to review the Application and other Project-related documentation. Please refer to Exhibit B-7-1, BC Hydro's response to BCUC IR 1.14.4, Confidential Attachment 1.

BC Hydro does not know why to-date Matsqui have not registered as interveners in this BCUC proceeding.

48.0 Reference: First Nations Consultation
Exhibit B-7-2, Response to Kwantlen IR 1.3.2
Project Cost Approval

2.48.1 If the BC Hydro Senior Executives approved $80,000 to continue with Identification phase work in March 2006, why did BC Hydro not notify the Kwantlen of the Project until November 2006 and other potentially affected First Nations until March 2007 and later?

RESPONSE:

Case law provides that the duty to consult arises when three elements are met: (1) the Crown has real or constructive knowledge of the potential Aboriginal claim or right; (2) Crown conduct is contemplated; and (3) this conduct may have an adverse impact on the claim or right:

- **The BC Hydro Senior Executive Management approval of $80,000 in March 2006 related to the development of technically feasible options for the Dam portion of the Project and occurred at the beginning of the Identification phase of the Dam portion of the Project. As set out in Exhibit B-7-2, BC Hydro's response to Kwantlen IR 1.3.2, the Identification phase is the earliest phase of project development. Prior to this point in time the Project had not even been conceptualized, and all that had occurred was pre-Identification phase study of Right Abutment and Upper Dam-related problems through Dam Deficiency Investigations (DI). Dam DI work is not a stage in project development – it is undertaken to identify facility conditions and risk factors. Dam DI work may lead to the conclusions that no action is needed to be taken at a particular facility; or that operational changes should be developed; or that capital works are required, which may lead to initiation of a project. In BC Hydro's view, the preliminary funding of studies at the beginning of the earliest stage in project development to determine the feasibility of options does not in and of itself trigger the duty to consult;**

- **The BC Hydro Board of Directors (Board) authorization of $3 million in August 2006 was for initial engineering work with respect to the Dam. This decision occurred during the Identification phase of the Dam portion of the Project. At this point in time BC Hydro was early in the process of screening options to address Right Abutment and Upper Dam deficiencies to determine if the options were even feasible. For example, BC Hydro began examining whether short-term mitigation measures were feasible.**

In BC Hydro's view, the duty to consult was likely triggered after August 2006. Later in 2006, with the beginnings of conceptualization of the Dam portion of the

Project in response to the problems identified through DIs, a decision was made to approach the closest and most potentially impacted First Nation (Kwantlen). In November 2006 the Dam portion of the Project was moving into the very beginning of Definition phase. The Powerhouse portion of the Project did not move into Definition phase until February 2008. During the Definition phase of a project, preliminary design occurs, project scope is defined, alternatives are developed and reviewed, and applications are made for required regulatory and government agency approvals. The Project is currently at the end of the Definition phase (refer to Exhibit B-1, page 5-1, line 17), and BC Hydro has been consulting with Kwantlen for approximately four and a half years with respect to the Project.

As set out in Exhibit B-7, BC Hydro's response to BCUC IR 1.26.1, early in 2007 BC Hydro sought and received advice from Sto:lo Nation and Sto:lo Tribal Council that Kwantlen was the appropriate group to consult with respect to the Project.

48.0 Reference: First Nations Consultation
Exhibit B-7-2, Response to Kwantlen IR 1.3.2
Project Cost Approval

2.48.2 If the BC Hydro Board of Directors approved $3 million for initial engineering work in August 2006, why did BC Hydro not notify the Kwantlen of the project until November 2006 and other potentially affected First Nations until March 2007 and later?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.48.1.

48.0 Reference: First Nations Consultation
Exhibit B-7-2, Response to Kwantlen IR 1.3.2
Project Cost Approval

2.48.3 What was the earliest date that BC Hydro included the concept of upgrading Ruskin Dam in its Long Term Resource Plan or Integrated Resource Plan?

RESPONSE:

Neither the Project nor the concept of upgrading the Ruskin Dam and/or Powerhouse was included in BC Hydro's 2006 Integrated Electricity Plan/Long-Term Acquisition Plan (2006 IEP/LTAP) because the Project was in the Identification phase at the time the 2006 IEP/LTAP was submitted to the BCUC in March 2006.

Neither the Project nor the concept of upgrading the Ruskin Dam and/or Powerhouse were specifically included in BC Hydro's 2008 LTAP because the Resource Smart bundles examined in the 2008 LTAP consisted only of capital growth/expansion projects, and the Project is a sustaining capital project to address the significant seismic/safety and reliability risks presented by the Ruskin Facility; please refer to Exhibit B-7-2, BC Hydro's response to BCSEA IR 1.4.1.

Accordingly, the earliest date that BC Hydro included the Project and/or the concept of upgrading the Ruskin Dam and/or Powerhouse in a long-term resource plan is the 2010 Resource Options Report (ROR), which will form part of the 2011 Integrated Resource Plan (IRP).

48.0 Reference: First Nations Consultation
Exhibit B-7-2, Response to Kwantlen IR 1.3.2
Project Cost Approval

2.48.4 What was the earliest date that BC Hydro funded a study on the upgrade or future possibilities for the Ruskin Dam?

RESPONSE:

As set out in BC Hydro’s response to Kwantlen IR 1.3.2, the March 2006 Senior Executive approval of $80,000 was the earliest date that BC Hydro “funded a study on the upgrade or future possibilities for the Ruskin Dam”. Please also refer to BC Hydro’s response to BCUC IR 2.48.1.

48.0 Reference: First Nations Consultation
Exhibit B-7-2, Response to Kwantlen IR 1.3.2
Project Cost Approval

2.48.5 If either of the dates of inclusion in the Long Term Resource Plan, Integrated Resource Plan or of completion of the studies are earlier than March 2006, why did BC Hydro not notify the Kwantlen of the Project until November 2006 and other potentially affected First Nations until March 2007 and later?

RESPONSE:

As set out in BC Hydro's response to BCUC IRs 2.48.1, 2.48.3 and 2.48.4:

- **The date of inclusion of the Project and/or the concept of upgrading the Ruskin Dam/Powerhouse in a BC Hydro long-term resource plan was 2010; and**

- **The date of funding a study on the upgrade or future possibilities for the Ruskin Dam was March 2006.**

Neither date is earlier than March 2006.

49.0 Reference: Seismic Capability
Exhibit B-7, BCUC 1.2.1, Attachment 1, page 8 of 44

2.49.1 Please provide the Sandwell memos referenced as items (3), (4), (5) and (6) on page 8 of 44 of the Attachment to BCUC 1.2.1.

RESPONSE:

The requested documents are provided as Attachments 1 to 4 to this IR response.

The public version of Attachments 2, 3, and 4 are redacted with respect to the breakdown of cost estimate information for work that has yet to be contracted. In accordance with section 42 of the ATA and the Confidential Filings Practice Directive, BC Hydro respectfully requests that the redacted portions of Attachments 2, 3, and 4 concerning matters to be negotiated with suppliers and the breakdown of cost estimate for work that has yet to be contracted be kept confidential on the basis that disclosure will result in: 1) undue financial loss to BC Hydro and undue financial gain to contractors it will be negotiating with to undertake construction or to supply and install equipment; 2) significant prejudice to BC Hydro's competitive negotiation position with these contractors; and 3) BC Hydro has consistently treated this commercial and financial information on a confidential basis.

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Memo

To	**Andrea Loewie**	Date	**8 May 2007**
		Job No.	**162 164**
From	**Ulf Topf, with review by John Sherstobitoff**	File	**162 164**

Reference:

Previous reviews of the Ruskin Powerhouse carried out by Sandwell Engineering as a subconsultant to Siefken Engineering in 2000 indicated that structural deficiencies limit the withstand of the superstructure to a level much less than the 1:475 level earthquake evaluated but that the powerhouse could be retrofitted to withstand an earthquake with this return period.

The Ruskin Powerhouse was previously analyzed for structural performance, with and without the switchyard located on the powerhouse roof, using a 3-dimensional finite element model (SAP2000, Version 7.2.1). The review was based on a seismic return period of 1:475 (using a BC Hydro provided response spectra, herein referred to as "BC Hydro2000") and an importance factor of 1.0 (per Part 4, 1995 National Building Code). This model and the associated analysis carried out in 2000 were the basis for the scope of work of Task 1 described below.

Task 1

Scope of Work and Deliverables:

Verify and document the performance of the existing powerhouse superstructure, and switchyard located on the powerhouse roof, based on the previous structural review (Siefken and Sandwell Engineering, 2000 using NBC 95 demand per 1:475 seismic return period, importance factor of 1.0). For reference, compare the NBC 95, NBC 2005 and current BC Hydro response spectra for a 1:2475 return period to the spectrum used in the 2000 study.

Findings:

The existing powerhouse performance was documented in the earlier Sandwell/Siefken (Draft Jan 2000) structural review. A ductility factor R of 1.5 was used for the powerhouse superstructure, which reflects the minimal ability to deform inelastically before significant damage, deterioration of strength, or failure. The model was constructed without the switchyard located on the powerhouse roof.

The main finding of the year 2000 study was that several components of the existing structure cannot withstand a BC Hydro2000 (1:475) earthquake, even with an importance factor of only 1.0 and no switchyard on the powerhouse roof.

The main deficiencies found in the existing powerhouse structure are listed below with the powerhouse plan illustrated in Figure 1 attached.

- Bracing in Main East wall consists of steel rods, which are likely to perform poorly after multiple load reversals, as the bracing buckles in compression then "snaps" through to tension loading, leading to possible premature failure.
- West wall, acting as a lateral load resisting element subject to significant shear and moment, would experience uplift at the ends of the wall and high stresses around window openings;
- South wall does not have enough capacity to resist East-West shear;
- North wall does not have enough capacity to resist shear and tension in basement and shows high stresses around window openings;
- East and West Walls of North Wing have very high Demand/Capacity (D/C) ratios in wall shear and bending and high stresses around window openings;
- North Wall of North Wing does not have sufficient resistance for shear and uplift at wall ends;
- No structural connection between the original 1930 roof and the 1949 extension, which will likely result in damage due to "pounding".

Ultimately, these deficiencies indicate that under a 1:475 earthquake (1.0 importance factor, 1.5 ductility factor, BC Hydro2000 response spectrum, and no switchyard on the powerhouse roof) the powerhouse superstructure would experience significant damage with potential for collapse that would likely shut down the powerhouse.

In our current 2007 review, it was noted that the SAP2000 models "Ruskin5" (Existing Building) and "Ruskin6a" (Reinforced Building), as shown in Appendix B of the Year 2000 study, did not include the switchyard steel, which at 30 tonnes amounts to only approx. 0.7 % of the total mass of the powerhouse building (4430 tonnes). It was also found that the above models did not include the 25% snow load mass, which has to be applied for seismic analysis over the roof area. The roof snow load for Mission, according to NBC, is 1.9 kPa with an importance factor of 1.0. When applied to the 1530 m2 roof area, this adds a mass of 74 tonnes, which is 1.7% of the mass of the powerhouse building. The relatively small masses of the switchyard and the snow load (2.4% of total building mass) have minimal effect on the seismic response of the main powerhouse model and therefore will not affect any conclusions regarding seismic withstand of the powerhouse superstructure. Otherwise, based on our review of the models, analysis and results of the 2000 study, we agree with the conclusions in that report.

For reference purposes, the impact of different earthquake return periods, response spectra, and importance factors on seismic performance were also examined. The attached EXCEL graph shows the response spectrum BC Hydro2000 (1:475), which was used in the Year 2000 Sandwell/Siefken study, compared to site specific NBC 2005 (1:475 and 1:2475), and current BC Hydro 2007 (1:2475 and 1.5x 1:2475) spectra. Sandwell did not receive a current BC Hydro 2007 (1:475) spectra. The key parameters of the spectra are also tabulated below.

Spectra used	PGA	Sa (peak)
BC Hydro 2000 (1:475)	0.23	0.55
NBC 2005 (1:475)	0.244	0.485
NBC 2005 (1:2475)	0.455	0.923
BC Hydro 2007 (1:2475)	0.47	1.06
BC Hydro 2007 (1.5 x 1:2475)	0.705	1.59

The BC Hydro2000 (1:475) and site specific NBC 2005 (1:475) are in close agreement, with BC Hydro being slightly lower at higher periods and slightly higher at periods of less than 0.3 seconds As a result, the BC Hydro 2000 spectra produces a seismic demand up to 13% higher than NBC for very stiff structures with periods between 0.1 and 0.2 seconds. Comparison of the site specific NBC 2005 (1:2475) and BC Hydro2007 (1:2475) spectral values shows BC Hydro to be similarly conservative by about 15% in the 0.1 to 0.2 second period range, reducing to match the NBC values at about 2 seconds. According to the NBC 2005, an importance of 1.5 factor has to be applied for the design of new post-disaster rated structures in accordance with Clause 4.1.8.5(1) to the site specific (1:2475) spectral values. As can be seen from the graph, the spectral accelerations for a 1:2475 spectrum (I=1.0) are approximately double of those used in the Year 2000 retrofit study. For the 1:2475 spectrum (I=1.5) the accelerations are approximately 3 times that used in the 2000 analysis.
The use of BC Hydro spectrum rather the NBC 2005 spectrum results in more conservative estimates of the seismic demands and thus will result in more conservative estimates of the requirements and costs to upgrade.

Looking at the different spectra, it is clear that the existing structure cannot withstand a 1:2475 level earthquake (nor the amplified I=1.5 level demand) without severe damage or collapse. Task 3 will evaluate whether the powerhouse can be retrofitted to resist the current BC Hydro 1:2475 earthquake (I=1.5) by increasing the shear wall thicknesses, increasing the number of soil anchors against overturning, etc.

There are currently no mandatory requirements in BC to upgrade existing conventional buildings unless renovations or additions invoke certain "triggers", such as change of use or occupancy. A code or guideline to more effectively address this issue, uniformly across BC, is currently being developed.
Since a BC Hydro seismic upgrade would be voluntary, the extent of upgrading and the selection of a return period and importance factor would be by BC Hydro to achieve the level of performance desired for the superstructure. Similarly, using response spectra analysis or the more rigorous and less conservative time history analysis would be the decision of BC Hydro. In many cases conventional buildings are upgraded to only 75% of I=1.0 code seismic requirements to achieve life safety performance.

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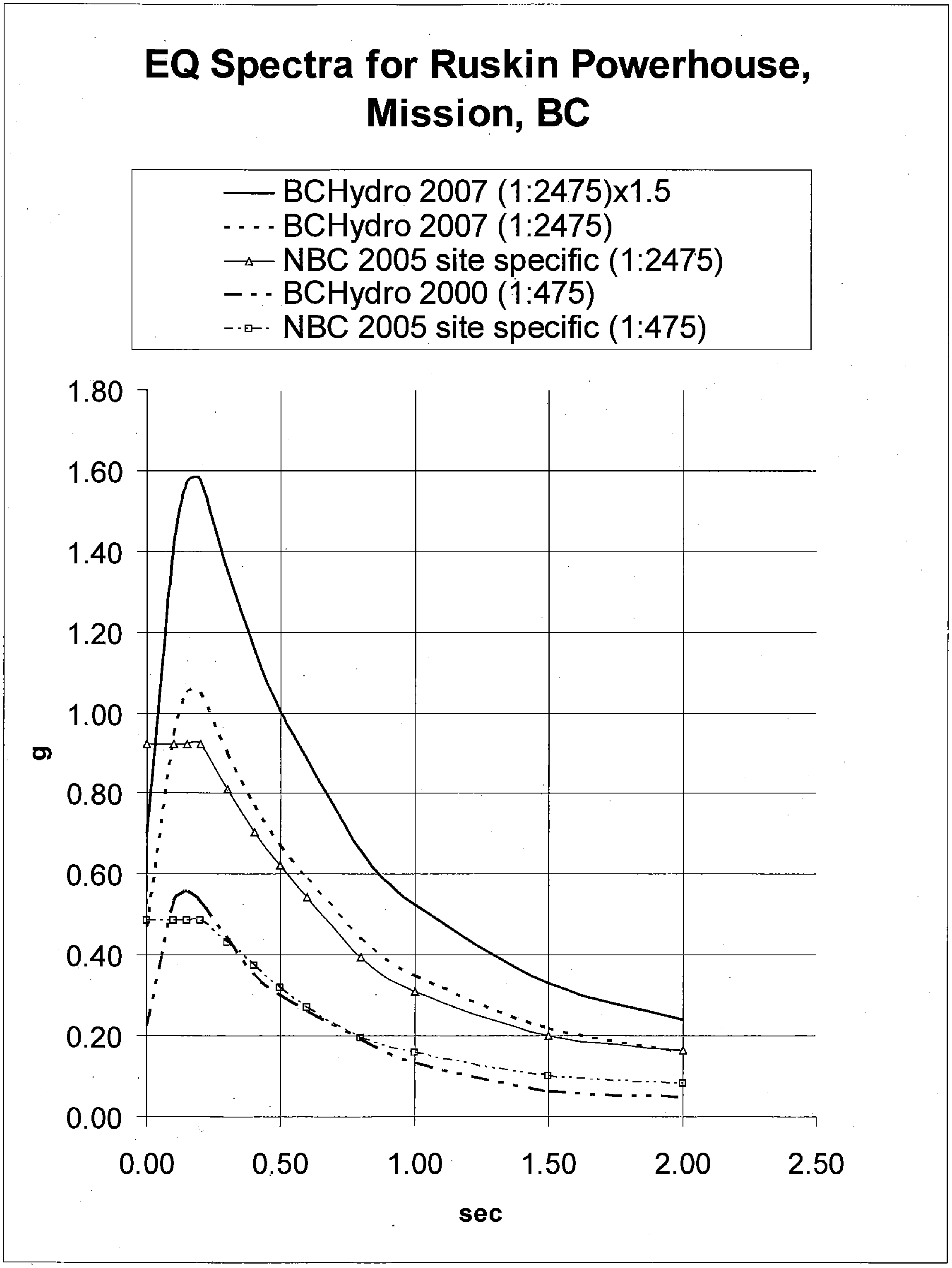
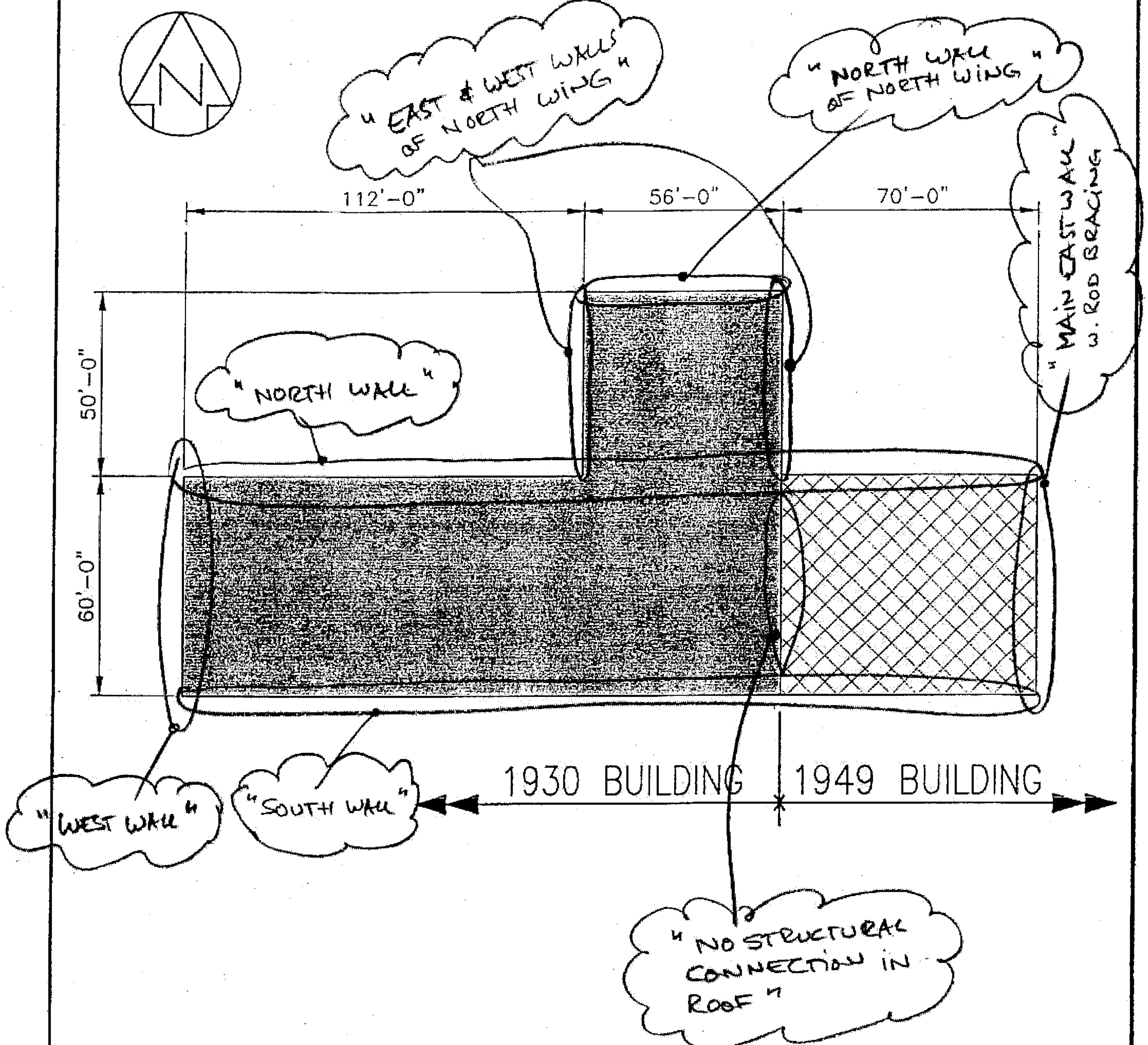
To **Andrea Loewie**
From **Ulf Topf**

Date **7 May 2007**
Page **4**

Memo





POWERHOUSE PLAN

Sandwell

		YR.	MO.	DAY
SCALE	NTS			
DRAWN	RMM			
APP'D.				

SANDWELL CAD FILE NO. 4163-SK100 | A. 114163-SK100 | REV | P1

FIGURE 1.

2005 National Building Code Seismic Hazard Calculation

INFORMATION: Eastern Canada English (613) 995-5548 français (613) 995-0600 Facsimile (613) 992-8836
Western Canada English (250) 363-6500 Facsimile (250) 363-6565

Requested by: ,

April 12, 2007

Site Coordinates: 49.1954 North 122.4073 West

User File Reference:

National Building Code ground motions:
2% probability of exceedance in 50 years (0.000404 per annum)

Sa(0.2)	Sa(0.5)	Sa(1.0)	Sa(2.0)	PGA (g)
0.923	0.621	0.310	0.165	0.455

1:2475

Notes. Spectral and peak hazard values are determined for firm ground (NBCC 2005 soil class C - average shear wave velocity 360-750 m/s). Median (50th percentile) values are given in units of g. 5% damped spectral acceleration (Sa(T), where T is the period in seconds) and peak ground acceleration (PGA) values are tabulated. Only 2 significant figures are to be used. ***These values have been interpolated from a 10 km spaced grid of points. Depending on the gradient of the nearby points, values at this location calculated directly from the hazard program may vary. More than 95 percent of interpolated values are within 2 percent of the calculated values.*** Warning: You are in a region which would be affected by the ground motion from a Cascadia subduction event. The interpolator includes consideration of the deterministic ground motions from Cascadia for 0.0021, 0.001 and 0.000404 per annum probabilities, but not for 0.01 per annum.

1:475

Ground motions for other probabilities:

Probability of exceedance per annum	0.010	0.0021	0.001
Probability of exceedance in 50 years	40%	10%	5%
Sa(0.2)	0.220	0.485	0.662
Sa(0.5)	0.142	0.320	0.440
Sa(1.0)	0.074	0.159	0.217
Sa(2.0)	0.038	0.083	0.115
PGA	0.114	0.244	0.328

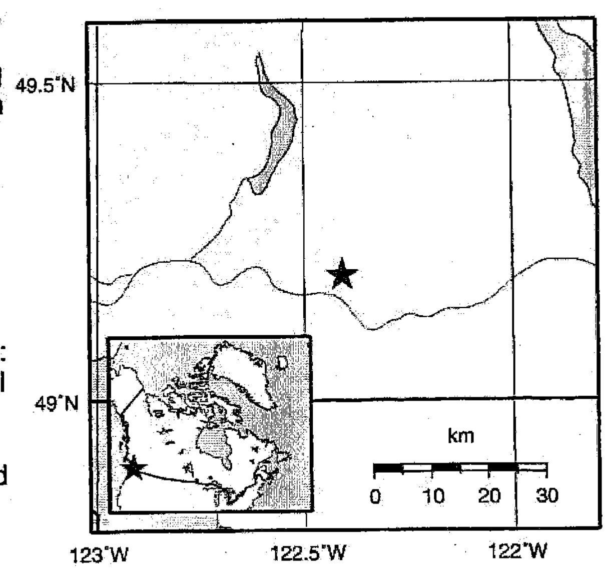
References

National Building Code of Canada 2005 NRCC no. 47666; sections 4.1.8, 9.20.1.2, 9.23.10.2, 9.31.6.2, and 6.2.1.3
Appendix C: Climatic Information for Building Design in Canada - table in Appendix C starting on page C-11 of Division B, volume 2

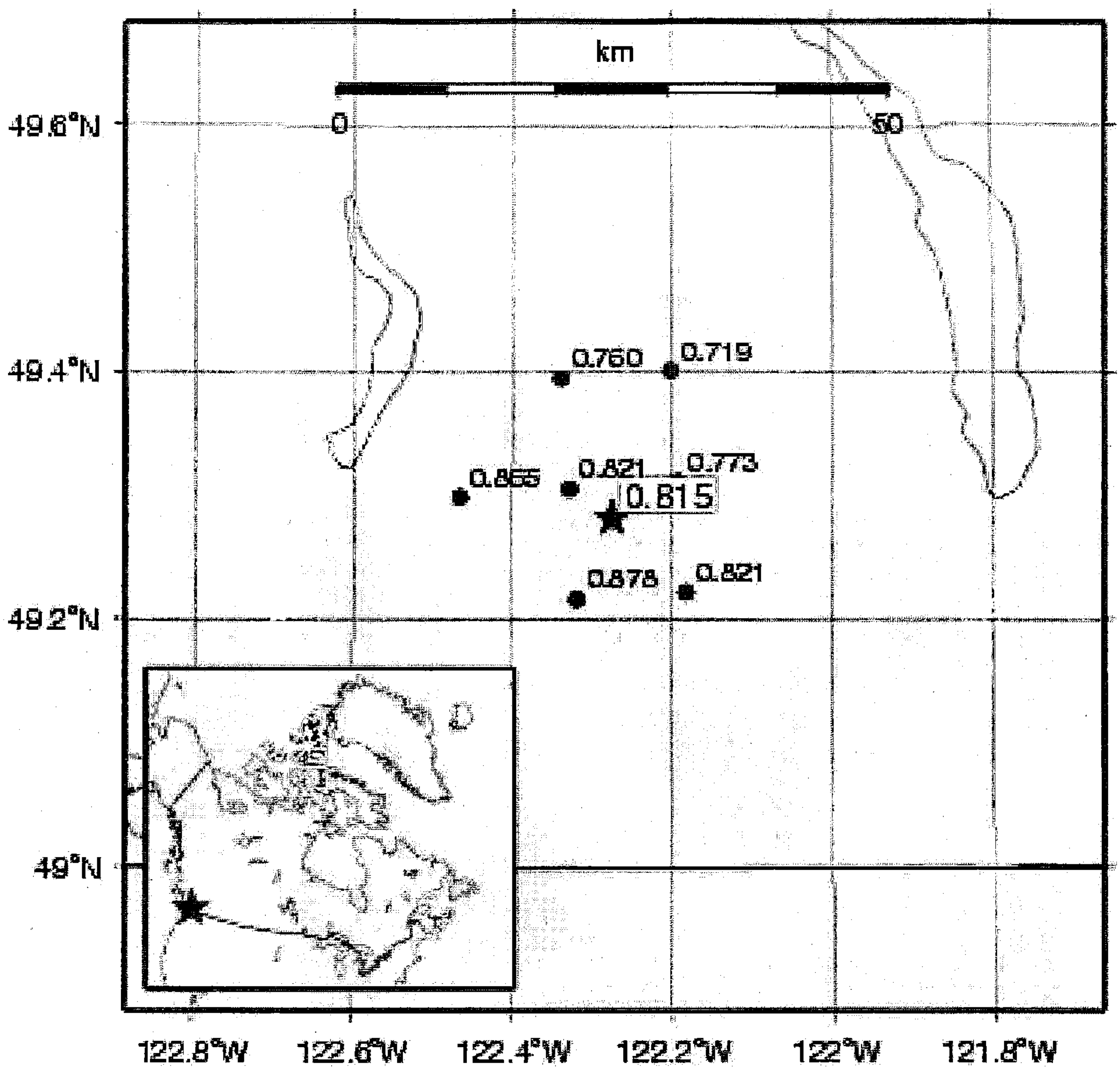
User's Guide - NBC 2005, Structural Commentaries NRCC no. 48192
Commentary J: Design for Seismic Effects

Geological Survey of Canada Open File xxxx
Fourth generation seismic hazard maps of Canada: Grid values to be used with the 2005 National Building Code of Canada (in preparation)

See the websites *www.EarthquakesCanada.ca* and *www.nationalcodes.ca* for more information



Aussi disponible en français



km
0
50
49.6°N
49.4°N
49.2°N
49°N
0.760
0.719
0.865
0.821
0.773
0.815
0.878
0.821
122.8°W
122.6°W
122.4°W
122.2°W
122°W
121.8°W

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Memo

To	**Andrea Loewie**	Date	**8 May 2007**
		Job No.	**162 164**
From	**Ulf Topf, with review by John Sherstobitoff**	File	**162 164**

Reference:

Previous reviews of the Ruskin Powerhouse carried out by Sandwell Engineering as a subconsultant to Siefken Engineering in 2000 indicated that structural deficiencies limit the withstand of the superstructure and the HT switchyard steel to a level much less than the 1:475 level earthquake evaluated but that the powerhouse and switchyard steel could be retrofitted to withstand an earthquake with this return period.

As part of that study, Siefken prepared a budgetary cost estimate for the Ruskin Powerhouse superstructure based on design and details prepared by Sandwell. That cost estimate dated January 7, 2000 was based on year 2000 market construction costs and was for direct costs only.

Later in year 2000, after a detailed computer analysis and conceptual seismic retrofit design for the switchyard steel structure (HT Switching Structure) located on the powerhouse roof, Sandwell prepared a cost estimate for the direct construction costs related to the switchyard structure upgrade (again excluding all indirect costs).

Task 2

Scope of Work and Deliverables:

Verify and document the feasibility of upgrading the existing powerhouse superstructure to withstand the BC Hydro2000 seismic demand for a 1:475 seismic return period, with and without the switchyard located on the powerhouse roof, based on the existing retrofit design (Siefken and Sandwell Engineering, 2000) and summarize the existing cost estimate for implementing the retrofit. Provide estimate of current cost including escalation from 2000.

Findings:

Based on our review of the year 2000 studies and drawings, we agree that upgrading the powerhouse superstructure and switchyard is feasible and practical for the 1:475 level earthquake, with an importance factor of 1.0. The proposed upgrades were as follows:

- Construct new walls on the south, east and north sides of the 1949 addition in the form of reinforced concrete shear walls.

  - Infill some windows on the west, north and north wing walls
  - Install rock anchors and drag struts on the north wing and the west wall.
  - Add shear wall segments along the north wall basement.
  - Provide a structural connection between the 1930 and 1949 concrete roof slabs.
  - Replace and/or reinforce steel sections and connections of the switchyard; repaint

Current practises of using Fibre Reinforced Polymers (FRP) upgrade concrete structures could potentially reduce the cost of upgrading. Also, using current "performance based" practises for seismic upgrades, such as FEMA 356 (released in Nov 2000, now an ASCE standard) or using the software PERFORM, would also likely reduce the cost of an upgrade. Such optimization is not covered in this memo, and is left for future detailed design work.

Powerhouse Superstructure Cost Estimate:
The memo by Siefken dated January 7, 2000 itemizes and provides a cost estimate for a seismic upgrade for a 1:475 level earthquake, importance factor 1.0, of the following components:

[redacted]

HT Switchyard Steel Structure:
The Sandwell Memo, dated November 2000 and titled "Draft - Seismic & Condition Evaluation, Ruskin Powerhouse HT Switchyard Structure" itemized and provided a cost estimate for the seismic upgrade for a 1:475 level earthquake, importance factor 1.0, of the following components:

[redacted]

Based on construction cost trends observed by the Sandwell cost estimating department in other projects in Vancouver it is recommended to escalate the above year 2000 cost estimates by a factor of 1.7 (note that this factor is much higher than a common index such as the All Items Canada Price Index, which for Vancouver during the period of November 2000 to February 2007 increased by a factor of 1.13). This means the direct cost of the upgrades in 2007 dollars would be as follows:

Upgrade Powerhouse Superstructure	[redacted]
Upgrade HT Switchyard Structure	[redacted]

The above cost estimate for an upgrade to the I=1.0, 1:475 level earthquake should be treated as an "order of magnitude" estimate. The related cost estimate for an upgrade to the I=1.5, 1:2475 level earthquake is addressed in the Task 3 memo.

The other memos and drawings discussed above are attached.

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Memo

To	**Andrea Loewie**	Date	**7 May 2007**
		Job No.	**162 164**
From	**Ulf Topf, with review by John Sherstobitoff**	File	**162 164**

Reference: **BC Hydro Ruskin Powerhouse**
Seismic Re-Assessment of Superstructure -Task 3

Background:

The original intent to carry out Task 3 was to use the computer models prepared for Sandwell's work carried out in the year 2000, with new loading data per the current seismic demands. Unfortunately using the computer models proved much more difficult and less satisfactory than anticipated, and as such the re-assessment was also carried out using manual calculations per the seismic provisions of NBCC 2005.

The finite element models of the Sandwell analysis in the year 2000 were created with the program SAP2000 Version 7.x.x. Several different models of the powerhouse were found in Sandwell project archives. They are models of the existing (non-upgraded) powerhouse, and the existing (upgraded) powerhouse with and without the switchyard. However, incomplete documentation exists to explain the exact difference between some of the seemingly (graphically) identical models.

Some difficulty was experienced in running the models created in the earlier study by SAP2000 Version 7.x.x on the current SAP2000 used by Sandwell, Version 10.x.x. To run models created by SAP 2000 Version 7.x.x on SAP2000 Version 10.x.x, a "translation" of the models has to be performed within SAP2000 Version 10.x.x. It was noted that the translated files were approximately four times the size of the original file. Also, the analysis results of the "translated" powerhouse files seem to produce substantially different results for the same spectra (e.g. mass participation ratios vs. period) compared to printed output from the year 2000 analysis. The reason for this is currently being investigated by CIS (the authors of SAP 2000).

Sandwell was able to obtain a 30-day trial version of SAP2000 version7.5 and verified that most of the models created with V7.x.x in the year 2000 found in Sandwell archives, when run on SAP2000 version7.5, give identical results to those printed out in the year 2000. To avoid problems created by the translation of models as mentioned above, the SAP2000 program version 7.5 was used to analyze powerhouse models from the earlier study, suitably reinforced to withstand spectra loads per current BC Hydro design criteria.

Task 3 - Scope of Work and Deliverables:

Assess and document whether the existing retrofit design for the powerhouse superstructure can withstand the current earthquake design criteria (assume 1:2475, with an importance factor of 1.5 as required by the NBC2005), with and without the switchyard located on the powerhouse roof. If not sufficient, provide general recommendations and order of magnitude cost estimates for the structural upgrades required to meet current earthquake design criteria (i.e. sufficient to assess whether the relocation or replacement of the powerhouse should be considered).

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Task 3 Findings:

The existing (year 2000) retrofit design was tailored for the powerhouse superstructure to resist a BC Hydro2000 (1:475) earthquake with an importance factor of 1.0. To minimize cost, most of the retrofit upgrades proposed and detailed in the year 2000 study were designed to provide a D/C ratio between 0.8 and 1.0. This means that very little, if any, reserve capacity is available in the existing retrofit design to resist the significantly higher forces due to a (1:2475) earthquake applied with an importance factor of 1.5. Looking at the different spectra attached to the Memo for Task 1, it is clear that the existing structure cannot withstand a (1:2475) x1.5 level earthquake without severe damage or collapse, and that the upgrade proposed in 2000 needs to be modified for the larger demand.

Manual calculations per NBC 2005 indicate that it is feasible to retrofit the superstructure to withstand forces due to a (1:2475) earthquake with an importance factor of 1.5. The SAP2000 model was revised for the proposed retrofits determined by manual calculations. The resulting stresses in the key walls were similar to the stresses in the proposed year 2000 upgrade for the I=1.0 1:475 loading, however a detailed evaluation of the computer results was not carried and is beyond the scope of this assignment. For the level of effort carried out, it is concluded that the analyses also reasonably confirms the feasibility of the proposed retrofit.

The following superstructure retrofit is proposed, which is basically the concept of the retrofit design of the year 2000 study with increased scantlings and additional infill of openings:

- Construct 500mm new concrete shear walls down to bedrock elevation, surrounding Unit 3 on three sides (N, E and S). To preserve the appearance of the South wall recesses lined with reflective glass, matching the window pattern of the Units 1 and 2, will be incorporated in the new S shear wall.
- Infill all windows on the West, North and East walls of the North wing and add new interior 250mm thick concrete shear walls, doweled into the existing W, N & E walls.
- On the West wall of the powerhouse infill all windows and add a new 250mm thick internal concrete shear wall, doweled into the existing West wall. Again reflective glass could be used on the outer surface of the infilled windows if preserving appearance was essential.
- To resist overturning, provide rock anchors and vertical drag struts at the ends of all the shear walls.
- Construct a structural connection between the 1930 and 1949 roof slabs and provide drag struts to connect the North wing structure to the turbine hall of the powerhouse.
- Reinforce the west portion of roof to increase its diaphragm capacity
- Existing equipment door openings to be preserved, except at basement of North wall in way of new shear wall.

Note that the above retrofit is conceptual only and will require a detailed review to confirm constructability and compatibility of the proposed modifications with the BC Hydro mechanical and operational requirements for the powerhouse. There will likely be significant requirements to relocate services and equipment to accommodate the increased interior wall thickness and use of that space. All such relocation is deemed feasible, especially when carried out in parallel with the overall proposed powerhouse upgrade. Such costs are not included in the estimate below.

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Rough Order of Magnitude Cost Estimate:
(Note: Estimates are for 2007 direct construction costs only, excluding costs of equipment/service relocations as discussed above).

For illustration of major upgrading components, see attached 4 plots of computer model with hand mark-ups.

<u>Powerhouse Superstructure:</u>

From Task 2, the estimated cost for seismic upgrade of the powerhouse superstructure to resist 1:475 I=1.0 earthquake, with the switchyard located on the powerhouse roof, is approximately (incl. 20% contingency): [redacted]

[redacted]

<u>HT Switchyard Steel Structure:</u>

From Task 2, the estimated cost for seismic upgrade of the HT switchyard steel structure to resist 1:475 I=1.0 earthquake is approximately [redacted]

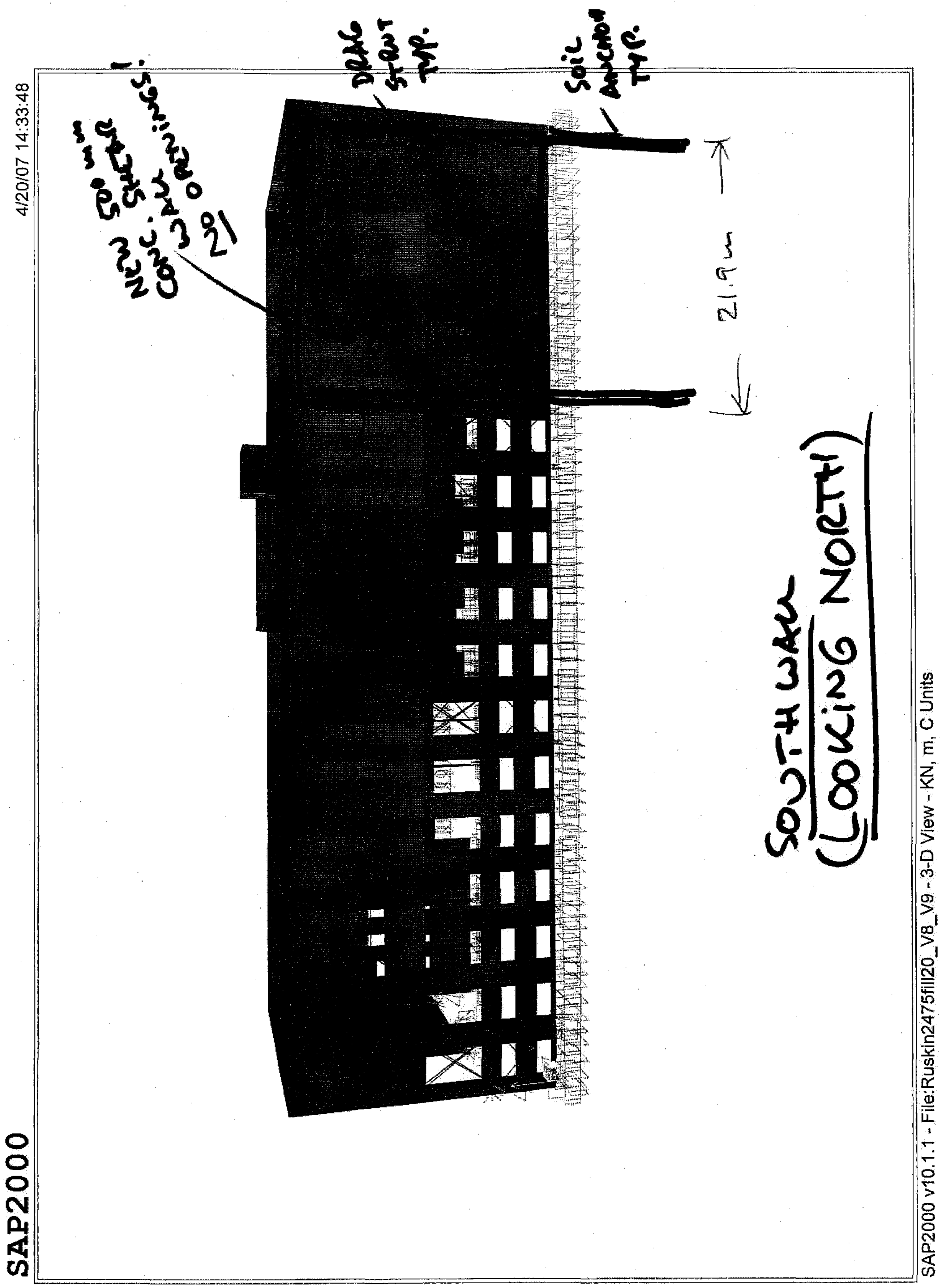
Estimated incremental (1:2475 EQ) upgrade cost ([redacted]

HT Switchyard Steel Structure Upgrade Total (Task 2 + Task3) [redacted]

Comment:

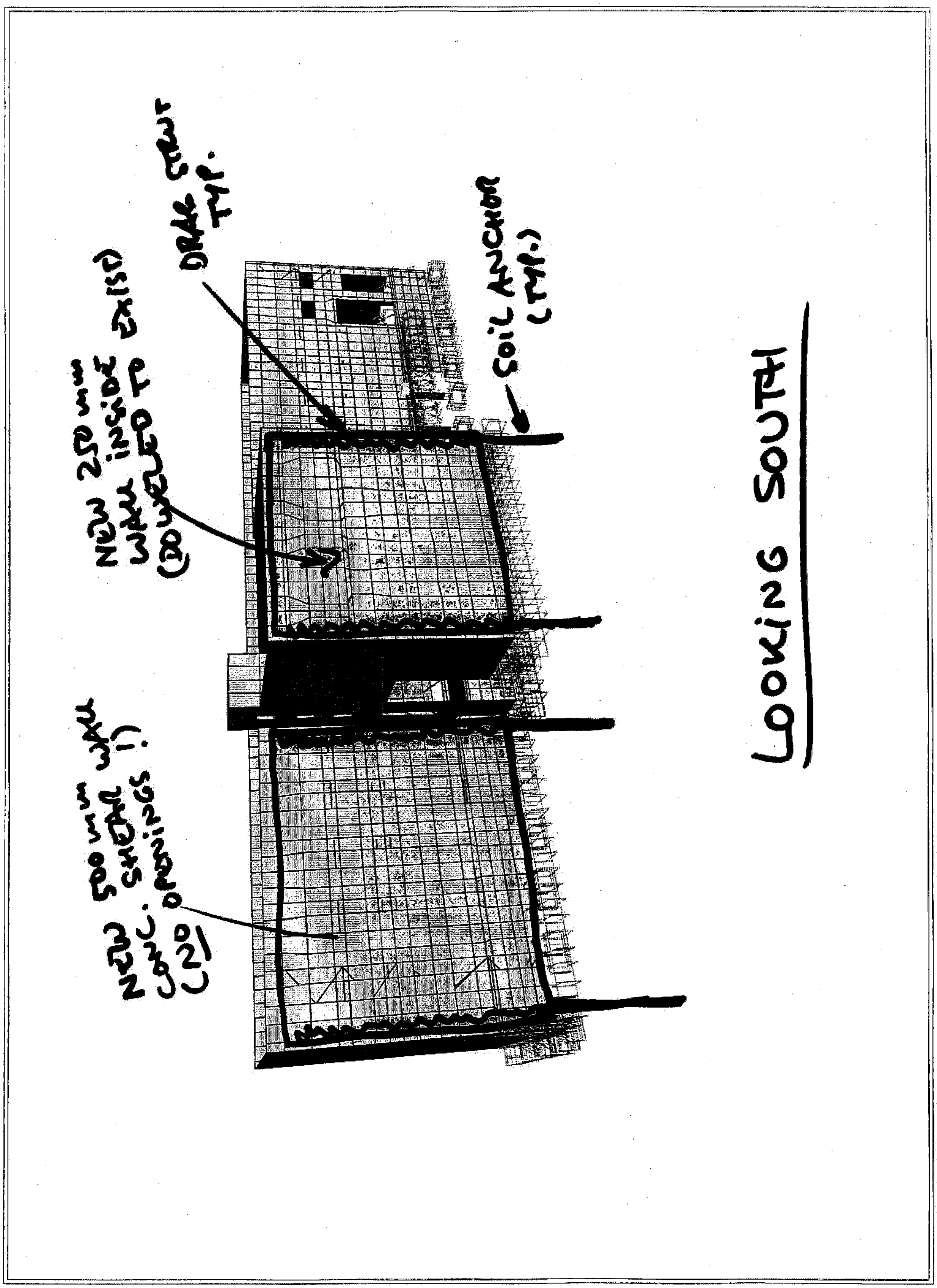
The upgrade of the powerhouse superstructure can be designed to withstand a (1:2475) x1.5 level earthquake without major damage or collapse. However, due to the low ductility of the older concrete walls (e.g. south and west wall of powerhouse Units 1 & 2, and all walls of "wing" to the north) there will likely still be significant cracking at the bottom of the walls and columns supporting the crane rails.
Subsequent non-linear time history analysis should incorporate non-linear elements of all columns to ensure the cracking does not affect the vertical load carrying capacity nor be significant enough to shutdown the powerhouse. If some upgrade is necessary, the use of Fibre Reinforced Polymers (FRP) to wrap affected columns is one very cost effective means to provide increased ductility and increased vertical load carrying capacity.

Consideration should be given to the cost/benefits of replacing the entire powerhouse superstructure with a lightweight steel superstructure with very high ductility (e.g. moment frames) or a structure with energy absorbing devices (dampers, buckling inhibited braces, etc.; as a means to keep the superstructure effectively undamaged following the design earthquake). This will significantly reduce the mass and, most importantly, have natural periods away from the peak of the earthquake response spectrum. A variation of this alternative would be to remove only the heavy concrete façade, retaining the steel skeleton including crane beams and crane, and installing new ductile bracing or other devices mentioned above.


SAP2000
4/20/07 14:33:48
SAP2000 v10.1.1 - File:Ruskin2475fill20_V8_V9 - 3-D View - KN, m, C Units
DRAG STRUT TYP.
SOIL ANCHOR TYP.
21.9m
SOUTH WALL
(LOOKING NORTH)

4/20/07 14:39:44

SAP2000



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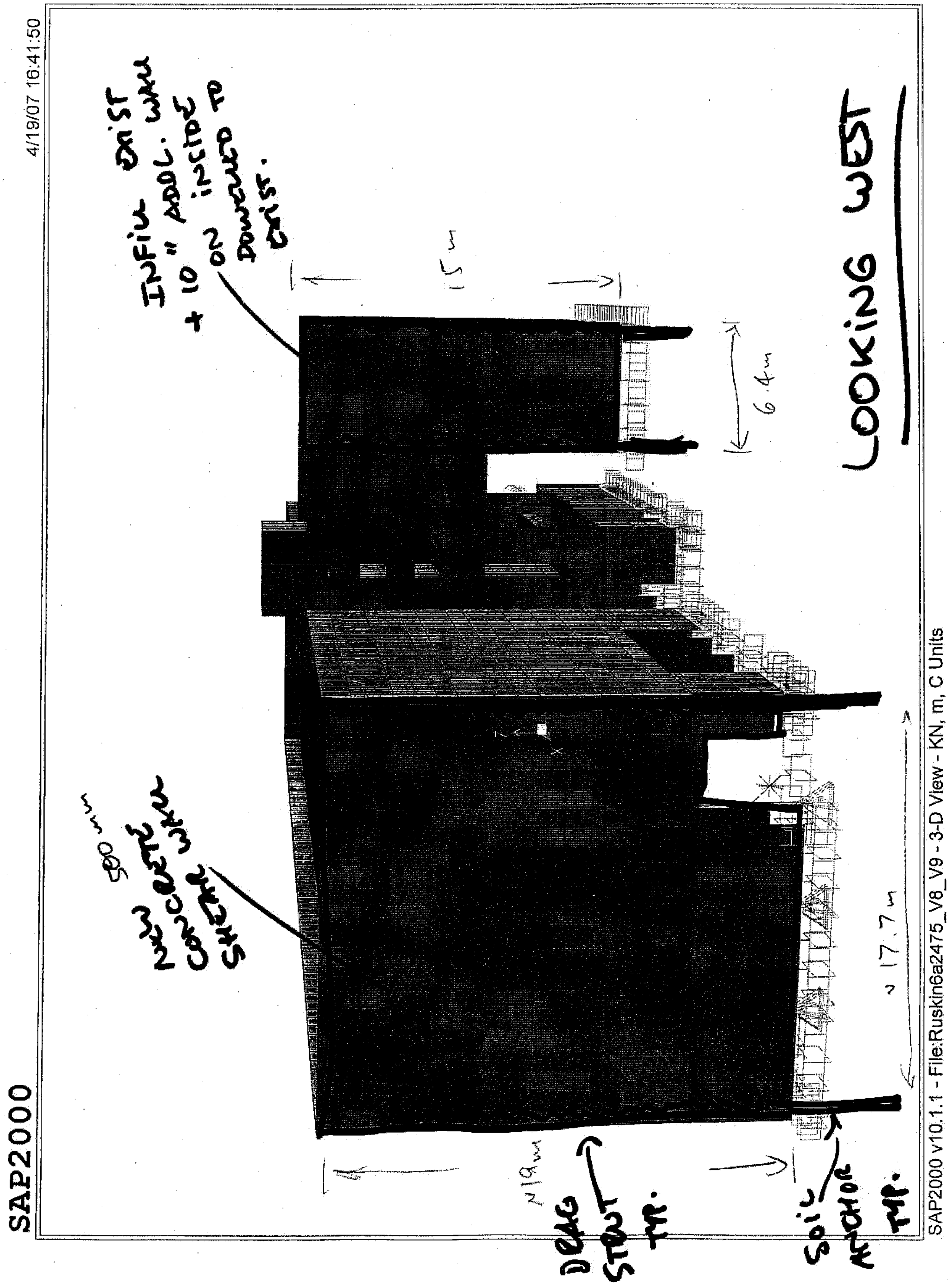
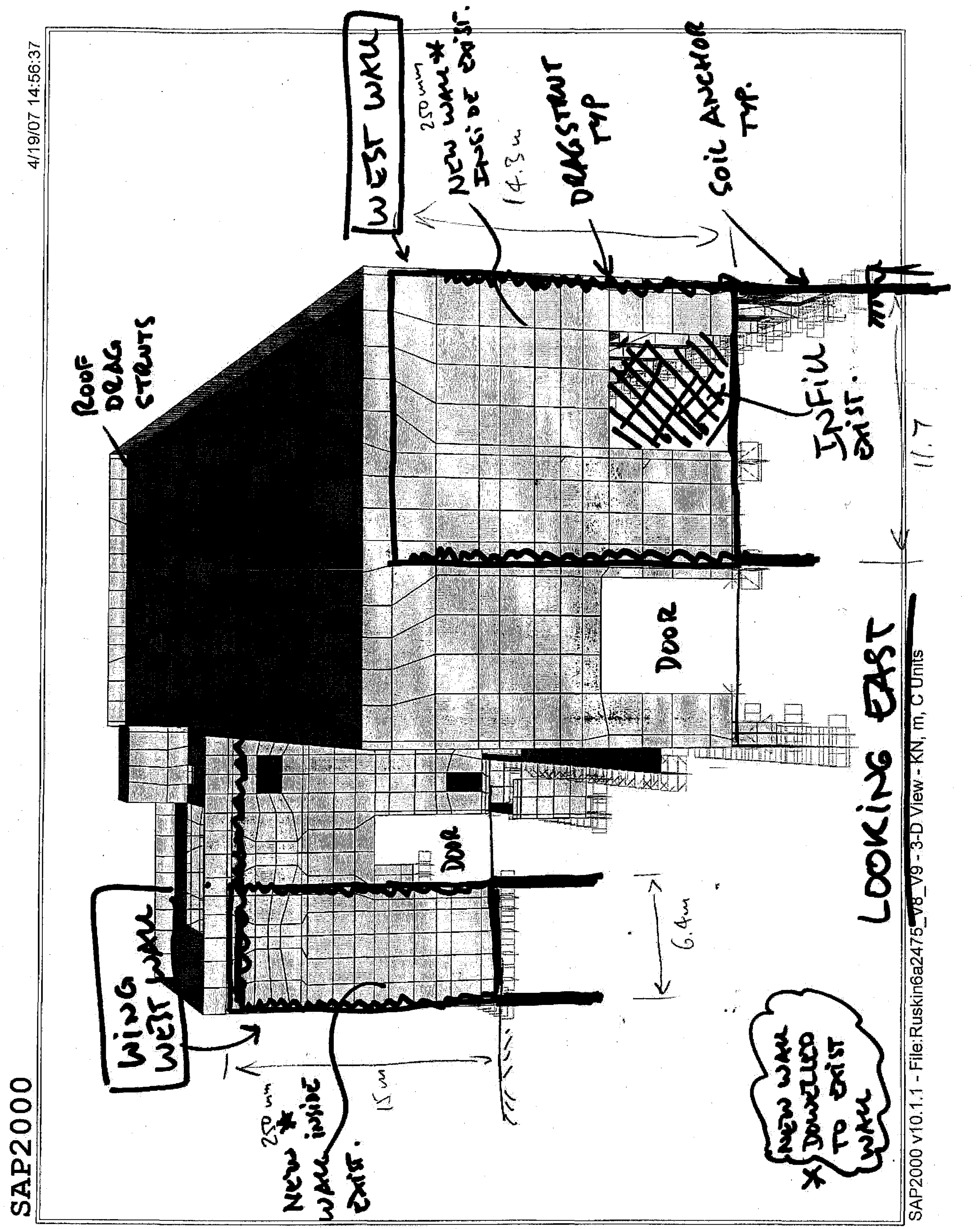

SAP2000
4/19/07 16:41:50
INFILL EXIST + 10" ADDL. WALL ON INSIDE DOWELLED TO EXIST.
15 m
6.4 m
LOOKING WEST
NEW 500 mm CONCRETE SHEAR WALL
~19 m
DRAG STRUT TYP.
SOIL ANCHOR TYP.
~ 17.7 m
SAP2000 v10.1.1 - File:Ruskin6a2475_V8_V9 - 3-D View - KN, m, C Units


4/19/07 14:56:37
SAP2000
ROOF DRAG STRUTS
WEST WALL
250 mm
NEW WALL * INSIDE EXIST.
14.3 m
DRAGSTRUT TYP
SOIL ANCHOR TYP.
INFILL EXIST.
11.7
DOOR
DOOR
WING WEST WALL
250 mm
NEW WALL * INSIDE EXIST.
15 m
6.4 m
LOOKING EAST
* NEW WALL DOWELLED TO EXIST WALL
SAP2000 v10.1.1 - File:Ruskin6a2475_V8_V9 - 3-D View - KN, m, C Units

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Memo

To	**Andrea Loewie**	Date	**7 May 2007**
		Job No.	**162 164**
From	**Ulf Topf, with review by John Sherstobitoff**	File	**162 164**

Reference: **BC Hydro Ruskin Powerhouse**
Task 4 -Seismic Assessment of Substructure

Previous reviews of the Ruskin Powerhouse superstructure carried out by Siefken Engineering and Sandwell Engineering in 2000 indicated that structural deficiencies limit the withstand of the superstructure during a 1:475 earthquake and that the powerhouse can be retrofitted to withstand this earthquake return period. A recent review of those results in the light of the latest code requirements was carried out in 2007 by Sandwell Engineering and has been documented in separate Memos.

BC Hydro asked Sandwell Engineering to also perform a high level assessment to assess and document the seismic withstand and performance of the powerhouse substructure under current earthquake design criteria and whether the powerhouse substructure can reasonably be upgraded to meet current earthquake design criteria (or whether relocation or replacement of the powerhouse should be considered). No previous study was done by Sandwell of the substructure seismic performance.

Information provided by BC Hydro for this assessment:
- Existing design drawings for the powerhouse substructure for units 1,2 and 3.
- Topographical/geological data (in the form of 3 drawings) from the ongoing penstock assessment.

Task 4

Scope of Work and Deliverables:

Assess and document the seismic withstand and performance of the existing powerhouse substructure under current earthquake design criteria (1:2475). If found deficient, provide general recommendations and order of magnitude cost estimates regarding the structural upgrades required to meet current earthquake design criteria (i.e. sufficient to assess whether the relocation or replacement of the powerhouse should be considered). The powerhouse substructure is to be assessed on a qualitative basis, using available structural and geological information, and will not be added to the 3D structural model. Comment on the appropriateness of this approach and note any significant assumptions / limitations

General:

For the purpose of this assessment, we consider the "Substructure" to consist of the structural concrete elements below El. 102/105 supporting the main powerhouse superstructure and the turbines & generators (see attached sketch). The structural elements below El. 102/105 are generally cast-in-place concrete with voids for the turbines, associated penstock inlets, scroll cases, turbine pits, draft tubes, drains, etc. all of which are lined with steel plate and some unlined access stairs/tunnels. According to the sections available on the drawings, the concrete is cast directly on/against bedrock on the base and on the upstream side. No information regarding the strength of the concrete was found on the available drawings.

Sandwell received 3 geological drawings showing the bedrock topography for the left dam abutment and the dam. However, these do not provide information in the area of the powerhouse regarding the type of bedrock, fissurization of the bedrock etc. and hence are not very useful for assessing seismic withstand of the powerhouse substructure.

Findings:

Some of the substructure drawings with sections show (pictorially) a fairly rough (presumably blasted) profile of the bedrock under the turbines. However, there are no specific notes about cleaning/surface preparation/minimum profile roughness of the rockface before placement of concrete.
If good bond between concrete and rock was achieved, the sliding & overturning resistance of the massive substructure is probably sufficient to meet current earthquake design criteria. However concrete core samples intercepting the interface between concrete and rock should be taken to verify the strength of the concrete, concrete to rock bond, the properties of rock below, and then determine the capacity of the concrete/rock interface and the capacity of a failure plane through the rock.

There is the potential for the entire substructure body to slide southwards during a major earthquake and this should be investigated in a future study. (Note that the spectral acceleration from the BC Hydro2007 (1:2475) spectrum in the short period range (where the combined response of the superstructure and substructure is expected to be varies from 0.5 – 1.1g for an importance factor of 1.0, to 0.7 – 1.6g with an importance factor of 1.5. Thus the seismic lateral load demand on the substructure could be as high as 1.6g and is worth investigating.

If it is found that there is not sufficient resistance, vertical and inclined rock anchors could be installed to fully secure the substructure to the rock. In our opinion this would be feasible during the proposed construction to replace equipment.

Allowing for an approximate combined weight of superstructure, equipment and substructure of 30,000 tonnes subject to a 1g horizontal acceleration, and assuming extremely conservatively that there is no substructure/rock interface resistance, then some 300 #20 anchors (estimated to cost installed [redacted]) would be needed to resist the lateral load. On this basis, an estimate of cost to resist all lateral load by anchors may be in the range of [redacted].

In the future it is recommended to initially analyze a 2D "slice" model of the superstructure/substructure/rock using software such as FLAC to determine if any anchorage is actually required; and if so, develop an estimate of the extent and cost of such anchorage.

A thorough review of generator/turbine concrete support structure details to determine whether they meet current earthquake design criteria is understood to be part of the planned replacement of the generators and turbines, including the following work:

- anchorage of major mechanical / electrical equipment such as tanks, transformers, etc.
- anchorage of secondary mechanical / electrical equipment such as pipes, cables, lighting fixtures etc.

In summary, it is possible (however very unlikely) that the entire powerhouse substructure could slide southwards during a major earthquake which if it happened would shutdown the powerhouse, and involve major rehabilitation. Such an occurrence would be considered catastrophic with regards to long term power production. Given the lack of information that appears to be available, we recommend that core samples be taken and as a minimum 2-D modelling be carried out to confirm whether and to what extent any rehabilitation of the structure is required. If the substructure withstand is found to be insufficient, we believe that this can be remedied by anchoring, at a cost in the order of magnitude of [redacted].

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To **Andrea Loewie**
From **Ulf Topf**

Date **7 May 2007**
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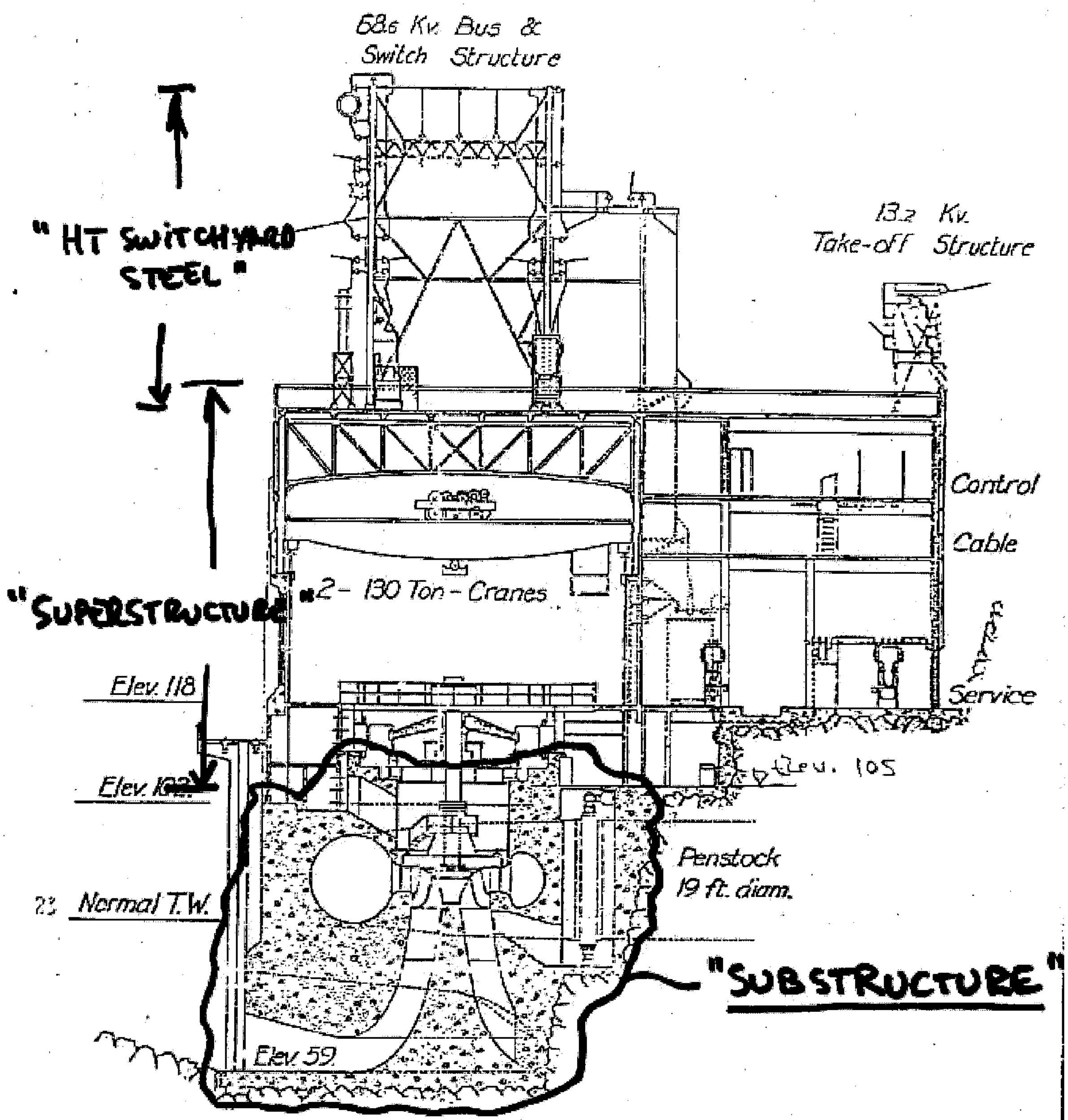


SECTIONAL ELEVATION

BCH & PA No. 423-M04-C70 R0

B. C. ELECTRIC RY. CO. LTD.

RUSKIN GENERATING STATION

PLANS & ELEVATION

VANCOUVER, CANADA. OCTOBER, 1929.

50.0 Reference: Crane Upgrade Costs
Exhibit B-7, BCUC 1.4.1

"BC Hydro rejected upgrading the existing cranes because while upgrading the existing cranes would be $1 million less than BC Hydro's proposal, this alternative would require significant work and would still have significant reliability risks."

"The proposed replacement of the existing crane system with a single 240 Ton crane at an estimated cost of $2.9 million results in lower cost compared to replacement with a dual crane system estimated to be $4.3 million."

2.50.1 Please reconcile these two statements.

RESPONSE:

The two quotations noted in the preamble are referencing different crane options described in Exhibit B-7, BC Hydro's response to BCUC IR 1.4.1.

The first preamble quotation compares the $2.9 million cost of the proposed installation of a new single 240 Ton crane with the $1.9 million cost of refurbishing the existing crane system and explained that while the refurbishment option would be $1 million less than BC Hydro's proposed crane solution, this alternative would require significant work and would still have significant reliability and schedule risks. These risks cannot be addressed through refurbishment.

The second preamble quotation compares the $2.9 million cost of the proposed installation of a new single 240 Ton crane with the cost to install a new dual 120 Ton crane system, estimated to cost $4.3 million.

50.0 Reference: Crane Upgrade Costs
Exhibit B-7, BCUC 1.4.1

"BC Hydro rejected upgrading the existing cranes because while upgrading the existing cranes would be $1 million less than BC Hydro's proposal, this alternative would require significant work and would still have significant reliability risks."

"The proposed replacement of the existing crane system with a single 240 Ton crane at an estimated cost of $2.9 million results in lower cost compared to replacement with a dual crane system estimated to be $4.3 million."

2.50.2 Please describe the remaining reliability risks after upgrading of the existing cranes if this option was chosen instead of a new crane.

RESPONSE:

Reliable operation of the Powerhouse cranes is a critical requirement both of the implementation of the Powerhouse Work and of the ongoing operation of the Ruskin Facility. There are significant worker safety and equipment issues with an unreliable crane. Further, any delays resulting from a failure of the crane to safely operate, particularly during installation of the generating units, will result in a delay in Project completion. In addition to Equitable Adjustment issues with contractors, IDC following a delay in the Powerhouse Work could more than offset the increased cost of a new crane.

The reliability risks in the crane operation would lie in the interface with any equipment to be retained. Components likely to be retained would include the structural girders, rails and crane trolleys. While it is possible that the existing girders remain structurally sound, BC Hydro would not receive any warranty to this effect. While the trolleys will be refurbished, these critical mechanical components would also not carry a warranty against defects. Risks in integration of new operating components of the cranes onto the existing crane structure also exist. Any unforeseen aspects of the crane structure inhibit the installation or operation of the new components may result in delays to commissioning and could impact future operation of the crane.

51.0 Reference: Powerhouse – New versus Rehabilitate/Replace
Exhibit B-7, BCUC 1.9.1

"With respect to the site on the left bank downstream of the existing Ruskin Facility, this location would require lengthy tunnels to be constructed, most of which would be constructed through earth instead of through bedrock. Bedrock dips steeply to the south and is likely at elevation -5 m, which is close to 10 m below the surface elevation. Designing the Powerhouse to meet seismic requirements without a solid foundation for both the new Powerhouse building and tunnels would be difficult and construction would be expensive."

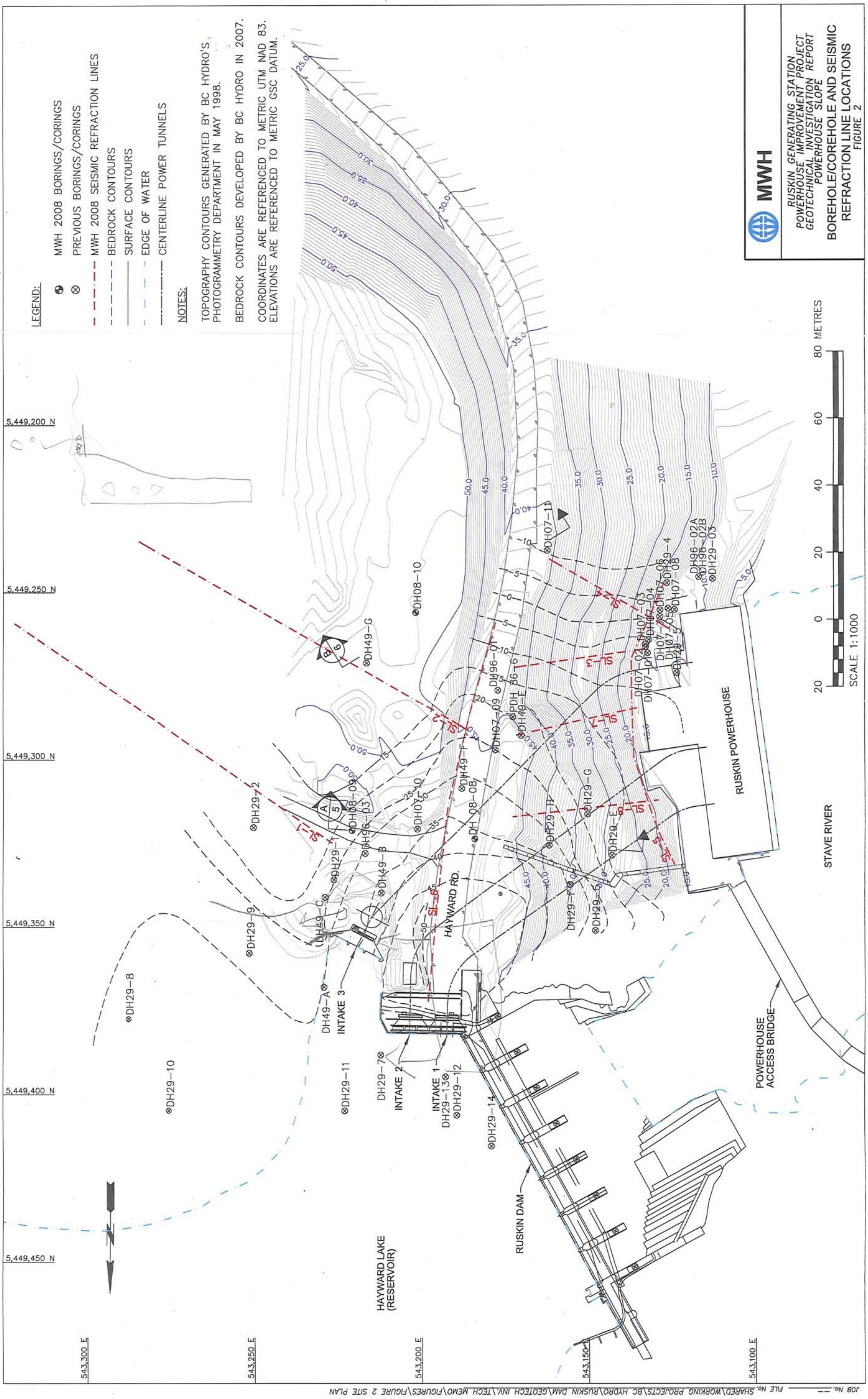
2.51.1 Please describe the elevation of the new tunnels for a new Powerhouse on the left bank and provide a more detailed analysis of the amount of tunnel in earth rather than bedrock.

RESPONSE:

A contour map is provided as Attachment 1 to this IR response. The contour map shows an approximation of the bedrock at the Ruskin Facility. Borehole locations are also identified to help indicate the level of data used to develop this map.

As seen on the attached map, along the alignment of the U3 tunnel and penstock the U3 penstock is only partially covered by bedrock at around elevation 7 m as it enters the Powerhouse. The bedrock contour has been measured to sit at elevation -2.4 m in a borehole roughly 10 m away from the U3 side of the Powerhouse (DH96-02 on the attached map), where the surface elevation at the location is at elevation 10 m. Additional borehole data along the toe of the slope behind the Powerhouse and upslope on Hayward Road suggest the bedrock dips steeply moving away from the Powerhouse along the left bank.

Based on this data, any tunnel in the hill slope towards the downstream recreational facility could not be founded in rock.


LEGEND:
MWH 2008 BORINGS/CORINGS
PREVIOUS BORINGS/CORINGS
MWH 2008 SEISMIC REFRACTION LINES
BEDROCK CONTOURS
SURFACE CONTOURS
EDGE OF WATER
CENTERLINE POWER TUNNELS
NOTES:
TOPOGRAPHY CONTOURS GENERATED BY BC HYDRO'S PHOTOGRAMMETRY DEPARTMENT IN MAY 1998.
BEDROCK CONTOURS DEVELOPED BY BC HYDRO IN 2007.
COORDINATES ARE REFERENCED TO METRIC UTM NAD 83. ELEVATIONS ARE REFERENCED TO METRIC GSC DATUM.
MWH
RUSKIN GENERATING STATION
POWERHOUSE IMPROVEMENT PROJECT
GEOTECHNICAL INVESTIGATION REPORT
POWERHOUSE SLOPE
BOREHOLE/COREHOLE AND SEISMIC REFRACTION LINE LOCATIONS
FIGURE 2
SCALE 1:1000
80 METRES
RUSKIN POWERHOUSE
STAVE RIVER
POWERHOUSE ACCESS BRIDGE
RUSKIN DAM
HAYWARD LAKE (RESERVOIR)
HAYWARD RD.
INTAKE 1
INTAKE 2
INTAKE 3
5,449,200 N
5,449,250 N
5,449,300 N
5,449,350 N
5,449,400 N
5,449,450 N
543,300 E
543,250 E
543,200 E
543,150 E
543,100 E
SL-1
SL-2
SL-3
SL-4
SL-5
SL-6
SL-7
SL-8
DH08-10
DH49-G
DH29-2
DH29-9
DH29-8
DH29-10
DH29-11
DH29-7
DH29-13
DH29-12
DH29-14
DH49-A
DH49-C
DH49-B
DH49-F
DH49-E
DH96-03
DH96-01
DH08-08
DH08-09
DH07-10
DH07-09
DH29-G
DH29-F
DH29-E
DH07-11
DH96-02A
DH96-02B
DH29-03
DH07-03
DH07-04
DH07-06
DH07-08
DH29-4
JOB NO. FILE NO. SHARED\WORKING PROJECTS\BC HYDRO\RUSKIN DAM\GEOTECH INV.\TECH MEMO\FIGURES\FIGURE 2 SITE PLAN

52.0 Reference: Interest During Construction Costs
Exhibit B-7, BCUC 1.53.3

2.52.1 Please provide the earliest possible in-service date for each of the Decommissioning Alternatives and confirm the amount of IDC costs associated with each alternative.

RESPONSE:

As set out at page 3-15, lines 5-7 of Exhibit B-1, an earliest in-service date (ISD) of November 2015 for each of the Decommissioning Alternatives was used for purposes of evaluating the Project. The November 2015 ISD was based on a five-year implementation period; refer to Exhibit B-1, page 3-39, lines 8 to 13. The amounts for IDC for the Project and all five Decommissioning Alternatives are set out in Table 3-3, on page 3-24 of Exhibit B-1, specifically the lines captioned "Interest During Construction (IDC)" pertaining to the Expected Amount and incremental IDC pertaining to Authorized Amount in the line captioned "IDC".

The five-year implementation period assumed the Decommissioning Alternative work would begin in approximately November 2010. More importantly, in BC Hydro's view the five-year implementation period is almost certainly too short for implementing Decommissioning Alternatives C and D, which result in the de-watering the entire Hayward Lake Reservoir, either through dismantling the Dam (Alternative C) or cutting a large opening at the base of the Dam to allow water passage (Alternative D). Alternatives C and D are major undertakings which trigger CEAA, BCEAA and a section 41 *Utilities Commission Act* permission to permanently cease operations application to the BCUC (refer to Table ES-1 of Hemmera Envirochem Inc.'s "Minimum Cost Study: Socio-Economic and Environmental Assessment Alternatives" found at Exhibit B-1, Appendix G-3, page 4 of 192 for the long list of government agency approvals that would be required to implement Alternatives C and D) and would be contentious. For example, both the District of Mission (Mission) and the Mission Chamber of Commerce have expressed concerns with these alternatives given that they would eliminate the ability of Mission to supply water to the Ruskin Townsite and reduce or eliminate recreational tourism opportunities associated with the existing Ruskin Facility. Accordingly, the IDC amounts shown in Table 3-3 are conservative and if any of the Decommissioning Alternatives were to be implemented the IDC would almost certainly be greater.

The assumption of a November 2015 ISD for each of the Decommissioning Alternatives does not mean that each of the Decommissioning Alternatives is equally likely. Please refer to Exhibit B-7-2, BC Hydro's response to BCUC IR 1.14.6. In BC Hydro's view, Decommissioning Alternative C is unlikely. BC Hydro also notes that it is the Board which is the decision-maker with respect

to which, if any, of the Decommissioning Alternatives would be implemented as a fall-back should the BCUC not issue a CPCN for the Project, or should the BCUC issue a CPCN for a part of the Project only. Among other things, one of the considerations would be the likely inability to replace the Ruskin Facility's firm energy and dependable capacity with resources located in the LM, BC Hydro's major load center. It is likely that such resources would be located outside the LM and some distance from load. Please refer to BC Hydro's response to CEABC IR 2.11.1.

A longer implementation period of perhaps six to seven years is likely more realistic for Alternatives C and D. However, assuming a longer implementation period does not change the relative attractiveness of the Project compared to the Decommissioning Alternatives; refer to Exhibit B-7-2, BC Hydro's response to BCOAPO IR 1.3.1.

53.0 Reference: Estimate Probability Distribution
Exhibit B-7, BCUC 1.53.4

2.53.1 Please provide the analysis for the P50 and P90 level of estimates using a normal distribution centered at the "most likely" estimate instead of a triangular distribution.

RESPONSE:

The requested information has been provided as Confidential Attachment 1 to this IR response. BC Hydro has recalculated the contingency amount for the P50 and P90 level estimates using a normal distribution in Palisades' @Risk software. The mean of each normal distribution has been set to be equal to the mean, or expected value, of the triangular distribution it replaces. The standard deviation of each normal distribution matches that of the triangular distribution it replaces. The attachment is filed in confidence because it contains commercially sensitive information, and in particular the anticipated cost of certain items of equipment and construction which will prejudice BC Hydro in its negotiations with contractors and suppliers and could result in a material financial loss to BC Hydro and its ratepayers. BC Hydro has consistently treated such information as confidential.

Use of a normal distribution is not best practice for cost estimating. Normal distributions are symmetric and unbounded. This does not accord with common experience in construction costs, which are "skewed right" indicating a higher risk of cost increases than decreases. By contrast, a normal distribution overstates the likelihood of cost under runs and understates the likelihood of cost over runs as compared to the methodology used in the Project estimate.

It is important to bear in mind that a Project estimate is not a commitment to expend funds; ratepayers are not exposed to estimated amounts or contingencies, but to actual amounts when spent and subsequently transferred to rate base. If the estimated costs (whether shown as direct, contingency, or reserve funds) are not required then they will never need to be recovered in rates. A contingency or reserve serves as a risk-management tool by reducing the likelihood that a non-economic project will be undertaken when an optimistic estimate understates the eventual costs and overstates the attractiveness of the project. BC Hydro's estimating methodology, including use of triangular distributions for line items, contributes to this risk management goal.

CONFIDENTIAL ATTACHMENT

FILED WITH BCUC ONLY

54.0 Reference: Energy Production
Exhibit B-7, BCUC 1.55.2, Attachment 1

2.54.1 Please explain why Scenario 1 in Attachment 1 (3 units) is dispatched for 1500 MW.h per day approximately 6 percent of the time [see Load Duration Curve – Daily (RUS – 3 units)], while in Scenario 4 [see Load Duration Curve – Daily (RUS – 2 units)] the facility is dispatched for 1500 MW.h per day approximately 9 percent of the time. It appears that for certain inflows, the 2 unit facility delivers more energy than the 3-unit facility.

RESPONSE:

BC Hydro notes that this IR reflects a misreading of the load duration curve shown for a three-unit Powerhouse (Scenario 1) set out in Exhibit B-7, Attachment 1 to BC Hydro's response to BCUC IR 1.55.2, which indicates output higher than 1,500 MWh/day (approximately 2,100 MWh/day and higher) for about 6 per cent of the time, and output of approximately 1,400 MWh/day for a further 4 per cent. By comparison, the load duration curve for a two-unit Powerhouse (Scenario 4) shows a dispatch level of 1,680 MWh/day (the maximum daily generation for this plant configuration, as noted on the load-duration curve) for about 9 per cent of the time.

This IR appears to be based on a misunderstanding both of a load-duration curve and on the effect of capacity at a hydroelectric facility. First, any particular location on the horizontal axis of a load duration curve does not represent the same time or the same inflow: it represents the same percentile of the range of output, which may occur at a different time or under different inflow conditions. Second, other than the minor difference in energy due to avoided spill, the two- and three-unit Powerhouse alternatives will deliver the same amount of energy over the year, since that is set by total inflow and available head[1], both of which will remain unchanged, and the total area under the load duration curve will be the same. The three-unit Powerhouse will be capable of delivering more of that energy in a short period of time, such as an afternoon of high demand – but that implies that in some other short period of time the three-unit Powerhouse must deliver *less* energy than the two-unit Powerhouse would have done. Dispatch is significantly higher with a three-unit plant as compared to a two-unit plant 6 per cent of the time; it follows that output from a three-unit Powerhouse will be lower than from a two-unit Powerhouse at some times.

[1] There may be differences in reservoir elevation leading to absolute differences in energy, but they will be minor compared to the differences described here.

54.0 Reference: Energy Production
Exhibit B-7, BCUC 1.55.2, Attachment 1

2.54.2 Please explain why the 3-unit scenario does not provide more power for certain inflow sets than the 2-unit scenario, and when do these situations occur?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.54.1 – the same location on the horizontal axis of a load duration curve does not necessarily represent the same inflow conditions.

54.0 Reference: Energy Production
Exhibit B-7, BCUC 1.55.2, Attachment 1

2.54.3 Please provide the annual generation for each unit at Ruskin since 2000, and the annual number of stops and starts for each unit.

RESPONSE:

Annual generation by Unit is as shown in Table 1. Unit starts and stops are as shown in Table 2.

Table 1 Ruskin Generating Station
Annual Generation by Unit
2000 to 2011 (MWh)

	Unit			Total
Year	U1	U2	U3	
F2000	162,785	141,323	88,246	392,354
F2001	161,725	79,857	45,974	287,556
F2002	153,200	120,910	92,950	367,060
F2003	160,010	97,120	138,050	395,180
F2004	92,128	95,320	103,154	290,602
F2005	120,364	73,189	161,105	354,658
F2006	157,996	111,036	76,861	345,893
F2007	178,343	102,321	65,881	346,545
F2008	150,101	130,595	86,250	366,946
F2009	102,057	99,958	92,517	294,531
F2010	106,254	103,118	97,348	306,720
F2011	144,727	68,477	126,027	339,231

Table 2 Ruskin Generating Station Annual Starts and Stops by Unit 2000 to 2011

Year	Starts by Unit			Stops by Unit			Total - Ruskin GS	
	U1	U2	U3	U1	U2	U3	Starts	Stops
F2000	31	107	187	32	106	188	325	326
F2001	7	38	139	6	39	139	184	184
F2002	20	136	89	21	135	89	245	245
F2003	57	108	126	56	108	125	291	289
F2004	40	53	55	40	54	55	148	149
F2005	72	84	80	72	84	81	236	237
F2006	89	78	79	89	78	79	246	246
F2007	43	81	24	43	80	24	148	147
F2008	60	45	35	60	46	34	140	140
F2009	12	23	26	12	22	27	61	61
F2010	43	49	21	43	50	20	113	113
F2011	9	19	11	10	18	11	39	39

55.0 Reference: Intake Modifications
Exhibit B-7, BCUC 1.55.2, Attachment 2, p. 12 of 88, p. 14 of 88

"The intake structures are not considered to be part of the water retaining structures; however, due to their importance in supporting power generation after an earthquake, they should be strengthened to the same seismic loading as the dam."

"Per the User Requirements, emergency shutoff of the water supply into the tunnels was to be considered. The User Requirements, however, did not include this capability as a requirement of the rehabilitation. The Identification Phase study has concluded that the benefits associated with the addition of an upstream control/emergency closure gate system at the intake warrants their addition. Emergency closure of the water supply with the existing Turbine Inlet Valves (TIV's) is not considered safe or dependable."

2.55.1 Please explain how the use of turbine inlet valves could be made "safe and dependable" considering that they have been used in other facilities and in this facility since it was built.

RESPONSE:

The turbine inlet valves (TIVs) can be refurbished, however the following criteria must be met:

1. **reliable closure following the MDE; and**
2. **capable of certification for single device isolation.**

To meet the first criterion the operating components of the gate would need to be strengthened to ensure the gate would remain functional following the MDE. This would include the operating mechanism, substructure and anchorage of the gate. The present unreliable operating mechanism would likely require complete replacement.

To ensure certification for single device isolation, the present system relying on water pressurized seal to maintain closure would need to be replaced. Either the entire gate would be replaced with a new system, or new seals would need to be installed around the perimeter of the gate. As stated in Exhibit B-7, BC Hydro's response to BCUC IR 1.3.1, there are enough significant challenges in providing new seals to eliminate this option. That response also outlined that the new TIV gates option was eliminated given that it was estimated to be a more expensive alternative than provision of new upstream intake gates.

55.0 Reference: Intake Modifications
Exhibit B-7, BCUC 1.55.2, Attachment 2, p. 12 of 88, p. 14 of 88

"The intake structures are not considered to be part of the water retaining structures; however, due to their importance in supporting power generation after an earthquake, they should be strengthened to the same seismic loading as the dam."

"Per the User Requirements, emergency shutoff of the water supply into the tunnels was to be considered. The User Requirements, however, did not include this capability as a requirement of the rehabilitation. The Identification Phase study has concluded that the benefits associated with the addition of an upstream control/emergency closure gate system at the intake warrants their addition. Emergency closure of the water supply with the existing Turbine Inlet Valves (TIV's) is not considered safe or dependable."

2.55.2 Please describe any failures BC Hydro has experienced with turbine inlet valves, and the consequences of those failures.

RESPONSE:

BC Hydro has experienced two TIV failures at the Elko Generating Station (GS), both of which resulted in an extended outage for valve component replacement and repair. In addition, significant leakage has been experienced in the past with aging TIV seals at Ruskin GS, Cheakamus GS, Lake Buntzen GS, Strathcona GS, Ladore GS and John Hart GS. If, for any reason, the turbine wicket gates fail to close when there is significant leakage past a closed TIV, it may not be possible to shutdown the unit. This could have catastrophic consequences under fault conditions. In addition, leaking seals mean that the TIV cannot be used as an isolation point for worker safety protection, which has a negative impact on the ability to perform maintenance on the unit.

While issues with leakage of the TIVs at Ruskin GS impact their safe and dependable use, the recommendation to install intake gates in place of turbine inlet valves was due to a number of factors. Please also refer to Exhibit B-7, BC Hydro's response to BCUC IR 1.3.1.

55.0 Reference: Intake Modifications
Exhibit B-7, BCUC 1.55.2, Attachment 2, p. 12 of 88, p. 14 of 88

"The intake structures are not considered to be part of the water retaining structures; however, due to their importance in supporting power generation after an earthquake, they should be strengthened to the same seismic loading as the dam."

"Per the User Requirements, emergency shutoff of the water supply into the tunnels was to be considered. The User Requirements, however, did not include this capability as a requirement of the rehabilitation. The Identification Phase study has concluded that the benefits associated with the addition of an upstream control/emergency closure gate system at the intake warrants their addition. Emergency closure of the water supply with the existing Turbine Inlet Valves (TIVs) is not considered safe or dependable."

2.55.3 Please provide a detailed line item cost estimate of the proposed intake gate work and the other work being driven by the proposed new intake gates (control buildings, hoists, roadway/superstructure modifications, etc).

RESPONSE:

BC Hydro requests confidential treatment of this IR response as it provides a breakdown of cost estimate information for work that has yet to be contracted. In accordance with section 42 of the ATA and the Confidential Filings Practice Directive, BC Hydro respectfully requests that as this information contains a cost estimate breakdown for work that has yet to be contracted, that it be kept confidential on the basis that disclosure will result in: 1) undue financial loss to BC Hydro and undue financial gain to contractors it will be negotiating with to undertake construction or to supply and install equipment; 2) significant prejudice to BC Hydro's competitive negotiation position with these contractors; and 3) BC Hydro has consistently treated this commercial and financial information on a confidential basis.

Confidential Attachment 1 to this IR response provides a detailed line item cost estimate of the proposed intake gate work and its related activities.

CONFIDENTIAL ATTACHMENT

FILED WITH BCUC ONLY

55.0 Reference: Intake Modifications
Exhibit B-7, BCUC 1.55.2, Attachment 2, p. 12 of 88, p. 14 of 88

"The intake structures are not considered to be part of the water retaining structures; however, due to their importance in supporting power generation after an earthquake, they should be strengthened to the same seismic loading as the dam."

"Per the User Requirements, emergency shutoff of the water supply into the tunnels was to be considered. The User Requirements, however, did not include this capability as a requirement of the rehabilitation. The Identification Phase study has concluded that the benefits associated with the addition of an upstream control/emergency closure gate system at the intake warrants their addition. Emergency closure of the water supply with the existing Turbine Inlet Valves (TIV's) is not considered safe or dependable."

2.55.4 Please provide a detailed line item cost estimate of a replacement turbine inlet valve system.

RESPONSE:

BC Hydro has contacted several major valve manufactures to assist in BC Hydro's response to this IR. None of the suppliers BC Hydro contacted were willing to provide a quote for a new TIV at the Ruskin Facility, nor were they interested in pursuing this work. BC Hydro has taken a quote for a smaller valve and factored the cost. Robar style couplers have also been assumed to join a mild painted carbon steel value to the 80-year old riveted penstock and spiralcase.

	Overview Conceptual Estimate (+100%/-25%) (Direct Costs without Contingency)	
Supply Items		**($ 000)**
Valves	**3 each at (107 tons @ $25,000/ton)**	**8,025**
Couplers	**6 each at $400,000/each**	**2,400**
Install Items		
TIV Access Improvements & Removals		**2,341**
Install		**1,962**
Total Direct Cost without Contingency		**14,728**

For the reasons why BC Hydro has scoped in intake gates as part of the Project and rejected TIVs, please refer to Exhibit B-7, BC Hydro's response to BCUC IR 1.3.1.

55.0 Reference: Intake Modifications
Exhibit B-7, BCUC 1.55.2, Attachment 2, p. 12 of 88, p. 14 of 88

"The intake structures are not considered to be part of the water retaining structures; however, due to their importance in supporting power generation after an earthquake, they should be strengthened to the same seismic loading as the dam."

"Per the User Requirements, emergency shutoff of the water supply into the tunnels was to be considered. The User Requirements, however, did not include this capability as a requirement of the rehabilitation. The Identification Phase study has concluded that the benefits associated with the addition of an upstream control/emergency closure gate system at the intake warrants their addition. Emergency closure of the water supply with the existing Turbine Inlet Valves (TIV's) is not considered safe or dependable."

2.55.5 Can a turbine inlet valve system be designed to have the same seismic withstand capability as the proposed intake gate system?

RESPONSE:

Yes. Please refer to BC Hydro's response to BCUC IR 2.55.1.

55.0 Reference: Intake Modifications
Exhibit B-7, BCUC 1.55.2, Attachment 2, p. 12 of 88, p. 14 of 88

"The intake structures are not considered to be part of the water retaining structures; however, due to their importance in supporting power generation after an earthquake, they should be strengthened to the same seismic loading as the dam."

"Per the User Requirements, emergency shutoff of the water supply into the tunnels was to be considered. The User Requirements, however, did not include this capability as a requirement of the rehabilitation. The Identification Phase study has concluded that the benefits associated with the addition of an upstream control/emergency closure gate system at the intake warrants their addition. Emergency closure of the water supply with the existing Turbine Inlet Valves (TIV's) is not considered safe or dependable."

2.55.6 Please identify the potential lost generation attributable to a seismic event if turbine inlet valves are used instead of the proposed intake gates.

RESPONSE:

If TIVs are designed and installed to meet the required seismic criteria, there is no reason to suppose that post-seismic generation will be affected, relative to inlet gates. BC Hydro notes that TIVs present a small continuous loss of generation, due to slightly higher head losses in the penstocks.

56.0 Reference: Access Bridge
Exhibit B-1, Section 2.2.2.2, Table 2-2, p. 2-28
Exhibit B-7-1, BCUC 1.40.1, CONFIDENTIAL Submission
Exhibit B-7, BCUC 1.55.2, PUBLIC Attachment 2, p. 51 of 88
Exhibit B-7-2, BCSEA 1.5.2

"The construction cost estimate provides for a $500,000 contingency for Access bridge repairs or new East side access road." (Exhibit B-7, BCUC 1.55.2, PUBLIC Attachment 2, p. 51 of 88)

2.56.1 Please provide a reconciliation of the costs associated with the access bridge in the above references and provide a detailed line item estimate for the access bridge work, in particular the cost of replacing the bridge bearings and armouring and encasing the intermediate pier.

RESPONSE:

BC Hydro requests confidential treatment of this IR response as it provides a breakdown of cost estimate information for work that has yet to be contracted. In accordance with section 42 of the ATA and the Confidential Filings Practice Directive, BC Hydro respectfully requests that as this information contains a cost estimate breakdown for work that has yet to be contracted, that it be kept confidential on the basis that disclosure will result in: 1) undue financial loss to BC Hydro and undue financial gain to contractors it will be negotiating with to undertake construction or to supply and install equipment; 2) significant prejudice to BC Hydro's competitive negotiation position with these contractors; and 3) BC Hydro has consistently treated this commercial and financial information on a confidential basis.

56.0 Reference: Access Bridge
Exhibit B-1, Section 2.2.2.2, Table 2-2, p. 2-28
Exhibit B-7-1, BCUC 1.40.1, CONFIDENTIAL Submission
Exhibit B-7, BCUC 1.55.2, PUBLIC Attachment 2, p. 51 of 88
Exhibit B-7-2, BCSEA 1.5.2

"The construction cost estimate provides for a $500,000 contingency for Access bridge repairs or new East side access road." (Exhibit B-7, BCUC 1.55.2, PUBLIC Attachment 2, p. 51 of 88)

2.56.2 Please identify any environmental issues addressed by the proposed access bridge work, and explain the requirement for BC Hydro to undertake this work. Also explain the consequences of not undertaking the proposed bridge repairs and instead constructing a new East side access road (and possibly a new vehicle access door).

RESPONSE:

The repairs to the access bridge are being performed to replace the deficient bearing pads. In the event of a low level earthquake it is likely the bridge will be shaken off its foundation and drop into the spillway plunge pool which, among other things, could cause environmental issues. Since the bearing pads require replacement regardless of the selected seismic withstand, for an incremental cost of approximately $35,000 (direct construction costs only at a Feasibility Design Level) the pads will be designed such that the access bridge will have a seismic withstand of 1:10,000 year (MDE).

Construction of a permanent access on the East side of the Powerhouse cannot sufficiently service the Ruskin Facility without extensive work to the Powerhouse building. The main level of the Powerhouse accessible to the Powerhouse crane is at elevation 14.55 m, which is approximately 4 m higher than the existing ground elevation at 10.6 m on the East side of the Powerhouse. To provide new access on the East side of the Powerhouse, the existing ground will require infilling by up to 4 m and the Powerhouse superstructure will require an extension to create a new service bay to extend the reach of the Powerhouse crane. This extension would be problematic given that bedrock dips steeply down to elevation -2.5 m just outside the East side of the Powerhouse. Foundation work would be extensive. In addition, an East side access road would cross through a highly used recreational area. Given these issues, BC Hydro did not pursue this option beyond the Identification phase.

56.0 Reference: Access Bridge
Exhibit B-1, Section 2.2.2.2, Table 2-2, p. 2-28
Exhibit B-7-1, BCUC 1.40.1, CONFIDENTIAL Submission
Exhibit B-7, BCUC 1.55.2, PUBLIC Attachment 2, p. 51 of 88
Exhibit B-7-2, BCSEA 1.5.2

"The construction cost estimate provides for a $500,000 contingency for Access bridge repairs or new East side access road." (Exhibit B-7, BCUC 1.55.2, PUBLIC Attachment 2, p. 51 of 88)

2.56.3 Please provide a comparative cost estimate for removing the Powerhouse access bridge and creating a dedicated access road to the east of the Powerhouse. Please also discuss other issues arising from the potential relocation of the access road to the east side of the Powerhouse including the interaction with the proposed right and left bank seismic stability improvements.

RESPONSE:

As outlined in BC Hydro's response to BCUC IR 2.56.2, the Powerhouse access bridge provides the only viable access delivery of large equipment into the Powerhouse. While BC Hydro has assumed that a contractor will utilize the east access of the Powerhouse as an entry point to the Ruskin Facility during construction, for the reason stated in BC Hydro's response to BCUC IR 2.56.2 access into the Powerhouse with large equipment will be limited to objects no larger than what can be delivered through a double door. It is the extensive work required to extend the Powerhouse superstructure that caused BC Hydro to reject the option of accessing the Powerhouse from the East side in the Identification phase.

Access to the Powerhouse will not impact stability on either the left or right bank.

BC Hydro has not generated the requested cost estimate because it would entail designing an extension of the Powerhouse superstructure and substructure, which would take at least one month to develop. However, BC Hydro can state with certainty that the cost of extending the Powerhouse, removing the Powerhouse access bridge and creating a dedicated access road to the east of the Powerhouse would be higher than BC Hydro's proposal to strengthen the Powerhouse access bridge.

57.0 Reference: Value of Firm Energy and Capacity
Exhibit B-7, BCUC 1.56.1

2.57.1 Please describe if either the Clean Power Call RFP or Bioenergy Phase 1 RFP called for seasonally firm or hourly firm energy commitments.

RESPONSE:

Proponents in the Bioenergy Call Phase 1 Request for Proposals (RFP) and the Clean Power Call RFP were given the option of electing to deliver either seasonally or hour firm energy:

- **For the Bioenergy Call Phase 1 RFP, two of the successful proponents chose seasonally firm energy and the other two chose hourly firm energy; and**

- **For the Clean Power Call RFP, all but one of the successful proponents chose to deliver seasonally firm energy. The only successful proponent opting for hourly firm energy is the** [redacted] **Ultimately, BC Hydro selected 27 projects for the award of 25 Electricity Purchase Agreements (EPAs) under the Clean Power Call (three projects were combined into a single EPA).**

In accordance with section 42 of the ATA and the Practice Directive of the Confidential Practice Directive, BC Hydro respectfully requests confidential treatment of the identity of the Clean Power Call proponent that elected to deliver hourly firm energy. The identity of this proponent has been redacted in the public version of this IR response. The identity of proponents who elected to provide energy on an hourly firm basis has been consistently treated as confidential by both BC Hydro and proponents because such information is commercially sensitive information; for example, in the Bioenergy Phase 1 RFP, the identity of the two proponents who provided energy on an hourly firm basis was not publicly disclosed in the Bioenergy Phase 1 RFP-related filing with the BCUC or otherwise.

57.0 Reference: Value of Firm Energy and Capacity
Exhibit B-7, BCUC 1.56.1

2.57.2 Please describe the premium for hourly firm energy as compared to seasonally firm energy for both the Clean Power Call RFP or Bioenergy Phase 1 RFP, both as offered in the RFP (if applicable), and the range of awarded premiums (if applicable) for hourly firm products.

RESPONSE:

Proponents who elected to deliver hourly firm energy did not receive a price premium but rather their projects were provided with an evaluation credit or deduction to determine the adjusted firm energy price. The magnitude of the adjuster depended on the proponent's profile of on-peak hourly firm energy. For a project with a "flat" hourly energy profile, the adjuster was approximately $4.00/MWh.

For the EPAs awarded under the two referenced RFPs, the actual evaluation credits (in 2010 dollars) for hourly firm energy were as follows:

- **Two Bioenergy Phase 1 RFP EPAs: $4.04/MWh;**
- **One Clean Power Call RFP EPA: $5.18/MWh.**

57.0 Reference: Value of Firm Energy and Capacity
Exhibit B-7, BCUC 1.56.1

2.57.3 Please explain why the hourly firm energy premium above a seasonally firm energy profile does or does not adequately recognize the capacity associated with the firm energy.

RESPONSE:

BC Hydro is of the view that the evaluation credit for hourly firm energy from the Bioenergy Phase 1 RFP and the Clean Power Call RFP adequately recognizes the dependable capacity benefits associated with the firm energy for RFP decision-making purposes. The Clean Power Call credit was applied as follows:

- **For a project with a flat profile the credit was $4/MWh of firm energy ($2009); and**
- **A project that was able to provide a greater hourly firm output during High Load Hours and during winter months could get a higher credit. This occurred with respect to only one Clean Power Call proponent awarded an EPA who chose the option of delivering hourly firm energy. Please refer to BC Hydro's response to BCUC IR 2.57.2.**

There are two differences between the Clean Power Call credit and the Project capacity valuation:

- **Different Lowest Cost Marginal Capacity Units - The Clean Power Call and Bioenergy Phase 1 RFP credits were based upon Mica Unit 5, which at the time of the Clean Power Call was the marginal capacity unit with a Unit Capacity Cost (UCC) of $34/kW-year ($2008). At the time of the Clean Power Call development, Mica Unit 5 was not a committed resource. The UCC used for Project evaluation is the Revelstoke Unit 6 UCC of $55/kW-year, because Revelstoke Unit 6 is now BC Hydro's lowest cost non-committed future capacity resource. As set out at page 3-14 of Exhibit B-1, footnote 21, Mica Units 5 and 6 are committed resources and accordingly do not represent BC Hydro's lowest cost marginal B.C.-based capacity resource and thus are not appropriate to use for Project evaluation purposes;**
- **Project Differences - In the Clean Power Call, an hourly firm credit was applied to one project over which BC Hydro has less operational control than it has over the Ruskin Facility, which is dispatchable, and no detailed**

water record history required for optimal reservoir operation. With respect to the Project, BC Hydro is of the view that the capacity credit based upon the dependable capacity rating is appropriate for a plant that BC Hydro is able to dispatch and has an 80-year record of water inflows required for optimal reservoir operation.

For comparative purposes, BC Hydro recalculated the hourly firm credit for the one Clean Power Call proponent using the dependable capacity method applied to the Project [as shown in Attachment 1]. In doing this calculation, BC Hydro retained the $34/kW-yr ($2008) value of capacity based upon Mica Unit 5 and assumed that the proponent had a dependable capacity rating calculated by averaging the hourly firm output from November 15 through February 15. Based upon this analysis, the proponent's capacity credit increased from $5.18/MWh to $5.42/MWh (all in $2010). This additional adjustment of $0.24/MWh would not have materially impacted the Clean Energy Call firm energy price of $129/MWh.

Similarly, for comparative purposes, BC Hydro recalculated the Ruskin Facility capacity credit based upon the Clean Power Call methodology [as shown in Attachment 2]. This calculation resulted in the Project's capacity credit dropping from $16.5/MWh to $10.95/MWh (in $2011) as shown in Table 3-5 on page 3-28 of Exhibit B-1. This change in value, if used, does not change the cost-effectiveness of the Project as demonstrated in Table 3-7, Exhibit B-1, which indicates in the first line (Capacity Credit = 'none') the Project has a positive NPV ignoring any value for capacity, as well as in BC Hydro's response to BCUC IR 2.65.6, which shows that the Project was cost effective with zero capacity credit.

57.0 Reference: Value of Firm Energy and Capacity
Exhibit B-7, BCUC 1.56.1

2.57.4 Please explain why the BC Hydro power call RFPs do not provide for a value for firm capacity in addition to firm energy.

RESPONSE:

As set out in Exhibit B-7-2, BC Hydro's response to BCOAPO IR 1.6.1, the Clean Power Call weighted average adjusted price for firm energy delivered to the Lower Mainland included a credit where applicable for dependable capacity if a proponent was able to supply hourly firm energy. As set out in BC Hydro's response to BCUC IR 2.57.1, only one proponent in the Clean Power Call was able to provide hourly firm energy.

58.0 Reference: Spillway Gate Reliability
Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35
Exhibit B-7, BCUC 1.93.1, Attachment 3, p. 290 of 301
Exhibit B-7-2, CECBC 1.22.1

"…Operating rules should specify the maximum time period for which degraded conditions will be allowed to exist without contingency action." (Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35)

2.58.1 Please describe the maximum period for the return to service of unimproved gates if only two gates are replaced.

RESPONSE:

The maximum period would depend on the nature of the failure. The worst case would be a failure that required replacement of gates, reconstruction of associated piers and replacement of the roadway bridge above. Such a post-disaster replacement could take up to four years, including time required for design, procurement and construction.

58.0 Reference: Spillway Gate Reliability
Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35
Exhibit B-7, BCUC 1.93.1, Attachment 3, p. 290 of 301
Exhibit B-7-2, CECBC 1.22.1

"…Operating rules should specify the maximum time period for which degraded conditions will be allowed to exist without contingency action." (Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35)

2.58.2 Please describe the probability and consequences of seismic failure of the spillway gates if the failure caused uncontrolled spill.

RESPONSE:

As described in Section 2.2.1.2 of Exhibit B-1, cracking of the existing spillway piers could occur in earthquake accelerations exceeding 0.12g PGA (1 in 100 year return period), which is much lower than the MDE. Uncontrolled spill could be the result of an earthquake larger than the 1 in 100 year return period event.

Complete failure of one or more gates could cause significant downstream impacts to businesses and recreational users, flooding of homes and injury or death. Post-earthquake consequences could include loss of generation. If the gates did not catastrophically fail, they could be damaged beyond operation. If the gates were jammed, their inoperability even in the face of moderate flood events would endanger the Dam.

58.0 Reference: Spillway Gate Reliability
Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35
Exhibit B-7, BCUC 1.93.1, Attachment 3, p. 290 of 301
Exhibit B-7-2, CECBC 1.22.1

"…Operating rules should specify the maximum time period for which degraded conditions will be allowed to exist without contingency action." (Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35)

2.58.3 Please explain why it is not possible to only upgrade/replace a minimum number of gates in order to be assured of passing flows 99 percent of the time or 99.9 percent of the time following a seismic event.

RESPONSE:

Seismic criteria derived from the Canadian Dam Association's Dam Safety Guidelines (CDA Guidelines) are: (1) that there be no damage to the spillway gate system in 1/500 year earthquake; and (2) at least two gates must survive a 1/10,000 year earthquake. All the gates need to be replaced to meet the first seismic criteria. Not all of the existing piers and gates would survive a 1/500 year earthquake. Damage to piers is expected at a 1/100 year earthquake.

58.0 Reference: Spillway Gate Reliability
Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35
Exhibit B-7, BCUC 1.93.1, Attachment 3, p. 290 of 301
Exhibit B-7-2, CECBC 1.22.1

"…Operating rules should specify the maximum time period for which degraded conditions will be allowed to exist without contingency action." (Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35)

2.58.4 How many new spillway gates are required to pass inflows for 99 percent and 99.9 percent of the time?

RESPONSE:

Replacement of all of the spillway gates results from the application of seismic criterion and is not driven by flood passage.

One new gate is capable of passing the 99th percentile of annual inflows and two new gates are capable of passing the 99.9th percentile annual inflow. However, BC Hydro must ensure that the PMF can be safely passed through the spillway. At the Ruskin Facility four new gates can pass the PMF as long as there is no debris build up under the gates. Since debris can be expected in the water during severe flood events, it is considered important to be able to reliably open all five new gates.

58.0 Reference: Spillway Gate Reliability
Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35
Exhibit B-7, BCUC 1.93.1, Attachment 3, p. 290 of 301
Exhibit B-7-2, CECBC 1.22.1

"…Operating rules should specify the maximum time period for which degraded conditions will be allowed to exist without contingency action." (Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35)

2.58.5 Please provide the percentage of time the facility is required to operate with one spillway gate open, two spillway gates open, etc., to maximum spillway gates open for the projected distribution of inflows.

RESPONSE:

At Normal Maximum Reservoir Level (NMRL) spillway discharge capability is as follows:

- **One new spillway gate open: capacity = 610 m^3/s. Total inflow < 610 m^3/s 99.54 per cent of the time;**
- **Two new spillway gates open: capacity = 1,270 m^3/s. Total inflow < 1,270 m^3/s 99.99 per cent of the time;**
- **Three new spillway gates open: capacity = 1,920 m^3/s. Total inflow has been below this for the period of record (peak daily inflow since 1,984 = 1,440 m^3/s);**
- **Four new spillway gates open: capacity = 2,580 m^3/s; and**
- **Five new spillway gates open: capacity = 3,230\ m^3/s.**

This data does not capture the high inflow events that could happen in future – frequency analysis would be required for this. The PMF at the Ruskin Facility, which would raise the reservoir above the NMRL is 3,650 m^3/s.

58.0 Reference: Spillway Gate Reliability
Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35
Exhibit B-7, BCUC 1.93.1, Attachment 3, p. 290 of 301
Exhibit B-7-2, CECBC 1.22.1

"…Operating rules should specify the maximum time period for which degraded conditions will be allowed to exist without contingency action." (Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35)

2.58.6 Please discuss whether BC Hydro has considered a hybrid solution of a minimum number of new spillway gates and piers combined with seismically strengthening the remaining existing piers and rehabilitating the remaining existing spillway gates.

RESPONSE:

As explained in Exhibit B-1, page 3-50, a pier hybrid option (Option 1) was considered that replaced three of the existing central piers with new piers, anchored the remaining three of the weaker existing central piers and installed seven new radial gates. Analysis in 2007 indicated it might be possible to rehabilitate and reinforce the existing gate structures if certain deformations were considered acceptable.

However, Option 1 was not selected because it was determined not to be a feasible solution. In particular it would:

- **Not meet the MDE;**
- **Limit space available for vertical anchors (which limits flexibility in design);**
- **Prohibit the ability to easily incorporate a stop log system; and**
- **Have the lowest maximum spill capacity of the considered options (therefore reducing flexibility in spill management).**

58.0 Reference: Spillway Gate Reliability
Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35
Exhibit B-7, BCUC 1.93.1, Attachment 3, p. 290 of 301
Exhibit B-7-2, CECBC 1.22.1

"…Operating rules should specify the maximum time period for which degraded conditions will be allowed to exist without contingency action." (Exhibit B-7, BCUC 1.61.1, Attachment 1, p. 1 of 35)

2.58.7 Please discuss the approach to redundancy and reliability for the spillway gate pump motor power supply. For instance, in addition to main and backup pump motors, each with a receptacle and bypass to allow supply and operation from a mobile generator set, the supply arrangement has a diesel generator, an uninterruptible power supply, three transfer switches, two connections to an external distribution feeder, and supply from the powerhouse station service bus (which itself has redundant sources). Does such an arrangement suffer from reliability issues simply from the shear number of components (as the number of devices goes up, the probability of failure of one of the devices goes up and hence the reliability of the system goes down)? Has a reliability analysis been performed to assess the required supply arrangement to achieve a probability of failure on demand of 1 in 1,000 to 1 in 10,000?

RESPONSE:

Yes a reliability analysis has been performed. The criteria of achieving a probability of failure on demand of 1 in 1,000 to 1 in 10,000 applies to the whole gate system, including power supply system, control system and hydraulic system. Since the power, control and hydraulics systems must all work to open a gate, the individual system reliabilities must all be greater than the overall reliability criteria. The required high sub-systems reliability is achieved mainly through redundancy.

The reliability analysis of the proposed multiple redundant power supplies indicates that multiple supplies are needed to meet the reliability criteria. The distribution feeders are not reliable in severe flood or earthquake conditions, leaving two robust built-in sources of supply: the Powerhouse station service diesel on the left side and the uninterruptible power supply on the right side. These sources are then backed up by a portable diesel generator. Since any one of the sources alone can power the gates, adding multiple independent sources increases the reliability of the system.

59.0 Reference: Spillway and Spillway Gates System
Exhibit B-7, BCUC 1.70.1

"The scope of work being undertaken for the spillway gates is primarily to address seismic risk; in particular, the gates must reliably operate after a seismic event to retain the reservoir, permit reservoir drawdowns to reduce loading on the Dam and water retaining structures, and to safely pass flows less than the PMF and as low as average annual inflow."

2.59.1 Please describe any critical review BC Hydro has undertaken to optimize the amount of seismic strengthening of the facility versus the amount spillway capability and explain why it is critical for all the spillway gates to be operable after a seismic event.

RESPONSE:

BC Hydro has not carried out any optimization studies between seismic strengthening of the facility versus the amount of spillway capability. The primary objective of the proposed Project scope is to address the seismic risk which requires rebuild of the piers/gates; please refer to BC Hydro's response to BCUC IR 2.58.3. The available discharge capacity of the new spillway system is sufficient to also address the flood risk (i.e., passage of the PMF without overtopping of the dam). No optimization studies were required; however an objective of studies to date was to ensure spillway capacity would not be reduced when the number of gates is reduced from seven gates to five.

The proposed Project scope includes installing five new spillway gates to safely pass the PMF, and to have at least two out of five gates operational after the MDE. The available discharge through the two gates is sufficient to draw down Hayward and Stave Lake Reservoirs in a timely manner (within days), if required, and to safely pass normal flows after a seismic event.

60.0 Reference: Right Abutment Seismic Capability
Exhibit B-7, BCUC 1.73.1

"While BC Hydro cannot quantify the exact amount of time it would take for a failure to result in an uncontrolled release, with high rates of seepage, the fills and sands may erode quickly towards the reservoir, possibly leading to a Dam breach."

2.60.1 Please discuss the seismically-induced failure mechanisms of the right abutment, including an estimate of the approximate potential elapsed time, both with and without the proposed Stage 2 work. Please confirm the Stage 2 right abutment cut-off wall work is being designed to withstand the MDE.

RESPONSE:

Earthquakes could crack and fail the existing upstream concrete facing and cut-off wall and expose the right abutment directly to the reservoir. This would lead to increased seepage through the Right Abutment, with seepage exiting the right bank slopes downstream of the Dam. The increased seepage may erode the fills and sands, possibly leading to a breach. Without the Right Abutment Work-related Stage 2 cut-off wall, seepage and piping through the Right Abutment could develop within hours to days after an earthquake. Any pre-existing defects in the Right Abutment could accelerate the process.

The Stage 2 cut-off wall system is designed to withstand the MDE and allow for a drawdown of the reservoir in a timely manner, post-earthquake, if required.

61.0 Reference: Site Seismicity
Exhibit B-7, BCUC 1.77.1

2.61.1 For the scope items in the proposed Project please identify (if possible) the incremental cost associated with the criterion of 0.71g as compared to 0.54g.

RESPONSE:

As set out in Exhibit B-7, BC Hydro's response to BCUC IR 1.66.1, the 0.71 g seismic criterion results from the Very High Consequence classification of the Ruskin Facility pursuant to the B.C. Dam Safety Regulation and the CDA Guidelines. Therefore, BC Hydro used 0.71 g criterion when designing the Upper Dam Work, Right Abutment Work and Left Abutment Work.

The 0.54 g criterion referenced in this IR represented the MDE at the time of the Dam DIs carried out prior to 2005. No detailed designs were carried out for options that satisfied the 0.54 g option at the time of the DIs because DIs do not entail project design work – DIs are undertaken to identify facility conditions and risk factors (please refer to BC Hydro's response to BCUC IR 2.48.1). Therefore, it is not possible to identify the incremental cost associated with designing to the criterion of 0.71 g as compared to 0.54 g. There is no value in generating a cost estimate with respect to the 0.54 g as it would not address the MDE.

62.0 Reference: Spillway Gate Reliability
Exhibit B-7, BCUC 1.93.1, Attachment 3, pp. 173, 174 of 301

"The spillway gates will only be manually operated (remote or local) although there will be provisions made for local automatic spillway gate control and/or supervisory control if needed in the future."

"Four control stations will be available for each gate control; at the Powerhouse, Main Control Room Back-up Control Room, and at the SPOG. (The control rooms located on top of the piers are also known as the mechanical rooms). The control system will be robust, contain redundancy, and will also include at least one emergency by-pass."

2.62.1 Please explain why so many points of control are required for the spillway gates and how the increased device count affects overall reliability.

RESPONSE:

Reliability studies during detailed design showed that a lesser number of independent control stations are needed to achieve system reliability objectives. In addition, the dependent Powerhouse control station was eliminated in favour of control from the main control building on the Left Abutment.

The proposed control system includes:

- **Control of each individual gate from its pier control room; and**
- **Control of all five gates from the main control building.**

The proposed control system results from ongoing design refinements, which occurred after the report cited in this IR was prepared.

62.0 Reference: Spillway Gate Reliability
Exhibit B-7, BCUC 1.93.1, Attachment 3, pp. 173, 174 of 301

"The spillway gates will only be manually operated (remote or local) although there will be provisions made for local automatic spillway gate control and/or supervisory control if needed in the future."

"Four control stations will be available for each gate control; at the Powerhouse, Main Control Room Back-up Control Room, and at the SPOG. (The control rooms located on top of the piers are also known as the mechanical rooms). The control system will be robust, contain redundancy, and will also include at least one emergency by-pass."

2.62.1.1 Please explain if the gate controls can be operated simultaneously from any control station or if the system relies on a local/remote selector switch that permits control from only a single control station at a time. If the latter, please explain how the gates can be operated during an emergency if access to the selector switch is not possible and the remaining control stations are "locked out" by the inaccessible L/R selector switch.

RESPONSE:

Each pier control room has a selector switch that determines if the gate is operated from the pier control room or the Main Control Building (MCB). This switch will assume control at the pier control room regardless of the switch position in the MCB. It is assumed that pier control buildings will always be accessible via either the employee walkway bridge or the roadway bridge.

In addition, an emergency control station and direct operation of the hydraulic power unit are provided at the pier control rooms as backup systems.

62.0 Reference: Spillway Gate Reliability
Exhibit B-7, BCUC 1.93.1, Attachment 3, pp. 173, 174 of 301

"The spillway gates will only be manually operated (remote or local) although there will be provisions made for local automatic spillway gate control and/or supervisory control if needed in the future."

"Four control stations will be available for each gate control; at the Powerhouse, Main Control Room Back-up Control Room, and at the SPOG. (The control rooms located on top of the piers are also known as the mechanical rooms). The control system will be robust, contain redundancy, and will also include at least one emergency by-pass."

2.62.2 Please describe why a local control station at the gate HPU and the Powerhouse control room are insufficient to provide the required redundant control of the gates.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.62.1.

62.0 Reference: Spillway Gate Reliability
Exhibit B-7, BCUC 1.93.1, Attachment 3, pp. 173, 174 of 301

"The spillway gates will only be manually operated (remote or local) although there will be provisions made for local automatic spillway gate control and/or supervisory control if needed in the future."

"Four control stations will be available for each gate control; at the Powerhouse, Main Control Room Back-up Control Room, and at the SPOG. (The control rooms located on top of the piers are also known as the mechanical rooms). The control system will be robust, contain redundancy, and will also include at least one emergency by-pass."

2.62.3 Please provide a cost estimate for the proposed Main Control Room and Back-up Control Room and the associated control wiring for the spillway gate controls.

RESPONSE:

Please refer to BC Hydro's Confidential Attachment 1 to this IR response.

BC Hydro requests confidential treatment of Attachment 1 to this IR response as it provides a breakdown of cost estimate information for work that has yet to be contracted. In accordance with section 42 of the ATA and the Confidential Filings Practice Directive, BC Hydro respectfully requests that as this information contains a cost estimate breakdown for work that has yet to be contracted, that it be kept confidential on the basis that disclosure will result in: 1) undue financial loss to BC Hydro and undue financial gain to contractors it will be negotiating with to undertake construction or to supply and install equipment; 2) significant prejudice to BC Hydro's competitive negotiation position with these contractors; and 3) BC Hydro has consistently treated this commercial and financial information on a confidential basis.

CONFIDENTIAL ATTACHMENT

FILED WITH BCUC ONLY

63.0 Reference: Left Abutment
Exhibit B-7, BCUC 1.95.1

"Given that a local failure of the Left abutment has already occurred, BC Hydro does not view this as an acceptable risk trade-off."

2.63.1 Please describe the magnitude and provide photographs showing this Left Abutment failure.

RESPONSE:

The slope behind the Powerhouse was cleared and steepened as part of the original construction of the Powerhouse (in 1930 and again in 1950). The slopes were about 25 m high and were cut to an overall angle of about 40 degrees. Over time, erosion and sloughing have left local areas standing almost vertical. A slope failure occurred in 1971 and was described as 9 m wide by 0.6 m deep, which slid into the back of the Powerhouse control building. Due to the ongoing erosion and sloughing, the slopes were flattened to about 35 degrees in 1991, which has reduced but not stopped the deterioration. Additional work on the Left Abutment is planned as part of the Project scope to address safe reservoir retention following the MDE.

Ruskin
September 1991

Photos 11 & 12 - Flattening of slope above Unit 3

Taken by: R. Brighton

Ruskin
1991

Photo 13 - Slope above Unit 3 before stabilization work.

Photo 14 - As above on completion of stabilization
Taken by: R. Brighton

Ruskin
16 December 1991

Photo 15 - Bench at toe of flattened slope above powerhouse.

Photo 16 - Erosion observed at location of arrow on Photo 15.

Taken by: R. Brighton

Ruskin Slope Protection

17 September 1991

Geotechnical Department Photo

64.0 Reference: Future Rate Increases
Exhibit B-7-2, AMPC 1.1.1

"As set out in footnote 17, page 3-11 of Exhibit B-1, the LTRF does not represent BC Hydro's view as to future Revenue Requirement Applications (RRAs), and any rate increases requested in future RRAs will be based on BC Hydro's assessment of its expected revenue and cost at the time of filing."

2.64.1 Has BC Hydro prepared an estimate or assessment of future rate increases, even if for internal purposes? If not, why not?

RESPONSE:

The text set out in the preamble of this IR is intended to make it clear that BC Hydro cannot predict with precision the levels of future rates that BC Hydro will recover from its customers as future rate changes are not determined solely by BC Hydro. Rate changes are approved by the BCUC following the conclusion of the RRA review process. The most recent BCUC-approved rate for BC Hydro covers the F2011 period.

The starting point for the development of the baseline against which the Project impact is compared for rate impact purposes is BC Hydro's F2011 RRA. The Long-Term Rate Forecast (LTRF) also forms part of the baseline, and provides an indicative view of the direction of future rate increases and is the only medium to long range directional view of rates used by BC Hydro.

A six-page document providing an overview of and describing the assumptions used in the LTRF was provided to BCUC staff and Intervenors participating in the 2011 IRP Technical Advisory Committee at its meeting on December 14, 2010. This document is provided as Attachment 1 to this IR response.

Long-Term Rate Forecast

PURPOSE

To provide information on the Long-Term Rate Forecast (LTRF) used by BC Hydro in the Integrated Resource Plan (IRP)

OVERVIEW

This brief provides background information on the Long-Term Rate Forecast (LTRF) used in the 2011 Integrated Resource Plan (IRP). It is similar to the report filed as Attachment 1 to BCUC IR 1.7.1 in the 2008 Long-Term Acquisition Plan (2008 LTAP), which represented BC Hydro's compliance with directive 17 from the British Columbia Utilities Commission (BCUC) decision on BC Hydro's 2006 Integrated Electricity Plan and Long-Term Acquisition Plan (2006 IEP/LTAP)[1].

The forecasting of BC Hydro's electricity rates over an extended period of time (10 to 20 years) requires a significant number of input assumptions with respect to a wide range of variables:

- external forecasts, such as interest rates, inflation rates, and exchange rates;
- timing and magnitude of capital programs and projects, and demand-side management (DSM) expenditures (and energy savings); and
- other revenue requirement inputs (for example, the different elements of the cost of energy, operating costs, amortization rates, trade income, deferral account transfers and recoveries).

A long-term rate forecast is highly uncertain and is subject to significant variability depending on the assumptions made. The forecasting exercise is not a trivial task and necessitates many simplifications. In addition, any such forecast does not capture potential future changes in government policy and changes in legislation and regulations.

Because of the above, the LTRF presented in this brief is indicative only, produced for the purpose of informing the load forecast and DSM analysis in the context of the IRP planning process. The forecast does not represent BC Hydro's view as to its future revenue requirements applications beyond F2011. Any rate increases requested in those applications will be based on BC Hydro's detailed assessment of its expected revenues and costs at the time of filing, taking into account the operating conditions and plans forecast for the relevant test period.

In particular, a rate increase forecast beyond a 10-year period relies on so many uncertain assumptions, and in theory could come about from many possible future scenarios, that, in BC Hydro's view, to attempt to make specific year-by-year forecasts of annual rate increases for that period is of little value. For that reason BC Hydro chooses to assume a uniform annual rate increase for the second 10 years of the 20-year forecast.

Section 1 of this brief summarizes the financial forecast overview and the input assumptions used to develop the forecast. Section 2 provides the rate increase forecast in both real and nominal terms. Section 3 describes how the long-term rate increase forecast will be used in the 2011 IRP, and shows the variance from the long-term rate forecast provided in the 2008 LTAP. Section 4 describes recent activities regarding rate mitigation.

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[1] *In the Matter of British Columbia Hydro and Power Authority's 2006 Integrated Electricity Plan and 2006 Long-Term Acquisition Plan,* Decision, May 11, 2007, page 154.

1. Forecast Overview and Assumptions

1.1 Forecast Overview

The financial forecast uses F2010 rates, including the deferral account rate rider, as the reference rate, or starting point. The forecast has been developed using a variety of inputs including forecast revenues, operating expenses, capital expenditures, debt balances, and economic variables over a 20-year forecast period (F2011 to F2030). The inputs are used to estimate the incremental revenue required to achieve an assumed return on equity each year during the 20-year period. This incremental revenue can be presented in real or nominal terms, and is an indicative estimate of across-the-board rate changes that the assumptions and inputs would give rise to. The forecasted changes in rates also take account of the change in the deferral account rate rider from year to year, using BC Hydro's deferral account rate rider mechanism.

The forecast rate increase for F2011 is based on the F2011 Revenue Requirements Application (F11 RRA) Negotiated Settlement approved by the BCUC on December 2, 2010. The forecast rate increase for F2012 – F2015 is based on the quarterly financial update prepared for the BC Hydro Board and Shareholder in October 2010 ("October 2010 Quarterly Update"), updated to include the estimated impact of both the December 2, 2010 F11 RRA decision and recent rate mitigation announcements which impact the method by which water rental rates and return on equity are calculated.

1.2 Inputs and Assumptions

The inputs and assumptions used in the financial forecast are described below.

Economic Variables – Forecasts of economic variables provided by the B.C. Ministry of Finance in July 2010 for the period F2011 to F2015 are used as inputs into the financial forecast. Table 1 below summarises the assumptions. For the F2016 to F2030 forecast period, the forecasts for F2015 are assumed.

Table 1: Economic Variables

Economic Variables	F2011	F2012	F2013	F2014	F2015	F2016-F2030
Inflation (BC CPI) (%)	1.7	1.9	2.1	2.1	2.1	2.1
Short Term Interest Rate (%)	0.93	2.20	3.15	4.15	4.96	4.96
Long-Term Interest Rate (%)	4.16	4.63	5.08	5.91	6.72	6.72
Exchange Rate C$/US$	1.04	1.01	1.02	1.02	1.02	1.03

Capital Structure – The forecast assumes the definition of equity as set out in Special Directive HC1 and Special Direction HC2, but incorporates the expected changes to the definition of deemed equity arising from the rate mitigation measures announced by the Province on December 2, 2010 (see below). The forecast also assumes that dividend payments to the Province must not result in a greater than 80:20 debt to book equity ratio, to be consistent with Special Directive HC1.

Return on Equity – Consistent with the F11 RRA, the forecast assumes a return on equity for BC Hydro of 14.35 per cent in F2011. For F2012, the forecast return on equity is 14.37 per cent, decreasing to 12.74 per cent throughout the F2013 to F2030 forecast period. The forecast assumes a deemed equity for ratemaking purposes equalling 30 per cent of the 'rate base', to be consistent with a recent rate mitigation announcement which will result in changes to Special Direction HC2. Beginning in April 2011, deemed equity will be based only on assets in service and not on debt and equity levels.

Load Forecast – For the 20-year forecast period, the forecast assumes the 2009 Load Forecast, with the exception that for the F2011 to F2015 period, the forecast assumes updated load forecast volumes used to inform the October 2010 Quarterly Update.

DSM (Energy Savings and Expenditures) – The financial forecast assumes DSM energy savings that are consistent with the DSM Option A – Mid scenario (included as part of the 2008 LTAP) throughout the forecast period. The forecast also assumes:

- DSM expenditures that are consistent with the DSM Plan costs included in the 2008 LTAP; and
- DSM expenditures will continue to be subject to regulatory deferral treatment, and are amortized over a 10-year period.

Domestic Revenue – The forecast calculates domestic sales volumes based on the 2009 Load Forecast and DSM energy savings described above. F2010 rates by customer class (including the deferral account rate rider) are applied to forecast domestic sales volumes to determine forecast total domestic revenue before rate increases, on an annual basis, for the F2011 to F2030 forecast period.

Trade Income – Trade Income is the net income of Powerex Corp., adjusted for rate-setting purposes to be no more than $200 million and no less than $0. The forecast assumes net trade income for F2011 to F2015 will increase from approximately $70 million to $100 million. For F2016 to F2030, trade income is assumed to be $100 million annually.

Energy Costs – For F2011 and F2015, the forecast assumes the cost of energy forecast as per the October 2010 Quarterly Update. These costs are based on the resource operating decision process documented in the F11 RRA at section 4.2 “System Optimization Overview”.
For the fiscal years beyond F2015, the forecast assumes cost of energy, on an annual basis, based upon the hypothetical resource portfolio consistent with an IRP level Base Resource Plan. It was developed using the combination of the HYSIM and MAPA models, which are described in on page 5 of Appendix F15 to BC Hydro’s 2008 LTAP. The portfolio assumes that BC Hydro will achieve self-sufficiency by 2016 and will meet the 3,000 GWh annual insurance requirement by 2020. Mica 5, Mica 6 and Site C are included in this portfolio as future resources.

Water Rental Costs –The forecast assumes water rental rates as of January 1, 2011 are applied to forecasted hydroelectric generating capacity and forecasted generation output on an annual basis to estimate water rentals. Additionally, the forecast assumes that future water rental rates are indexed to forecasted inflation (BC CPI), as per a December 2, 2010 rate mitigation announcement from the B.C. Government.

Operating Costs – For F2011 and F2015, the forecast assumes operating costs as per the October 2010 Quarterly Update. From F2016 operating costs, excluding those subject to regulatory treatment, are assumed to increase by inflation.

Capital Expenditures – The forecast includes estimated capital expenditures by major business group, developed for this forecasting exercise. On average, capital expenditures are assumed to total approximately $2 billion per year through the forecast period. These are high level estimates only, and actual capital plans and projects over the forecast period will depend on many variables. For the F2011 to F2015 forecast period, the forecast assumes capital expenditure and additions as per the October 2010 Quarterly Update. For the F2016 to F2030 period, high level estimates were used solely for the purposes of preparing the LTRF.

Amortization – The forecast assumes property, plant and equipment in service are amortized over the expected useful lives of the assets using the straight-line method. All depreciation rates used are the same as those used in the F11 RRA.

Finance Charges – Finance charges represent the cost of BC Hydro's debt portfolio, and mainly comprise of interest charges on BC Hydro debt. The forecast assumes interest costs on existing debt are based on actual interest rates at the time the debt was issued. Interest costs on future debt are based on forecast debt issues at forecast interest rates, as provided by the B.C. Ministry of Finance for F2011 to F2015 (see Table 1).

Deferral & Regulatory Accounts – The forecast assumes the ongoing treatment of the Deferral Accounts and other regulatory accounts as either previously approved by the BCUC or as proposed by BC Hydro in the F11 RRA, including the deferral account rate rider mechanism (DARR). As part of the F11 RRA Negotiated Settlement approved by the BCUC on December 2, 2010, BC Hydro has committed to propose a new DARR effective April 1, 2011, based on a 5-year amortization of the Trade Income Deferral Account and 10-year amortization of the Non-Heritage Deferral Account and Heritage Deferral Account. As this work has not been completed, the LTRF assumes a 2.5 per cent rate rider will remain in place until the Deferral Account balances would be fully amortized in F2021.

Basis of Presentation – The LTRF has been prepared based on current Canadian GAAP. Commencing in Fiscal 2013, BC Hydro will report its financial results based on accounting standards in accordance with a Directive issued by Treasury Board pursuant to section 23.1 of the Budget Transparency and Accountability Act and section 9(1) of the Financial Administration Act. The new standard is International Financial Reporting Standards plus the application of United States Financial Accounting Standards Board Accounting Standards Codification 980 (Regulated Operations). We have not reflected the impact of the transition to IFRS on the LTRF.

2. Forecast Changes in Rates

As noted in the initial Overview section of this brief, the forecast changes in rates provided below are indicative only, rely on a large number of assumptions, and have been produced solely for the purpose of informing the load forecast and the DSM analysis. Estimated changes in future rates include the impact of changes to deferral account rate rider, and are presented in Table 2 below in real terms (net of forecasted inflation rates) with 2010 as the base year. The rate forecast uses F2010 rates, including the deferral account rate rider, as the starting point.

Table 2: Estimated Real Changes in Rates (net of forecasted inflation rates)

F11	F12	F13	F14	F15	F16	F17	F18	F19	F20	F21-F30
5.5%	11.4%	3.5%	6.0%	5.5%	5.4%	3.4%	1.5%	2.3%	2.8%	0.9%

Note that nominal rate increases for each year would be around 2.1 per cent higher, based on the forecast of inflation.

3. Use of Forecast Output

As part of the 2011 IRP, BC Hydro is incorporating the LTRF for the purpose of determining the 2010 Load Forecast and the energy savings and lost revenue associated with the DSM Plan.

3.1 DSM Analysis

The LTRF is used to estimate energy savings from proposed conservation rate structures in the DSM Plan as part of the 2011 IRP. The resulting pricing levels within the rate structures, along with the rates savings estimates, are also used to inform DSM program assumptions, such as incentive levels and participation rates. In addition, the resulting pricing levels are used to estimate lost revenues in the DSM Plan. Lost revenues are an input to the Non-Participant test.

3.2 2010 Load Forecast

The LTRF contained in this brief has been used as an input to the 2010 Load Forecast presented in the 2011 IRP. The rate increase forecasts impact the after-DSM load forecast in two ways, and these impacts are determined separately. Firstly, the assumed across-the-board rate increases under current rate structures produce a demand response (given an assumed price elasticity), and reduce the before-DSM load forecast. Secondly, assumed new stepped rate structures (with prices based on the forecast rate increases), produce a demand response (given assumed price elasticity). These rate structure-induced energy savings are considered to be part of DSM savings and are subtracted to produce the after-DSM load forecast.

3.3 Current Forecast Compared to 2008 LTAP Rate Increase Forecast

The August 2008 Long-Term Rate Increase Forecast set out in the attachment to BCUC IR 1.7.1 of the 2008 LTAP was used in developing the 2008 Load Forecast as part of the 2008 LTAP Evidentiary Update. Since that time, updates have been made to the long-term rate forecast inputs and assumptions including: (1) updated 5-year financial forecast; (2) updated capital expenditure estimates; (3) changes to assumptions regarding basis of water rental rate escalation; (4) updated energy portfolio from the 2008 LTAP; (5) new policy directions regarding timing of self-sufficiency and insurance energy requirements; and (6) updated trade income estimates, among others.

The difference between the current long-term rate increase forecast and the 2008 LTAP long-term rate forecast is shown in Table 3. The variations between the two forecasts illustrate generally the sensitivity of rate increase forecasting to the inputs and assumptions, and demonstrate why such a forecast must be viewed as indicative only.

Table 3: Variance from January 2008 forecast

	F11	F12	F13	F14	F15	F16	F17	F18	F19	F20	F21-F28
Increase (decrease)	0%	8%	0%	2%	2%	1%	0%	(3)%	2%	3%	1%

4. Rate Mitigations

In the recent F11 RRA Negotiated Settlement, approved on December 2, 2010, BC Hydro committed to increase its focus on the management and control of its cost structure with the objective of reducing potential future rate increases, and to undertake to propose to government changes to government-related aspects of BC Hydro's revenue requirement, also with the objective of mitigating potential future rate increases.

BC Hydro acknowledges the concern of customers regarding the currently projected future rate increases, and shares this concern. BC Hydro has already been in active discussions with the Province on potential rate mitigation measures and on December 2, 2010, BC Hydro and the Province announced changes to water rental rate escalation, as well as to the methodology of calculating shareholder return on equity.

The estimated impact of these changes have been included in the LTRF and, on average, these measures help reduce the annual real rate increases by 0.75 per cent through F2015, and by 0.3 per cent annually over the 20-year forecast period.

KEY PLANNING QUESTIONS

LTRF Update – the rate forecast is based on several assumptions (load forecast, DSM plans, and financial assumptions, among others) which may be revisited over the next several months. We will determine the appropriate time to update the LTRF that would result based upon the Base Resource Plan developed as part of the draft IRP.

Contact the Integrated Resource Plan project team for more information:

Integrated Resource Plan
PO Box 2850 Vancouver BC V6B 3X2
Email: integrated.resource.planning@bchydro.com

64.0 Reference: Future Rate Increases
Exhibit B-7-2, AMPC 1.1.1

"As set out in footnote 17, page 3-11 of Exhibit B-1, the LTRF does not represent BC Hydro's view as to future Revenue Requirement Applications (RRAs), and any rate increases requested in future RRAs will be based on BC Hydro's assessment of its expected revenue and cost at the time of filing."

2.64.2 Please provide BC Hydro's most recent estimate or assessment of approximate annual rate increases through to F2022, along with the underlying assumptions.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.64.1.

65.0 Reference: IPP Purchases
Exhibit B-7-2, AMPC 1.1.2

"However, as noted in BC Hydro's response to Kwantlen IR 1.5.6, while the Clean Power Call is the best available proxy for future IPP energy purchases, past experience suggests that future IPP costs may be higher than the $129/MWh resulting from the Clean Power Call."

2.65.1 Please provide a copy of BC Hydro's 2011 Integrated Resource Plan (IRP) Consultation Workbook.

RESPONSE:

A copy of the 2011 Integrated Resource Plan Consultation Workbook (IRP Workbook) is provided as Attachment 1 to this IR response.

Please refer to BC Hydro's response to BCUC IR 2.65.2 with respect to the relevance of the cost ranges shown at pages 14 to 15 of the IRP Workbook for purposes of evaluating the Project.

2011 INTEGRATED RESOURCE PLAN

PLANNING FOR A CLEAN ENERGY FUTURE

CONSULTATION WORKBOOK

MARCH 1 – APRIL 30, 2011

bchydro.com/irp

BC hydro FOR GENERATIONS

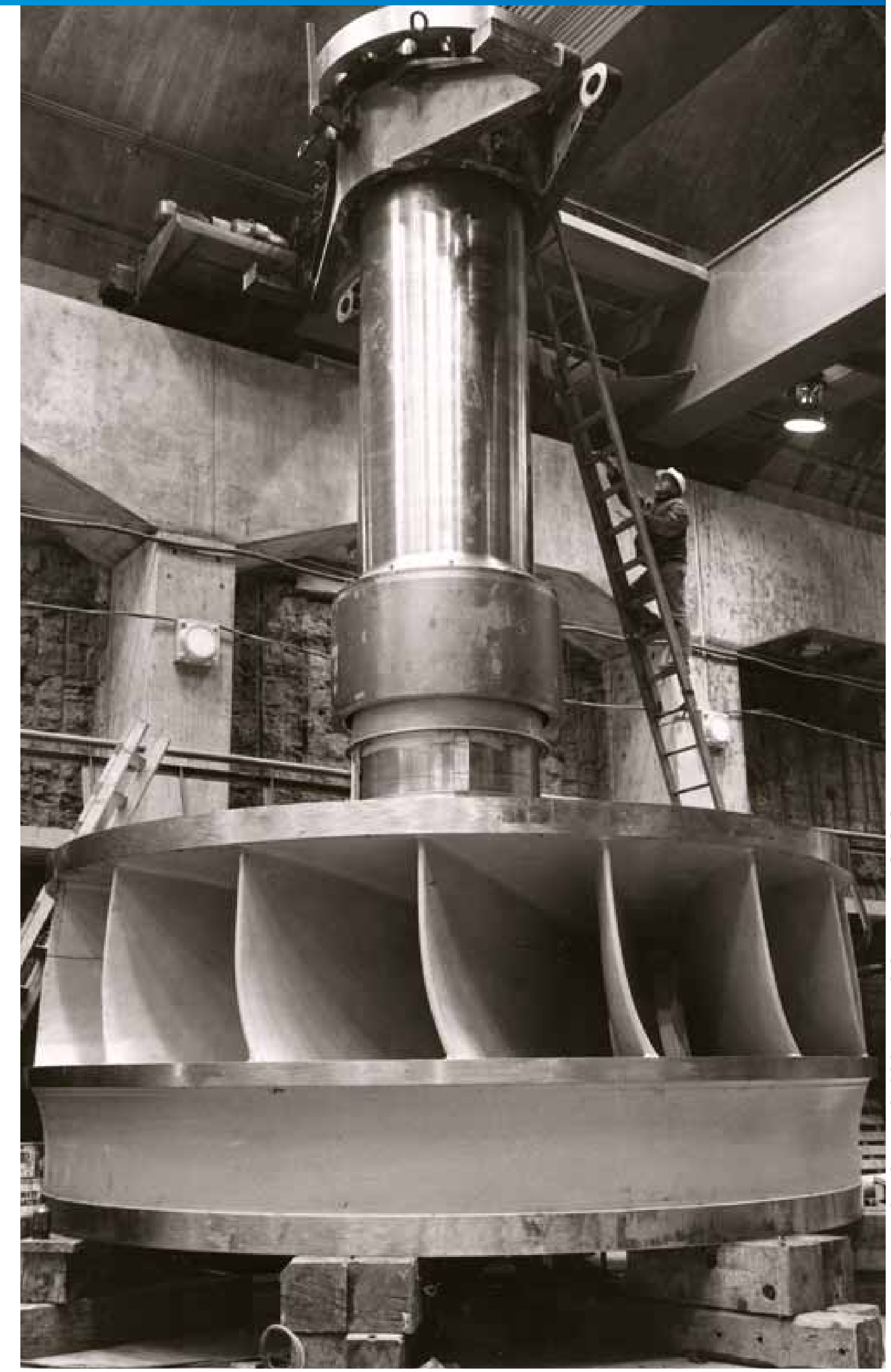
BC HYDRO OVERVIEW

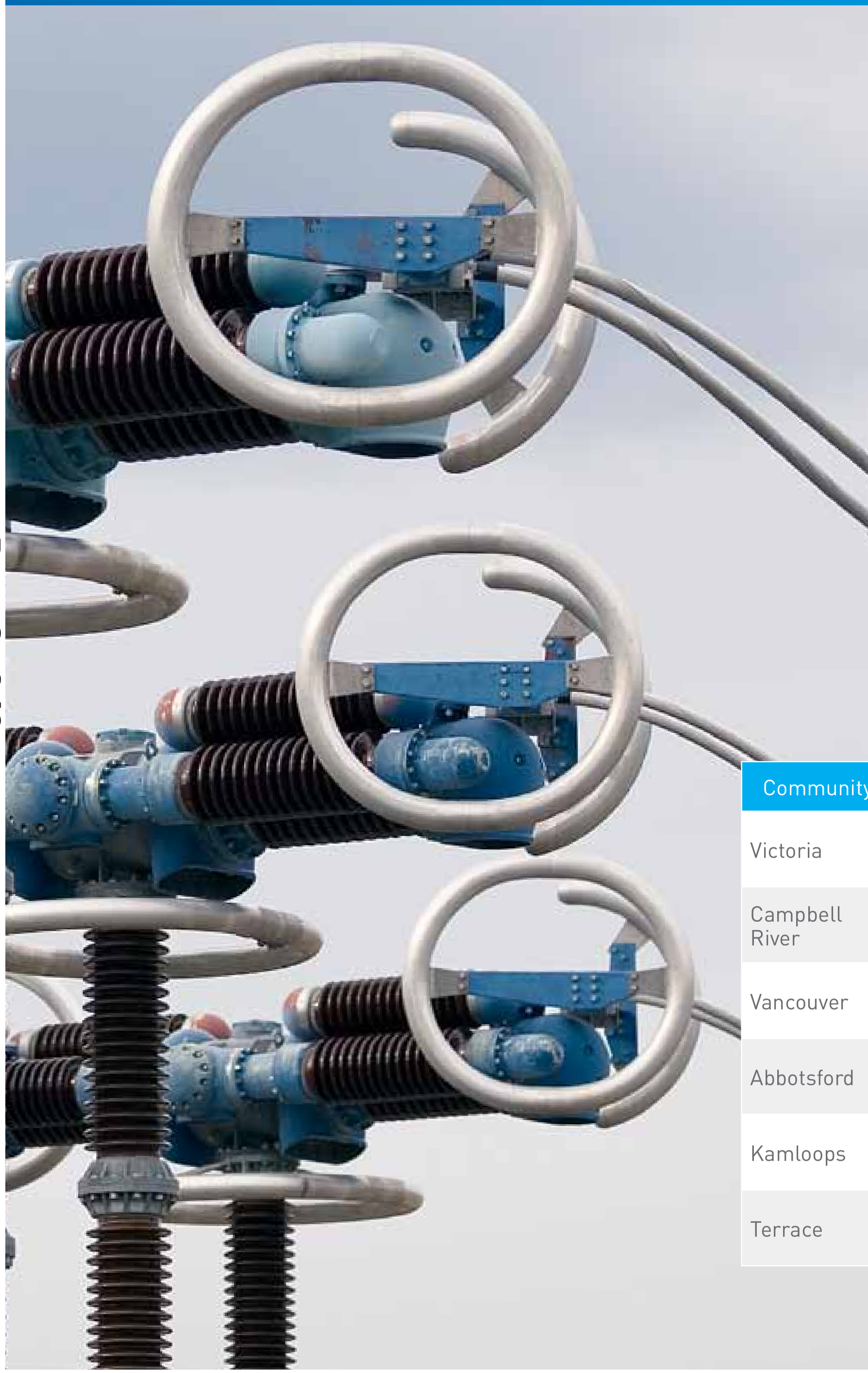
Fifty years ago, BC Hydro was created as a Crown corporation to deliver electricity to homes and businesses throughout much of the province. Investments in dams, generating stations, transmission and distribution networks, and programs to encourage conservation have provided a reliable supply of electricity for generations of British Columbians at some of the lowest rates in North America.

Currently, BC Hydro serves 1.8 million customers in an area containing more than 94 per cent of British Columbia's population. The third-largest electric utility in Canada, BC Hydro provides electricity to its customers through an integrated grid. BC Hydro generates the majority of its power from large hydroelectric stations on the Columbia and Peace rivers. The remainder of its domestic electricity supply comes from smaller BC Hydro-owned generating stations and purchases from Independent Power Producers (IPPs).

In years when domestic requirements have exceeded domestic supply, BC Hydro has also imported some of its total net annual supply from other jurisdictions. Facing a growing population with an increasing appetite for electricity-driven technology and signs of new growth in the energy-intensive industrial sector, BC Hydro is forecasting that demand for power will increase by approximately 40 per cent over the next 20 years, before accounting for savings that can be achieved through promoting energy efficiency and conservation.

On its 50th anniversary, BC Hydro is looking back on its legacy in helping to develop the province, and it is examining the challenges that await British Columbians in the next 50 years. To ensure that future generations will continue to enjoy the competitive advantage of clean, reliable power, BC Hydro must plan ahead to upgrade and expand its heritage facilities, secure new supplies of renewable energy, build new transmission and distribution lines, encourage conservation, and integrate new technologies to modernize the system.





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Please check bchydro.com/irp for schedule updates.

POWER FOR OUR HOMES AND WORKPLACES

It can seem like a bit of magic: you flick a switch and whatever gadget or appliance you choose jumps to life. You get heat, you get light. You get music or entertainment. All this electrical "fuel" arrives at our homes or workplaces safely, silently and consistently. It leaves no smell, and there is never any left over when you finish. You just turn it off and it stops. It all seems so simple.

Of course, it's not. The electricity that powers our lives comes in the form of a strictly controlled current of electrons. Most of the actual electricity is generated in the far corners of the province and carried over thousands of kilometres of transmission and distribution lines to reach the bulk of us who live in the province's southwest corner. Along the way, it passes through a range of landscapes, habitats and communities before it arrives at our homes and places of business.

The tricky part is that electricity doesn't actually "go away" when you turn off the switch. Once generated, it has to be used or it can overload and crash the system. Accordingly, BC Hydro must anticipate how much people will want at any given time of the day or year and introduce exactly that amount into the network. BC Hydro continually monitors the entire system to ensure that they estimated correctly or to adjust the flow accordingly.

Over the longer term, BC Hydro must also anticipate future demand. It can take five to seven years to build a new generation facility and even longer to build transmission, so BC Hydro must plan carefully – and well into the future – to ensure that it has encouraged conservation and acquired the right mix of generation and transmission resources to meet its customers' needs.

Whether it's our homes, communities, businesses or industries, we depend on affordable, reliable electricity when and where we need it. It's essential that BC Hydro understands customers' needs and meets the demand for electricity now and for years to come. It's also essential that we consider the consequences of our decisions from a broad range of perspectives – for example, on our pocketbooks, on our economy, and on the people and the environment where our electricity is generated and transmitted.

THE INTEGRATED RESOURCE PLAN

The Integrated Resource Plan – the IRP – is BC Hydro's long-term plan for acquiring the resources to meet customers' needs for the next 20 years. It is guided by the government of British Columbia's new *Clean Energy Act,* which came into effect in June 2010 and sets specific new energy objectives for BC Hydro with respect to its long-term electricity plan (see page 8). Notably, long-term electricity planning is not a once-every-20-years exercise. Over the course of its history, BC Hydro has renewed its long-term plan at regular intervals. Most recently, it developed an Integrated Electricity Plan in 2006 and a Long-Term Acquisition Plan in 2008. Once developed, BC Hydro will renew the Integrated Resource Plan periodically.

Integrated electricity systems are inherently complex and capital-intensive, and most new resources require significant lead times to develop. As a result, electric utilities must plan ahead to be sure that the required resources will be in place when needed. And implementation of long-term electricity plans require a staged and flexible approach to account for changes in everything from the economy to technology.

Notably, BC Hydro's IRP does not, by itself, lock the utility into any of the specific projects identified over the planning horizon. Rather, the plan, if approved by government, will set out a path for BC Hydro and will require key actions to be taken over the next few years that will ensure customers' needs can be met over the next 10 and 20 years. Any specific project that is later developed in response to the IRP – whether a transmission line, a generation project, a power call or a conservation plan – will have its own individual design, consultation, permitting and approval process.

As BC Hydro considers how to meet B.C.'s electricity needs over the next 20 years, it asks three basic electricity planning questions:

1. **How much electricity will British Columbians need over the next 20 years?** This depends on a host of issues, some that may increase demand on the system, and some that may reduce demand. The demand must also be understood in two ways: how much energy will be required on an annual basis, and how much energy might be needed at any given point in time to meet peak demand and to ensure that we can "keep the lights on", even on the coldest days in winter.

2. **What is the gap between existing supply and forecast electricity demand?** What electricity generation and transmission assets does BC Hydro currently have that can continue to be relied upon going forward, and how much electricity can it source from its existing contracts with B.C.-based Independent Power Producers?

   As well, to what degree can current conservation and efficiency measures such as conservation rates be relied upon to reduce demand?

3. **How can BC Hydro close the gap?** What blend of additional conservation measures and generation and transmission resources will be needed to meet demand, reliably and cost-effectively?

   As BC Hydro examines how to close the gap, it considers:

   - How much savings can be achieved from conservation and efficiency
   - What portfolio of electricity generation options it should plan on
   - How much electrification will contribute to growth in electricity demand
   - What the transmission requirements will be
   - What the export market potential may be

CLEAN ENERGY SUPPLY AND TRANSMISSION

The majority of B.C.'s electricity demand is located in the Lower Mainland and on Vancouver Island, while the overwhelming majority of supply is remote and must be moved over very long distances across rugged terrain and through a relatively small number of transmission lines.

More than 93 per cent of BC Hydro's electricity supply is renewable, and creates little or no greenhouse gas emissions, making it desirable at a time when the world faces climate change. BC Hydro's energy supply comes from a combination of its own heritage resources (see below) and power purchases from Independent Power Producers who generate their energy from a range of sources, including hydro, biomass and wind.

BC Hydro is regulated by the BC Utilities Commission and governed by the *BC Hydro and Power Authority Act*, the *Utilities Commission Act* and the B.C. *Clean Energy Act*. Collectively, this legislation ensures that BC Hydro will continue to provide clean, reliable and cost-effective electricity to its customers.

BC HYDRO GENERATION

HOW MUCH ELECTRICITY WILL BRITISH COLUMBIANS NEED OVER THE NEXT 20 YEARS?

BC HYDRO'S ELECTRICITY LOAD FORECAST

The annual long-term load forecast provides planners with an understanding of how much electricity will be required 10 and 20 years from now. Trends that influence future electricity needs include economic growth and population growth, as well as predictions on how electricity use will change as a result of changes in lifestyle, electricity rates, legislation and technology.

The 2010 Electricity Load Forecast indicates that demand will increase by approximately 40 per cent in the next 20 years before accounting for savings that can be achieved through conservation and efficiency.

The demand forecast is developed by examining BC Hydro's three customer classes: residential, commercial and industrial. The primary drivers for future increased electricity consumption among residential customers include population growth and housing starts. Drivers for the commercial sector are general economic activity, which includes gross domestic product (GDP) and retail sales, and employment. The industrial sector's demand is the most volatile year over year, and it is the most challenging to forecast, as it is sensitive to the unpredictability of international commodity prices, economic cycles, natural disasters (e.g., mountain pine beetle), regulatory approvals and labour disputes.

WHAT AFFECTS LOAD GROWTH?

Population – The B.C. population is expected to grow to nearly 5.8 million people over the next 20 years, an increase of almost 25 per cent over the current population of 4.6 million.

Conservation – Programs, such as BC Hydro's award-winning Power Smart, have been effective in helping people use electricity more efficiently and reduce the amount of energy they use, through everything from turning out the lights, to turning down the heat, to improving home insulation.

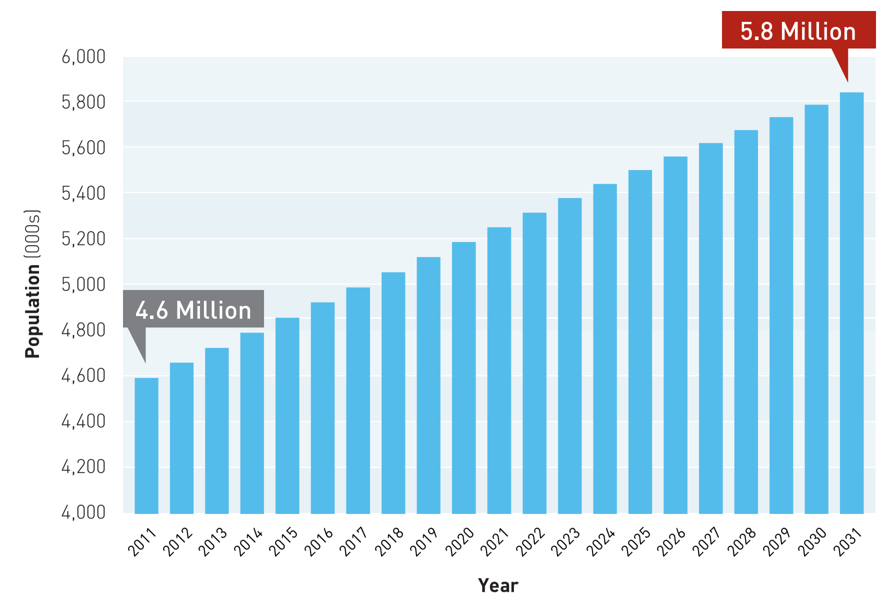
Consumption – The increased popularity of computers, larger televisions and other consumer products has greatly increased the demand for electricity in individual homes.

Efficiency – Manufacturers are consistently producing conventional goods (washers, dryers, refrigerators, compact fluorescent light bulbs) that use much less electricity.

Electrification – The rising price, environmental impact and threatened shortage of fossil fuels may drive people to choose electricity to power everything from home heating to automobiles.

Economic Activity – The current forecasted expansion in the mining and the oil and gas industry has the potential to significantly increase electricity use in B.C.

B.C.'S PROJECTED POPULATION GROWTH 2011 – 2031



WHAT IS THE GAP?

A LOOK AT EXISTING RESOURCES COMPARED TO FORECAST DEMAND

Before BC Hydro can assess the future gap between supply and demand, it first must assess how much electricity it can produce and rely upon from its current generating facilities, its existing contracts with Independent Power Producers and its current conservation plan.

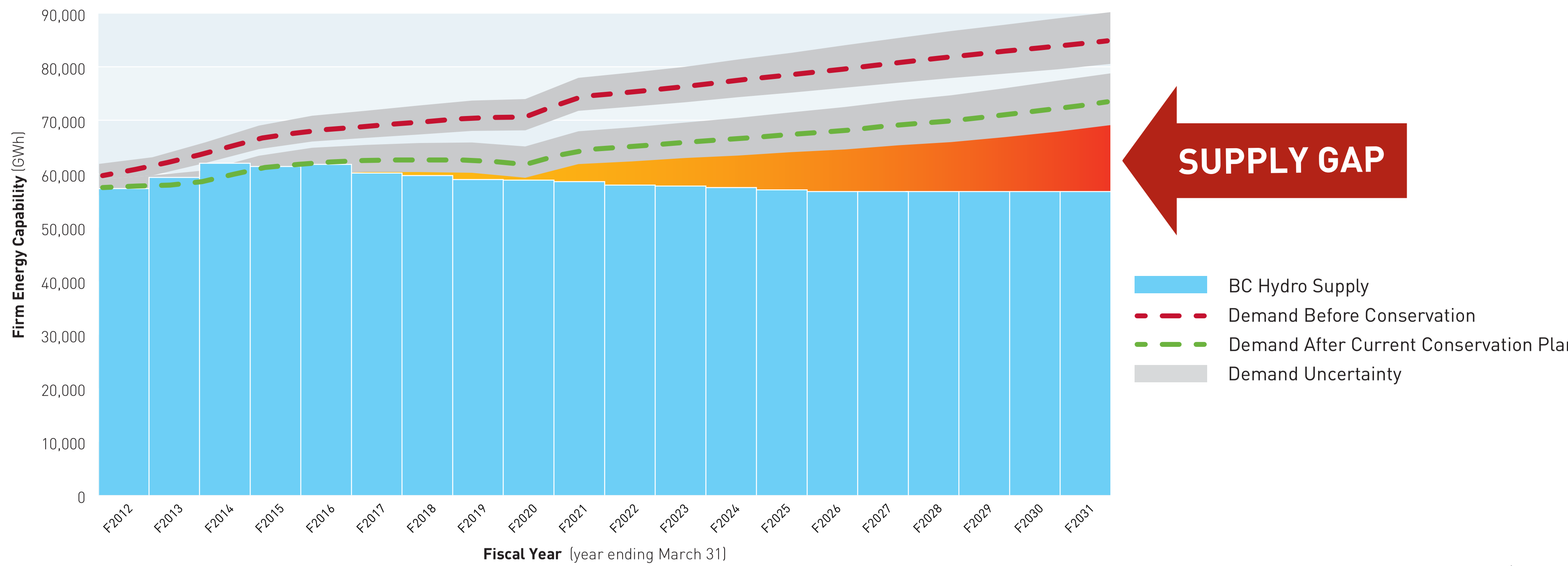
Approximately 85 per cent of domestic supply comes from generation resources owned and operated by BC Hydro; the remaining 15 per cent of electricity need is met with power purchased from Independent Power Producers in B.C.

Of the electricity produced by BC Hydro, almost 80 per cent comes from its large hydroelectric installations in the Peace and Columbia river basins.

BC Hydro currently has more than 100 electricity-purchase agreements with Independent Power Producers, some of which date back to the 1980s. Sixty-five of these purchase agreements involve projects that have reached commercial operation. While the majority of these projects generate electricity from run-of-river hydro plants, there are also a number of wind and biomass generating plants. In wind alone, BC Hydro has purchase agreements with Independent Power Producers that represent a total of 700 megawatts (MW), of which 100 MW has reached commercial operation as of January 2011.

As the "gap" diagram below illustrates, even after the increase in demand for electricity is adjusted to account for savings from BC Hydro's current conservation and efficiency plan, an energy gap between future electricity needs and current resources still exists, particularly after 2020. The planning challenge begins with the task of how best to fill the gap.

ENERGY DEMAND/SUPPLY BALANCE FORECAST



HOW CAN THE GAP BETWEEN FUTURE ELECTRICITY NEEDS AND EXISTING RESOURCES BE CLOSED?

FUTURE RESOURCE OPTIONS

After identifying the gap between forecasted demand and current supply, planners look at possible new sources of electricity, or resource options. These include additional conservation and efficiency measures, supply-side options such as new generating resources (supplied by BC Hydro or Independent Power Producers), and the necessary transmission options to ensure that the energy from these resources can be optimally brought to customers.

BC Hydro periodically updates its inventory of potential future resources, most recently in the *2010 Resource Options Report*.

ADDITIONAL ELECTRICITY CONSERVATION AND EFFICIENCY

Encouraging electricity conservation and efficiency is called demand-side management (DSM). This can be voluntary, as when BC Hydro encourages its residential, commercial and industrial customers to use less electricity by, for example, adopting efficient technology options such as ENERGY STAR® windows, or it can be regulated, as when governments pass regulations that, by similar example, mandate low-emissivity windows. BC Hydro can also design electricity rates that encourage conservation, for example, by charging more for power at certain times of the day in an attempt to shift the time of use and lower the peak demand. There is potentially more to gain from conservation (a reduction of up to 79 per cent under the current plan) than what is mandated under the *Clean Energy Act*.

Power Smart is BC Hydro's branded program encompassing all of its demand-side management programs. Power Smart uses a wide range of approaches, including information programs, incentives specific to particular enterprises or homes, and rebate programs to assist customers in paying for conservation or efficiency measures.

Overall, demand-side management helps to keep rates low, as saving electricity is lower in cost than new generation.

GENERATION AND TRANSMISSION OPTIONS

For an overview of generation options and their potential implications, see the table on pages 14–15. For a discussion on approaches to transmission planning, see pages 22–24.

ENERGY, CAPACITY AND CUSTOMER DEMAND

Electricity consumption varies by customer type, by day, and by year. Some customers, such as large industries, need a steady amount of electricity delivered. Others consume in short bursts. Residential customers, for example, draw most of their energy in the early evening when they are preparing dinner, using appliances and watching TV. Over the whole year, demand is highest in November, December and January, when people use more electricity for heat and light.

To meet the demand for electricity, a utility must have:

- **Firm Energy** – refers to electricity that is available at all times. Resources typically providing firm energy include large hydroelectric dams, bioenergy, geothermal and natural gas.
- **Dependable Capacity** – the maximum amount of electricity that all of the generating stations combined can reliably produce in any one instant, usually measured in megawatts (MW)
- **Adequate Generation Reserve** – sufficient additional capacity to cover forecast uncertainties, unscheduled outages, and system fluctuations

WHICH BLEND OF FUTURE RESOURCES WILL BEST MEET ELECTRICITY NEEDS?

To effectively compare resource portfolios (bundles of different resource options), BC Hydro uses characteristics to evaluate at a high level the reliability, cost, economic development and environmental implications of different portfolios. Characteristics include:

- **Technical:** How much dependable capacity can it provide? In the case of conservation, how much energy or capacity savings can it offer?
- **Financial:** What are the estimated costs of the resource options? The costs associated with developing additional generation facilities, including building new roads and transmission lines or undertaking more conservation, ultimately affect the cost of electricity to consumers.
- **Economic Development:** What are the characteristics of different resource options to support economic development? For example, employment and gross domestic product impacts.
- **Environmental:** What are the environmental characteristics of the different resource options? For example, what is their greenhouse gas emissions profile?

The characteristics listed above are appropriate for comparing a wide range of resource options across a range of environments located throughout the province.

COMPARING ALTERNATIVE PORTFOLIOS

There are many combinations of resource options that could be used to fill the gap between future demand and the current supply. These combinations, or bundles, are described as "portfolios". It is important to look at resources in combination, because the limitations of some resources can be balanced by the strengths of others. For example, some resources are intermittent and must be backed up by a dependable supply of power. As well, the sequence or timing of acquiring or developing new resources is important to ensure that supply is available, to avoid unnecessary costs, and to ensure reliable power.

Later on in this workbook, we examine several portfolios for the purpose of seeking input on the draft plan. Planners examine the performance of many portfolios to understand the consequences of different mixes of resource options.

Risk management also is a central focus in resource planning. A robust portfolio consists of electricity resources that will ensure that customer needs are met cost-effectively, reliably and at low risk.

INDEPENDENT POWER PRODUCERS

Since the 1980s, Independent Power Producers (IPPs) have been helping BC Hydro meet its customers' electricity demand. Currently, IPPs provide BC Hydro with approximately 12,000 GWh/year of electricity, equal to about 15 per cent of BC Hydro's total supply. IPPs include independent power companies, municipalities, First Nations and customers, working alone or in partnership.

BC Hydro has 100 electricity purchase agreements with IPPs, 65 of which have reached commercial operation. Electricity comes from a range of sources including wind, run-of-river hydro, and biomass.

BENEFITS OF IPP POWER

IPPs identify, design and build innovative clean renewable power projects that help BC Hydro meet customers' electricity needs and achieve electricity self-sufficiency at competitive prices. Through the development and operation of their projects, IPPs are responsible for securing all necessary regulatory approvals and permits. IPPs take on the financial, development, construction and operating risk associated with their projects while delivering electricity at secured prices over the life of the contract with BC Hydro.

WHAT IS THE PLANNING CONTEXT?

BC Hydro's electricity plans and planning processes are shaped by government legislation and policies, by changing market structures and conditions, and by new developments in technologies.

On June 3, 2010, the government of British Columbia passed the *Clean Energy Act*, legislation that changes the approach that BC Hydro must take to planning. The Act reaffirms the requirement that BC Hydro must achieve electricity self-sufficiency by 2016 and each year after.

The *Clean Energy Act* also sets out several new or updated objectives, including:

- Generate at least 93 per cent of all electricity in British Columbia from clean or renewable sources and build the infrastructure necessary to transmit that electricity
- Use renewable power potential to help achieve the provincial government's greenhouse gas (GHG) reduction targets
- Meet at least 66 per cent of any increase in demand through conservation and efficiency
- Include an assessment of anticipated transmission requirements over the next 30 years as part of the Integrated Resource Plan
- Encourage economic development
- Explore and pursue, subject to Cabinet approval, the opportunity to develop and sell clean energy into the interprovincial and international markets
- Foster the development of First Nations and rural communities through the use and development of clean and renewable resources

PROVINCIAL GREENHOUSE GAS TARGETS

The government of British Columbia has ambitious targets for reducing greenhouse gas emissions. Having always delivered most of its power from hydroelectric sources, BC Hydro has one of the smallest "carbon footprints" of any major utility in Canada or the U.S. It is BC Hydro's intention – and responsibility under the provincial *Clean Energy Act* – to maintain and improve upon that position by concentrating on development in clean, renewable sources of energy while maintaining reliability and low cost. B.C.'s low-carbon electricity can play a key role in reducing emissions by offering customers a low-emission alternative to fossil fuels for vehicles, homes, businesses and industry.

WHAT'S IN THE PLAN?

The Integrated Resource Plan will provide an analysis and outlook that can guide BC Hydro operations for two decades and beyond. It will include:

- A 20-year Base Resource Plan that sets out a mix of demand reduction and generation and transmission options that are able to fulfill the forecasted demand
- Contingency Resource Plans that address the uncertainties inherent in long-term planning, such as higher than expected demand. Contingency resource plans put forth a range of alternate resource options that would be relied upon if conditions change significantly.
- A 30-year transmission plan

These plans will include addressing key questions, such as:

- How much further can demand be reduced by conservation?
- How can the Site C Project help meet future demand?
- When should the next call for power from Independent Power Producers be made? Should it include natural gas?
- What are the transmission requirements?
- How does BC Hydro balance competing policy objectives?

The IRP will also include a consideration of:

- The potential to use electrification to reduce greenhouse gas emissions in B.C.
- The opportunity to develop revenue-earning clean energy exports, and the potential associated costs of building capacity to serve such a market

The planning process includes consultation with the public, First Nations and other stakeholders. An account of those consultations and a thorough review of stakeholder feedback will form part of the final Integrated Resource Plan when it is submitted for government consideration by early December 2011.

PUBLIC, STAKEHOLDER & FIRST NATIONS CONSULTATION PROGRAM

BC Hydro will consult with First Nations, stakeholders and the public as it develops an Integrated Resource Plan that responds to its service obligations, B.C.'s energy objectives and its obligations as set out in the *Clean Energy Act*. The process for developing the Integrated Resource Plan includes three phases:

TECHNICAL REVIEW AND FOUNDATION FOR INTEGRATED RESOURCE PLANNING (FALL 2010)

In the first phase of developing the IRP, BC Hydro focused on assembling key pieces of technical data necessary to construct a plan, and sought input from selected First Nations and stakeholders with regard to the design of the consultation process. BC Hydro also worked with its Electricity Conservation and Efficiency Advisory Committee as it constructed conservation plan options for energy conservation. During this phase, BC Hydro also updated its forecast of future electricity demand to establish the "gap" between future demand and existing and committed energy resources.

An IRP Technical Advisory Committee was established that will assist BC Hydro in creating a plan through detailed technical advisory input and feedback. This advisory input is in addition to input provided by the public, First Nations and stakeholders through the province-wide consultation process.

CONSIDERING OUR CLEAN ENERGY FUTURE – ASSESSING AND EVALUATING OPTIONS (WINTER/SPRING 2011)

In the second phase of developing the IRP, BC Hydro is using the technical data prepared in the fall to compare alternative ways of meeting growing demand and associated clean energy objectives. BC Hydro is asking the public, First Nations and stakeholders to consider relevant topics being addressed in the IRP. These topics include the approach to conservation and efficiency, electricity generation options, electrification, approaches to planning transmission, and export market potential. As part of this phase, and considering resource alternatives, BC Hydro is examining the Site C Clean Energy Project, a potential third dam and hydroelectric generating station on the Peace River in northeastern B.C. Input received through consultation will be considered, along with technical, financial, environmental and economic development input, as BC Hydro evaluates alternatives and drafts the Integrated Resource Plan.

REVIEWING THE DRAFT INTEGRATED RESOURCE PLAN (FALL 2011)

In this final phase, First Nations, the public and stakeholders will be invited to provide their feedback on the draft Integrated Resource Plan. BC Hydro will consider this feedback as it prepares its final draft IRP for submission to government in early December 2011, after which government will review the plan and decide whether to approve it.

BC Hydro wants to hear from British Columbians as it develops its Integrated Resource Plan. To add your voice, attend a public open house in a community near you.

IRP PUBLIC OPEN HOUSE SCHEDULE*

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CONSULTATION TOPICS

Through this Consultation Workbook and Feedback Form, BC Hydro is seeking input on the following consultation topics:

1. **Conservation and Efficiency**
2. **Electricity Generation Options**
3. **Electrification**
4. **Transmission Planning**
5. **Export Market Potential**

A brief description of each of the consultation topics is provided below.

1. **Conservation and Efficiency** The first and best way to meet our future electricity needs is to reduce demand through conservation and energy efficiency. Conservation occurs when customers change their behaviours, business operations, equipment purchases, or capital investment decisions in ways that reduce electricity use. Methods of conservation include programs, electricity rates and government regulations designed to encourage or require customers to conserve electricity. The current conservation and efficiency plan is designed to reduce the forecast growth in demand by 79 per cent by 2020. This is above the new *Clean Energy Act* target of 66 per cent. One of the important questions in the IRP is whether BC Hydro should target additional savings from conservation and efficiency over and above our current significant plan to reduce growth by 79 per cent by 2020.

2. **Electricity Generation Options** While British Columbians are doing more than ever to conserve electricity, electricity use is expected to continue to increase over the coming decades due to growth in population and among energy-intensive industries. BC Hydro will develop and analyze various portfolios (sets of resource options) that may be used to meet future electricity needs and clean energy objectives. Potential resource generation options include run-of-river hydro, biomass, wind, large hydroelectric with storage (Site C), natural gas, and emerging technologies, such as tidal and wave.

3. **Electrification** Electrification describes the process of switching from other fuel sources to electricity. For example, switching vehicles from petroleum to electric or switching household heating or large industrial processes from natural gas. Efficient electrification is one way of supporting the province's greenhouse gas emission reduction targets. The Integrated Resource Plan will consider how potential electrification can affect electricity demand over time and what measures BC Hydro may need to take to serve its customers.

4. **Transmission Planning** The transmission system, the essential link between electrical generators and energy consumers, is planned and designed to deliver energy efficiently and reliably. Because transmission lines require long lead times to plan and construct, the Integrated Resource Plan will assess the demand forecast and the transmission options that will most effectively meet those demands over the next 30 years.

5. **Export Market Potential** While BC Hydro currently trades electricity when it has a short-term surplus, the B.C. *Clean Energy Act* includes the objective that the province be a net exporter of clean or renewable power. The Integrated Resource Plan will assess the export market potential, including the share of the clean energy market that B.C. could expect to capture, and make recommendations to the provincial government about what actions, if any, are required now.

TOPIC 1:

CONSERVATION AND EFFICIENCY

The latest forecasts show that demand for electricity in B.C. will grow by approximately 40 per cent over the next 20 years. That's the equivalent of adding the energy demand of five more cities the size of Vancouver to our system, before accounting for savings that can be achieved through conservation and efficiency. Conservation is the cleanest and least expensive way to meet demand.

Conservation – often referred to as demand-side management (DSM) – is BC Hydro's first strategy for closing the gap between future electricity demands and existing resources. Conservation options include programs, specifically designed electricity rates (e.g., residential inclining block rate), and government regulations.

From a planning perspective, however, it is difficult to guarantee a particular volume of conservation over time – dependent as that is on customers' behavioural response.

To be sure that it can reliably meet future demand, BC Hydro must evaluate conservation plans in a way similar to new generation options. Key questions include:

- How much additional electricity can be saved, in particular above the current plan, to reduce growth in demand by 79 per cent?
- By when can the electricity be saved?
- How certain are the savings in the existing conservation plan? How much risk is associated with extending that target? How persistent are the savings?
- What is the cost to create these savings?

Depending on what combination of conservation and efficiency measures is undertaken, BC Hydro can target different levels of savings. For this IRP, BC Hydro is evaluating a range of options that could provide savings of between 66 per cent and 83 per cent of the gap between current resources and anticipated demand.

GREATER CONSERVATION AND EFFICIENCY

To achieve significantly higher energy savings from current targets, BC Hydro would have to:

- Expand its Power Smart programs
- Send stronger signals through specially designed electricity conservation rates
- Request that the provincial and federal governments commit to bring in new conservation regulations

These measures combined would be expected to change societal norms and energy consumption patterns throughout the entire provincial electricity market. They might include making all buildings net zero consumers of electricity, meaning they produce as much electricity as they consume over the course of a year. This would require super-efficient building envelopes, widespread integration of district energy systems and small distribution generation, and more community densification, as well as best practices in construction and renovation. Every British Columbian would have to make energy efficiency a personal responsibility beyond what we currently do.

BC hydro
power smart

The table below compares BC Hydro's current plan to an approach that could achieve greater conservation and efficiency:

CONSERVATION (DSM) APPROACH	DESCRIPTION	TECHNICAL	FINANCIAL	ENVIRONMENTAL	ECONOMIC DEVELOPMENT
Current Plan	Combination of initiatives that include government regulations, conservation rates and Power Smart programs for all classes of customers (see sidebar).	Targets reducing 79 per cent of future load growth by 2020. Moderate uncertainty that expected electricity savings will materialize.	Less costly than buying or building new electricity supply.	Avoid environmental footprint because BC Hydro would not need to build new generation and transmission.	Moderately more jobs relative to new electricity generation options.
Greater Conservation and Efficiency	Increase in mandatory government regulations on energy efficiency. Send stronger rate signals through conservation rates. Expanded Power Smart programs to help consumers find savings.	Could achieve more savings than current approach above. Significant uncertainty that electricity savings will materialize.	Less costly than buying or building new electricity supply.	Avoid greater environmental footprint because BC Hydro would not need to build new generation and transmission.	More jobs relative to current plan and more jobs relative to an equivalent bundle of electricity generation options.



CURRENT CONSERVATION AND EFFICIENCY PLAN

BC Hydro is currently implementing a 20-year conservation and efficiency plan from the 2008 Long-Term Acquisition Plan that targets reducing the forecast growth in demand by 79 per cent by the year 2020. It contains four main strategies:

1. **Government regulations:** The introduction of approximately 30 new federal and provincial government regulations and building code standards aimed at making buildings and equipment more energy efficient, including water heaters, windows, electronic equipment, lighting, appliances, motors, building code standards, and commercial and industrial equipment.
2. **Conservation rates:** These rates, in place for more than 90 per cent of BC Hydro's customers, encourage conservation by delivering a specially designed higher price signal for a portion of customers' consumption. The rates are revenue neutral, in that BC Hydro collects the same amount of revenue as the original standard rate.
3. **Power Smart programs:** Approximately 20 programs aim to help customers improve their energy efficiency and conserve electricity. Programs target residential, commercial and industrial customers and range from collecting old or second refrigerators to ensuring that new industrial plants are as energy efficient as possible.
4. **Supporting initiatives:** These initiatives focus on things like public awareness, community engagement, and technology innovation and provide a foundation for the other three main strategies.

In the fiscal year ending March 31, 2010, BC Hydro spent $135 million on conservation and efficiency measures for its 1.8 million customers.

For more information about BC Hydro's Power Smart programs, go to bchydro.com/powersmart.

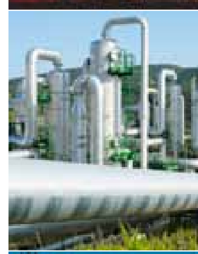
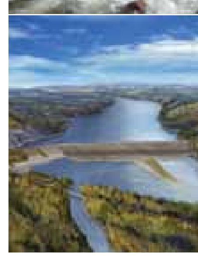
BC hydro powersmart

TOPIC 2:

ELECTRICITY GENERATION OPTIONS

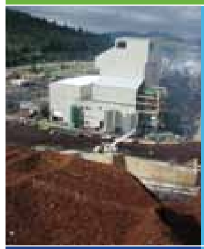
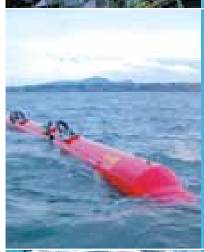
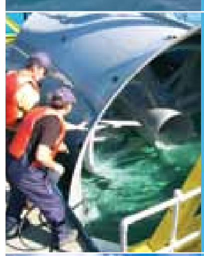
While conservation can meet at least two-thirds of growth in our future electricity needs, BC Hydro must still consider other made-in-B.C. power supply options to meet anticipated demand. B.C. is fortunate to have a wealth of potential clean resources, including hydroelectric generating stations, biomass facilities and wind projects. The provincial *Clean Energy Act* requires that at least 93 per cent of B.C.'s electrical supply comes from clean or renewable sources, which allows for a limited amount of gas-fired generation to serve transmission-constrained areas and/or help meet peak loads. When considering these options, BC Hydro weighs key trade-offs including technical, financial, environmental, and economic development characteristics.

Options under consideration include a combination of BC Hydro projects, such as a hydroelectric dam, reservoir and generating station at Site C on the Peace River, as well as electricity purchases from potential projects representing a range of resource types.

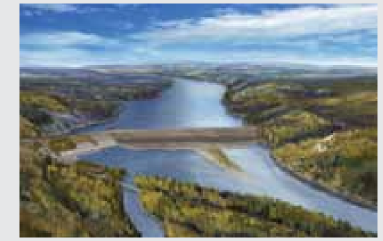
POTENTIAL ENERGY RESOURCES		DESCRIPTION	RESOURCE POTENTIAL	Cost Range ($F2011 / MWh)
	**Biomass:** **• Wood-Based** **• Municipal Solid Waste** **• Biogas (Landfill)**	• Electricity generated by burning wood residues from the forest industry • Biogas from landfills or municipal solid waste • Provides reliable supply with both dependable capacity and firm energy	• Potential varies with availability of fuel source • Some uncertainty may arise with regard to long-term fuel availability • Wood-based biomass availability varies with the state of the forest industry • Project developers face costs of emissions mitigation • Identified within BC Clean Guidelines and may be certified as green energy	$77–$200*
	**Wind**	• Electricity generated from onshore or offshore wind farms using large wind-powered turbine generators • Provides intermittent supply with low dependable capacity	• Potential located across the province • Identified within BC Clean Guidelines and may be certified as green energy	$95–$200*
	**Geothermal**	• Electricity generated from high temperature naturally occurring gaseous or liquid water at a depth of up to 3000 m used to drive conventional power generation technologies • Provides reliable supply with both dependable capacity and firm energy once geological formation is discovered and proven	• Potential varies with geological formations • Large and uncertain initial capital investment related to exploration phase and confirmation of resource potential • Identified within BC Clean Guidelines and may be certified as green energy	$71–$200*
	**Run-of-River**	• Electricity generated from water temporarily diverted from a stream (i.e., not significant storage reservoir), passed through turbines and returned to the stream • Provides intermittent supply with low dependable capacity	• Potential located across the province • Identified within BC Clean Guidelines and may be certified as green energy	$58–$200*
	**Large Hydro (Site C)**	• Electricity generated from water released from a storage reservoir and passed through turbines • Would typically involve the construction of a dam on a river • Provides reliable supply with both dependable capacity and firm energy • Dispatchable with storage	• Large hydro projects often require long lead times – 10 years or more – and require early evaluation and study • Proposed Site C dam on the Peace River would optimize upstream storage and regulation by taking advantage of water already stored in the Williston Reservoir • *Clean Energy Act* prohibits, with the exception of the proposed Site C project, future large hydro projects in B.C.	$85**

* Prices capped at $200/MWh to reflect what might be acquired over the planning horizon.

** Cost is based on Site C's 30-year-old historical design, as per Scenario G in the Site C Stage 1 Report ($6.6 billion). An updated cost forecast is expected by spring 2011, based on an upgraded design for the proposed project.

POTENTIAL ENERGY RESOURCES		DESCRIPTION	RESOURCE POTENTIAL	Cost Range ($F2011 / MWh)
	**Natural Gas-Fired Generation & Cogeneration**	• Electricity generated from high-efficiency gas-fired turbines • Provides reliable supply with both dependable capacity and firm energy • May be situated on existing industrial sites • Dispatchable	• Project developers face long-term fuel availability/price risks and cost of greenhouse gas emissions	$79–$109
	**Coal-Fired Generation with Carbon Capture and Storage**	• Integrated Gasification Combined Cycle (IGCC) process gasifies coal into a synthetic gas that is burned in a combined cycle generator to produce electricity • Provides reliable supply with both dependable capacity and firm energy	Emerging Technology: • Large-scale greenhouse gas capture and sequestration technology not yet commercially available • Project developers face long-term fuel availability/price risks and cost of greenhouse gas emissions, sequestration	$81
	**Wave**	• Electricity generated from waves • Provides intermittent supply with low dependable capacity	Emerging Technology: • Technologies at early stages of commercial development	$480–$824
	**Tidal**	• Electricity generated from tides • Predictable intermittent supply with low dependable capacity	Emerging Technology: • At early stage of tidal current technologies • Limited total extractable resource owing to technical limitations and environmental considerations	$227–$850
	**Large-Scale Solar**	• Electricity is generated from sunlight using photovoltaic cells. • Provides intermittent supply with low dependable capacity	• Potential varies with length of day and availability of sunlight. Throughout the year, power generation fluctuates with cloud cover.	$351–$410

SITE C PROJECT DESCRIPTION



BC Hydro is proposing to develop a dam and hydroelectric generating station on the Peace River in northeast B.C. The Site C Clean Energy Project (Site C) would involve the construction and operation of a third dam and hydroelectric generating station on the Peace River, downstream from the existing Williston and Dinosaur reservoirs and the respective BC Hydro generating facilities at G.M. Shrum and Peace Canyon.

If approved, Site C will provide approximately 900 megawatts (MW) of capacity, and produce an average of 4,600 gigawatt hours (GWh) of electricity each year – enough to power more than 400,000 homes. Site C would be publicly owned and become a heritage asset for BC Hydro. Compared to conventional or renewable alternatives, Site C would have higher up-front capital costs but lower long-term operating costs, and it would provide a clean and renewable source of firm and reliable electricity for more than 100 years.

SITE C PUBLIC AND STAKEHOLDER CONSULTATION

Site C is currently in Stage 3 (Environmental and Regulatory Review). This stage will include consultation with the public, communities and property owners, as well as with the Province of Alberta and the Northwest Territories. In addition, BC Hydro and First Nations communities are engaged in a continuing consultation process.

The following public and stakeholder consultation will be included:

- Local Government Liaison
- Property Owner Consultation
- Environmental Assessment and Regulatory Processes
- Preliminary Design Consultation

A range of consultation methods will be utilized, including the Fort St. John and Hudson's Hope Community Consultation Offices, stakeholder meetings, open houses, print and online feedback forms, and written submissions.

For more information on Site C, visit bchydro.com/sitec.

COMPARING RESOURCE ELECTRICITY GENERATION OPTIONS

Here are three example portfolios that could serve the additional electricity needs of our customers. These portfolios have different blends of electricity generation options and the associated backup that may be required to meet customer needs at all times of the year.

The example portfolios contain different combinations of potential wind and run-of-river projects from Independent Power Producers, the Site C project and gas-fired generation (up to 7 per cent, based upon the 93 per cent *Clean Energy Act* target).

Depending on the amount of intermittent resources like wind and run-of-river in a portfolio, more backup generation may be required. Backup options include additions at existing BC Hydro large hydroelectric generating facilities, or new pumped storage facilities or gas-fired generation.

Each portfolio is described in terms of the resources it would contain and the associated technical, financial, environmental, and economic development characteristics.

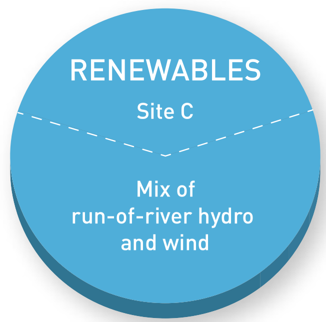
These portfolios are offered as examples to illustrate key trade-offs that arise between various electricity generation options.

RENEWABLES

Mix of run-of-river hydro and wind

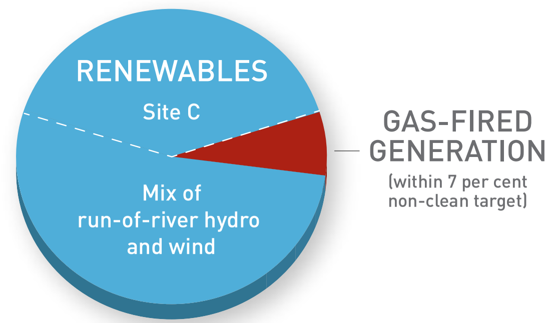
PORTFOLIO 1 – RENEWABLE MIX

This portfolio includes a mix of renewable resources such as wind, run-of-river and biomass from Independent Power Producers. The Site C Project is specifically excluded. Given that wind and run-of-river hydro are intermittent resources, this portfolio requires backup resources when the intermittent sources are not available. These backup resources would generally consist of additions at existing BC Hydro generating facilities, or new pumped storage facilities or gas-fired generation. This portfolio has low greenhouse gas emissions, with a geographically widespread environmental footprint. The cost of renewable resources and the need for backup resources make this the most expensive portfolio of the three.



PORTFOLIO 2 – RENEWABLE MIX WITH SITE C

This portfolio includes a mix of renewable resources that include Site C along with wind, run-of-river and biomass projects from Independent Power Producers. Site C is included to provide system storage and capacity to back up intermittent resources, but ongoing additions at existing BC Hydro generating facilities and additional capacity and storage still may be required if a large amount of intermittent resources are added. This portfolio has the lowest greenhouse gas emissions, with its environmental and social footprint concentrated in the Peace region. This portfolio will have a lower cost than Portfolio 1.



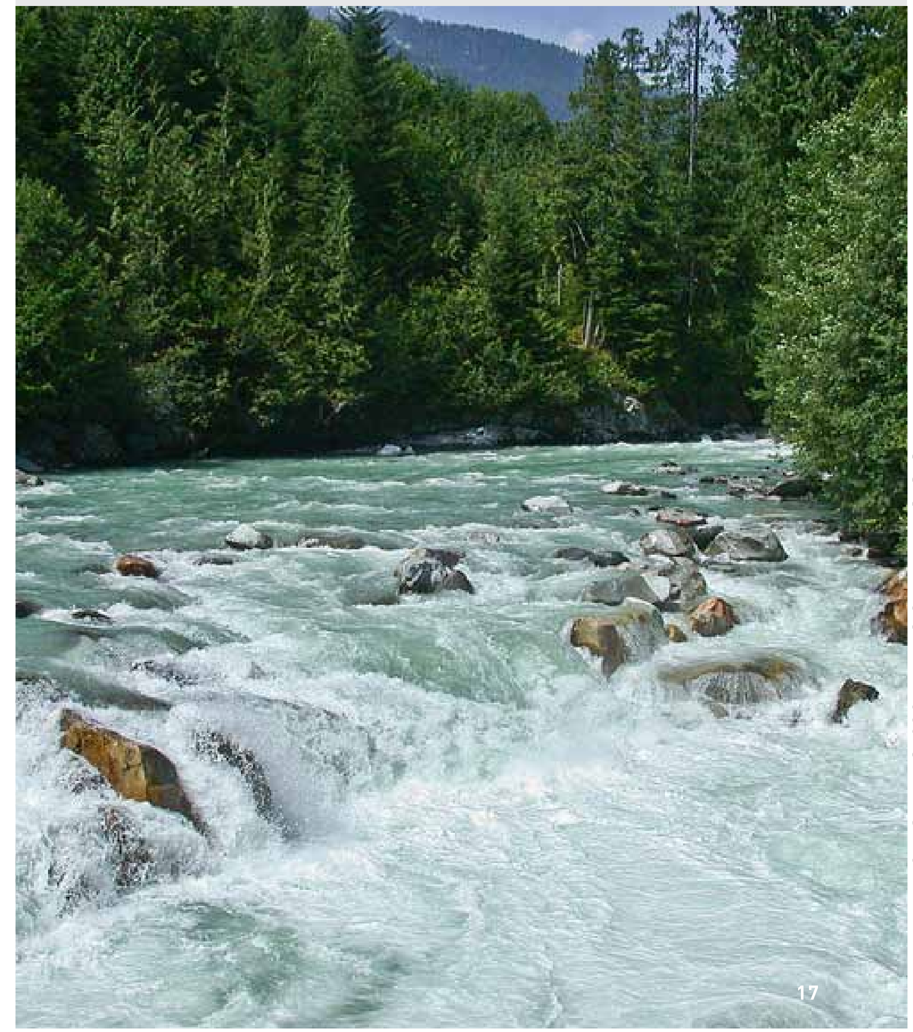
PORTFOLIO 3 – RENEWABLE MIX WITH SITE C AND GAS-FIRED GENERATION (WITHIN 93 PER CENT *CLEAN ENERGY ACT* TARGET)

This portfolio includes Site C, other potential renewable resources such as wind and run-of-river from Independent Power Producers, and gas-fired generation allowable under *Clean Energy Act* limits. Both Site C and gas-fired generation are available to back up intermittent resources. This portfolio has higher greenhouse gas emissions than Portfolios 1 and 2 due to its reliance on natural gas-fired generation, and has a more concentrated environmental footprint in the Peace region. It has the lowest cost if the price of natural gas remains low but, again, this is subject to uncertain natural gas and carbon emission prices.

POLICY CONTEXT FOR PORTFOLIOS

The *Clean Energy Act* specifies limits for what can be included in a portfolio:

- Future development of specified large-scale hydroelectric storage projects on river systems in B.C. is limited to Site C
- No nuclear resources
- No coal resources without the capture and storage of carbon dioxide



The table below highlights different characteristics and trade-offs associated with each electricity generation portfolio:

ELECTRICITY GENERATION PORTFOLIO	DESCRIPTION	TECHNICAL	FINANCIAL	ENVIRONMENTAL	ECONOMIC DEVELOPMENT
PORTFOLIO 1 Renewable Mix	Renewable mix. No Site C. No gas. Base Energy: 827 72 Backup:	Requires backup generation. Reduces the electricity system's flexibility to respond to changes in demand.	Higher cost. No ownership of assets at end of contract term with Independent Power Producers. $$$$	Lower GHG emissions. Geographically widespread environmental footprint.	Geographically widespread jobs. Same GDP and tax revenue.
PORTFOLIO 2 Renewable Mix With Site C	Renewable mix including Site C. No gas. Base Energy: 496 43 1 Backup:	Increased system flexibility to respond to changes in demand. Requires less backup generation than Portfolio 1.	Lower cost of clean resource. Lower long-term price risk. Larger up-front single capital cost but low operating costs. Public ownership of a 100-year expected life asset. $$$$	Lower GHG emissions. More concentrated/localized footprint in the Peace region.	More job-intensive capital project and concentrated jobs in the Peace region. Same GDP and tax revenue.
PORTFOLIO 3 Renewable Mix with Site C and Gas-Fired Generation (within 93 per cent *Clean Energy Act* target)	Renewable mix with wind, Site C and gas within 93 per cent *Clean Energy Act* target. Base Energy: 438 38 1 1 Backup:	Requires no backup. Highest flexibility of system to respond to changes in demand.	Lowest cost of the three. $$$	Higher GHG emissions. More concentrated/localized footprint in the Peace region.	More job-intensive capital project and concentrated jobs in the Peace region and wherever the gas plant is sited.

Note: The symbols provide a general reference tool to compare the three sample portfolios. They represent resource requirements for a 10,000 GWh and 1,800 MW sample portfolio, and relative portfolio costs.

WIND TURBINES · RUN-OF-RIVER PROJECTS · GAS PEAKING PLANTS · LARGE HYDRO (SITE C) · BACKUP · $ COST

TOPIC 3:

ELECTRIFICATION

WHAT IS ELECTRIFICATION?

Provincial greenhouse gas (GHG) reduction targets will require making deep cuts in GHG emissions in the coming decades. One way to reduce those emissions is by switching from fossil fuel energy to electrical energy derived from clean generation sources. This is referred to as electrification. BC Hydro's clean electricity supply therefore has a key role to play in BC's Climate Action Plan by helping the province reduce GHG emissions.

The *Clean Energy Act* includes, as an energy objective for B.C., "to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia".

WHERE MIGHT ELECTRIFICATION OCCUR?

Fuel switching to clean electricity could occur across the economy. The transportation sector is the largest source of GHG emissions in B.C., and replacing vehicles that use gasoline and diesel with electric vehicles could be one of the most significant long-term actions B.C. could take to reduce emissions.

Many of the large automakers are bringing electric vehicles to market in the near future; key models include the Chevy Volt and the Nissan LEAF. The impact of electric vehicles will depend on availability, price and customer acceptance.

Successful introduction of electric vehicles will require that consumers are able to charge their vehicles, and that any charging infrastructure is smoothly integrated into the grid. BC Hydro has an obligation to be ready to serve electric vehicles' electricity requirements, should our customers decide to embrace the technology.

Also in the transportation sector, the provision of shore power can enable ships to avoid running generators while in port. The cruise ship terminal in Vancouver and the container terminal in Prince Rupert already have shore power.

Air and ground source heat pumps can be extremely efficient sources of energy for heating and cooling homes and buildings. Switching from oil or natural gas to efficient heat pumps can significantly reduce residential and commercial GHG emissions and can lower overall energy consumption.

In the industrial sector, electrification options include the use of electric compressors to replace those fuelled by natural gas in the growing number of natural gas fields in northeastern B.C. Electricity can also be used to replace diesel generators and to drive mining conveyor systems that replace diesel trucks.

Given that economic growth, energy prices and other factors are already driving electrification, BC Hydro includes all reliable new demand in its load forecast. The 2010 Electricity Load Forecast incorporates some electric vehicle take-up and also some industrial conversion from fossil fuels, particularly in the oil and gas sector.

ELECTRIC VEHICLES

A long-term benefit of electric vehicles is the potential to reduce GHG emissions, as 38 per cent of B.C.'s emissions are attributed to transportation. A move to plug-in vehicles will also reduce the cost of fleet operations and reduce reliance on fuel imports.

A potential fuel switch of this magnitude presents a number of issues for the provincial electricity grid, including:

- Long-term impacts to transmission and generation (the rate of load growth from electric vehicles is expected to be gradual and well within BC Hydro's planning cycles)
- Near-term impacts on distribution infrastructure
- Impacts on the relationship with customers and their expectations of BC Hydro as a transportation energy supplier

To prepare for this possibility in the next five to 20 years, BC Hydro has undertaken numerous initiatives over the past few years to learn more about how plug-in vehicles will interact with the hydroelectric system, including:

- The creation of charging infrastructure guidelines
- Participation in a provincial working group
- Implementation of agreements with manufacturers to demonstrate different models of plug-in vehicles in B.C.

WHEN MIGHT ELECTRIFICATION OCCUR?

Electrification requires equipment changes that normally occur over the short, medium or long term. In some sectors, equipment is replaced fairly frequently; for example, vehicle fleets will turn over several times by 2050. In other cases, infrastructure is replaced slowly; most of the 2050 housing stock has already been built.

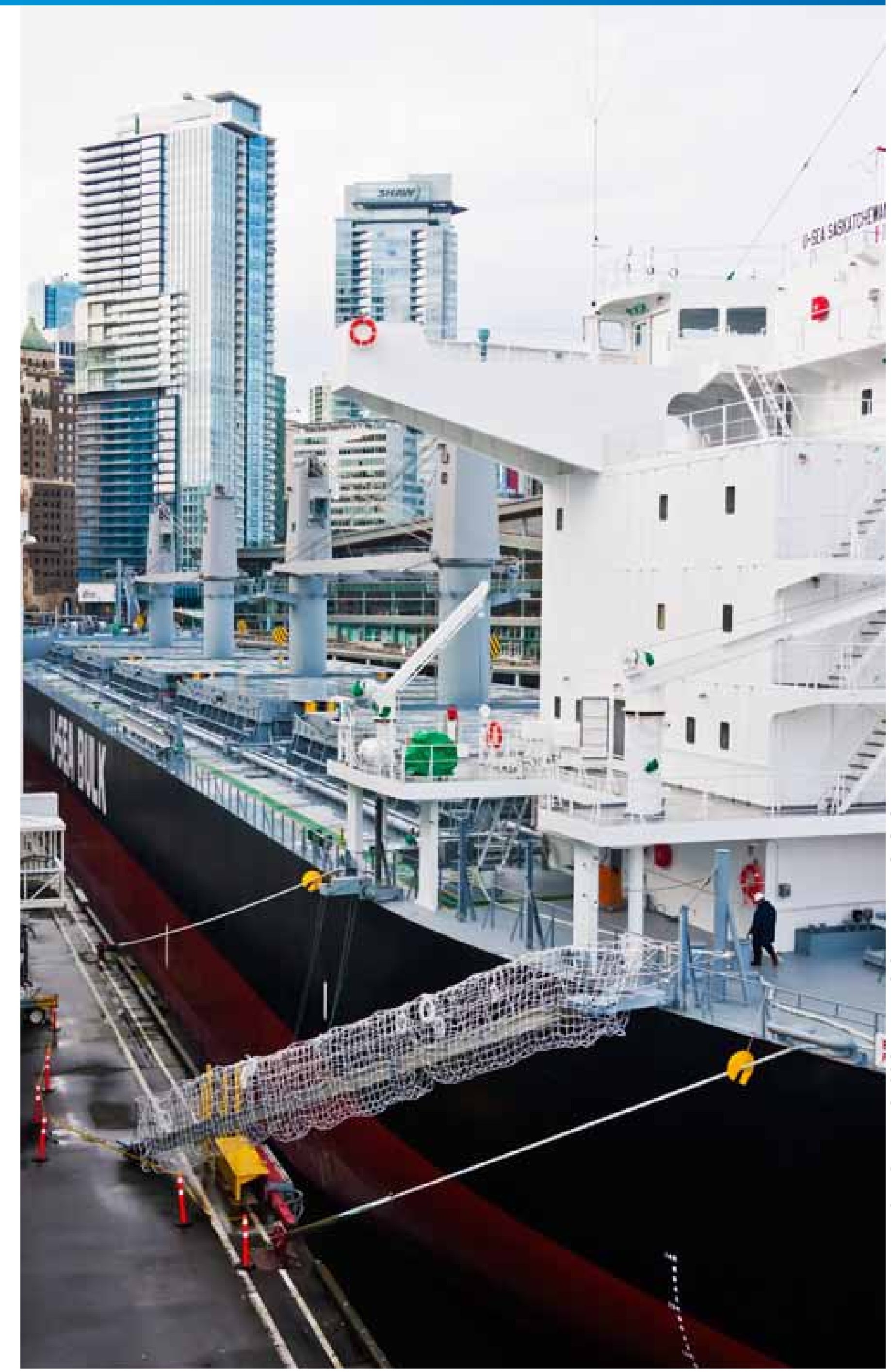
Electrification also depends on the rate of commercialization and acceptance of new technologies. For example, electric vehicles will not likely gain wide acceptance until the purchase costs are closer to conventional vehicles and consumers are satisfied they will have reliable places to recharge.

Government and BC Hydro actions can also influence the timing and nature of new investments in energy-using equipment, as well as the commercialization of new technologies, and therefore influence the rate at which electrification occurs.

APPROACH TO ELECTRIFICATION

Under its current responsive approach (outlined on the next page), BC Hydro does not encourage fuel switching; rather, it forecasts and responds to the fuel switching that occurs naturally. As part of its obligation to serve, BC Hydro will ensure that, as electric vehicles arrive in B.C. and as customers request electricity services, the generation, transmission and distribution systems are able to meet that demand.

In a proactive approach, BC Hydro would work with government and other partners to promote and encourage efficient electrification to benefit customers and to reduce greenhouse gas (GHG) emissions. Under this approach, BC Hydro could support the development of charging infrastructure in advance of significant electric vehicle sales in B.C., thereby encouraging consumers to purchase electric vehicles. BC Hydro could also introduce programs to encourage electrification in other market sectors, such as industry and port operations. BC Hydro can also expand its transmission and distribution systems, providing electricity service to new customers. The wider availability of clean electricity will not only reduce emissions but may also spur new investment and economic activity. In this approach, BC Hydro would work to ensure that new electricity consumption is as efficient as possible.



The table below highlights different characteristics and trade-offs associated with each electrification approach:

ELECTRIFICATION APPROACH	DESCRIPTION	TECHNICAL	FINANCIAL	ENVIRONMENTAL	ECONOMIC DEVELOPMENT
RESPONSIVE APPROACH TO ELECTRIFICATION	BC Hydro responds to electrification driven by customers' needs, and works to ensure electricity is used efficiently as part of its obligation to serve customers' needs.	Increased electricity supply required to support this level of electrification is already being considered by BC Hydro.	Natural electrification included in current rate forecast.	Modest long-term reductions in GHG emissions in B.C. from displaced fossil fuel use. Modest reductions in air pollutants. Environmental footprint from additional electricity supply.	Modest increase in clean energy sector economic development/jobs. This would result in redistribution of economic resources to clean energy sector from other parts of the economy.
PROACTIVE APPROACH TO ELECTRIFICATION	BC Hydro works with government and other partners to facilitate and encourage increased efficient electrification.	Requires additional electricity supply beyond what BC Hydro is currently considering. Most electrification growth would occur after 2020.	Increase in utility costs to supply electricity and promote electrification. Financial risk if electrification does not occur as forecasted.	Significant reductions in GHG emissions in B.C. Significant reductions in air pollutants and human health impacts. Additional environmental footprint from additional electricity supply.	Moderate increase in clean energy sector economic development/jobs. This would result in shifting economic resources to clean energy sector from other parts of the economy. Expansion of the electricity grid could spur new economic activity.

Courtesy of Port Metro Vancouver

Courtesy of Port Metro Vancouver

TOPIC 4:

TRANSMISSION PLANNING

The system that delivers electricity to British Columbians is divided into two major infrastructures: the transmission system, which carries high-voltage electricity from where it is generated to the cities, towns and industrial centres where it is consumed, and the distribution system, which delivers lower voltage electricity to individual customers. The IRP will examine the high-voltage province-wide transmission system by analyzing the investments that may be needed to ensure the system can meet future electricity requirements. The IRP will also examine regional transmission requirements in areas such as Fort Nelson, where new transmission may be an option for an area that is facing potentially significant demand growth from the oil and gas sector. The IRP will also examine regional transmission requirements needed to connect clusters of new generation resources to the bulk system.

As a result of the *Clean Energy Act*, which integrated BC Hydro with the former BC Transmission Corporation, BC Hydro's IRP will now include a description of transmission infrastructure demands 30 years out, which is a reflection of the long lead times required for planning, siting and constructing transmission lines.

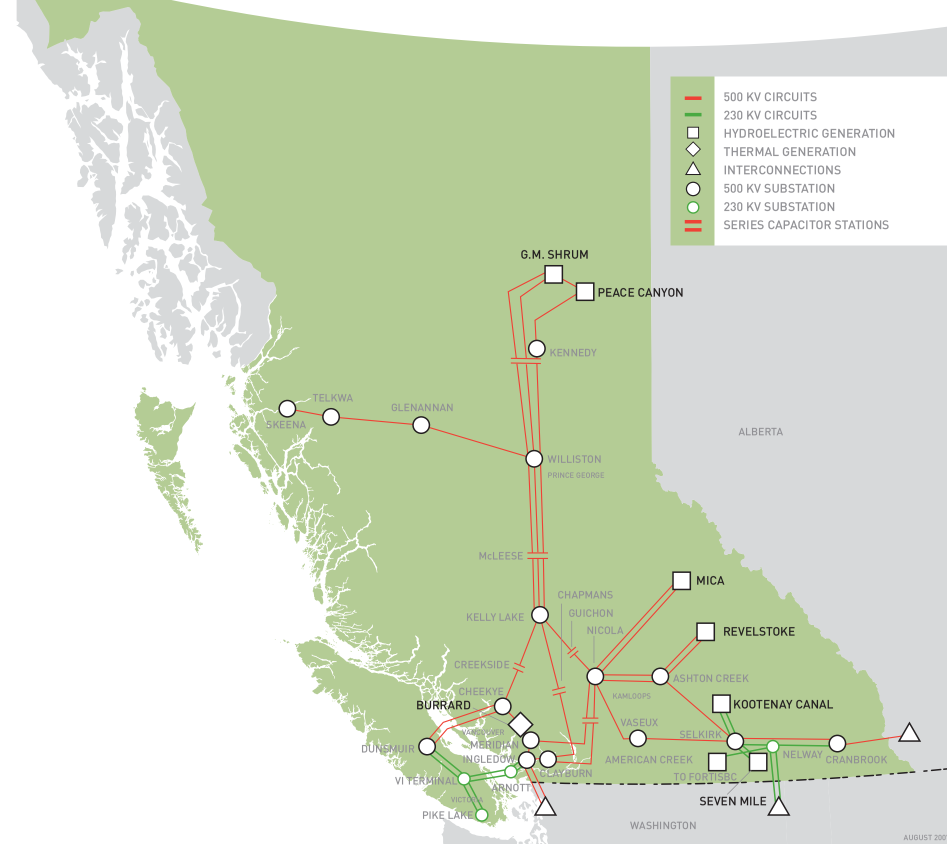
When assessing future bulk transmission system requirements, planners need to consider the following:

- The need to maintain an optimal level of reliability for customers
- Growth in demand by geographic area
- Potential location and size of new generation resources
- The need to minimize electricity losses that occur when electricity is carried over long distances
- The expected retirement or refurbishment of existing transmission resources

In recent years, the provincial government and utilities have become increasingly concerned about timely development of transmission infrastructure. In the past, transmission systems have been planned in response to generation projects and demand growth that were expected to occur. This approach increasingly poses the following risks:

- Generation projects may be completed before transmission lines are ready or may need to be delayed until lines can be finished
- Generation projects might develop in a way that leads to a spiderweb of intersecting transmission lines that are inefficient and have avoidable adverse environmental impacts (see diagrams on page 23)
- New demand for electricity may occur sooner than transmission lines can be built to provide the service

BC HYDRO BULK TRANSMISSION SYSTEM



Planners are now looking farther into the future to anticipate where the largest potential exists for generation options and consumer needs. Rather than responding to individual projects, this process identifies where clusters of projects could appear across the province (i.e., regions with a combination of run-of-river, wind and biogas potential). This allows planners to lay out transmission systems in an optimal way. However, a key risk is that a transmission investment might be stranded if generation resources do not develop as expected.

Other considerations in this longer term planning regime include the following:

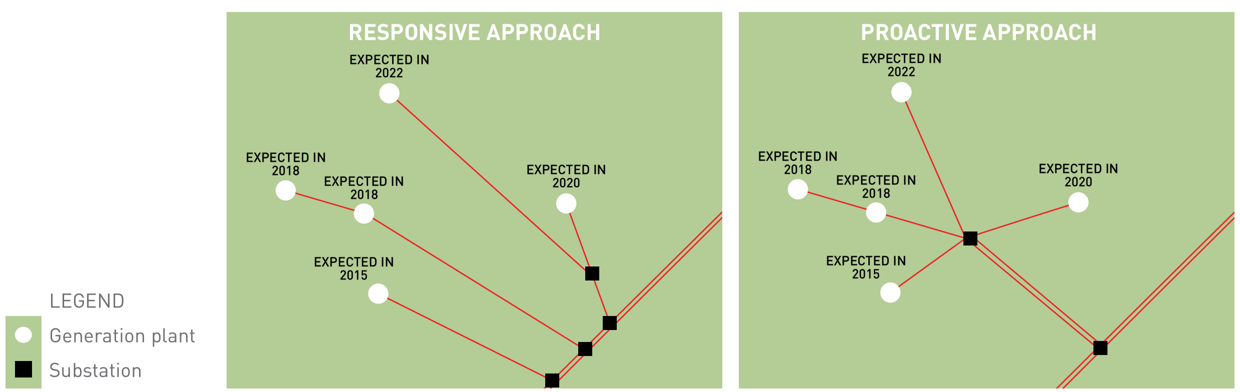
- Potential for transmission lines to spur regional economic development
- Potential cost savings and environmental benefits from avoiding multiple transmission lines
- Potential to facilitate the use of clean or renewable electricity rather than GHG-intensive fuels; for example, by targeting transmission for the oil and gas sector in the province's northeast

The critical question is the extent to which BC Hydro should consider, plan and build transmission lines in anticipation of need. Two broad and distinctly different approaches are described for consultation purposes:

RESPONSIVE APPROACH: BC Hydro develops transmission plans in response to forecast need.

PROACTIVE APPROACH: BC Hydro develops long-term transmission plans in anticipation of potential future need over a 30-year horizon.

While BC Hydro is likely to use both approaches going forward, emphasis can be placed on one or the other.



The table below highlights different characteristics and trade-offs associated with each transmission planning approach:

TRANSMISSION PLANNING APPROACH	DESCRIPTION	TECHNICAL	FINANCIAL	ENVIRONMENTAL	ECONOMIC DEVELOPMENT
RESPONSIVE APPROACH	BC Hydro develops transmission plans in response to forecast need.	Higher reliability risk if transmission delayed. May lead to suboptimal build of the transmission system in the long run.	Lower transmission costs in the short term but risk of higher costs in the long run due to suboptimal system build.	Lower transmission footprint in the short term, but higher in the long term due to suboptimal system build.	May constrain economic development in certain regions or communities, as there may not be enough transmission.
PROACTIVE APPROACH	BC Hydro develops long-term transmission plans in anticipation of potential future need over a 30-year horizon.	Lower reliability risk. Leads to larger transmission projects.	Higher transmission costs in the short term. Lower costs in long term due to optimal system design if growth materializes. Risk of stranded investment if need does not materialize.	Higher transmission footprint in the short term but lower in the long run if need materializes.	May facilitate economic development in certain regions or communities, as transmission has been planned and built to facilitate this.

TOPIC 5:

EXPORT MARKET POTENTIAL

ENERGY EXPORT

BC Hydro, through its wholly owned subsidiary Powerex, has a long and successful track record of trading electricity. As discussed in the sidebar, BC Hydro's reservoirs and the connectivity of its integrated bulk transmission system to Alberta and the western United States have enabled electricity trading that has provided a range of benefits for BC Hydro and its customers. For example, it has provided power and system stability when British Columbians have needed it, and it has enabled BC Hydro to keep rates lower by taking advantage of imported electricity when it is inexpensive. In the future, these transmission links could open up markets for new clean electricity generated by producers in B.C. to support economic development in regions across the province.

WHAT IS NEW?

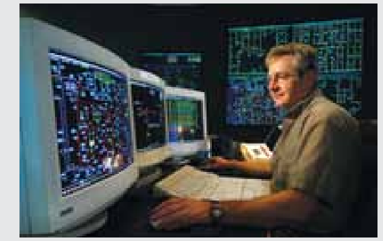
In the new *Clean Energy Act*, one of B.C.'s energy objectives is that B.C. should be a net exporter. The Act directs BC Hydro to assess the potential export market for clean resources. BC Hydro may also acquire, subject to Cabinet approval, renewable energy from Independent Power Producers in B.C. for the sole purpose of exporting to Alberta or the U.S. Importantly, the Act protects existing BC Hydro ratepayers from the cost risks associated with energy purchased solely for export. It stipulates that the benefits derived from the existing BC Hydro system are to continue to flow to ratepayers and that the costs of building or acquiring renewable energy solely for the purpose of exporting are not to be recovered from ratepayers.

For planning purposes, it is important to distinguish between two different types of potential export activity:

- **Current Approach – "Traditional" Exports:** these are exports of surplus energy during times when BC Hydro has excess water in the hydroelectric system, including energy that is acquired to achieve the legal requirement of self-sufficiency by 2016 with an additional 3,000 GWh of "insurance" by 2020
- **Clean Generation for the Purpose of Export:** these are exports that would come from the aggregation of renewable energy from Independent Power Producers in B.C. for the sole purpose of long-term export contracts

For purposes of the IRP, the latter new approach to considering export is the focus of this Consultation Topic: Export Market Potential.

IMPORTING AND EXPORTING ELECTRICITY HAS BENEFITS



Exports and imports are a natural part of integrated electricity systems. In regions that are dependent on hydroelectric power, as is the case in B.C. and the Pacific Northwest of the United States, trade in electricity helps utilities address natural variations in water supply (wet years and dry years) that change by season and year. Similarly, trade can be beneficial when different regions have different electricity usage depending on the season – for example, in winter, when usage is highest in the Pacific Northwest, it is lower in the desert regions of the southwest.

While electricity exports happen in every year, just as imports do, it is the difference between the two that determines whether a utility is a net exporter or importer. For many years, BC Hydro sold more energy than it bought. However, as domestic demand has crept up, BC Hydro has found itself becoming a net importer – in some years, purchasing more than 10 per cent of B.C.'s total annual electricity consumption.

BC Hydro, through its wholly owned subsidiary Powerex, has had a long and successful track record of importing and exporting energy for the benefit of British Columbians. Originally established in 1988 to market the province's surplus electricity, Powerex's trading activity has evolved and now much of Powerex's trading activity is not directly linked to the BC Hydro system. Powerex has enabled BC Hydro to make the best use of its resources and has ensured a stable electricity supply while generating revenue that has helped keep rates low for customers.

BC Hydro's bulk transmission system has connection points both to Alberta and the western United States. A key ingredient in BC Hydro's electricity trade is the flexibility created by the large reservoirs behind its major dams. These reservoirs enable BC Hydro to make economic decisions about when to use the water to generate electricity and when to take advantage of the other sources. For example, when water levels in B.C. are high, or demand in the market is high (during peak periods of the day or the year), Powerex can export electricity at a premium. And if water levels are low or import prices are attractive (in non-peak periods), Powerex can purchase electricity from our neighbours in Alberta and the western United States.

CLEAN GENERATION FOR EXPORT

The *Clean Energy Act* requires BC Hydro to prepare an IRP by December 2011 (and every five years thereafter). Among other things, the IRP must include:

- An assessment of demand for renewable energy in markets that BC Hydro can serve
- An estimate of the market share that BC Hydro might capture
- An estimate of the expenditures that will be required to undertake exports beyond traditional exports

Upon reviewing the IRP, the provincial government may direct BC Hydro to begin acquiring energy from Independent Power Producers in B.C. explicitly for export. The government has stated that it will only begin this process if there is a clear business case demonstrating that such exports will provide a benefit to British Columbians.

BC Hydro will consider a number of factors when examining export market opportunity, including:

- Current and potential federal, provincial and state energy and environmental policies
- The estimated size of the renewable electricity market under current and potential policies
- The amount of existing clean or renewable generation capacity
- The competitiveness of B.C. resources and the market share that B.C. could expect to capture
- The transmission infrastructure needed to optimize power generation to satisfy self-sufficiency with insurance requirements
- The transmission infrastructure necessary to enable long-term electricity exports
- Public, First Nations and stakeholder input

The table below summarizes the differences between the current approach – "traditional" exports – and an additional approach - clean generation for the purpose of export:

EXPORT APPROACH	DESCRIPTION	TECHNICAL	FINANCIAL	ENVIRONMENTAL	ECONOMIC DEVELOPMENT
CURRENT APPROACH – "TRADITIONAL" EXPORTS	Sell the surplus capability (system) including that which arises from achieving self-sufficiency by 2016 and insurance by 2020.	System reliability maintained at planned levels.	First $200 M of net income from trade goes to ratepayers. Any losses and any net income above $200 M goes to the Province.	The transmission system will only be expanded to maintain reliability, to meet domestic load, and to comply with the requirement of self-sufficiency/insurance.	Sources of attractively priced power may provide economic development benefits to B.C.
CLEAN GENERATION FOR THE PURPOSE OF EXPORT	Acquiring additional renewable energy produced in B.C. for the sole purpose of export. This will cause additional Independent Power Producers generation projects to be built in B.C.	System reliability maintained at planned levels.	Additional revenues for the Province to the extent that sales of renewable energy exceed the costs involved in delivering electricity to other jurisdictions.	Additional environmental footprint in B.C. and elsewhere due to building additional clean generation resources and additional transmission in B.C. to deliver electricity to markets in the U.S.	Potentially more jobs, GDP and tax revenue than current approach. (Will lead to additional clean electricity generation construction and generation jobs in the regions.)

WE WANT TO HEAR FROM YOU!

2011 INTEGRATED RESOURCE PLAN

PLANNING FOR A CLEAN ENERGY FUTURE

CONSULTATION WORKBOOK

MARCH 1 – APRIL 30, 2011

FEEDBACK FORM

CONSERVATION & EFFICIENCY

Refer to pages 12–13 for more information

GREATER CONSERVATION & EFFICIENCY

To achieve higher energy savings from conservation and efficiency than BC Hydro already targets, BC Hydro would need to rely on additional changes to federal and provincial regulations, send stronger rate signals through specially designed electricity conservation rates, and expand Power Smart programs. Greater emphasis would be placed on changing province-wide market parameters, and on changing societal norms and patterns that influence electricity savings.

From a planning perspective, BC Hydro must be highly confident that savings from conservation and efficiency will be achieved as and when expected – otherwise it risks falling short of meeting future energy requirements. Increasing the current aggressive target carries risk that the savings will not materialize, meaning that BC Hydro would not have the adequate supply to meet legislated self-sufficiency requirements and would need to act quickly to procure a potentially more costly supply from Independent Power Producers.

Here are some trade-offs and other factors to consider:

- This approach would require you and your neighbours to reduce your electricity consumption by adopting additional energy-efficient technologies, responding to conservation rates, and making conserving energy a focus of your daily activity
- It would require additional regulations to make energy-efficient building practices and technologies mandatory
- If higher electricity savings are not achieved, higher cost electricity may need to be acquired from other jurisdictions on the open market or from accelerated power acquisition processes in B.C.

Q1.

Please indicate your level of agreement with this greater conservation and efficiency approach. In developing your response, please consider the summary to the left, including the trade-offs and other factors that have been provided.

(please check one box only)

- ❑ Strongly Agree
- ❑ Somewhat Agree
- ❑ Neither Agree nor Disagree
- ❑ Somewhat Disagree
- ❑ Strongly Disagree

Please provide any comments in the space provided below to explain the reasons for your agreement or disagreement.*

*For privacy reasons please do not provide opinions about identifiable third parties.

ELECTRICITY GENERATION OPTIONS

Refer to pages 14–18 for more information

These portfolios are offered as examples to illustrate key trade-offs that arise between generation options.

PORTFOLIO 1:
RENEWABLE MIX

This portfolio includes a mix of renewable resources such as wind, run-of-river and biomass from Independent Power Producers. The Site C Project is specifically excluded. Given that wind and run-of-river hydro are intermittent resources, this portfolio requires backup resources when the intermittent sources are not available. These backup resources would generally consist of additions at existing BC Hydro generating facilities, or new pumped storage facilities or gas-fired generation. This portfolio has low greenhouse gas emissions, with a geographically widespread environmental footprint. The cost of renewable resources and the need for backup resources make this the most expensive portfolio of the three.

Here are some trade-offs and other factors to consider:

- More diverse mix of renewable resources
- More dispersed regional jobs
- Lower greenhouse gas emissions and more dispersed environmental footprint
- Requires additional backup (capacity) resources
- Costs more than other portfolios

Base Energy: **827** **72** Backup:

Cost: **$$$$**

Q2.1

Please indicate your level of agreement with Portfolio 1 – Renewable Mix. In developing your response, please consider the summary to the left, including the trade-offs and other factors that have been provided.

(please check one box only)

- ❑ Strongly Agree
- ❑ Somewhat Agree
- ❑ Neither Agree nor Disagree
- ❑ Somewhat Disagree
- ❑ Strongly Disagree

Please provide any comments in the space provided below to explain the reasons for your agreement or disagreement.*

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PORTFOLIO 2:
RENEWABLE MIX WITH SITE C

Refer to pages 14–18 for more information

This portfolio includes a mix of renewable resources, that include Site C along with wind, run-of-river and biomass projects from Independent Power Producers. Site C is included to provide system storage and capacity to back up intermittent resources, but ongoing additions at existing BC Hydro generating facilities and additional capacity and storage still may be required if a large amount of intermittent resources are added. This portfolio has the lowest greenhouse gas emissions, with its environmental and social footprint concentrated in the Peace region. This portfolio will have a lower cost than Portfolio 1.

Here are some trade-offs and other factors to consider:

- Economic and environmental impacts are relatively more geographically concentrated
- Lowest greenhouse gas emissions
- Requires less backup generation than Portfolio 1
- Relatively lower cost – lower than Portfolio 1, but higher than Portfolio 3

Base Energy: 496 43 1 Backup:

Cost: $$$$

Q2.2

Please indicate your level of agreement with Portfolio 2 – Renewable Mix with Site C. In developing your response, please consider the summary to the left, including the trade-offs and other factors that have been provided.

(please check one box only)

- ❑ Strongly Agree
- ❑ Somewhat Agree
- ❑ Neither Agree nor Disagree
- ❑ Somewhat Disagree
- ❑ Strongly Disagree

Please provide any comments in the space provided below to explain the reasons for your agreement or disagreement.*

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PORTFOLIO 3:
RENEWABLE MIX WITH SITE C AND GAS-FIRED GENERATION (WITHIN 93 PER CENT *CLEAN ENERGY ACT* TARGET)

Refer to pages 14–18 for more information

This portfolio includes Site C, other potential renewable resources such as wind and run-of-river from Independent Power Producers, and gas-fired generation allowable under *Clean Energy Act* limits. Both Site C and gas-fired generation are available to back up intermittent resources. This portfolio has higher greenhouse gas emissions than Portfolios 1 and 2 due to its reliance on natural gas-fired generation, and has a more concentrated environmental footprint in the Peace region. It has the lowest cost if the price of natural gas remains low but, again, this is subject to uncertain natural gas and carbon emission prices.

Here are some trade-offs and other factors to consider:

- Fewer renewable resources and relatively higher greenhouse gas emissions
- High degree of operating control (as a result of lower intermittency) and no backup resources required
- Lower initial cost, but higher risk of higher future costs due to volatile natural gas prices and greenhouse gas emissions offset cost

Base Energy: **438** **38** **1** **1** Backup:

Cost: **$$$**

Q2.3

Please indicate your level of agreement with Portfolio 3 – Renewable Mix with Site C and Gas-Fired Generation (within 93 per cent *Clean Energy Act* target). In developing your response, please consider the summary to the left, including trade-offs and other factors that have been provided.

(please check one box only)

- ❑ Strongly Agree
- ❑ Somewhat Agree
- ❑ Neither Agree nor Disagree
- ❑ Somewhat Disagree
- ❑ Strongly Disagree

Please provide any comments in the space provided below to explain the reasons for your agreement or disagreement.*

Q2.4

Do you have any other comments about electricity generation resource options to meet customers' future electricity needs? (please provide any comments in the space provided)*

*For privacy reasons please do not provide opinions about identifiable third parties.

ELECTRIFICATION

ELECTRIFICATION: ACTIVE PROMOTION BY BC HYDRO

Refer to pages 19–21 for more information

With a proactive approach to electrification, BC Hydro would work with government and other partners to facilitate and encourage increased electrification where it can reduce greenhouse gas (GHG) emissions and benefits to customers. Under this approach, BC Hydro could support the early development of an electric vehicle charging infrastructure in advance of significant electric vehicle sales in B.C., thereby encouraging consumers to purchase these vehicles. BC Hydro could also introduce other programs to encourage electrification in other areas.

Here are some trade-offs and other factors to consider:

- Additional reductions in provincial greenhouse gas emissions can be achieved
- Additional electrification, over what will happen in B.C. on its own, would increase the need for electricity generation resources to be built in the province
- BC Hydro's promotion of electrification could result in increased electricity rates for BC Hydro customers because of the additional resources needed to serve and promote the new demand

Q3.

Please indicate your level of agreement with this approach to electrification that involves active promotion by BC Hydro. In developing your response, please consider the summary to the left, including as well as the trade-offs and other factors that have been provided.

(please check one box only)

- ❑ Strongly Agree
- ❑ Somewhat Agree
- ❑ Neither Agree nor Disagree
- ❑ Somewhat Disagree
- ❑ Strongly Disagree

Please provide any comments in the space provided below to explain the reasons for your agreement or disagreement.*

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TRANSMISSION PLANNING

Refer to pages 22–24 for more information

PROACTIVE APPROACH: PLAN TRANSMISSION TO ANTICIPATE FUTURE NEED

This approach plans the transmission system in anticipation of future need.

This planning process involves identifying and considering opportunities for developing the transmission system in the following ways:

- Building bulk transmission based on anticipated need over a 30-year time horizon rather than responding to need over a 20-year time horizon
- Building regional transmission to serve an area with significant generation resource potential rather than individual generation projects under development
- Building regional transmission to serve an area with significant economic development potential (e.g., mines, natural gas) rather than responding to individual requests for service as they arise

Here are some trade-offs and other factors to consider:

- Higher short-term cost, but potentially lower long-term cost if new generation and load materialize
- Higher stranded investment risk if need does not materialize
- Increased ratepayer cost, but significant potential benefits from reduced transmission footprint, more concentrated generation footprint
- May facilitate economic development in certain regions or communities, as transmission has been planned to facilitate this

Q4.

Please indicate your level of agreement with this proactive approach to transmission planning. In developing your response, please consider the summary to the left, including the trade-offs and other factors that have been provided.

(please check one box only)

- ❑ Strongly Agree
- ❑ Somewhat Agree
- ❑ Neither Agree nor Disagree
- ❑ Somewhat Disagree
- ❑ Strongly Disagree

Please provide any comments in the space provided below to explain the reasons for your agreement or disagreement.*

*For privacy reasons please do not provide opinions about identifiable third parties.

EXPORT MARKET POTENTIAL

Refer to pages 25–26 for more information

CLEAN GENERATION FOR THE PURPOSE OF EXPORT

Consistent with the *Clean Energy Act*, which requires BC Hydro to undertake an assessment of the export market demand for clean or renewable energy, the energy would come from the aggregation of renewable energy acquired from Independent Power Producers in B.C. solely for the purpose of exporting this electricity to markets outside B.C.

Here are some trade-offs and other factors to consider:

- Additional electricity generation projects would be built by Independent Power Producers within the province
- The environmental footprint from additional clean or renewable electricity generation projects would occur in B.C., versus other jurisdictions
- Building generation resources across the province would lead to increased construction and maintenance jobs in the regions
- Ratepayers are protected from bearing any negative financial consequences, as per the *Clean Energy Act*
- Economic benefits and additional revenue from this electricity generation would flow to the Province

Q5.

Please indicate your level of agreement with this export approach. In developing your response, please consider the summary to the left, including the trade-offs and other factors that have been provided.

(please check one box only)

- ❑ Strongly Agree
- ❑ Somewhat Agree
- ❑ Neither Agree nor Disagree
- ❑ Somewhat Disagree
- ❑ Strongly Disagree

Please provide any comments in the space provided below to explain the reasons for your agreement or disagreement.*

*For privacy reasons please do not provide opinions about identifiable third parties.

ADDITIONAL COMMENTS:

PLEASE PROVIDE ANY ADDITIONAL COMMENTS.*

*For privacy reasons please do not provide opinions about identifiable third parties.

THANK YOU FOR YOUR INPUT.

Input received through consultation will be considered, along with technical, financial, environmental, and economic development input, as BC Hydro evaluates alternatives and drafts the Integrated Resource Plan.

HOW INPUT WILL BE USED

Input received through consultation will be considered, along with technical, financial, environmental, and economic development input, as BC Hydro evaluates alternatives and drafts the Integrated Resource Plan.

A Consultation Summary Report summarizing input received through consultation, will be posted on BC Hydro's website at bchydro.com/irp.

FEEDBACK DEADLINE:

Please submit your feedback by **APRIL 30, 2011**.

Please provide your contact information *(optional)*:

Name: ______________________________

Address: ______________________________ Postal Code: ______________

Phone: ______________________________ Email: ______________

Consent to Use Personal Information

I consent to the use of my personal information by BC Hydro for the purpose of contacting me and keeping me updated about future consultations on integrated resource planning. For the purposes of the above, "my personal information" includes name, mailing address, telephone number, and email address, as per the information I provide.

Signature: ______________________________ Date: ______________

BC Hydro is collecting information with this form for the purpose of its Integrated Resource Plan in accordance with BC Hydro's mandate under the ***Hydro and Power Authority Act***, the BC Hydro Tariff, the ***Clean Energy Act*** and related Regulations and Directions. If you have any questions regarding the information collection undertaken on this form, please contact the IRP Project Team Administrator at 1 888 747-4832.

For further information or to submit your feedback form:

BC Hydro Integrated Resource Plan
Email: integrated.resource.planning@bchydro.com
Web: bchydro.com/irp
Mailing Address:
P.O. Box 2850
Vancouver, B.C. V6B 3X2

BC hydro
FOR GENERATIONS

7. GLOSSARY (IN ALPHABETICAL ORDER)

- **ALTERNATIVE TECHNOLOGIES** Non-conventional electricity generation methods such as fuel cells, tidal current, solar, wind and wave energy sources.
- **ATTRIBUTE** A characteristic that describes a resource option or portfolio, used to assess its performance in meeting the planning objectives.
- **BASE LOAD** An amount of electricity committed or available over a period of time at a steady rate.
- **BLACKOUT** Loss of all electrical load in a given area.
- **BC TRANSMISSION CORPORATION (BCTC)** The Crown corporation created by the government of B.C. in 2003 to plan, operate and maintain BC Hydro's high-voltage transmission system. The 2010 *Clean Energy Act* consolidated BC Hydro and BC Transmission Corporation.
- **BC UTILITIES COMMISSION (BCUC)** An independent regulatory agency of the provincial government operating under and administering the *Utilities Commission Act*. The BCUC regulates BC Hydro's domestic supply and rates and the safety and reliability of the BC Hydro system, as well as operating, management and administrative costs, and also assesses concerns from ratepayers regarding BC Hydro's service.
- **BULK TRANSMISSION** The transfer of electricity on the major high-voltage transmission system that carries the majority of power from the generators to the lower-voltage distribution systems.
- **CAPACITY** The instantaneous power output or electricity demand at any given time, normally measured in kilowatts (kW) or megawatts (MW). A transmission facility's ability to transmit electricity at any instant.
- **CLEAN OR RENEWABLE ENERGY** is defined by the *Clean Energy Act* as including biomass, biogas, geothermal heat, hydro, solar, ocean, wind or other prescribed resources.
- **COGENERATION** The simultaneous production of electrical or mechanical energy and useful heat energy from a single fuel source.
- **COLUMBIA RIVER TREATY** A treaty signed in 1961 between Canada and the U.S. that enabled storage reservoirs to be built and operated in British Columbia to regulate Columbia River flows to the U.S. for power production and flood control.
- **CONSERVATION** Reducing the level of energy service to reduce energy consumption. For example, turning off unused lights.
- **CURTAILMENT** A reduction in demand as a result of demand-side management.
- **DEMAND** Customers' requirement for electric power.
- **DEMAND-SIDE MANAGEMENT** Actions, programs and initiatives aimed at modifying or reducing energy consumption through conservation, energy efficiency and distributed generation.
- **DEPENDABLE CAPACITY** The amount a plant can reliably produce when required, assuming all units are in service, measured in megawatts (MW). Factors external to the plant affect its dependable capacity. For example, steamflow conditions can restrict the dependable capacity of hydro plants and fuel supply constraints can impact thermal plant dependable capacity. Planned and forced outage rates are not included. The dependable capacity used for long-term planning is the maximum capacity that a plant/unit can reliably provide for three hours in the peak load period of week days during two continuous weeks of cold weather.
- **DISPATCHABLE** A resource whose output can be adjusted to meet various conditions including fluctuating customer demand, weather changes, outages, market price changes and non-power considerations.
- **DISTRIBUTION SYSTEM** Electrical lines, cables, transformers and switches used to distribute electricity over short distances from substations to the customer, generally at voltages lower than 69 kV.
- **EFFICIENCY** The effective rate of conservation of a natural resource (e.g., electricity) to usable energy; the effective rate of conversion of electricity to an end use (e.g., heating).
- **ELECTRICITY** is a type of energy fuelled by the transfer of electrons from positive and negative points within a conductor.
- **ELECTRICITY PURCHASE AGREEMENT (EPA)** The contract that defines the terms and conditions by which BC Hydro purchases electric energy from Independent Power Producers.
- **EMERGING TECHNOLOGIES** Technology at the first stages of development or demonstration. Not readily available in commercial markets and not in commercial use, as evidenced by at least three generation plants generating energy for a period of not less than three years, to a standard of reliability generally required by good utility practice.
- **ENERGY** The amount of electricity produced or used over a period of time, usually measured in kilowatt hours, megawatt hours and gigawatt hours.
- **ENERGY CAPABILITY** is the amount of energy that can be generated under specified conditions by a generating unit or by the electric system over a period of time, typically expressed in GWh/year.
- **FIRM ENERGY** refers to electricity that is available at all times. Resources typically providing firm energy include large hydroelectric dams, bioenergy, geothermal and natural gas.
- **GREEN ENERGY** Energy produced from a green power project. BC Hydro uses the EcoLogo standard to determine green projects.
- **GREENHOUSE GASES (GHG)** Gases that contribute to global climate change, or the "greenhouse effect," including carbon dioxide (CO_2), carbon monoxide (CO) and methane (CO_4).
- **GRID** A network of distribution or transmission lines.
- **GWh** stands for gigawatt hour, a unit of electrical energy equal to one billion watt hours.
- **HERITAGE CONTRACT** A 49,000 gigawatt hour per year contract between BC Hydro's generation and distribution lines of business to ensure BC Hydro customers benefit from the existing low-cost hydroelectric and thermal resources in the BC Hydro system.
- **INDEPENDENT POWER PRODUCER (IPP)** A non-utility-owned electricity-generating facility that produces electricity for sale to utilities or other customers.
- **INTEGRATED RESOURCE PLAN** The document describing BC Hydro's long-term plan to meet customers' needs using existing and new resources and demand side management.
- **INTEGRATED SYSTEM** An interconnected network of transmission lines, distribution lines and substations linking generating stations to one another and to customers throughout a utility's service area. Excludes customers located in remote locations who are connected via non-integrated generating plants.
- **INTERMITTENT** Electricity supply that fluctuates or is not available at all times. For example, wind energy only produces power when the wind is blowing.
- **LARGE HYDRO (SITE C)** Site C is a proposed third dam and hydroelectric generating station on the Peace River in northeast B.C.
- **LOAD** The amount of electricity required by a customer or group of customers.
- **LOAD FORECAST** The expected amount of electricity required to meet customer needs in future years.
- **MW** stands for megawatt, a unit of electrical power equal to one million watts.
- **OUTAGE** A planned or unplanned interruption of one or more elements of an integrated power system.
- **PEAK CAPACITY** The maximum amount of electrical power that generating stations can produce in any instant.
- **PEAK DEMAND** The maximum instantaneous demand on a power system. Normally, the maximum hourly demand.
- **PORTFOLIO** A group of individual resource options to be acquired in a sequence over time to fill customers' future electricity needs.
- **POWER** The instantaneous rate at which electrical energy is produced, transmitted or consumed, typically measured in watts, kilowatts (kW), or megawatts (MW).
- **POWER SMART** BC Hydro's demand-side management initiative to encourage energy efficiency by its customers. Originally launched in 1989, Power Smart includes a full range of DSM programs aimed at BC Hydro's residential, commercial and industrial customers.
- **RATE** Term used for a utility's unit price of service.
- **RATE STRUCTURE** Represents the set of rates paid by a class of customers (e.g., residential) for use of electricity.
- **REINFORCEMENT** Improvements in the transmission system to maintain or increase reliability and security of supply.
- **RELIABILITY** A measure of the adequacy and security of electric service. Adequacy refers to the existence of sufficient facilities in the system to satisfy the load demand and system operational constraints. Security refers to the system's ability to respond to transient disturbances in the system.
- **RESERVE** System generating capacity beyond that required to meet peak demand, ensuring sufficient generation is available if some generating units are not available; necessary to meet reliability criteria for planning and operation.
- **RESERVOIR STORAGE** The volume available in a reservoir to hold water for power generation or flood control.
- **RESOURCE OPTION** A source of electricity that is available to help meet or reduce electricity demand, including generation, purchases, demand-side management and transmission facilities.
- **RUN-OF-RIVER** A hydroelectric facility that operates with no significant storage facilities.
- **SCENARIO ANALYSIS** A set of planning assumptions to test the long-term performance of a portfolio.
- **TRANSMISSION SYSTEM** Electrical facilities used to transmit electricity over long distances, usually at voltages greater than 69 kV.
- **VOLTAGE** The strength of electromotive force (EMF).

bchydro.com/irp

For more information, please visit: **bchydro.com/irp**

You can also provide feedback and learn more about the Integrated Resource Plan by:

- Attending a public open house: **bchydro.com/irp**
- Online feedback form: **bchydro.com/irp**
- Written submissions: **integrated.resource.planning@bchydro.com** or **P.O. Box 2850, Vancouver, B.C. V6B 3X2**
- Toll-free phone: **1 888 747-4832**

Integrated Resource Plan

BC hydro FOR GENERATIONS

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65.0 Reference: IPP Purchases
Exhibit B-7-2, AMPC 1.1.2

"However, as noted in BC Hydro's response to Kwantlen IR 1.5.6, while the Clean Power Call is the best available proxy for future IPP energy purchases, past experience suggests that future IPP costs may be higher than the $129/MWh resulting from the Clean Power Call."

2.65.2 Please discuss the lower limit of the prices shown on pages 14 and 15 of BC Hydro's 2011 Integrated Resource Plan Consultation Workbook for the following technologies: biomass, wind, geothermal, run-of-river, large hydro, natural gas-fired generation and cogeneration and coal-fired generation with carbon capture and storage. Please include any assessment BC Hydro has performed that quantifies the amount of energy potentially available for $100/MWh or less for each resource technology.

RESPONSE:

BC Hydro believes that the most appropriate energy price used for project evaluation is the price resulting from the most recent BC Hydro competitive power acquisition process because such power acquisition processes provide a reasonable indicator of B.C. market prices. In the case of the Project, the Clean Power Call is the most recent, broadly based, competitive power acquisition process. Please refer to Exhibit B-7, BC Hydro's response to BCUC IR 1.56.1.

The Unit Energy Costs (UECs) estimates shown on pages 14 and 15 of the IRP Workbook result from BC Hydro's planning level assessment of the B.C.-based supply-side resource option potential undertaken between September and December 2010. Since December 2010, following the ROR-related report-out session and a written comment period, the UEC values shown on pages 14 and 15 of the IRP Workbook have been reviewed and revised for the purposes of the final 2010 ROR. As reflected in Table 1 below, revisions have changed the lower cost ranges of some resource options including biomass, run-of-river, large hydro represented by Site C, as well as natural gas-fired generation and cogeneration to, among other things, reflect the increased costs of delivery to the LM, the main load center where the Ruskin Facility is located.

In BC Hydro's view, using the lower limits of the UEC values shown on pages 14 and 15 of the IRP Workbook for purposes of evaluating the Project is not appropriate for the following reasons:

- **Planning Level Estimates - The IRP Workbook values present a high level planning assessment of resource type costs, rather than to compare a set of high level resource option costs to a site specific project cost established through detailed site specific optimization studies, and as such may not be indicative of future B.C. market prices set through BC Hydro's power acquisition processes.**

For example, historically, the resource options with the lowest unadjusted UEC values are not always bid into BC Hydro's power acquisition processes. A case in point is the geothermal resource option which appears to be low cost, based on an unadjusted UEC value of $71/MWh and upward, but has never been bid into a BC Hydro power acquisition process by independent power producers. In addition, there has been only one biogas project with a small volume of energy bid into a BC Hydro power acquisition process (in 2003, in two phases, resulting in two Electricity Purchase Agreements).

- **Unadjusted UECs - The UEC values presented in the IRP Workbook reflect basic estimates of resource type costs at the point of interconnection (POI) and include the sum of three estimated components: plant gate costs, road costs and transmission interconnection costs. The UEC values presented in the IRP Workbook are not adjusted to reflect the cost of the resource types delivered to the LM or cost factors considered by proponents of site specific projects.**

- **Site Specific Information and Development Risk - The UEC ranges do not reflect site specific information, permitting constraints and other development risks. For example:**

    - **The UECs for the biogas resource option ($54-$95/MWh) are based on a model developed to provide a high-level estimate of landfill gas generation for inventory purposes, and do not reflect costs associated with differences in site specific landfill waste composition or risks associated with variations in biogas supply resulting from seasonal or climatic conditions;**

    - **The UECs for the natural gas-fired generation resource options do not reflect that Combined Cycle Gas Turbine facilities (CCGT) are unlikely to be permitted in the LM by Metro Vancouver, the government agency responsible for issuing air emission permits in the LM, and the policy uncertainty with respect to the acceptability of replacing a Heritage Asset with natural gas-fired generation, which is not clean or renewable as defined by section 1 of the B.C. *Clean Energy Act*. The UECs for natural gas must also be adjusted for greenhouse gas (GHG)-related costs; refer to Table 1 below.**

    - **The UECs estimated for the geothermal resource options do not reflect the significant exploration risks associated with drilling and proving site specific resource potential.**

- **Not Commercially Available Technologies - Some of the resource options are emerging technologies, and thus have an added level of uncertainty. For example,**

    - **Coal-fired generation with carbon capture and storage (CCS) is estimated to have an unadjusted UEC value of $81/MWh, but is not yet commercially available. The earliest ISD for coal-fired generation with CCS in B.C. is estimated to be 2028.**

- **The UEC ranges for wave, tidal and large-scale solar are far above the Clean Power Call proxy price for firm energy of $129/MWh, and so these resource options need not be considered further for purposes of responding to this IR.**

Nevertheless, for purposes of responding to the entire BCUC IR 2.65 series, BC Hydro adjusted the resource options UECs for purposes of valuing the Ruskin Facility post-Project's energy as follows. The process used to adjust UEC values to reflect the cost of the resource types delivered to the LM is similar to the approach taken in bid evaluation during the power acquisition call processes and includes:

- **Freshet Firm Energy Adjustment;**
- **3x12 Pricing Adjustment;**
- **Cost of Incremental Firm Transmission (CIFT);**
- **Line Losses Adjustment;**
- **GHG Offset Costs;**
- **Capacity Credit; and**
- **Wind Integration Cost Adder.**

Though this process facilitates the comparison of resource options with diverse characteristics located in different areas of the Province, and reflects some of the costs of resources delivered to the lower mainland in keeping with a process similar to the Clean Power Call bid evaluation process, the adjustment of UECs is still inadequate to compare values which are based on high-level estimates rather than detailed site specific project knowledge, and do not reflect the specific risks faced by developers of such resources.

Table 1 presents BC Hydro's assessment of the amount of energy potentially available for UECs (adjusted and unadjusted) of $100/MWh or less for each resource technology. The UECs are adjusted to reflect potential costs to BC Hydro customers using a process similar to the Clean Power Call bid evaluation process. The "Total Adjusted UEC" values are higher than $100/MWh in some cases.

Table 1 UECS at POI below $100/MWh and Adjustments

Resource Option	Project Name	CAPEX Region	Average Annual Energy (GWh)	UEC[1] ($/MWh)	Total Adjusters[2] ($/MWh)	Total Adjusted UEC[3]
Biogas	Bailey	LM	12	54	-4	49
Biogas	Comox Valley	Vancouver Island (VI	8	63	-5	59
Biogas	Minnie's Pit	LM	7	64	-4	60
Biogas	Alberni valley	VI	7	69	-5	64
Biogas	Cache Creek	Kelley Lake/Nicola (KLY/NIC)	27	66	0	66
Biogas	Foothills Blvd	Central Interior (CI)	17	64	2	66
Biogas	Glenmore	Selkirk (SEL)	18	66	3	69
Biogas	Ecowaste	LM	13	86	-4	82
Biogas	Greater Vernon	SEL	7	82	4	87
Biogas	Campbell Mtn	SEL	7	86	4	90
Biogas	Mission Flats	KLY/NIC	6	95	1	97
Coal[4]	Proxy	Peace River (PR)	3,896	81	12	93
Co-gen	Small projects	LM	1,600	99	6	105
Geothermal	Mt. Garibaldi	LM	394	71	-5	67
Geothermal	Pebble Creek	LM	788	72	-5	67
Geothermal	South Meager Creek	LM	788	73	-5	68
Geothermal	Mt. Edziza	North Coast (NC)	1,577	72	3	75
Geothermal	Mt. Cayley	LM	394	83	-5	78
Geothermal	Kootenay Lake	SEL	140	96	5	101
Geothermal	Hoodoo Mountain	NC	394	97	4	101
Geothermal	Lakelse Lake	NC	140	98	4	102
Geothermal	Hudson's Hope	PR	140	96	9	106
Large Hydro	Site C	PR	5,100	95	9	104
MSW	MSW 2	LM	285	81	-4	77
Natural Gas: CCGT	500 MW	KLY/NIC	2,940	77	8	84
Natural Gas: CCGT	250 MW	KLY/NIC	1,450	80	7	87
Run of River Hydro	ROR_T1R1_60-80_LM	LM	301	71	14	86
Run of River Hydro	ROR_T1R1_80-90_VI	VI	435	83	23	106

Resource Option	Project Name	CAPEX Region	Average Annual Energy (GWh)	UEC[1] ($/MWh)	Total Adjusters[2] ($/MWh)	Total Adjusted UEC[3]
Run of River Hydro	ROR_T1R1_80-90_LM	LM	545	84	25	108
Run of River Hydro	ROR_T1R1_70-80_KN	KLY/NIC	588	78	32	111
Run of River Hydro	ROR_T1R1_90-110_VI	VI	488	95	17	112
Run of River Hydro	ROR_T1R1_70-100_NC	NC	153	89	35	124
Run of River Hydro	ROR_T1R1_90-100_LM	LM	482	95	31	126
Run of River Hydro	ROR_T1R1_80-100_KN	KLY/NIC	285	92	44	136
Run of River Hydro	ROR_T1R1_80-100_EK	East Kootenay	255	94	46	139
Wind – Onshore	PC28	PR	536	95	20	114
Wind – Onshore	PC20	PR	574	99	21	120

Note:

1 **Unadjusted UEC @ 6 per cent Real at POI ($F2011/MWh),**

2 **Adjusters include Freshet Firm Energy Adjustment, 3 x 12 Pricing Adjustment, CIFT, Line Losses Adjustment, GHG Offset Costs, Capacity Credit, and Wind Integration Cost Adder,**

3 **Values are rounded to the nearest integer,**

4 **Coal with carbon capture and storage proxy: 750 MW Integrated Gasification Combined Cycle.**

Please also refer to BC Hydro’s response to BCUC IRs 2.65.4 and 2.65.6, which demonstrate that even if the price ranges derived from the blended lowest cost 5,000 GWh/year and 10,000 GWh/year resource option bundles are used (e.g., $74.21/MWh for 5,000 GWh/year and $84.52/MWh for 10,000 GWh/year as set out in the “No Coal” row in the Table set out in BC Hydro’s response to BCUC IR 2.65.4), the Project remains cost-effective.

65.0 Reference: IPP Purchases
Exhibit B-7-2, AMPC 1.1.2

"However, as noted in BC Hydro's response to Kwantlen IR 1.5.6, while the Clean Power Call is the best available proxy for future IPP energy purchases, past experience suggests that future IPP costs may be higher than the $129/MWh resulting from the Clean Power Call."

2.65.3 Has BC Hydro stated in the 2011 Integrated Resource Plan public consultation forums that it expects to be able to procure a certain amount of power at the lower limits of the prices shown on pages 14 and 15 of BC Hydro's 2011 Integrated Resource Plan Consultation Workbook for each of the technologies shown?

RESPONSE:

BC Hydro has no expectations regarding the timing and/or volume of the next power acquisition process, or whether through such a power acquisition process BC Hydro will have the ability to procure supply-side resources at the lower limits of the UEC ranges shown at pages 14 to 15 of the IRP Workbook provided as Attachment 1 to BC Hydro's response to BCUC IR 2.65.1. However, there are reasons to doubt that a future power acquisition process will result in the procurement of supply-side resources at the lower limits of these UEC ranges for the reasons set out in BC Hydro's response to BCUC IR 2.65.2.

Please also refer to BC Hydro's response to BCUC IR 2.65.2 with respect to the general relevance of the UEC ranges shown at pages 14 to 15 of the IRP Workbook for purposes of evaluating the Project.

65.0 Reference: IPP Purchases
Exhibit B-7-2, AMPC 1.1.2

"However, as noted in BC Hydro's response to Kwantlen IR 1.5.6, while the Clean Power Call is the best available proxy for future IPP energy purchases, past experience suggests that future IPP costs may be higher than the $129/MWh resulting from the Clean Power Call."

2.65.4 Please provide BC Hydro's assessment of the blended cost of the next 5,000 and 10,000 GW.h of lowest-cost resource available using the price ranges shown on pages 14 and 15 of BC Hydro's 2011 Integrated Resource Plan Consultation Workbook.

RESPONSE:

The following table presents the blended costs of the next 5000 GWh and 10000 GWh of lowest-cost resource options. The costs reflect the adjustments to the UECs outlined in BC Hydro's response to BCUC IR 2.65.2, including delivery to the LM. The costs are shown in three ways: (1) without coal-fired generation given that coal with CCS is an emerging technology that is not currently commercially available; (2) the cost of (1) but also without natural gas-fired generation given the permitting and policy issues associated with natural gas-fired generation; and (3) the cost of (2) but also without geothermal because this resource option has never been bid into a BC Hydro power acquisition process and without biogas because it is not a utility-scale resource option.

	5000 GWh ($)	10000 GWh ($)
No Coal	74.21	80.94
Plus No Gas	74.21	84.52
Plus No Biogas & Geothermal	107.65	102.12

For purposes of responding to the BCUC IR 2.65 series, BC Hydro would conservatively use the "No Coal" UEC for both the 5,000 GWh/year and 10,000 GWh/year resource option bundles. Please refer to BC Hydro's response to BCUC IR 2.65.6, and also to BC Hydro's response to BCUC IR 2.65.2 with respect to the general relevance of the cost ranges shown.

65.0 Reference: IPP Purchases
Exhibit B-7-2, AMPC 1.1.2

"However, as noted in BC Hydro's response to Kwantlen IR 1.5.6, while the Clean Power Call is the best available proxy for future IPP energy purchases, past experience suggests that future IPP costs may be higher than the $129/MWh resulting from the Clean Power Call."

2.65.5 Please discuss why the Clean Power Call based pricing should be used as the reference price for the value of the Ruskin facility products rather than BC Hydro's assessments in the IRP or other processes.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.65.2.

65.0 Reference: IPP Purchases
Exhibit B-7-2, AMPC 1.1.2

"However, as noted in BC Hydro's response to Kwantlen IR 1.5.6, while the Clean Power Call is the best available proxy for future IPP energy purchases, past experience suggests that future IPP costs may be higher than the $129/MWh resulting from the Clean Power Call."

2.65.6 Please repeat the NPV analysis provided in Table 3-4 of Exhibit B-1 for the proposed Project, except use a capacity value of $0/kW-year and solve for the weighted average energy value necessary to provide a project NPV of zero. Using this weighted average energy value and a capacity value of $0/kW-year, please also provide the NPV for Alternatives A through E.

RESPONSE:

By definition, the value of energy that would result in a zero NPV for any project is the levelized cost of energy calculated for that project or facility. Accordingly, the weighted average value of energy that corresponds to a zero NPV for the Project if the value of capacity is set to $0/kW-Year is the levelized cost shown in Table 3-7 of Exhibit B-1 (page 3-33) with a Capacity Credit of "None," or $67.46/MWh.

At this weighted average value of energy and no value for capacity, the NPV of the various alternatives are:

Project NPV ($ million)	Expected	Authorized
Project – Retain 3	-	(38.3)
Alt A – De-Rate 2	28.8	(31.5)
Alt B – Overflow	-	-
Alt C – Remove	(71.8)	(94.6)
Alt D – Tunnel	(67.5)	(89.2)
Alt E – De-Rate 3	(28.2)	(110.6)

The details of these calculations can be observed in the working excel spreadsheet supplied as Appendix C-2 to Exhibit B-1 by setting the value of capacity entered in Cell B16 to zero and overwriting the calculated weighted average value of energy in Cell B15 to $67.46/MWh. This break even energy value is less than the lowest 5,000 GWh and 10,000 GWh resource option bundles set out in BC Hydro's response to BCUC IR 2.65.4. Accordingly, the Project is cost-effective even if those resource option values are used, particularly considering that no value has been given to capacity.

66.0 Reference: Seismic Standards
Exhibit B-7-2, AMPC 1.5.2

"BC Hydro is upgrading the Ruskin Facility, which was originally constructed in 1930, to current seismic and safety standards. However, these standards, which are described in Part II of this response in greater detail, are not "BC Hydro current standards", but rather are standards which are either set by or adopted by British Columbia (B.C.) government agencies such as the B.C. Comptroller of Water Rights, charged with administering the B.C. Dam Safety Regulation (Upper Dam, Right Abutment and Left Abutment seismic) and the B.C. Ministry of Energy and Mines' Safety Standards Branch, responsible for the B.C. Building Code (Powerhouse superstructure seismic) or by organizations such as the Canadian

Dam Association (CDA) which reflect international best practices and are referred to by B.C. government agencies."

2.66.1 Has BC Hydro sought exemption from the applicability of the 0.71g criterion and other seismic criteria at the Ruskin facility or otherwise confirmed the applicability of those criteria with any regulatory authority? If not, why not?

RESPONSE:

The 0.71 g (one in 10,000-year return period) criterion is part of the MDE for the Dam and water retaining structures; refer to Exhibit B-1, page 3-3, lines 1 to 2. There was no need to confirm the applicability of the 1 in 10,000-year criterion because it results from the Very High Consequence classification of the Ruskin Facility, which was confirmed by the CWR; refer to Exhibit B-7, Attachment 1 to BC Hydro's response to BCUC IR 1.65.1, page 2 of 8.

In BC Hydro's view, it would be inappropriate to seek to design the Upper Dam, Right Abutment and Left Abutment Work to a less stringent seismic criterion resulting in an increased risk to public safety. Such a design would require approval of the CWR pursuant to section 4 of the B.C. Dam Safety Regulation, and would be tantamount to seeking a relaxation of the Very High Consequence classification set out in the Dam Safety Regulation and the CDA Guidelines with respect to the Ruskin Facility. It is unclear on what basis BC Hydro would seek to apply less stringent seismic criterion since designing to less stringent criterion would not ensure that the Project is constructed in a manner that provides the appropriate level of security of life, property and the environment. In BC Hydro's view it is unlikely that the CWR would grant approval to carry out the Upper Dam Work, Right Abutment Work and Left Abutment Work on the basis of a departure from seismic criterion and standards the Dam Safety Regulation and the CDA Guidelines set out for protection of the public. Engagement with other government agencies, such as DFO and WorkSafeBC, would be required. In BC Hydro's

view such an exemption request would generate significant opposition as it would be an attempt by BC Hydro to design the Project to a less stringent seismic criterion than is generally accepted by other operators of large dams.

The other seismic criterion governing the Project is the National Building Code of Canada (NBCC) with respect to the Powerhouse superstructure and substructure. There was no need to verify the applicability of the NBCC to the Powerhouse; the NBCC is a widely recognized objective standard. With respect to a decision to rehabilitate the Powerhouse to a seismic criterion that is less stringent than that mandated by the NBCC, it is again unclear on what basis BC Hydro would seek to rebuild the Powerhouse superstructure to a less stringent criterion.

67.0 Reference: Current Design Status
Exhibit B-7, BCUC 1.93.1, Attachment 4, p. 25 of 406

"This WDB is intended to be a "living document" and is updated as required during the life of the project."

2.67.1 Please confirm the referenced Interim Working Design Basis document, dated October 2008, is the most recent Working Design Basis document and reflects the proposed project in the Application. If not able to confirm, please provide an updated and current Working Design Basis document.

RESPONSE:

Confirmed.

67.0 Reference: Current Design Status
Exhibit B-7, BCUC 1.93.1, Attachment 4, p. 25 of 406

"This WDB is intended to be a "living document" and is updated as required during the life of the project."

2.67.2 Please update Exhibit B-1, Table 2-2 with the most current WDB document information.

RESPONSE:

There is no need to update Exhibit B-1, Table 2-2 given that it is based on the most current Working Design Basis. Please refer to BC Hydro's response to BCUC IR 2.67.1.

1.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7-1, Response to BCUC IR 1.14.4, Confidential Attachment 1
Funding Summary

2.1.1 Please specify the services and/or products paid for by the invoices for Environmental and Archaeological services, Archaeological services (AOA), and Archaeological services (AIA).

This Information Request was originally submitted on a confidential basis, however, the response is public.

RESPONSE:

Environmental and Archaeological Services

Services and/or products received by BC Hydro related to the Environmental and Archaeological services included environmental monitoring support on the Crest Block Anchoring Project, the Stage 1 Ruskin Dam Safety Right Abutment Upgrade, and remaining Project area, archaeological inventory (field and lab) work, archaeological excavation and documentation of materials from an identified site, the production of detailed workplans and related interim and final reports, administrative costs, mileage and related expenses.

Archaeological services (AOA) and Archaeological Services (AIA)

Services and/or products received by BC Hydro related to AOA and AIA included an archaeological overview assessment of available desktop information for specified locations, and an archaeological impact assessment including field work for specified locations, and the production of related interim and final reports. This work involved the services of Archaeological and Environmental Monitors, an Archaeological Project Director, multiple Senior Field Workers, a Heritage and Lands Officer, an Archaeologist, a Project Manager and administrative personnel.

1.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7-1, Response to BCUC IR 1.14.4, Confidential Attachment 1
Funding Summary

2.1.2 Were the bids for Archaeological services or Tree Clearing services put out for competitive tender? If not, how were the vendors selected?

This Information Request was originally submitted on a confidential basis, however, the response is public.

RESPONSE:

No, the bids for Archaeological services or Tree Clearing services were not put out for competitive tender. These contracts were awarded to Kwantlen under BC Hydro's Aboriginal Procurement Policy.

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British Columbia Hydro & Power Authority **Ruskin Dam and Powerhouse Upgrade Project CPCN Application**	**Exhibit: B-10**

1.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7-1, Response to BCUC IR 1.14.4, Confidential Attachment 1
Funding Summary

2.1.2.1 Do these contracts align with BC Hydro's purchasing policy? If not, why not? Please explain.

This Information Request was originally submitted on a confidential basis, however, the response is public.

RESPONSE:

Please refer to BC Hydro's response to BCUC Confidential IR 2.1.2.

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2.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.5, Confidential Attachment 1 and BCUC 1.15.1.1, p. 2
Accommodation Costs

2.2.1 Please provide a detailed breakdown of the accommodation cost estimate for the Project. Please specify what impacts to Aboriginal rights or interests are being accommodated and to whom.

This Information Request was originally submitted on a confidential basis, and the response is confidential.

RESPONSE:

In accordance with section 42 of the B.C. *Administrative Tribunals Act* and the Confidential Filings Practice Directive, BC Hydro respectfully requests that BC Hydro's responses to the Confidential BCUC IR 2.2.1, 2.2.1.1, 2.2.1.3, 2.2.2, 2.2.3 and 2.2.3.1 be kept confidential. As set out in Exhibit B-7-1, BC Hydro's response to BCUC IR 1.14.5, the disclosure of information set out in BC Hydro's responses to these Confidential BCUC IRs would likely cause significant harm and prejudice to BC Hydro's negotiating position with not only First Nations interested in the Project but also other First Nations interested in other BC Hydro projects. The information relates to the development of Impact Benefit Agreement (IBA)-related costs for the Project, which is sensitive financial information. This financial information is confidential and has consistently been treated as confidential by BC Hydro. The disclosure of this information could adversely influence BC Hydro's ability to negotiate potential IBA(s) with Kwantlen and therefore adversely affect ratepayers, both on the Project and future projects.

Detailed cost estimate information is contained in the IR and/or the IR response for BCUC Confidential IRs 2.3.2, 2.4.5, 2.4.6, and 2.5.1. BC Hydro requests confidential treatment of the confidential version of these IR responses on the basis that its disclosure will result in: 1) undue financial loss to BC Hydro and undue financial gain to contractors it will be negotiating with to undertake construction or to supply and install equipment; 2) significant prejudice to BC Hydro's competitive negotiation position with these contractors; and 3) BC Hydro has consistently treated the commercial and financial information contained in the confidential version of this IR response on a confidential basis.

2.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.5, Confidential Attachment 1 and BCUC 1.15.1.1, p. 2
Accommodation Costs

2.2.1.1 Does this estimate include any costs included in Confidential Attachment 1 to BCUC IR 1.14.4? If so, please specify.

This Information Request was originally submitted on a confidential basis, and the response is confidential.

RESPONSE:

For the reasons set out in BC Hydro's response to BCUC Confidential IR 2.2.1, BC Hydro respectfully requests that BC Hydro's response to this IR be kept confidential.

2.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.5, Confidential Attachment 1 and BCUC 1.15.1.1, p. 2
Accommodation Costs

2.2.1.2 Does this estimate include any accommodation for historical infringements on Aboriginal rights? If so, please specify.

This Information Request was originally submitted on a confidential basis, however, the response is public.

RESPONSE:

No, the estimate does not include any accommodation for historical infringements on Aboriginal rights.

British Columbia Utilities Commission **CONFIDENTIAL** Information Request No. **2.2.1.3** Dated: **May 18, 2011** British Columbia Hydro & Power Authority Response issued **June 16, 2011**	Page 1 of 1
British Columbia Hydro & Power Authority **Ruskin Dam and Powerhouse Upgrade Project CPCN Application**	**Exhibit:** **B-10**

2.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.5, Confidential Attachment 1 and BCUC 1.15.1.1, p. 2
Accommodation Costs

2.2.1.3 Does this estimate include any accommodation for impacts to traditional uses? If so, please specify.

This Information Request was originally submitted on a confidential basis, and the response is confidential.

RESPONSE:

For the reasons set out in BC Hydro's response to BCUC Confidential IR 2.2.1, BC Hydro respectfully requests that BC Hydro's response to this IR be kept confidential.

2.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.5, Confidential Attachment 1 and BCUC 1.15.1.1, p. 2
Accommodation Costs

2.2.2 Please discuss the overall accommodation estimate in relation to BC Hydro's assessment that the overall project incremental impacts will be low. In other words, when BC Hydro has assessed the potential impacts as minimal, what impacts is it estimating accommodation payments for?

This Information Request was originally submitted on a confidential basis and the response is confidential.

RESPONSE:

For the reasons set out in BC Hydro's response to BCUC IR 2.2.1, BC Hydro respectfully requests that BC Hydro's response to this IR be kept confidential.

2.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.5, Confidential Attachment 1 and BCUC 1.15.1.1, p. 2
Accommodation Costs

2.2.3 What methodology does BC Hydro use to determine accommodation levels? Is it on a case-by-case negotiation or is there standardization?

This Information Request was originally submitted on a confidential basis, and the response is confidential.

RESPONSE:

For the reasons set out in BC Hydro's response to BCUC Confidential IR 2.2.1, BC Hydro respectfully requests that BC Hydro's response to this IR be kept confidential.

2.0 Reference: First Nations Consultation and Public Consultation
Exhibit B-7, Response to BCUC IR 1.14.5, Confidential Attachment 1 and BCUC 1.15.1.1, p. 2
Accommodation Costs

2.2.3.1 If the potential impacts of a project are low, does BC Hydro believe or practice that the accommodation payments will be lower than a project that has high impacts? Does BC Hydro believe or practice that the accommodation payments are in accordance with the level of impact?

This Information Request was originally submitted on a confidential basis, and the response is confidential.

RESPONSE:

For the reasons set out in BC Hydro's response to BCUC Confidential IR 2.2.1, BC Hydro respectfully requests that BC Hydro's response to this IR be kept confidential.

3.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.55.2, MWH Attachment 2, pp. 24 and 78

2.3.1 Please confirm the maximum power output of a replacement turbine is either 44 MW or 47 MW. Please describe the size of units to be installed by the Project.

This Information Request was originally submitted on a confidential basis, however, the response is public.

RESPONSE:

The maximum power output from the replacement turbine is currently assumed to be 44 MW.

BC Hydro has decided not to reconstruct the existing water passages (tunnels, scroll case, turbine pit and draft tubes). As a result, the physical size of the turbine is limited by the existing facility with the draft tube throat diameter measuring 3.78 m.

3.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.55.2, MWH Attachment 2, pp. 24 and 78

2.3.1.1 Would there be any advantages to employing 2 units with a combined output of 88 to 94 MW and the 3rd unit having an output with its maximum efficiency designed around minimum flows for fish (for discussion say 20-25 MW)?

This Information Request was originally submitted on a confidential basis, however, the response is public.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.29.6.1 for BC Hydro's rationale in selecting three identical units designed for high efficiency over a greater range of flows at the Ruskin Facility.

British Columbia Utilities Commission **CONFIDENTIAL** Information Request No. **2.3.2** Dated: **May 18, 2011** British Columbia Hydro & Power Authority Response issued **June 16, 2011**	Page 1 of 1
British Columbia Hydro & Power Authority **Ruskin Dam and Powerhouse Upgrade Project CPCN Application**	**Exhibit:** **B-10**

3.0 Reference: Ruskin Facility
Exhibit B-7, BCUC 1.55.2, MWH Attachment 2, pp. 24 and 78

2.3.2 Please explain Line D25150 Generator Upgrade - Installed 3 at $ for a total of $. What is this item and please explain how this differs from Line D25130 (i.e., what is the difference between a “New Turbine Generator” and a “Generator Upgrade”?

This Information Request was originally submitted on a confidential basis. The response is public but the IR has been redacted to protect confidential information.

RESPONSE:

Item D25130 should have been labelled as “New Turbine”. At the time the Feasibility Design Report was prepared, work defined by this cost item related to replacement of all non-embedded parts of the turbine and refurbishment of the embedded parts.

The cost estimate assumes a generator refurbishment which is covered in line D25150. This cost item entails redesign and installation of a new water cooled generator and refurbishment of the rotor, generator shaft and generator bearing.

4.0 Reference: Project Need
Exhibit B-7, BCUC 1.67.2, p. 1; Exhibit B-1, RRA F2012 to F2014, Appendix J, p. 18; Exhibit BCUC 1.76.2, Attachment 1, p. 132
Right Abutment

"The proposed Project-related Right Abutment work includes the construction of a new slurry panel cut-off wall."

2.4.1 Please describe in detail the full scope of the proposed Right Abutment work as there is confusion around what is actually fully planned. Does the scope include repair/replacement/anchoring of any of the component(s) of the existing cut-off wall system?

This Information Request was originally submitted on a confidential basis, however, the response is public.

RESPONSE:

Yes, the Right Abutment Work includes anchoring the gravity wall that supports the first two existing cut-off wall slabs. Anchoring the gravity wall increases the seismic stability of the section immediately upstream of the concrete dam. No other improvements are planned for the existing cut-off wall system.

The scope of the Right Abutment Work is clearly set out in Table 2-1 of Exhibit B-1 as follows "Install new seepage cut-off wall to prevent seepage through the abutment and install jet grout columns in the Right Abutment soils; Anchor the existing upstream concrete gravity wall to prevent failure during MDE; and Reinforce the downstream retaining wall to prevent failure during the MDE."

4.0 Reference: Project Need
Exhibit B-7, BCUC 1.67.2, p. 1; Exhibit B-1, RRA F2012 to F2014, Appendix J, p. 18; Exhibit BCUC 1.76.2, Attachment 1, p. 132
Right Abutment

"The proposed Project-related Right Abutment work includes the construction of a new slurry panel cut-off wall."

2.4.2 Please describe in detail each of the scope elements identified in worksheet (i) in the Excel spreadsheet attachment to Exhibit B-7-1, BCUC 1.94.2 - Confidential.)

This Information Request was originally submitted on a confidential basis, however, the response is public.

RESPONSE:

The detailed scope description of worksheet (i) in the excel spreadsheet attachment to Exhibit B-7-1, BCUC 1.94.2 - Confidential is as follows:

General Requirements for the Right Bank Stage II – Describes the contractors costs to mobilize for the cut-off wall, jet grouting and to prepare the site. The site preparation scope consists of the contractor's offices, grout plant, bentonite plant, de-sanding equipment and any hoarding/fencing required.

Cut-Off Wall Right Bank Stage II:

- **A new slurry panel cut off wall;**
- **Related guide wall construction and demolition;**
- **The Contractor's exploratory work; and**
- **The tie into the right abutment concrete non-overflow section of the main dam with overlapping cores and grouting.**

Downstream Adit Area Right Bank Stage II:

- **A new downstream cut-off wall constructed of 2.0 m diameter overlapping jet grout columns parallel to the existing drainage adit; and**
- **All related contractor exploration work.**

Dam Abutment Connection Area Right Bank Stage II:

- **A new series of reinforced 1.5 m diameter overlapping jet grout columns parallel upstream and down stream of the existing Right Abutment concrete non overflow section of the Ruskin dam; and**
- **All related contractor exploration work.**

Ground Improvement Area Right Bank Stage II:

- **A new series of reinforced 2.0 m diameter overlapping jet grout columns to reinforce the new slurry panel cut off wall;**
- **Final graveling and clean up of the cut off wall area; and**
- **All related contractor exploration work.**

4.0 Reference: Project Need
Exhibit B-7, BCUC 1.67.2, p. 1; Exhibit B-1, RRA F2012 to F2014, Appendix J, p. 18; Exhibit BCUC 1.76.2, Attachment 1, p. 132
Right Abutment

"The proposed Project-related Right Abutment work includes the construction of a new slurry panel cut-off wall."

2.4.3 Please provide a copy of the final Engineering or Advisory Board recommendation or reference where it can be located in the Application.

This Information Request was originally submitted on a confidential basis, however, the response is public.

RESPONSE:

Please refer to Exhibit B-1, Attachment 3 to BC Hydro's response to BCUC IR 1.93.1, pages 70 and 115.

4.0 Reference: Project Need
Exhibit B-7, BCUC 1.67.2, p. 1; Exhibit B-1, RRA F2012 to F2014, Appendix J, p. 18; Exhibit BCUC 1.76.2, Attachment 1, p. 132
Right Abutment

"The proposed Project-related Right Abutment work includes the construction of a new slurry panel cut-off wall."

2.4.4 Please explain why the costs of the Stage 1 work, that are projected at $15.2 to $21.6 million, are substantially higher than the $8.1 million for Option 1.1 referenced in Engineering Report E08 i.e. "If reliable post-earthquake operability of the gates is not available, the recommended option is to upgrade the existing cut-off, Option 1.1, (which also includes the includes the downstream slope, Weir 9 and gallery drain improvements), at a cost of $8.1M." (emphasis added).

This Information Request was originally submitted on a confidential basis, however, the response is public.

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the grounds that it is out of scope. As is clearly set out in Exhibit B-1, the Stage 1 Ruskin Dam Safety Right Abutment Upgrade is not part of the proposed Project. The appropriate forum for reviewing the prudence of the costs with respect to Stage 1 Ruskin Dam Safety Right Abutment Upgrade is BC Hydro's RRA.

4.0 Reference: Project Need
Exhibit B-7, BCUC 1.67.2, p. 1; Exhibit B-1, RRA F2012 to F2014, Appendix J, p. 18; Exhibit BCUC 1.76.2, Attachment 1, p. 132
Right Abutment

"The proposed Project-related Right Abutment work includes the construction of a new slurry panel cut-off wall."

2.4.4.1 Please confirm that the scope and cost of Option 1.1 of Engineering Report E08 is associated with a criterion of 0.54 g.

This Information Request was originally submitted on a confidential basis, however, the response is public.

RESPONSE:

Yes, the 2004 conceptual design of Option 1.1 was based on an MDE of 0.54 g. For the 2007 feasibility studies, the MDE was revised to 0.71 g.

4.0 Reference: Project Need
Exhibit B-7, BCUC 1.67.2, p. 1; Exhibit B-1, RRA F2012 to F2014, Appendix J, p. 18; Exhibit BCUC 1.76.2, Attachment 1, p. 132
Right Abutment

"The proposed Project-related Right Abutment work includes the construction of a new slurry panel cut-off wall."

2.4.4.2 Please describe any additional work and costs in Option 1.1 of Engineering Report E08 associated with the change in criteria from 0.54 g.
(Reference: Exhibit B-7, BCUC 1.82.1)

This Information Request was originally submitted on a confidential basis, however, the response is public.

RESPONSE:

As stated in Exhibit B-7, BC Hydro's response to BCUC IR 1.82.1, conceptual Option 1.1 in the 2004 BC Hydro's E08 Report is not a feasible solution. The change from 0.54g seismic criteria to a 0.71g seismic criteria was not the driver in switching to the "slurry panel cut-off wall solution". As discussed in BC Hydro's response to BCUC IR 1.82.1, the primary driver for not pursuing Option 1.1 was due to post seismic deformations of the slabs and extensive reservoir drawdown schedule.

4.0 Reference: Project Need
Exhibit B-7, BCUC 1.67.2, p. 1; Exhibit B-1, RRA F2012 to F2014, Appendix J, p. 18; Exhibit BCUC 1.76.2, Attachment 1, p. 132
Right Abutment

"The proposed Project-related Right Abutment work includes the construction of a new slurry panel cut-off wall."

2.4.5 Please confirm that the Stage 2 right abutment work is currently estimated at $ million (fully loaded) bringing the total Implementation costs to $ million plus the amounts spent on the Investigative and Definition phases.

This Information Request was originally submitted on a confidential basis. The response is public, however detailed cost estimate information is redacted from both the IR and this response.

RESPONSE:

The stage two Right Abutment Work is currently estimated at $ million (direct). It is unclear what is meant by "bringing the total Implementation costs to $ million plus the amounts spent on the Investigative and Definition phases"; however, if this IR is probing at the costs of Stage 1 Ruskin Dam Safety Right Abutment Upgrade, BC Hydro respectfully declines to respond for the reasons set out in BC Hydro's response to BCUC Confidential IR 2.4.4.

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4.0 Reference: Project Need
Exhibit B-7, BCUC 1.67.2, p. 1; Exhibit B-1, RRA F2012 to F2014, Appendix J, p. 18; Exhibit BCUC 1.76.2, Attachment 1, p. 132
Right Abutment

"The proposed Project-related Right Abutment work includes the construction of a new slurry panel cut-off wall."

2.4.6 Please provide an order of magnitude for the Investigative and Definition phases of the right abutment work as collected by any EARs/CARs raised for this project over the last 15 years.

This Information Request was originally submitted on a confidential basis. The response is public, however, detailed cost estimate information is redacted from the IR response.

RESPONSE:

Identification Phase and Definition Phase direct costs for the Right Abutment work were $ and $ respectively.

4.0 Reference: Project Need
Exhibit B-7, BCUC 1.67.2, p. 1; Exhibit B-1, RRA F2012 to F2014, Appendix J, p. 18; Exhibit BCUC 1.76.2, Attachment 1, p. 132
Right Abutment

"The proposed Project-related Right Abutment work includes the construction of a new slurry panel cut-off wall."

2.4.7 Please explain why the work, as recommended in the E08 report, was not budgeted and implemented in 2005 or 2006.

This Information Request was originally submitted on a confidential basis, however, the response is public.

RESPONSE:

The BC Hydro Engineering Report E08 dated January 2004 entitled "Ruskin Dam Deficiency Investigation Right Abutment Stability Assessment" (E08) was a deficiency investigation which identified a number of potentially feasible options. E08 also indicated that, due to the complex nature of the problem, there were a number of outstanding uncertainties that required further work to address the considerable constructability risks. The E08 work lead to the continuation of the development of the options through the design stages of conceptual, preliminary and final design, including additional field investigations and analyses which took a number of years to complete. As a result of the additional work, the cut-off wall alignment was moved back into the abutment slopes requiring that the slopes above Wilson Road be excavated (this work was completed as part of the Stage 1 Ruskin Dam Safety Right Abutment Upgrade).

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5.0 Reference: Powerhouse
Exhibit B-1, Table 2-2, p. 2
Exhibit B-7-1, BCUC 1.40.1, CONFIDENTIAL Attachment, p. 2
Powerhouse Substructure

2.5.1 Please reconcile the statement in Exhibit B-1, Table 2-2 that states “No work required” in the Summary of Scope of Work column with the Exhibit B-7-1 entry of $ million for “Powerhouse Substructure Upgrades.”

This Information Request was originally submitted on a confidential basis. The response is public, however, detailed cost estimate information is redacted from the IR.

RESPONSE:

The determination that no work was required on the Powerhouse substructure was made after the estimate referenced in this IR was completed, but before Exhibit B-1 was filed with the BCUC. Such refinements of the Project scope and associated cost estimates are typical of project development in the Definition phase.

6.0 Reference: Powerhouse Substructure Stability Upgrade
Exhibit B-7-1, BCUC 1.55.2, CONFIDENTIAL Attachment 2, p. 98 of 124

2.6.1 Please explain how the anchors shown in the referenced drawing along bayline C and between column lines 4 and 5 and column lines 8 and 9 would be installed, as these appear to be at the unit intake tunnels.

This Information Request was originally submitted on a confidential basis, however, the response is public.

RESPONSE:

The conceptual anchoring layout in the Feasibility Design Report had assumed anchoring would have been performed under the power intakes in the chamber surrounding the Turbine Inlet Valve. However, while even this solution would be extremely challenging to implement, the designers had reduced the substructure anchoring requirement to 19 anchors in the Preliminary Design Report (a copy of which is found at Exhibit B-7, Attachment 1 of BC Hydro's response to BCUC IR 1.93.1).

Through ongoing refinement of Project scope, the Powerhouse substructure is not part of the Project scope as proposed; please refer to Table 2-2 of Exhibit B-1. Please also refer to BC Hydro's response to BCUC Confidential IR 2.5.1.