Appendix D

System Model & Assumptions

This Appendix provides more detailed information about the models and assumptions used in the Columbia River Treaty 2014 Review Technical Studies. Section 1.0 provides information on the BC Hydro system modelling used for the Columbia alternatives and also provides all the assumptions that went into the modelling. Section 2 provides describes the modelling and assumptions for the Kootenay alternatives.

1.0 BC Hydro System Modelling for Columbia Alternatives

The Columbia River operation cannot be examined in isolation from the rest of the BC electrical system because Mica and Revelstoke generating stations meet roughly one third of the Provincial electrical demand and G.M. Shrum and Peace Canyon generating stations on the Peace River meet an additional third of Provincial demand. Changes to the operations of one river system and its reservoirs must be coordinated with those in the other. To capture this interdependency, models that simulate the whole BC Hydro system are used for the Columbia alternatives in the Columbia River Treaty 2014 Review Technical Studies.

The fundamental reliability metric for ensuring that a hydroelectric utility can meet electric demand is called the firm load carrying capability (FLCC). The FLCC includes firm energy load carrying capability (FELCC) and firm peak load carrying capability (FPLCC). Different types of system studies are required to calculate the firm energy (necessary to assess the FELCC), dependable capacity (necessary to assess the FPLCC), and the average annual energy for the BC Hydro system.

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Operating studies were conducted for all the Columbia alternatives. Operating studies are performed to determine the average annual energy for each generating station as well as the operating strategy that would optimize the value of the BC Hydro system by using the system's flexibility to optimize trade with the electricity market within the constraints of the alternative. The alternative that limited the draft at Mica (Alternative 4) was expected to have a significant impact on BC Hydro's firm energy and this impact was approximated based on the energy that could have been generated with water below the studied limit. FELCC and dependable capacity studies were not conducted.

The primary model used in all these studies is the Hydro simulation Model (HYSIM).

1.1 Hydro simulation model (HYSIM)

HYSIM is used to determine the operation strategy that would optimize the operating value of the BC Hydro system, while making full use of system flexibility and market opportunities.

The HYSIM model is a monthly simulation model of the integrated BC Hydro electric generation system. It includes detailed hydraulic modelling of the hydro system as well as operating rules derived under the assumed Columbia River Treaty conditions and ancillary contracts and agreements such as supplemental operating agreements and Non-Treaty Storage Agreement. For a given load and resource portfolio (including electricity purchase contracts), the model will determine the most economic dispatch of the generating system subject to fixed operating constraints (i.e. dam safety, physical capability, flood control, regulatory requirements, third-party agreements), across an historical sequence of inflows and subject to external market opportunities. The US and Alberta external markets are represented with heavy- and light-load hour prices for both imports and exports as well as tie-line limitations.

HYSIM develops and refines value-of-storage tables for reservoir space in storage reservoirs, Non-Treaty Storage Agreement (NTSA) space in the Kinbasket Reservoir (if applicable, depending on the alternative), and flex storage between Kinbasket Reservoir and the Arrow Lakes(if applicable, depending on the alternative). These value-of-storage tables divide the available storage by elevation and month that are used in conjunction with market electricity prices to minimize the system operating cost while meeting domestic load on a monthly basis.

1.2 Study Assumptions

Forward looking studies such as these require a variety of forecasted and assumed data. The electrical load, electricity market prices, and BC Hydro's resources are all based on forecasts made in 2011 and 2012 for the water year beginning October 1, 2024 and ending September 30, 2025. This is an estimated of what the hydropower system could look like in 2024.

This section provides the base system assumptions that are used in all of the Columbia alternatives and the specific Columbia operation assumptions that are used in the Treaty Continue reference case (Ref-TC). All of the other Columbia alternatives vary the Columbia operations from this reference case as needed to meet the specific alternative objectives.

Table 1 provides the highlights of the modelling assumptions and further information is provided below.

Table 1: HYSIM Assumptions

• Forecast load 2024-25 (70,088 GWh/year)
• Streamflow sequence is from October 1928 to September 2000

• BC gas and electricity price forecast as used in 2012 IRP studies (scenario C)
  • Market prices are based on average monthly prices for heavy load and light load periods
  • Energy limit is based on the estimated monthly transmission availability to the US and Alberta
  • The market electricity prices are adjusted by water year to reflect the impacts of stream flow, weather and gas supply conditions in the Pacific Northwest.

• Resources
  • Base Resource Plan (April 2012) from the 2012 IRP for 2024/25 load year, the major resources include:
  • Existing and forecasted BC Hydro resources and Independent Power Producers
    • Includes REV Units 5 and 6, Mica Units 5 and 6, and Site C.
  • Arrow Lakes Hydro generation

- Additional generation contracts such as Canal plant Agreement, Alcan, the Island Generation natural gas-fired plant, and Waneta Expansion for example

- Columbia River Operations
  - Treaty operation based on 2016 Assured Operating Plan (AOP)
  - Flood control storage requirements based on 4.08/3.60 MAF flood control split at Kinbasket and Arrow Lakes reservoirs
  - Non-Treaty Storage operation follows the guidelines described in the 2012 NTSA. NTS consists of 4.5 Maf of total Non-Treaty storage, with 2.25 Maf for each of BCH and BPA. The operation is developed to minimize system operating costs with US matching BCH operation based on market price with consideration given to the US non-power needs.

- Peace River Water Use Plan Constraints
  - Williston Reservoir operating range as per water license
  - Site C ice flow constraints
    - 52 kcfs in January
    - Minimum 25 kcfs in February
    - Minimum 22 kcfs in March
    - Minimum 11 kcfs from April to November
    - Minimum 45 kcfs in December

Modelling approach

- Modeling period - stream flow sequence from October 1928 through September 2000
- Modelling time step. The study uses a monthly time step with heavy load and light load sub-time steps for market trades.
- The study optimizes the operation of the six major hydroelectric plants in the BC Hydro system (G.M. Shrum, Peace Canyon, Site C, Mica, Revelstoke and Arrow), a thermal plant (Island Generation Plant), and energy imports/exports to meet the system residual load.
- Libby Coordination Operation - Under the Libby Coordination Operation, Canada is provided the option to exercise a provisional draft at Arrow twice between 1 Jul and 31 Dec. Each draft is limited to a maximum rate of 4 kcfs and a total draft volume of 125 ksfd. These studies will assume the following draft schedule for all water years:

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Draft Volume	0	-30	-92	-30	0	0	0	0	0	0	-62	-124

- Non Treaty Storage Operation - The operation follows the guidelines described in the 2012 NTSA. Non Treaty Storage consists of 4.5 Maf of storage, with 2.25 Maf for each of BC Hydro and Bonneville Power Authority. During BC Hydro critical period assume US HK and no BCH HK. For all other water years assume US Federal HK and no BC HK. The operation is developed to minimize BCH system operating costs with US matching BC Hydro operation based on market price while enhancing Supplementary Operating Agreements and with consideration given to the US non-power needs.
- Non-Power Operations **-** Supplemental Operating Agreements (SOAs) are deviations from Treaty operations that are agreed upon for the purposes of meeting non-power constraints. The CRT 2014 Review reference case for Treaty Continues (Ref-TC) includes non-power objectives for white fish, rainbow trout, and U.S. flow augmentation.

- **Load**:

- The 2024/25 monthly load shape from Nov 2011 Load Forecast. The annual load in operating studies is 70,088 GWh and is based on the average water planning criteria, calculated as the FELCC plus 4,500 GWh of market reliance. The following table shows the load shape in terms of percent of annual total load energy.

Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
8.25%	8.97%	9.93%	9.85%	8.78%	8.99%	7.85%	7.63%	7.23%	7.57%	7.59%	7.37%

- **Market Prices:**
  - For System Operating study, market prices are based on the BC Hydro corporate forecast price, scenario C for the 2012 IRP studies at Pacific Northwest (Mid-C) area. The export price at the BC-US border is the price at Mid-C less wheeling and losses charges. The import price at the border is the price at Mid-C plus wheeling and losses charges. The market electricity prices are adjusted by water year to reflect the impacts of stream flow, weather and gas supply conditions in the Pacific Northwest.
- **Resources:**
  - The study resource portfolio is based on the Base Resource Plan (BRP, Apr 2012 version) from the 2012 IRP for 2024/25 load year which includes the BC Heritage resources[1].
  - IPP Energy. IPP energy is based on 2012 IRP which contains all existing IPPs already in service and IPPs with contracts under the previous energy calls such as Call 2006, 2008 Bio Energy Call, 2008 SOP and 2010 CPC. Aggregated firm monthly energy is used in critical period, and aggregated average monthly energy is used in other periods.
  - 2009 update of the Canal Plant Agreement Entitlement. This data includes updated Kootenay operation reflecting Libby operation changes, Brilliant upgrade and expansion, and 4 upgraded units at Waneta.
  - Waneta plant includes Waneta Expansion (using regulated flow from 2007 BPA Biological Opinion study) and returned entitlement (one third of total entitlement).
  - Island Generation Plant (ICG). Capacity of ICG is 285 MW, and its minimum generation is 254.4 GWh/year (Nov-Feb). 2012 IRP Low Market Price Scenario C is used for economical dispatching in Operating study.
  - Alcan Energy Purchase Agreement (2007) includes Tier1 and Tier 2 energy.

1.3 Uncertainty in Model Assumptions

While careful attention and expertise went into modeling and projecting what the future may hold in 2024-25 there are always uncertainties to those projections. Areas where uncertainty can be found include but are not limited to:

[1] The BC Hydro system includes the BC Hydro Heritage assets, thermal installations, IPPs and other contractual arrangements. According to the 2010 Clean Energy Act, the generation and storage assets belong to BC Hydro and designated as “Heritage” are: Aberfeldie, Alouette, Ash River, Bridge River, Buntzen/Coquitlam, Burrard Thermal, Cheakamus, Clowhom, Duncan, Elko, Falls River, Fort Nelson, G. M. Shrum, Hugh Keenleyside Dam (Arrow Reservoir), John Hart, Jordan, Kootenay Canal, La Joie, Ladore, Mica including units 1 to 6, Peace Canyon, Prince Rupert, Puntledge, Revelstoke including units 1 to 6 ,Ruskin ,Site C ,Seton ,Seven Mile, Shuswap, Spillimacheen, Stave Falls, Strathcona, Waneta, Wahleach, Walter Hardman, Whatshan.

- **Historical Stream flow Record**: The studies use the historical inflow record and simulated flow to represent the range of expected future stream flows. This range may not capture the full potential for low probability and high consequence extreme events. Future sequences may be drier or wetter than those within the historical record. Potential climate change scenarios were not included in these studies.
- **Load and Resource Assumptions**: Load and resources affect the operation of the system. As with any forecast, the numbers have an associated uncertainty around them.
- **Electrical Price Forecast**: Forecasting the electrical market price in the future has many risks and uncertainties as it is impacted by global factors such as the price of oil and gas and is also influenced by government policies in both Canada and the US.
- **Non Treaty Storage Operation**: The operation follows the guidelines described in the 2012 NTSA. Non Treaty Storage consists of 4.5 MAF of storage, with 2.25 MAF for each of BC Hydro and Bonneville Power Authority. The operation is developed to maximize operating values with US matching BC Hydro operation based on Mid-C price while enhancing Supplementary Operating Agreements and with consideration given to the US non-power needs. The NTSA is an enabling agreement and as such, releases and storage of water by either party must receive the other party's consent. In practice, this means that the power operations models are unable to account for all the possibilities, and provide an estimate of NTSA operations.
- **Requirements for Called Upon**: Canadian interpretation of Called Upon obligations are limited to a target flow objective of 600 kcfs at the Dalles and the use of all U.S. reservoirs capable of reducing peak flow at the Dalles. Based on the Canadian interpretation, Called Upon is not required in the historical stream flow record and as a result has not been modeled in these studies.

2.0 Model and Assumptions for Kootenay Alternatives

The Kootenay alternatives were modelled in three separate spreadsheet models for Libby, Duncan, and Kootenay Lake. These spreadsheet models simulate the operations using a prescribed set of rules. The projected outflows from the Libby and Duncan models, as well as local Kootenay lake inflow, are used as input to the Kootenay Lake model.

The Libby spreadsheet model was only used for the Early Koocanusa Refill alternative (Alternative 3a and 3b). BC Hydro did not simulate Libby Current Conditions (Alternative 1) or the Standard Flood Control and Power (Alternative 2); instead data sets from US Entity studies were used for these two alternatives.

Duncan operations were not altered between the three different alternatives since the focus of the studies was on Libby Dam operation and the resulting impacts downstream in Kootenay Lake and Kootenay River. Likewise, the rules governing Kootenay Lake operation were not altered between the alternatives and the results for Kootenay Lake reflect the changes to inflow resulting from different Libby dam operations.

2.1 Model Assumptions

All spreadsheet models

- Daily time step modelling

- Stream flow data: 2000 Modified Flows
- Stream flow period: Oct 1928 – Sep 1998 except Alternative 2 (Oct 1947 – Sep 1998)

Libby Dam Spreadsheet Model

- daily ramp rates included in modelling
- Other assumptions vary between alternatives as described in Section 2.2
- BC Hydro validated model by first mimicking Alternative 1 regulation obtained from Bonneville Power Administration. The model was then used with the additional constraints for Alternatives 3a and 3b

Duncan Dam Spreadsheet Model

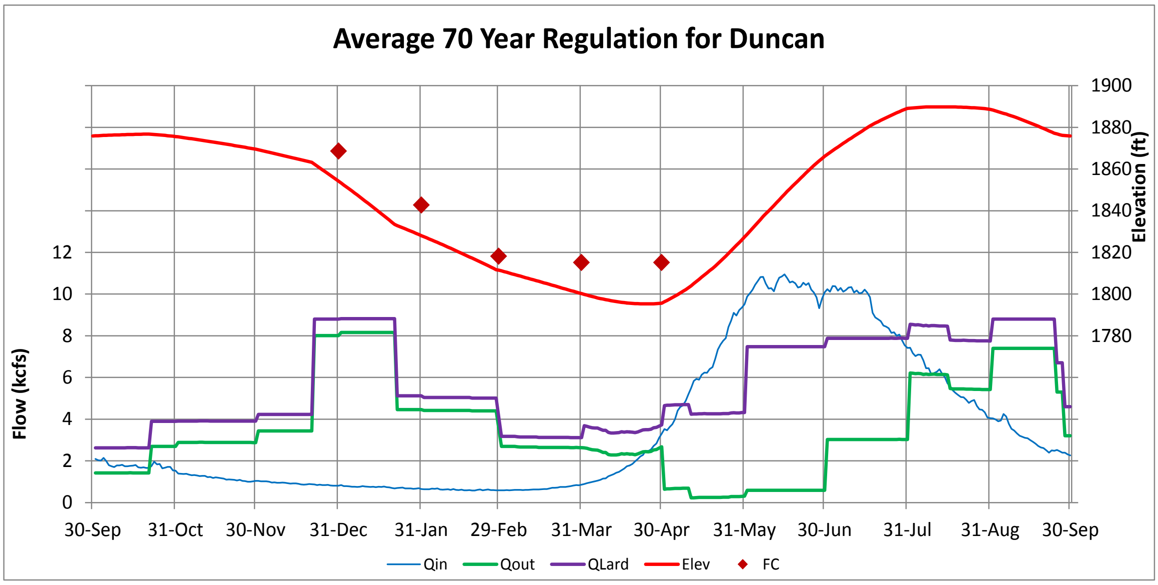
- Duncan operation is based on the WUP constraints including Duncan River Flow targets below Lardeau River confluence (see Table 1) and the summer recreation reservoir elevation targets:
  - Refill to within 1 ft of full between Aug 1-10
  - Draft 4 ft to 1888 ft (575.5 m) by Aug 31
- Monthly local Lardeau River flows estimated based on average monthly ratios of local Lardeau River inflows to Duncan inflows from 1984-2005
- Flood control levels – As determined from Duncan Storage Reservation Diagram, revised Nov 2009 (includes adjustment for end of Feb to 1812.5 ft or 552.45m)

Table 1: Duncan River Flow Targets (below Lardeau confluence)

Dates	m^3/s	
	minimum	maximum
August 1 – August 24	73	400*
August 25 – September 24	73	250
September 25-27	73	190
September 28-30	73	130
October 1 – 21	73	76
October 22 – December 21	73	110
December 22 – April 9	73	250
April 10 – May 15	73	120
May 16 – July 31	73	400

* During this time the licensee will target a maximum of 250 m^3/s.

The Duncan Reservoir operation that is used in all three Kootenay alternatives is provided in the following chart.



<u>Kootenay Lake and Kootenay River Hydroelectric Plants Spreadsheet Model</u>

Kootenay Lake Operations

- **April - August Objective:** minimize spill along Kootenay River by minimizing peak Kootenay Lake discharge subject to target maximum elevation of 1749.5 ft (if possible) and maximum Grohman Narrows discharge

- **Freshet operation:**
    1. minimize duration of elevations above the target maximum IJC elevation by releasing maximum discharge until Kootenay Lake drops to the target maximum elevation
    2. maintain at target maximum elevation until margin with IJC level becomes 0.3 ft
    3. maintain margin and follow IJC curve until elevation drops to 1743.32 ft
    4. maintain at 1743.32 ft until 31 Aug

- **Sep-Mar Operation:**
    - target 0.3 ft margin below the IJC elevation at end of each month with constant monthly flows
    - Some limited Kootenay Lake draft in fall to provide for meeting target minimum flow constraints at Brilliant [16 kcfs (Oct-Nov), 18 kcfs (Dec-Sep)]
    - minimum flows set to 10 kcfs to reduce Brilliant day to day flow fluctuations (during fall/winter period)

2.2 Description of Libby Operations in each Kootenay Alternative

Alternative 1: Current Libby Operations

- data set obtained from Bonneville Power Administration operational study [seems to imply a public/formal study, when it wasn't]
- Current fisheries requirements are included
    - spring sturgeon flows Jun 1-30 (25 kcfs, does not include additional shaping of sturgeon flows that may occur in this period)

  - bull trout minimum flows: 16 May – 30 Jun (6 kcfs), 1 Jul – 31 Aug (6-9 kcfs, depending on runoff volume), 1 – 30 Sep (6 kcfs)
  - VarDec/VarQ flood control and VarQ flows
  - 10/20 ft Sep draft depending on if May volume forecast >71.8 MAF or <71.8 MAF)
- Oct-Apr operations - daily operations include maximum 20 kcfs monthly average for Oct-Dec (for BPA planning purposes)

Alternative 2: Standard Flood Control and Power Libby Operations
- From USACE VarQ EIS operational study (Jul 2004) as described in report: "Draft Hydrologic Analysis of Upper Columbia Alternative Operations: Local Effects of Alternative Flood Control and Fish Operations at Libby Dam"
- Includes Standard flood control and power operations producing deeper drafts from Dec-Apr in comparison to Alternative 1.
- Includes 20 ft draft by end of September for downstream salmon

Alternative 3a & 3b: Early Refill at Libby
Alternative objectives:
  - Alternative 3a: refill to within 5 ft of full on 1 Jun
  - Alternative 3b: refill to within 5 ft of full on 30 Jun

- The initial BC Hydro simulation of current Libby operations (intended to mimic Alt 1 regulation from BPA) was used as a starting point and then modified meet early refill objectives
- Attempted to meet fish operations as per Alternative 1 where possible, but then bull trout, sturgeon and VarQ flows are relaxed as required to meet refill target date

Assumptions
- VarDec and VarQ flood control requirements maintained during drawdown period
- May-Sep operations (to meet refill date while avoiding uncontrolled Libby peak flows):
  - Libby discharge reduced uniformly from Alternative 1 simulation to the extent required to refill by target date (Libby minimum flow = 4 kcfs)
  - When reservoir is refilling too fast (leading to uncontrolled peak flows), Libby discharge increased to refill Koocanusa reservoir in 15 days
  - maximum Libby discharge set to 30 kcfs unless greater flows (up to 40 kcfs) are needed to avoid/reduce uncontrolled peak flows in future periods

Alternative 3a refilled by 1 Jun in only 17% of the years. Relaxing the assumptions (i.e. allowing Koocanusa to nearly refill by 1 June every year) would likely cause surcharge at Koocanusa reservoir or result in exceeding flood levels at Bonners Ferry, Idaho and Kootenay Lake, BC in many years. This alternative was dropped from further analysis.

Alternative 3b achieved the refill target date in 61 out of 70 water years (~87%). Inability to refill is primarily due to April flood control draft requirements combined with insufficient May-Jun inflows to refill by target refill date.