BC Hydro
Power smart

Fred James
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

October 4, 2017

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: Project No. 1598922
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Site C Inquiry – Round 2 Information Responses

As noted in the letter from Mr. Chris O'Riley of today's date, we are enclosing further responses to the questions set out in the Commission's Preliminary Report. The Commission asked that we endeavour to provide answers as they become available and we have been doing so. Enclosed with this letter are further responses. There remain some outstanding responses that will be provided in the next few days, as soon as we have them.

As noted in our previous IR submissions, our approach has been to number all of the requests in the Preliminary Report starting with BCUC IR 2.1.0 (representing the first question in the second round of questions the Commission has posed to BC Hydro). The number of responses enclosed with this letter are non-sequential, as we are providing responses as soon as they become available.

The responses to the following information requests are partially redacted for the reasons set out below. Unredacted versions have been filed with the Commission on a confidential basis:

- BCUC IR 2.8.0 – contains information that fits within Category B of the Commission's existing order regarding contract costs and budgets.
- BCUC IR 2.22.1 – contains information that fits within Category C of the Commission's existing order relating to load and business information of individual customers.
- BCUC IR 2.81.1 – contains information that fits within Category B of the Commission's existing order regarding suspension costs.

In the event the Commission requires clarification of any of these responses, we would be pleased to do that.

For further information, please contact Fred James at 604-623-4317 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

fj/af

Enclosure

1.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 15

2.1.0 the Panel asks BC Hydro to add a column to Table 6 of its submission (i.e. F1-1, p. 24) showing the PMB plan dates for each interim milestone and to comment on any material variances between the PMB plan dates and the actual completion dates.

RESPONSE:

Please refer to the updated Table 6 presented below, with the addition of a column showing the June 2016 Performance Measurement Baseline (PMB) dates for each interim milestone. Delays in milestones up to June 30, 2017 did not result in delays to the overall project schedule as either work being not on the critical path or any lost schedule was able to be subsequently recovered. Please refer to BC Hydro's response to BCUC IR 2.3.0 for a discussion of schedule impacts identified for work after June 30, 2017.

Description / Status	Final Investment Decision Plan Date	Performance Measurement Baseline Plan Date	Completed
Site Prep, North Bank Complete	February 2016	June 2016	October 2016
Peace River Temporary Bridge Complete	May 2016	March 2016	March 2016
Worker Accommodation – Phase 3	July 2016	August 2016	August 2016
Main Civil Works – Commence Mobilization to Site	September 2016	January 2016	March 2016
Main Civil Works – Commence North Bank Excavation	January 2017	April 2016	June 2016
Main Civil Works – South Bank Stage 1 Cofferdam Complete	May 2018	April 2017	April 2017
Main Civil Works – Powerhouse Excavation Complete	April 2018	April 2017	July 2017

Please refer to the discussion of schedule variances below.

<u>Variances (Actual to Performance Measurement Baseline Plan):</u>

Site Preparation, North Bank: Key scope for North (or Left) Bank Site Preparation included constructing approximately 7 km of access roads and excavation of approximately 1.5 million cubic metres of material. The North Bridge Approach was completed in February 2016 but displacements in the embankment foundation required slower placement of the embankment fill, delaying completion until October 2016. North Bank Road gully embankment construction commenced in February 2016. Installation of cross drainage (culverts) and lock block debris catches were required. Underlying embankment movement on River Road near

"Blind Corner" required stabilization. Delays in the completion of North Bank Site Preparation did not impact other subsequent schedule milestones.

Peace River Temporary Bridge: No Variance

Worker Accommodation – Phase 3: No Variance

Main Civil Works – Commence Mobilization to Site: The Main Civil Works contract was signed on December 18, 2015 and the contractor mobilized to site on March 22, 2016, approximately two months later than plan. Initial activities included establishing office facilities on the North (Left) Bank, preparations for the establishment of the roller-compacted concrete batch plant and geotechnical site investigations to assess the aggregate quality available for the planned roller-compacted concrete test pour. The two-month delay in mobilization had the following impacts on the commencement of construction by the Main Civil Works contractor:

- **Two-month delay in the start of Left Bank Excavation; and**
- **Two-month delay in the start of Right Bank activities, including Right Bank Drainage Tunnel, Right Bank Cofferdam, preparation of Relocated Surplus Excavated Material sites and the Right Bank Excavations.**

The Main Civil Works contractor and BC Hydro worked collaboratively to re-sequence planned work over fall and winter 2016 to ensure that key milestones were maintained.

Main Civil Works – Commence North Bank Excavation: The Main Civil Works component of North (Left) Bank Excavation (permanent work) commenced on June 10, 2016, approximately two months later than plan. The Main Civil Works contractor rescheduled the work on the Left Bank into two phases. As noted above, work was re-sequenced to ensure that key milestones were maintained.

Main Civil Works – South Bank Stage 1 Cofferdam: No variance.

Main Civil Works – Powerhouse Excavation: The Powerhouse excavation was completed several months behind schedule, due in part to a delay in mobilization to site and difficulties with preparing the final slopes to ensure worker safety and preserve the quality of the rock for roller compacted concrete placement. Refer to BC Hydro's response to BCUC IR 2.3.0 for a discussion of impacts of this delay following June 30, 2017.

2.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 15

2.2.0 The Panel asks BC Hydro to add two columns to Table D-3, one column for the planned percentage complete by June 30, 2017 according to the PMB schedule and one column for the planned percentage complete by June 30, 2017 according to the FID schedule. BC Hydro is to comment on any material variances between the planned and actual percentages complete.

RESPONSE:

Table D-3 has been amended to add two additional columns, as requested. It should be noted that the Final Investment Decision plan did not specify quantities by month, therefore the per cent complete has been identified based on the schedule milestone completion dates as:

(i) zero per cent (not expected to have started by June 30, 2017);

(ii) one hundred per cent (expected to have been completed by June 30, 2017); or

(iii) "In Progress" (expected that work would have commenced but not be completed at June 30, 2017).

					Complete (%)		
Dam Site Clearing		Unit	Contract Quantity	Complete to Date	Actual	PMB Plan to Date	FID Plan to Date
Left bank	Clearing and removal of merchantable timber	ha	218	218	100	100	100
	Construction and deactivation of access roads	km	8	8	100	100	100
Right Bank	Clearing	ha	622	622	100	100	100
	Construction and deactivation of access roads	km	30	30	100	100	100

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

Dam Site Clearing: No variances.

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

Dam Site Clearing: No variances.

					Complete (%)		
North Bank Site Preparation		Unit	Contract Quantity	Complete to Date	Actual	PMB Plan to Date	FID Plan to Date
Left Bank Excavation	Clearing and Grubbing	ha	15	15	100	100	100
	Excavation of topsoil, clay, silt, sand, gravel, boulders or loose rock, and weathered rocks from Left Bank Excavation area and placement in RSEM Area L3	m^3	1,534,873	1,534,873	100	100	100
Left Bank Road	Clearing and Grubbing	ha	2.5	2.5	100	100	100
	Construction of a permanent two-lane access road traversing the north bank	km	3.7	3.7	100	100	100
River Road	Clearing and Grubbing	ha	14.8	14.8	100	100	100
	Construction of a permanent two-lane road connecting Old Fort Road to the North Bridge Approach	km	3.7	3.7	100	100	100
North Bridge Approach	Construction of a temporary causeway connecting River Road to the Peace River Construction Bridge	m	250	250	100	100	100
Wuthrich Quarry Development	Clearing and Grubbing	ha	15	15	100	100	100
	Developed Wuthrich Quarry including soil excavation and stockpiling riprap		N/A	N/A	100	100	100

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

North Bank Site Preparation: No variances.

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

North Bank Site Preparation: No variances.

					Complete (%)		
Right Bank Site Preparation		Unit	Contract Quantity	Complete to Date	Actual	PMB Plan to Date	FID Plan to Date
Septimus Road	Construction of a permanent 4.3 km gravel access road on South Bank of dam site	km	4.3	4.3	100	100	100
Substation Pad & Associated Roads	Clearing and Grubbing	ha	26	26	100	100	100
	Construction of Substation Access Road - a permanent 1.2km road to access temporary Substation	km	1.2	1.2	100	100%	100
	Construction of South Bank Access Road - connecting Septimus Road on south bank of dam site	m	120	120	100	100	100
	Construction of Substation Pad		N/A	N/A	100	100	100
South Bank Initial Access Road	Construction of a temporary road providing access from the existing road to the South Bridge Approach	km	1.1	1.1	100	100	100
Septimus Rail Siding	Clearing and Grubbing	ha	53	53	100	100	100
	Construction of Temporary Fuel Siding		N/A	N/A	100	100	100
	Construction of Permanent Material Siding		N/A	N/A	100	100	100

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

Right Bank Site Preparation: No variances.

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

Right Bank Site Preparation: No variances.

					Complete (%)		
Peace River Construction Bridge		Unit	Contract Quantity	Complete to Date	Actual	PMB Plan to Date	FID Plan to Date
Design and Build Peace River Construction Bridge	Supply and Install 11.2 m wide steel girder bridge connecting both banks of Peace River	m	329	329	100	100	100
	Supply and Install abutments, barriers and all other associated components for the bridge		N/A	N/A	100	100	100

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

Peace River Construction Bridge: No variance – bridge construction completed on schedule.

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

Peace River Construction Bridge: No variance.

					Complete (%)		
Worker Accommodation		Unit	Contract Quantity	Complete to Date	Actual	Plan PMB to Date	Plan FID to Date
All Phases	Piles	ea	3,868	3,868	100	100	100
Phase 1	Dorm modules	ea	114	114	100	100	100
	BC Hydro Office modules	ea	24	24	100	100	100
Phase 2	Dorm modules	ea	351	351	100	100	100
	Core modules	ea	96	96	100	100	100
Phase 3	Dorm modules	ea	141	141	100	100	100
	Core modules	ea	34	34	100	100	100

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

Worker Accommodation: No variances

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

Worker Accommodation: No variances

					Complete (%)		
Offsite Public Roads Upgrades		Unit	Contract Quantity	Complete to Date	Actual	PMB Plan to Date	FID Plan to Date
240 Road	Embankment	m^3	6,020	6,020	100	100	100
	Excavation	m^3	5,400	5,400	100	100	100
	Paved	km	1.6	1.6	100	100	100
269 Road	Embankment	m^3	5,054	5,054	100	100	100
	Excavation	m^3	8,019	8,019	100	100	100
	Paved	km	0.9	0.9	100	100	100
271 Road (*)	Embankment	m^3	19,500	14,625	75	100	100
	Excavation	m^3	27,500	20,625	75	100	100
	Paved	km	3	-	0	100	100
Old Fort Road	Embankment	m^3	40,136	40,136	100	100	100
	Excavation	m^3	34,247	34,247	100	100	100
	Paved	km	5.2	5.2	100	100	100
(*) 271 Road to be completed in September 2017							

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

Offsite Public Roads Upgrades: Final Paving of 271 Road not completed, however as the road was still usable this did not impact other work.

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

Offsite Public Roads Upgrades: Final Paving of 271 Road not completed, however as the road was still usable this did not impact other work.

					Complete (%)		
Lower Reservoir Clearing		Unit	Contract Quantity	Complete to Date	Actual	PMB Plan to Date	FID Plan to Date
Lower Reservoir Clearing	Clearing and removal of merchantable timber	ha	217.5	214.0	98	100	100
	Construction and deactivation of access roads	km	9.2	9.2	100	100	100
	Supply, install and removal of temporary Moberly River Bridge		N/A	N/A	100	100	100
	Construction and deactivation of snow bridges	m	13	13	100	10	100

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

Lower Reservoir Clearing: The variance includes areas left uncleared due to active eagle nests, worker safety concerns, and riparian vegetation clearing restrictions. The schedule impact to other areas is minimal and work is planned to be completed in early 2018.

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

Lower Reservoir Clearing: See explanation above.

					Complete (%)		
Moberly River Clearing		Unit	Contract Quantity	Complete to Date	Actual	PMB Plan to Date	FID Plan to Date
Moberly River Clearing (Season 1)	Clearing and removal of merchantable timber	ha	100	77	77	100	100
	Construction and deactivation of access roads	m	5,149	5,149	100	100	100
	Construction and deactivation of ice bridges	m	276	276	100	100	100
	Disposal of non-merchantable timber	ha	123	-	0	0	0
Moberly River Clearing (Season 2 - not started)	Clearing and removal of merchantable timber	ha	150	-	0	0	0
	Construction and deactivation of access roads	m	TBD	-	0	0	0
	Construction and deactivation of ice bridges	m	TBD	-	0	0	0
	Disposal of non-merchantable timber	km	TBD	-	0	0	0

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

Moberly River Clearing: BC Hydro postponed the start of clearing of the Moberly River in response to First Nations concerns raised during an injunction application regarding a number of Site C permits. The variance also includes areas left uncleared due to slope stability concerns, worker safety concerns, and delays related to early onset of warm weather. The schedule impact on other scopes of work is minimal. The remaining work will be completed at the same time as the second season of Moberly clearing, currently planned for November 2018 through March 2019.

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

Moberly River Clearing: Refer to the explanation above.

					Complete (%)		
Eastern Reservoir Clearing		Unit	Contract Quantity	Complete to Date	Actual	PMB Plan to Date	FID Plan to Date
Eastern Reservoir Clearing (Right Bank East End)	Clearing and removal of merchantable timber	ha	17.4	8.4	48	10	100
	Construction and deactivation of access roads	km	2.0	1.5	73	7	In progress
	Wood Waste Disposal	ha	13.6	-	0		0
Eastern Reservoir Clearing (Right Bank Remaining)	Clearing and removal of merchantable timber	ha	375	-	0	0	0
	Construction and deactivation of access roads	km	TBD	-	0	0	0
	Disposal of non-merchantable timber	ha	TBD	-	0	0	0

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

Eastern Reservoir Clearing: The variance includes areas left uncleared due to slope stability concerns. The schedule impact to other areas is minimal. The remaining work will be completed as part of the helicopter clearing of South Bank Eastern Reservoir Clearing, planned for September 2018 through March 2019.

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

Eastern Reservoir Clearing: See above.

					Complete (%)		
Main Civil Works		Unit	Contract Quantity	Complete to Date	Actual	PMB Plan to Date	FID Plan to Date
Excavation	Left Bank	m^3	8,858,889	4,754,268	54	52	In progress
	Approach Channel	m^3	8,200,000	2,454,665	30	28	In progress
	Right Bank Powerhouse	m^3	845,000	738,488	87	100	0
	Right Bank Stilling Basin	m^3	347,844	347,844	100	100	n/a[1]
	Right Bank Spillway	m^3	1,242,156	265,531	21	2	0
	Right Bank Dam	m^3	544,000	381,653	70	0	0
Tunnels	Right Bank Drainage Tunnel	M	1,089	26	2	100	In progress
Cofferdams	Stage 1 Right Bank Cofferdam Slurry Wall	M	1,570	1,570	100	100	0
	Inlet Cofferdam Slurry Wall	m^2	5,755	470	8	100	100
Tension Crack, including mitigation	Left Bank Toe Buttresses	m^3	160,000	160,000	100	n/a	n/a

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

Excavation - Right Bank Powerhouse: Work was completed on target. The contract quantity was estimated higher than the actual quantity ultimately required. There is no impact on other scopes of work.

Excavation – Right Bank Spillway: Excavation commenced earlier than planned in order to increase Right Bank Powerhouse slope stability.

Excavation – Right Bank Dam: Excavation commenced earlier than planned in order to increase Right Bank Powerhouse slope stability.

Right Bank Drainage Tunnel: work on the Right Bank Drainage Tunnel has been delayed since February 2017 as the contractor's methodology for controlling silica on site didn't meet WorksafeBC's control requirements.

Cofferdams – Inlet Cofferdam Slurry Wall: Work on the Inlet Cofferdam Slurry Wall was delayed due to the left bank tension crack. The impact of the delays to the construction of the left bank cofferdam slurry walls has been minimal and has been offset by the delays to excavation of the left bank slope, Inlet and outlet portals..

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

Most of the Main Civil Works scope commenced significantly earlier than the FID plan contemplated.

[1] **The Stilling Basin work was included in the Spillway work in the FID plan.**

					Complete (%)		
Highway 29		Unit	Contract Quantity	Complete to Date	Actual	PMB Plan to Date	FID Plan to Date
Clearing and Grubbing	Cache Creek segment	ha	120	120	100	100	100

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

Clearing and Grubbing: No variance.

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

Clearing and Grubbing: No variance.

					Complete (%)		
Transmission		Unit	Contract Quantity	Complete to Date	Actual	PMB Plan to Date	FID Plan to Date
Clearing	East	ha	270	181	67	100	100
	West	ha	300	0	0	0	0

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

Transmission Clearing – East: Percentage complete is less than planned as the contract was awarded two months later than planned and the vendor experienced resourcing challenges. Clearing has been further delayed by BC Hydro commitments not to undertake clearing during this inquiry. If the clearing delay is not recovered there is potential impact to the start of the transmission line construction. BC Hydro is assessing options to recover the clearing schedule.

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

Transmission Clearing – East: Percentage complete is less than planned. See explanation of variance above.

3.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 15

2.3.0 The Panel asks BC Hydro to provide its current assessment of the probability that the project will achieve the river diversion in September 2019.

RESPONSE:

Following a meeting on September 27, 2017 between senior executives of BC Hydro and the Main Civil Works contractor, the parties determined that River Diversion is not achievable in 2019 and would be postponed until 2020. Further details are provided below.

In its August 30 Filing,[1] BC Hydro indicated that two tension cracks occurring in February and May of 2017 had placed pressure on the Left Bank schedule milestones leading up to the river diversion in 2019, and that we were working with the contractor to complete a constructability review to recover the schedule with the objective of achieving river diversion in 2019.

Prior to the start of Site C construction, extensive geotechnical studies were undertaken throughout the project area, including an analysis of slope stability. These studies confirmed that a large excavation on the steep Left Bank was required to remove unstable materials and flatten the slope for long-term stability. Slope stabilization activities include the construction of access roads and haul roads, excavation of unstable materials and relocation and storage of excavated materials for future use on other areas of the project.

Left bank temporary haul roads are required to be constructed across the slope on the north bank of the Peace River in order to complete excavations for the diversion inlet and outlet portals and the final design slope.

The February 2017 tension crack was remediated and the project was still on track to meet 2019 diversion. This event is currently the subject of a joint insurance claim by BC Hydro and the contractor, which if successful would mitigate some cost impacts.

A second tension crack occurred in May 2017. Work continued in the area until July 2017 when it was stopped by wet weather. BC Hydro and the contractor worked collaboratively to develop a solution to remediate the second tension crack and the contractor commenced these remediation efforts, but production through August and September was below plan.

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[1] **BC Hydro Submission to the British Columbia Utilities Commission, Inquiry into the Site C Clean Energy Project, page 37.**

The parties entered into a joint constructability review to work to develop construction options that would recover schedule and maintain the 2019 river diversion milestone. The constructability review identified options to maintain river diversion by 2019, but the parties were unable to reach agreement on the schedule, options and allocation of cost.

The parties are in dispute over the causes of the delays.

[redacted]

[redacted]

Independent of the constructability review with the contractor described above, discussions were held with the Site C Project's Technical Advisory Board over the period from July to September. The Technical Advisory Board was kept apprised of and provided feedback on the technical developments arising from excavation of the left bank and the inlet portal.

On September 27, 2017 a Joint Executive meeting between BC Hydro and the contractor was held, where the parties discussed the current challenges related to project progress, commercial issues and path forward to complete the project. At that meeting, the parties determined that river diversion is not achievable in 2019.

Although the parties are in dispute over the cause of some of the delays, BC Hydro proposed taking a lead in developing a response to address the challenges for construction to proceed. Such a response could include design modifications, changes to construction methodologies and development of shared metrics to track progress going forward. The parties have agreed to work together on this issue. In addition, BC Hydro has outlined steps to enable work to continue over the winter months.

The assessment of the cost of this change in scheduled date of River Diversion is presented in the response to BCUC IR 2.15.0.

4.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 15

2.4.0 The Panel asks BC Hydro to provide an update on its discussions with PRHP, and to explain in detail how the lost time on the main civil works schedule can be recovered.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.3.0.

6.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 22

2.6.0 the Panel asks BC Hydro to provide a point-in-time assessment of its progress to June 30, 2017 using the earned value method, including analysis of schedule variance, cost variance, schedule performance and cost performance as compared to both the FID and PMB plans.

RESPONSE:

Earned value methodology requires a project's work packages to be broken down to a sufficient level of detail for analysis. While BC Hydro can prepare an earned value analysis compared to PMB for major work packages, BC Hydro has not performed an earned value analysis compared to the FID baseline as it lacks sufficient level of detail to asses using earned value methodology.

Further excluded from the analysis are the scopes of work as follows:

(i) Where construction has not yet commenced (Transmission, Generating Station & Spillway, and Highways);

(ii) Level-of-Effort based work packages (e.g. indirect work packages) where earned value is of limited use;

(iii) Turbine & Generators as it is milestone based with no on-site activities completed; and

(iv) Reservoir Clearing as not enough work has been completed to accurately analyze using the earned value methodology.

In response to recommendation #3 in the 2016 Ernst & Young/BTY Cost and Risk Assessment, BC Hydro agreed to "implement Earned Value metrics on sub-projects: main civil works, generating station & spillway, transmission, and turbines & generators, as work commences". BC Hydro has been adapting the project schedule to enable earned value analysis and plans to commence reporting on earned value metrics in December 2017. We provide here a preliminary assessment of earned value to June 30 based on our earned value implementation work completed to date.

MAIN CIVIL WORKS – PMB EARNED VALUE ANALYSIS

BC Hydro analyzed the Main Civil Works work packages compared to the June 2016 PMB and provides the following analysis.

Component	PMB Planned Value ($ million)	PMB Actual Cost at June 30, 2017 ($ million)	PMB Earned Value ($ million)	Cost Performance Index	Schedule Performance Index
Main Civil Works	520.3	441.7	456.4	.98	.89

Main Civil Works PMB Earned Value Variance Explanations

The two most significant schedule performance variances are due to a difference between the planned expenditure profile and the actual work progress. The PMB budget planned for the Approach Channel excavation expenditures to be incurred between January 2016 and August and the Left Bank Excavation expenditures to be incurred between April 2016 and May 2017. Subsequent to the June 2016 PMB, the scope of work was further elaborated and re-sequenced indicating a different work progress profile, impacting the schedule performance.

EARLY WORKS – COST VARIANCE

BC Hydro assessed the cost performance of Early Works compared to the FID and PMB plans based on plan versus actual cost, including draws on contingency, rather than by earned value analysis as the work is complete.

FID Budget ($ million)	PMB Budget ($ million)	LTD Actual Costs as at June 30, 2017 ($ million)	Variance PMB – Life To Date Actual to June 30, 2017 ($ million)	Variance FID – Life To Date Actual to June 30, 2017 ($ million)
187.4	170.7	174.6	(3.9)	12.0

PMB Cost Variance Explanation

- **The Early Works PMB scope included excavation activities on the North Bank. Costs increases are attributed to additional work required to address slope stability issues on the North Bank Road Gully and to address increased requirements for erosion control, instrumentation and additional excavation. Additional costs were also incurred as a result of the protest activity at Rocky Mountain Fort which delayed clearing efforts.**

FID Cost Variance Explanation

- **Portions of the FID budget for Early Works were reallocated to Main Civil Works and Transmission work packages to reflect changes in the planned delivery of the scope resulting in a positive variance for Early Works compared to the FID budget.**

8.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 33

2.8.0 the Panel asks BC Hydro to provide a detailed breakdown and justification of its $630 million estimate.

RESPONSE:

The estimate of $630 million was published on June 7, 2017 as part of a Technical Briefing reviewing issues related to Highway 29 construction activities.

The estimate of $630 million was based on a delay related only to Highway 29 construction activities, requiring postponement of river diversion from September 2019 to September 2020 (shifting the final unit in-service date from November 2023 to November 2024). The estimate was specific to these circumstances, and costs of delay may be different if delay is a result of different circumstances. For clarity, this assessment assumed that BC Hydro was responsible for the delay to the diversion date. If the delay was a result of contractor performance, BC Hydro may have contractual remedies that may reduce the costs of delay to ratepayers from those estimated here.

The table below shows the composition of BC Hydro's $630 million estimate of delay.

Description	Explanation	Amount ($ million)
Ongoing project costs	Estimated incremental costs to maintain project team for 12 month delay period	95
Site and environmental maintenance	Estimated incremental site and environmental maintenance costs to be incurred during 12 month delay period	10
Main Civil Works	Demobilization for delay period. Additional overheads for period of delay Re-mobilization following delay period.	120
Turbines & Generators	Storage of components and equipment for period of delay	25
Generating Station & Spillways	Increase in bid costs as a result of procurement uncertainty and late-process changes.	60
Worker Accommodation	Fixed worker accommodation costs for 12 month delay period	15
Total Direct Costs		**325**
Inflation	Increase in nominal dollar cost of expenditures incurred after 2019 due to inflation increases	105
Interest During Construction	Increase in finance carrying charges due to increased project duration	200
Total Cost of Delay		**630**

Key Assumptions:

- **Twelve Month-delay results from delay in river diversion (i.e., from September 2019 to September 2020) due to delay in Highway 29 relocation construction without mitigation of impact on construction critical path;**

- **Other construction activities continue, where possible, to minimize potential delay claims. There are no delays in construction activities not tied to river diversion;**

- **Direct Contract Costs:**

    - **Main Civil Works: Additional 12 months of overhead required; construction activities will cease for a period of time, requiring demobilization and remobilization payments.** [redacted]

    - **Turbines & Generators: 12 months of storage required for turbines & generators and related equipment.** [redacted]

    - **Generating Station & Spillways:** [redacted]

    - **Worker Accommodation: Additional 12 months of fixed costs, calculated as per contract.**

- **Inflation: Calculated at 2 per cent, applied to all expenditures post September 2019, arising from 12-month delay in expenditures; and**

- **Interest-During-Construction: Increased costs due to 12 month delay to asset in-service dates, with no delay in the timing of major construction activities other than those with schedules dependent on Highway 29 realignment. Interest costs were estimated at BC Hydro's forecast weighted average cost of debt (between 3.4 and 3.9 per cent per annum, depending upon the fiscal year).**

13.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 33

2.13.0 The Panel asks BC Hydro provide an updated version of table D-4 in appendix D of their submission, adding a quantification of the budget impact for each risk identified in the table, should the risk come to pass. This analysis should be consistent with section 4(v) of the Commission's 2015 CPCN Guidelines.

RESPONSE:

The Commission's 2015 CPCN Guidelines are as follows (section 4(v)):

> **Risk analysis identifying all significant risks to successful completion of the project, including an assessment of the probability of each risk occurring and the consequences and the cost to mitigate the risk. The applicant should provide a summary description of significant project risks, including an assessment of the impact of each risk, the proposed risk mitigation strategy, and to the extent known, the financial and schedule impacts if the risk is realized. The risk evaluation should incorporate a risk assessment matrix with appropriate levels of severity and probability, a risk register and risk treatment as recommended in the latest revision of AACE International Recommended Practices.**

Site C risk management practices follow BC Hydro's standard practices. This includes the use of a risk register to track and manage risks and utilizes a risk assessment matrix in preparation of a risk register. For each risk identified, there is an assessment of the impact of the risk (severity), the probability of its occurrence, the risk mitigation approach or treatment plan, and monitoring activities to be conducted until the risk is closed.

Below is Table D-4 from Appendix D of the submission, presenting the material project risks, updated to reflect any changes in risk assessment since the filing of the application, with the addition of columns quantifying the risk based on BC Hydro's Risk Management practices.

The risk quantification follows the BC Hydro Project Delivery Risk Matrix (Table 2) included at the end of this response. The risk severity and probability are quantified by select the applicable range based on the risk consequence type resulting in the final risk score (5 - 13).

Table D-4 Material Project Risks and Response

		Quantification		
Risk Event/ Description	Risk and Response Summary	Severity Impact	Probability of Risk Occurring (%)	Risk Level
Delay to Permitting	Permits and licences are still required for several portions of construction activity. Delays to these permits and licences could result in delays to the associated construction work. BC Hydro is proactively working with contractors, federal and provincial authorities, and First Nations to mitigate this risk.	$10 million - $100 million	10	10
Environmental Requirements	The Project must comply with the requirements of the Environmental Assessment Certificate (Provincial) and the Federal Decision Statement as well as conditions in licenses, permits and authorizations. All Contractors on the Project have experienced difficulties in adapting their construction methodologies to achieve the Project's environmental commitments. To address this, BC Hydro has added additional environmental specialists and is working with the Contractors to implement solutions that meet regulators' expectations.	$10 million - $100 million	30	10.5

		Quantification		
Challenges to Project Approvals	There are two outstanding challenges of Project permits/approvals: (i) An appeal of one of the Conditional Water Licences before the Environmental Appeal Board; that appeal is proceeding in writing and dates have not been set; (ii) An appeal of the dismissal of the judicial review of 36 provincial permits. The appellants (two First Nations) are not actively pursuing the appeal and will require a court order to proceed. BC Hydro has agreements in place with six First Nations, who have indicated they do not oppose or object to the Project. These agreements provide First Nations with Project benefits and mitigate the risk of legal challenges. In the absence of agreements with all of the identified potentially affected First Nations, there remains risk of challenges to authorizations issued for the Project. We are continuing to negotiate agreements with several First Nations. The status of some specific negotiations is confidential at this time.	$10 million - $100 million	1	9
Other Litigation	There remains a risk that litigation could be initiated with respect to construction matters.	$1 million - $10 million	10	9
Market response to procurement	BC Hydro has received positive and competitive market responses in major contract procurements to date. Market response risks will continue to be monitored. Risk remains for major procurements in progress, including generating station and spillway, transmission and Highway 29.	$10 million - $100 million	10	10

		Quantification		
Labour Relations & Stability	Due to multiple employers at site with different union affiliations there is a risk of site labour disruption that could result in issues. BC Hydro is using an inclusive labour approach with a managed open site that allows for participation by all union and non-union labour groups and allows access to the largest pool of skilled and experienced labour. All major contracts contain no strike, no lockout, and no raiding provisions. In addition, BC Hydro has implemented a site wide Labour Relations Contractor Committee to support labour stability on the site.	$1 million - $10 million	30	9.5
Geotechnical risks	Changes to geotechnical ground conditions remain a risk impacting the schedule and cost. There have been extensive geotechnical studies over many years. Construction plans have been developed to mitigate these impacts, for example, the Left Bank slope is being excavated to remove known historical instability. There is a risk that during construction, instability in the Left Bank causes temporary stoppages to the work while the slope is being remediated. Further mitigation has been achieved by transferring some degree of ground condition risk to the contractor, such as including conducting field-scale trials and applying additional monitoring to determine the response when shale bedrock is exposed to the elements.	$10 million - $100 million	10	10
Construction cost – labour	Potential cost increases could arise if there is competition with other projects for labour resources, labour instability, or changing workforce demographics. Based on current market conditions in the infrastructure and energy sector, the labour risk is low; however, the recent federal announcement of pipeline projects could impact labour prices and availability of skilled labour. There remains the potential for market labour conditions to shift in the future and if so this risk may increase.	$10 million - $100 million	10	10

		Quantification		
Construction cost – commodities and equipment	Construction commodity and equipment cost risks have declined slightly over the past year and Canadian exports are down. Key commodities such as steel, diesel and gasoline are below BC Hydro's forecast when preparing the original cost estimate. Diesel and gasoline rack pricing are currently slightly below the baseline rate established for fuel escalation in the Main Civil Works contract, although underlying oil prices rose during the 2016 calendar year. There remains an external risk of higher-than-expected commodity costs, and specifically steel, due to a material change in market conditions or changes to North American Free Trade Agreement that may impact Site C contracts not awarded that include commodities.	$10 million - $100 million	10	10
Construction execution	The Main Civil Works contractor has experienced delays on several of their critical path activities, requiring a re-sequencing of planned work. Refer to section 4.3 of the Application for further details.	$10 million - $100 million	30	10.5

		Quantification		
Foreign exchange	Some of Site C project costs are in foreign currency, and will be affected by fluctuations in the exchange rate between the Canadian Dollar and these foreign currencies. Approximately 20 per cent of the Site C direct construction costs are based on foreign currency. The Canadian dollar has weakened significantly compared to the U.S. dollar since the 2014 capital cost estimate was developed. However, the award of major contracts (particularly the Turbine Generator contract) has reduced BC Hydro's exposure to currency fluctuations by transferring the risk to the contractor after award. The impact on future procurements may be larger than BC Hydro has seen to date, depending on future movement in foreign exchange markets, future movement in commodity and equipment markets, and the ability of the proponents to source from a range of foreign markets. Residual risk on contracts yet to be procured is partially mitigated through contractor flexibility around sourcing of material, resulting in an exposure to a basket of currencies, rather than solely the U.S. dollar.	$10 million - $100 million	1	9
Interest rate variability	Interest during construction costs will be affected by fluctuations in market interest rates. Currently, market interest rates are expected to be lower than assumed in BC Hydro's budget at the Final Investment Decision. BC Hydro has reduced its exposure to variable rate debt and increased its exposure to fixed rate debt. In March 2016, the British Columbia Utilities Commission approved a Debt Hedging Regulatory Account for BC Hydro to capture the gains and losses related to the hedging of future debt issuance. BC Hydro has hedged 50% of its forecast future debt issuances from fiscal 2017 to fiscal 2024 through the use of derivative contracts.	$100 million - $1 billion	1	10

		Quantification		
Change in Tax Rates	There is the potential for a change in tax rates that apply to Site C (e.g., PST, carbon tax) as well as the potential for a portion of GST to be unrecoverable. BC Hydro is monitoring potential changes to federal and provincial taxes and their potential effects. Where appropriate, BC Hydro will secure advance rulings on tax applicability to reduce uncertainty in treatment.	$10 million - $100 million	1	9

Table 2 BC Hydro Project Delivery Risk Matrix

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PROBABILITY OF CONSEQUENCE (Duration of Project through implementation)			BC Hydro PROJECT DELIVERY Risk Matrix					
60%	Likely More than even chance to occur	L7	8	9	10	11	12	13
30%	Fairly Likely Often occurs	L6.5	7.5	8.5	9.5	10.5	11.5	12.5
10%	Possible Could well occur	L6	7.0	8.0	9.0	10.0	11.0	12.0
1%	Remote May occur	L5	4	5	6	9	10	11
0.1%	Very Unlikely Not expected to occur	L4	5	6	7	8	9	10
CONSEQUENCE TYPE			CONSEQUENCE SEVERITY					
			S1	S2	S3	S4	S5	S6
Safety		Worker	First Aid	Treatment by Medical Professional	Temporary Disability	Permanent Disability	Fatality	Multiple Fatalities
		Public	Near Miss	First Aid	Treatment by Medical Professional	Temporary Disability	Permanent Disability	Fatality
Environmental			Minor	Low	Moderate	High	Extreme	Catastrophic
Financial Loss			$10K to $100K	$100K to $1M	$1M to $10M	$10M to $100M	$100M to $1B	$1B to $10B
Reputational			Limited complaints to company or shareholder	Negative local profile	Small but vocal minority of customers critical	Many customers critical	Loss of trust- strategic change imposed by regulator and/or shareholder	Loss of consent to operate
Reliability		Supply	N/A	N/A	Require voluntary load reduction	Localized load shedding	Significant load shedding required	BC load shedding spreads to WECC
		Customer (hours lost per event)	< 5K	5K to 50K	50K to 500K	500K to 5M	5M to 50M	50M to 500M

Project Risk Zone	Risk Communication Guidelines
	Detailed analysis and discussion at project VP level, with engagement of business group EVP or SVP. Input from Executive Team generally should be sought.
	Analysis and discussion between Portfolio Manager, Project Manager, and Initiator about the risks and appropriate courses of action.
	Risk generally analysed and discussed with PM at project team level. Safety risks should be reviewed with the Project Initiator.

Purpose of the Project Delivery Risk Matrix

1. To provide a standard representation of the results of risk analyses for use in the evaluation and communication of project delivery risks.

2. As a risk governance tool. The Project Risk Zone relates to the level of management oversight to aid in decision-making.

3. Not used to describe risk tolerance.

4. A comparison of differing risks may also be conducted based on the Risk Levels.

To use the Risk Matrix

1. Select the Consequence Type.

2. Select the highest appropriate Consequence Severity.

3. Select the Probability level of the Consequence Type and Severity.

4. Plot the Consequence severity and Probability level pair to determine the Risk Level and associated Project Risk Zone.

5. Based on the Project Risk Zone, review Risk Communication Guidelines to determine action.

NOTE: The rigour of analysis in analyzing consequence and frequency should be commensurate with the Project Risk Zone. This may be an iterative process.

This Project Delivery Risk Matrix is aligned to the Corporate Risk Matrix.

15.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 34

2.15.0 the Panel asks BC Hydro to comment on the likelihood of each of the three outcomes listed by Deloitte.

RESPONSE:

For reference, the three scenarios referenced by the Commission that Deloitte[1] developed are as follows:

Impact	Schedule (In Service Date)	Cost Impact to FID Budget ($8.335 billion)		Final Cost Range at Completion ($ million)	
		Low	High	Low	High
Low	On time (2024), cost pressures of 0% - 10%	0%	10%	$8,335	$9,169
Moderate	One year delay (2025) or cost pressures of an additional 10%-20%	10%	20%	$9,169	$10,002
High	More than one year delay or cost pressures of an more than 20%	20%	50%	$10,002	$12,503

From a schedule perspective, there is a high probability that the project will be completed on time, with the last generating unit to be placed into service by November 2024.

From a cost perspective, there is a reasonable probability that the total project cost will be in either the "Low" or "Moderate" range identified in the table above.

This assessment can be further refined once the outstanding major procurements for Generating Station & Spillway, Transmission and Highways have been completed, as these are the most significant cost pressures still to be resolved.

<u>Schedule</u>

Despite missing the 2019 diversion window as referenced in BC Hydro's response to BCUC IR 2.3.0, BC Hydro remains on track to achieve the 2024 in-service date by applying the one year of float held by BC Hydro to the activities associated with River Diversion.

[1] **Deloitte Report #1, page 2.**

As part of the Generating Station & Spillway - Civil contract procurement process, BC Hydro is now revising the project schedule to reflect a plan for River Diversion in 2020.

Most of the key infrastructure is in place for the project to achieve the 2024 in-service date:

- **The right bank coffer dam is completed and performing according to expectations;**
- **The left bank coffer dams are substantially complete with no major issues identified;**
- **All the key batching, crushing and washing equipment is in place and placement of Roller Compacted Concrete is underway by the Main Civil Works contractor;**
- **All of the road access and laydown areas are substantially complete on the right bank. Work on Relocated Surplus Excavation Materials Area R6 is scheduled to be completed by December 2017; and**
- **The powerhouse buttress is scheduled to be completed by summer 2018 to allow the Generating Station and Spillway contractor to mobilize and start construction of Generating Unit 1 in September 2018.**

BC Hydro has an advanced design for the main civil works, and the risk of delay due to design changes or incomplete design is low.

The remaining geotechnical risk going forward for surface works has been significantly reduced, as the majority of the work zones at the dam site have been developed and largely excavated. The ground conditions are now known.

While BC Hydro has had complications (tension cracks) with the left abutment excavations, these issues are well understood and the engineering team is working with the Main Civil Works contractor to develop a schedule to meet river diversion in 2020. Please refer to the response to BCUC IR 2.3.0 for additional information.

<u>Cost</u>

In the response to BCUC IR 2.8.0, BC Hydro indicated that postponement of river diversion from September 2019 to September 2020 would cost approximately $630 million.

The table below compares BC Hydro's estimate of the cost impacts of postponing River Diversion to 2020, as described in the response to BCUC IR 2.3.0 ("Current") with the estimate provided in the response to BCUC IR 2.8.0:

Description	Explanation	Amount ($ million)	
		Current	**IR 2.8.0**
Ongoing project costs	Incremental indirect costs	[redacted]	[redacted]
Site and environmental maintenance	Incremental site and environmental maintenance costs	[redacted]	[redacted]
Main Civil Works	Incremental costs	[redacted]	[redacted]
Turbines & Generators	Storage of components and equipment	[redacted]	[redacted]
Generating Station & Spillways	Incremental costs (primarily inflation)	[redacted]	[redacted]
Worker Accommodation	Fixed worker accommodation costs	[redacted]	[redacted]
Total Direct Costs		**$397**	**$325**
Inflation	Increase in nominal dollar cost of expenditures incurred after 2019 due to inflation increases	Included above	105
Interest During Construction	Increase in finance carrying charges	162	200
Contingency	Increase in contingency	51	-
Total Cost of Postponing River Diversion to 2020		**$610**	**$630**

Using the estimate of $610 million above, the Site C Project budget would be increased by 7.3 per cent from $8.335 billion to $8.945 billion. This revised budget remains within Deloitte "Low" scenario (0 per cent to 10 per cent) as presented above.

Additional cost risk remains with the project, even with this higher total budget value, including the following:

- **Large procurements not yet completed such as the Generating Station & Spillway, which may be impacted by the change in the project schedule. Please see the response to BCUC IR 2.10.0 for additional details; and**

- **Potential changes to the Highway 29 design due to geotechnical conditions. Please see the response to BCUC IR 2.14.0 for additional details.**

<u>Assessment of Other Scenarios</u>

We assess the potential for a "Moderate" impact scenario (using Deloitte's characterization) as possible. The Moderate scenario could occur due to an additional one year delay from BC Hydro's current expectations, or would result

from a major risk materializing with respect to works not yet under construction. The following events, were they to materialize, may present a risk of the Moderate scenario materializing:

- **Gross underperformance or a total default by the Main Civil Works contractor;**
- **A prolonged period of uncertainty in the project schedule and whether it will proceed, during which BC Hydro is unable to progress its procurement contracts and/or continue site construction;**
- **New, unforeseen regulations that require major redesign and/or substantial changes to the means and methods of construction;**
- **A resurgence of the oil sands developments, and/or shale gas drilling in the Peace region, causing significant resource shortages;**
- **Gross underperformance or a total default by the not yet selected Generating Station & Spillway - Civil contractor;**
- **Geotechnical conditions varying greatly from what they are anticipated to be, requiring a complete redesign of the diversion tunnels; and**
- **Major shortages of aggregate or till material, or serious deficiencies in the quality of aggregate material used for concrete such that placed material is incapable of meeting the project specifications.**

In BC Hydro's opinion, a "High" impact scenario (using Deloitte's characterization) has a very low likelihood of occurring, as this would represent a two or more year delay against BC Hydro's currently expected schedule, or a combination of a number of the major risk factors above materializing.

20.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 66

2.20.0 The Panel requests that BC Hydro (and any other parties) specifically address:

The Panel requests that BC Hydro (and any other parties) specifically address:

- The downside risk of a lower load forecast over a 70 year time horizon;
- How this risk could be mitigated (for example, policy changes to encourage electrification, sale of surplus energy to other markets); and
- To what extent the risk of a lower load forecast over a 70 year time horizon should result in a preference (all else equal) for a portfolio with smaller sized generation/demand components.

RESPONSE:

BC Hydro does not agree that it has only identified upside risks to the load forecast and has not identified any downside risks. BC Hydro does not produce a point load forecast, but rather provides a range within which the mid-forecast is an unbiased mid-point expectation. BC Hydro's August 30 Filing shows this range and discusses the drivers of the normal band of load forecast uncertainty both upside and down as follows:

- **The current load forecast is shown in section 5.2 Figures 9 and 10 and again in the net load resource balance as shown in section 5.3 Figures 13 and 14.**
- **BC Hydro discusses the factors that drive the load forecast and the load forecast range in section 5.2.2.**
- **Further explicit details of the factors and the directions that they are trending are provided in Appendix J.**

In addition, BC Hydro has undertaken analysis to demonstrate the impacts on the economics of portfolios with and without Site C including the high and low gaps as shown in section 8. The high and low gaps are substantial uncertainty bands representing the upside and downside risks to resource requirements.

BC Hydro views the current global focus on fighting climate change and working to reduce GHGs as a potential paradigm shift. It is outside of the ordinary range of load growth that would be expected to happen as normal economics are shifted towards meeting environmental goals. An example is the City of Vancouver's

Renewable City Strategy (RCS) that sets a goal of meeting all of the city's energy needs from renewable resources by 2050 (http://vancouver.ca/files/cov/renewable-city-strategy-booklet-2015.pdf). BC Hydro has recently carried out a joint study with the City of Vancouver to examine the electricity demand impacts of the RCS. Results indicate that net electricity demand after efficiency measures would almost double by 2050. Given the unusual nature of the electrification potential, BC Hydro has not included this within the normal uncertainty band but has treated it as an additional aspect that needs to be considered and has undertaken the development of future scenarios to help understand possible futures. These are further discussed below.

The information request asks BC Hydro to address the downside risk of lower demand over a 70-year time horizon and strategies to mitigate this risk. Risk is a function of both uncertainty and consequence. The response is broken into three discrete sections that will look at:

1 Uncertainty around the load forecast over 70 years; then

2 Risk mitigation strategies and their consequence with Site C as part of the overall portfolio; and

3 Risk mitigation strategies and their consequences if Site C is replaced by "smaller sized generation …. components".

<u>Downside demand uncertainty over 70 years</u>

While BC Hydro has not developed load forecasts over a seventy year period, it has started its own analysis on long term planning scenarios for its next Integrated Resource Plan covering timeframes up to 2050. These scenarios are in the preliminary stages of development and are only in the early stages of being tested with stakeholders and intervenors. The details of these scenarios are evolving, but a general description of them is as follows:

- **Borders Rising – stagnant economic performance globally is accompanied by rising trade protectionism. There is an increasing distrust of government entities as a solution to social problems, and reduced commitment to efforts to combat climate change. Society focuses less on broad social issues and hunkers down to deal with more local and personal issues. Short-term and low-cost solutions such as coal and natural gas for electricity and gasoline for transportation persist.**

- **Last Resort – A lack of progress on the side of renewable energy technologies and storage, combined with a rising determination to combat climate change leads to the adoption of large scale, centrally controlled clean technologies such as nuclear. Electrification of the transportation sector is widespread. Coal and baseload natural gas are phased out.**

- **Great Expectations – Widespread economic growth and a broad desire to meet GHG reduction targets meets with a lack of coordination amongst political entities regarding a common approach to reduce GHGs. Local (e.g., state, provincial) efforts to reduce GHGs prevail, leading to balkanized policies and standards. Electrification of transportation sector widespread and coal is phased out as natural gas forms a bridge technology to a reduced carbon future that meets current GHG reduction commitments.**

- **Integrated Markets – Widespread economic growth and a broad drive to meet current GHG reduction targets is matched with a trans-continental approach to matching clean and low cost energy suppliers with demand. Jurisdictional and technological transformations allow the continent to act as an integrated and efficient grid allowing supply clusters to be built in the lowest cost locations, to be aggregated across diverse areas to serve distant loads.**

- **Tech Transforms – Massive leaps in technological innovation drive huge gains in energy efficiency. Distributed generation and storage and a decrease in trust of public intuitions such as governments and utilities lead to widespread adoption of Distributed Energy Resources (DERs). While carbon pricing policy features in government policy, natural conservation and electrification of transportation means that the attainment of current GHG reduction targets is more technology-driven than pushed through policy levers.**

It is important to note that these are scenarios, not forecasts. In keeping with a common approach to scenario creation, BC Hydro will not be applying probabilities to these scenarios. The High and Low bands used in BC Hydro's 20-year forecast contain the fundamentals of some of these trends, and the current load forecasting process is structured in such a way that it is appropriate to establish probabilities around this range of uncertainty. Pushing beyond the 20-year horizon widens the number of "unknown unknowns" almost exponentially.

BC Hydro is working with consultants from the firm IHS to translate these high level themes into specific IRP-relevant details such as load growth paths and market prices over time. A preliminary qualitative assessment would suggest that some scenarios (Integrated Markets, Last Resort) could see a large increase in demand for BC's clean resources and a premium put on a product that is flexible and dispatchable as intermittent energy displaces coal and baseload gas. Other scenarios (Tech Transforms, Borders Rising) see lower growth rates, decreasing market demand for clean resources, and perhaps even a shuttering of borders to trade in goods and electricity.

As BC Hydro's work is in progress, BC Hydro provides here an overview of insights BC Hydro has gathered in surveying others' scenario work in this area[1]. In particular, there are several common themes emerging in the energy planning context that could result in future loads falling above or below current expectations for the future. In response to the Commission's request we highlight here some of these themes that have the potential to reduce load for BC Hydro over the longer term:

1. **Long term economic stagnation depresses load growth – there are a number of factors which may make economic growth and load growth diverge. However, most scenario work posits that a permanent shift to lower economic growth will tend to drag down electricity load growth.**

2. **A deindustrialization trend that pulls industrial load growth below expected levels – this can be tied to electricity rates, but can also be driven by other comparative cost factors between B.C. and its trade competitors such as government policy, technological productivity, resource availability, currency levels and openness to trade.**

   While this trend is prevalent in high manufacturing jurisdictions, the natural resource base of B.C.'s industrial sector is likely to temper this negative pressure. It is possible that a region's manufacturing sector hollowed out and moved to another location. However, the non-mobile nature of B.C.'s natural resources and the fundamental importance of forestry, mining, and natural gas to any future scenario would limit the impact of this downward trend somewhat for B.C.;

3. **Natural conservation of energy driven by technological advances – advances in energy efficiency in terms of lighting, electric motors, and customers' choices of end use products could drive future use at the residential and consumer level far below the expected growth levels; and**

4. **Distributed Energy Resources (DERs) remove load from BC Hydro's load resource balance – many energy scenarios extrapolate the trend of decreasing solar PV costs, decreasing wind power costs, and improving battery technologies to envisage an era where reducing reliance on BC Hydro, either partially or totally, becomes a cost effective strategy for individual customers or collections of customers (perhaps, in new**

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[1] **GE's 2017 Top Digital Trends for the Electricity Value Network (https://www.ge.com/digital/sites/default/files/Top-10-Digital-Trends-for-the-Electricity-Value-Network.pdf); 2016 Standard Scenarios Report from NREL (National Renewable Energy Laboratory); WECC 2013 (http://www.wecc.biz/committees/BOD/TEPPC/External/WECC_Scenarios.docx); UK National Grid.**

developments or concentrated urban locations). While this does not decrease electricity demand directly, it does remove that demand from the utility's load, and thus acts like a drop in demand from the utility's perspective.

To summarize, there are a number of future scenarios that could pull long term load growth off of its forecast trajectory. BC Hydro has identified some positive scenarios (such as electrification) in its August 30 Filing, and has provided additional information on negative scenarios above. If some negative trends emerge that depress electricity growth rates for the long term, then BC Hydro will mitigate these impacts given its current and predicted load resource balance and forecast future resource additions.

<u>Low growth risk mitigation strategies with Site C as an existing resource, and their consequences</u>

Site C is scheduled to come into service in fiscal 2024, delivering 5,286 GWh of firm energy and 1,132 MW of capacity. In order to meet B.C.'s Clean Energy Objectives of self-sufficiency, the project is built in advance of need for energy and capacity (except for a temporary market reliance of 300 MW). This results in a market surplus of energy, even for the mid level of load growth.

In early years, scenarios with long-term low load growth will be consistent with the Low load growth scenario already modelled by BC Hydro in previous submissions. If load continues to be below expected forecast levels and there is a surplus of energy for an extended period of time for decades into the future, then BC Hydro has a number of ways to mitigate these impacts on its ratepayers:

1. **Increased focus on load attraction and retention for the duration of the surplus. This strategy cuts across all drivers of downside uncertainty, but is particularly effective when targeting the loss of industrial load. To some extent, there is a natural hedge existing around the fossil fuel portion (i.e., Oil and Gas sector) of this industrial load;**

    a. **A world where fossil fuel use is severely curtailed in an effort to reduce GHG emissions would likely rely on natural gas as a bridge fuel in the transition period, and would also be favourable to a new source of clean, flexible energy provided by Site C; moreover**

    b. **A world where natural gas is still in demand means that a significant portion of BC Hydro's industrial load remains intact.**

2. **Incenting electrification (electric vehicles, fuel switching);**

3. **Sell surplus into export market. BC Hydro has provided evidence that the power from Site C, even when it is surplus to B.C. system needs, can be**

sold for prices above remaining uncommitted costs in the export market. Refer to Appendices F and S to BC Hydro's August 30 Filing; and

4. **Changes to rate structures to better capture the value provided by domestic supply flexibility. This is of use, for example, in a future where uptake of DERs is accelerated due to a mismatch between rate policy and the underlying valuation of the services BC Hydro offers.**

<u>Low growth risk mitigation strategies having cancelled Site C in favour of a portfolio with small clean resources</u>

The IR asks, in part, to imagine a future where "smaller sized …. demand components" are used in lieu of Site C. With or without Site C, DSM will be built out when cost effective opportunities arise. This response will focus on comparing a possible energy surplus from a portfolio with Site C against an energy surplus from a portfolio with smaller energy resources.

A future BC Hydro portfolio with "smaller sized generation …. components" in lieu of Site C requires some assumptions about how this portfolio is to be acquired.

- **In particular, in order to adequately isolate the value of acquisition flexibility it is assumed that this alternative portfolio could meet system needs (for a capacity shortfall in fiscal 2023 and an energy shortfall in 2028) if demand is there.**

- **It is also assumed that this acquisition of small, clean resources could be staged in a flexible enough way that some of this could be delayed if adequate load growth does not materialize and could be timed in such a way that the results still meet the *Clean Energy Act*'s self-sufficiency requirements for energy and capacity (allowing for a temporary market reliance of up to 300 MW as per BC Hydro's current base resource plan).**

Both of these assumptions are uncertain – acquiring sufficient clean capacity resources to meet the anticipated capacity shortfall in F2023 may be challenging, and BC Hydro's experience with previous calls for IPP power is that they are less flexible than contemplated here. Refer to BC Hydro's response to BCUC IR 2.50.1.

Table 35 (Mid Load Forecast with IRP DSM Plan, Site C Terminated) in the BC Hydro submission shows how capacity needs would be met in a world without Site C, planning for a future that matches the expected load growth. This view can be split into capacity and energy views and described separately.

From a capacity perspective, 1,000 MW of capacity (anticipated to be pumped storage) will be required early in the planning period, as shown in Table 35. This capacity need is near enough in the planning horizon that, if Site C is terminated, acquisition activities for this level of capacity would need to be started

immediately, and even then may not be able to deliver this capacity in time – pumped storage is estimated to take approximately eight to ten years to permit and construct. Given the short time available before capacity is needed, this capacity acquisition would need to be undertaken regardless of which future load scenario prevails. Thus, any flexible acquisition of smaller sized generation components would have to include 1,000 MW of capacity (currently expected to be pumped storage) and will need to consider attrition and delivery risk, regardless of the subsequent load growth.

From an energy perspective, Table 35 shows that preparing for the expected level of load growth means preparing to acquire roughly 2,800 GWh of energy by 2030. It is possible that the ability to stage energy resources will provide additional flexibility to match resources to load. However, there are two considerations with respect to this possibility:

- **<u>Long Lead Times</u>: A typical energy acquisition takes about eight years from the start of design to the point where about half of the projects have reached COD. Thus BC Hydro will encounter uncertainty in load growth and other drivers to the LRB over this time period.**

- **<u>Volume Requirements</u>: In acquiring resources from IPPs, there is an inherent trade-off between acquiring small volumes continually versus achieving low cost resources. BC Hydro is currently acquiring 150 GWh/year through the standing offer program at prices above $100/MWh. This energy may be more cost-effectively acquired through a larger, competitive call process to ensure that sufficient cost effective resources are acquired (however, there would be drawbacks in terms of ability to support communities and First Nations initiatives in this manner).**

  Past practice for BC Hydro, in an effort to establish an effective IPP community, was to hold acquisitions for significant volumes of power. By announcing the intention to acquire an adequate volume of resources, many proponents were drawn to the province and did a lot of exploration and development work in hopes of earning an EPA. BC Hydro's two open calls, the 2006 CFT and 2010 CPC acquired energy from projects totalling 5,000 GWh (after removing the two coal facilities that were later terminated) and 3,300 GWh respectively.

BC Hydro notes the following:

- **The energy volumes acquired in previous calls are not substantially different than the Site C energy volume;**

- **Due to the uncertainty in load growth over the procurement lead time and the volume requirements for calls, it is not possible to precisely time resource additions to load growth;**

- **While IPPs do absorb some cost risks in exploration and development, ultimately the risk of paying for resources during periods of low growth has remained with the ratepayer. That is being seen currently with the large load reductions in the large industrial sector and significant energy oversupply;**

- **BC Hydro's experience with the Standing Offer Program indicates that smaller energy procurements may not provide the same cost-effective benefits as a larger acquisition process; and**

- **It is unlikely that BC Hydro could have cost effectively undertaken the exploration and development work that resulted in the award of the 63 EPAs that were awarded in those two acquisitions.**

If BC Hydro acquires a smaller amount of energy than Site C provides and then load growth drops below the forecast levels there may still be a system surplus. BC Hydro has a number ways to mitigate the impacts of this surplus on ratepayers, but would also face a number of challenges in doing so. Note that several of these mitigation options are the same as in a "With Site C" portfolio.

1. **Cease future purchases of energy until load growth resumes. History has shown that it is difficult to cancel or defer further IPP acquisitions once a declared path of acquisitions has been announced. And deferring or terminating contracts that have not yet reached COD does add costs.**

2. **Increased focus on load attraction for the duration of the surplus. This cuts across all drivers of downside uncertainty, but in particular, the loss of industrial load. Unfortunately, having a surplus of energy arising from "smaller sized generation … components" is not a good match for domestic load additions. Additional capacity resources would needed in order to integrate with the intermittent resources.**

3. **Incenting electrification (EV, fuel switching).**

4. **Sell surplus into export markets. The ability to export a surplus of inflexible, clean energy will be extremely limited in the future – as jurisdictions continue to pursue clean power solutions through Renewable Portfolio Standards (RPSs), the value of spot market electricity will remain low, making it extremely difficult for BC Hydro to recoup its expenditures by exporting intermittent energy into such a market.**

5. **Depart from volumetric pricing to match system supply capabilities with demand. However, with less flexibility on the supply side, larger price signals will be needed to bring supply in line with demand over the course of a day, week, and year. This may be difficult to achieve for BC Hydro in a**

climate where reduction in customer load growth due to DERs are a significant factor, and so load retention is critical to retain a robust rate

While a focus on the far future is important in order to think through potential risks and mitigation strategies, it is important to remember that the first 20 years of any low growth scenario is likely to play out in a similar way to that of the Low load growth scenario already modelled by BC Hydro in previous submissions that examine the impact of excluding Site C from the resource stack.

<u>Conclusion</u>

Through sensitivity analysis we have already tested how portfolios with and without Site C perform across a number of different futures including using High and Low load growth bands as well as using a number of additional sensitivities on cost and resource assumptions. These analyses have demonstrated that excluding Site C from the future portfolio stack increases costs in every case examined because of its low cost combined with its clean, flexible, dispatchable product.

While a number of scenarios could include load growth that is higher than expected, in such scenarios excluding Site C would lead to continued losses into the future due to the higher cost of alternative resources. However, there are a combination of factors which could pull load growth below its forecast trajectory.

In all of these low load growth scenarios, regardless of whether Site C is included or excluded from its resource stack, BC Hydro will face the risk of acquiring energy in advance of need and having to sell surplus energy into the market. This energy surplus could be larger in a resource stack including Site C. However, in the cases examined above, having a flexible and dispatchable energy source with storage such as Site C not only adds value to this surplus product and is expected to provide sufficient capacity products that this energy can be sold above the remaining uncommitted costs of Site C. Similar to BC Hydro's other heritage hydroelectric resources, Site C costs will decline over time while the value of the energy and capacity will increase. In contrast, surplus with no inherent flexibility and no storage would be less valuable and costs would not experience the same declines as Site C.

22.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 72 to 74

2.22.1 BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow.

The Panel requests that BC Hydro respond to the following questions:

- Please provide a breakdown BC Hydro's market price forecast for F2025 (US $36/MWh) and F2034 (US $46/MWh) showing (in Can $ and US $): Mid C price; wheeling costs; real power losses; other (please describe).
    - Please explain whether (i) the market price forecast assumes the Mid C price is set by a CCGT; (ii) whether Mid C prices over the past 5 years support this assumption, and (iii) to what extent lower price renewables may increasingly set the Mid C price at lower levels in the future.

RESPONSE:

The Commission makes several comments on page 72 of the preliminary report seeking additional evidence on the expected future demand in external markets for any surplus capacity and flexibility provided by Site C. The points that follow are meant to provide the Commission context for the 22 series of IRs. We provide additional information regarding both current and future expected opportunities to monetize capacity and flexibility in the external markets in the western interconnect.

<u>Existing and Future Markets for Capacity and Flexibility</u>

<u>Background</u>

- **Site C will become part of the portfolio of resources that form the BC Hydro system. Site C is expected to be operated, and any Site C surplus capabilities monetized, as part of the BC Hydro system, rather than as a stand-alone resource.**

- **BC Hydro builds the system to meet peak needs, resulting in the system having surplus capacity and flexibility in most hours of the year when loads are lower than peak loads. This planning requirement is expected to continue going forward.**

- **BC Hydro makes surplus capacity and flexibility of the BC Hydro system available to Powerex to monetize in the external markets for the benefit of BC Hydro's ratepayers.**

- **Site C will *add* significant capacity and flexibility to the BC Hydro system, helping BC Hydro reliably meet BC Hydro's peak and annual load requirements. It will also increase the surplus capacity and flexibility during hours of the year when loads are lower than peak loads. As a result, all else being equal, Site C can be expected to increase Powerex's ability to generate value for BC Hydro ratepayers from the residual capacity and flexibility of the BC Hydro system. More specifically, the addition of Site C can be expected to increase the ability of Powerex to sell surplus energy in the higher-priced hours of the year, while also increasing the ability of Powerex to purchase energy in the lower-priced hours of the year (enabling additional sales in higher-priced hours). In addition to supporting increased energy sales and purchases, the increase in capacity and flexibility provided by Site C throughout the year can be expected to increase the ability of Powerex to sell capacity and/or flexibility products, whereby Powerex receives an explicit capacity and/or flexibility payment.**

- **In contrast, variable energy resources (wind, solar and run-of-river hydro) typically add a much lower level of capacity to the BC Hydro system, and generally increase the need for flexibility from the BC Hydro system (to follow fluctuations in variable energy resource output). Thus, the addition of variable energy resources generally tends to reduce the residual flexibility of the BC Hydro system, and hence tends to reduce the value that can be earned by Powerex in external markets for the benefit of BC Hydro ratepayers. For example, Powerex has experienced a materially reduced ability to import low-priced energy during the spring freshet in recent years, because the abundance of B.C. IPP run-of-river generation output in that period already uses up much of the ability of BC Hydro's flexible generators to reduce output.[1] Furthermore, the periods in which variable resources produce power may often coincide with periods of lower demand in B.C. and lower prices in external markets, resulting in sales of surplus energy at relatively low prices.**

<u>Current Markets for Capacity and Flexibility</u>

Surplus BC Hydro capacity and flexibility currently can be monetized through multiple different market opportunities, including:

- **To sell surplus energy in higher-priced hours within the year;**

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[1] **Please refer to the Transmission Service Freshet Rate Preliminary Evaluation Report for Year 1 – Appendix D, filed January 27, 2017 with the Commission by BC Hydro for more detail.**

- **To sell short-term energy in higher-priced hours while purchasing a similar quantity of short-term energy in lower-priced hours;**
- [redacted]
- [redacted];[2]

[redacted]

<u>Markets for Capacity and Flexibility Currently Under Design</u>

There are several initiatives currently under consideration or design to facilitate new markets for capacity and/or flexibility. While some of these initiatives may not succeed, it is currently expected that there will be expanded opportunities to monetize capacity and flexibility in the *near future*. These initiatives are driven by the rapidly growing need for flexibility, as more variable energy resources are added to the western grid, and include:

- **The California Independent System Operator (CAISO), together with the California Public Utilities Commission (CPUC), is exploring re-designing California's Flexible Resource Adequacy Criteria and Must Offer Obligation (FRACMOO) program, which is a program that provides sellers of flexible capacity with an explicit capacity payment (separate from any energy sales revenues) in exchange for a commitment to submit an offer to sell energy in CAISO's short-term markets. The current stakeholder process is examining expanding the eligibility criteria to include intertie participation (external participation). Refer to September 26, 2017 CAISO presentation on FRACMOO at https://www.caiso.com/Documents/Presentation-FlexibleResourceAdequacyCriteria_MustOfferObligationSep26_2017.pdf;**

- **In November 2016, CAISO implemented a Flexible Ramping Product (FRP). This is an enhancement to the CAISO real-time market that allows CAISO to**

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[2] [redacted]

procure flexible capacity on a very short-term basis, for which it provides explicit compensation that is separate from any payments for energy deliveries. See https://www.caiso.com/Documents/Jun242016_TariffAmendment-FlexibleRampingProduct_ER16-2023.pdf and https://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf; and

- **Alberta is in the process of designing a capacity market that will be in place by 2019 in time for a capacity auction for 2021. It is still unclear whether Alberta will allow external participation in their capacity market. However, Alberta is looking at the features of the existing eastern U.S. capacity markets in order to learn from their experience, and those markets generally permit external participation.**

Additional developments anticipated by the mid-2020s that are likely to impact opportunities for capacity and/or flexibility

- **In the U.S. Western Interconnect more than 4,500 MW of coal generation capacity is currently planned to be shut down by 2025.**[3]

- **In Alberta more than 6,000 MW of coal generation capacity is currently planned to be shut down by 2030.**[4]

- **In California, an additional 7,500 MW of natural gas and nuclear generation capacity is currently planned to be shut down by 2025, largely to deal with environmental concerns regarding once-through-cooling concerns.**[5]

- **Much of the energy produced from the retiring fossil-fuel plants is expected to be replaced with energy from renewable sources (mostly wind and solar), which generally provide much less capacity, and increase the need for flexible resources to follow fluctuations in variable energy resource output.**

- **If BC Hydro does have surplus capacity, flexibility and/or clean energy in the mid-2020s, there may be opportunities to use this surplus to displace or defer the building of new gas generation resources by other entities in the west. Such an arrangement could enable significant investment savings to the purchaser, which would be expected to be shared fairly with the seller under mutually acceptable terms.**

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[3] **Table 6.6 from EIA report at: https://www.eia.gov/electricity/monthly/pdf/epm.pdf.**
[4] **https://www.alberta.ca/climate-coal-electricity.aspx.**
[5] http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf.

- **As with any new opportunities, there are significant hurdles to overcome to enter into such transactions, despite potentially strong economic incentives for both BC Hydro and potential purchasers. For example, public power utilities, as well as local governmental agencies generally want to support the building of their own resources within their own state or province to support local jobs. Independently owned, state-regulated, investor-owned utilities also prefer to build or own their own resources in order to earn a return on their associated capital investments.**

- **Powerex is in regular confidential discussions with its customers in the western United States regarding a variety of short term and longer term capacity and flexibility products and services, and actively participates in organized market stakeholder processes on capacity and flexibility. Based on these discussions, Powerex anticipates that demand for such products and services will continue to emerge and grow as the western grid undergoes a substantial transition toward additional variable energy resources.**

- **Finally, it should be noted that there are existing efforts by the current U.S. federal government to maintain the viability of the existing coal and nuclear fleet. On September 29, 2017 the U.S. Department of Energy proposed a "Notice of Proposed Rulemaking" that, if adopted, would support base loaded "fuel secure" resources in organized markets. An ongoing debate is expected between state and federal governments on the future of coal and nuclear resources.[6] Importantly, the NOPR applies to resources within organized markets, whereas most of the coal resources in the western U.S. that are currently slated to retire between 2020 and 2025 are outside of organized markets.**

<u>Transmission Constraints</u>

Some participants in the Commission inquiry have expressed concern over BC Hydro's ability to export Site C energy due to transmission constraints. These concerns are unfounded. The rating of the B.C. to U.S. export path is 3,150 MW and the rating of the B.C. to Alberta path is 1,200 MW. While the operational export capability of these paths are closer to 2,500 MW and 450 MW respectively, the combined operational export capability is still more than what is necessary to support a very large volume of surplus energy. For example, exporting an annual energy surplus of as much as 9,000 GWh, which would only likely occur in a very high water year in B.C., would require only 1,027 MW of average transmission export capability, which is less than one-half of the typical operational rating. Put another way, even in the highly unlikely scenario in which BC Hydro had a very high water year, the existing transmission capacity is still more than enough to

[6] **https://energy.gov/articles/secretary-perry-urges-ferc-take-swift-action-address-threats-grid-resiliency.**

allow Powerex to export all of this energy out of the BC Hydro system during the higher-priced 50 per cent of the hours.[7] In addition to transmission to export power out of B.C., Powerex has long-term U.S. transmission agreements for about 2,500 MW of transmission rights between the Pacific Northwest and California, allowing it to pursue market opportunities throughout the west.

<u>Previous Statement on Export Sales Prospects</u>

On page 72 of the preliminary report the Commission pointed out that the 2012 draft IRP states that "the prospects of export sales of renewable energy in excess of that required to meet self-sufficiency requirements have diminished considerably." The Commission requests that BC Hydro update this information and provide an explanation as to the impact these issues could have on export sales.

This statement in the 2012 draft IRP is still applicable. This statement refers to the opportunity to build renewable resources in B.C. for the purpose of exporting qualifying renewable energy to load serving entities in the Western states to help them meet their Renewable Portfolio Standards (RPS). This statement was not intended to apply to the prospects of export sales of energy more generally, nor to the prospects of generating revenues in external markets from surplus capacity and/or flexibility.

Renewable energy sales opportunities continue to be limited from B.C., and are especially limited in the context of investing capital in new B.C. renewable resources for export, as:

- **RPS programs set a minimum percentage of load that each load-serving entity in the applicable region must serve with energy procured from renewable resources *that meet certain qualification requirements* defined by each particular state.**

- **The only B.C. resources that qualify for California's RPS, the largest market for renewable resources, are B.C. wind resources (despite considerable efforts to gain eligibility as renewable resources for other types of B.C. resources).**

- **The cost of building new wind resources in B.C., and delivering those resources to California (or other western U.S. markets to meet applicable state RPS targets), generally exceeds the cost of building local renewable resources in the destination state – especially with a 30 per cent investment tax credit for U.S. renewables.**

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[7] **(9,000,000 MWh per year) ÷ (8760 hours per year * 50%) = 2,055 MW.**

- **Similarly, Alberta has a recently established renewable resource program that has limited eligibility to in-province resources only.**

While there has generally been no improvement in the opportunities associated with building new B.C. resources to supply qualifying renewable energy to external markets, the growth in renewable resources in external jurisdictions (to meet evolving state and provincial renewable resource procurement targets) is having a positive effect on the value of surplus flexibility and capacity in export markets, as discussed above.

Question 22.1

- ***Please provide a breakdown BC Hydro's market price forecast for F2025 (US $36/MWh) and F2034 (US $46/MWh) showing (in Can $ and US $): Mid C price; wheeling costs; real power losses; other (please describe).***
    - ***Please explain whether (i) the market price forecast assumes the Mid C price is set by a CCGT; (ii) whether Mid C prices over the past 5 years support this assumption, and (iii) to what extent lower price renewables may increasingly set the Mid C price at lower levels in the future.***

Table 1 below shows BC Hydro's Mid C market price forecast for calendar year 2025 and 2034 in CAD and USD. Wheeling costs to and from Mid C are assumed to be constant at current levels of 6.28 CAD/MWh. Losses due to transmission to and from Mid C are 1.9 per cent of power transferred, resulting in in incremental costs for purchase and a loss of revenue for sales.

Table 1 ABB Spring 2016 Mid C Price Forecast, converted to B.C. Buy and B.C. Sell Prices

	Mid C 2016 USD/MWh			Mid C 2016 CAD/MWh			Losses (1.9%) 2016 CAD/MWh			Wheeling 2016 CAD/MWh	B.C. Buy 2017 CAD/MWh			B.C. Sell 2017 CAD/MWh		
Calendar Year	On Peak	Off Peak	Average	On Peak	Off Peak	Average	On Peak	Off Peak	Average	-	On Peak	Off Peak	Average	On Peak	Off Peak	Average
2025	36.46	35.76	36.16	45.70	44.82	45.32	0.87	0.85	0.86	6.28	53.58	52.68	53.20	39.09	38.22	38.72
2034	45.53	45.41	45.47	57.06	56.91	56.99	1.08	1.08	1.08	6.28	65.32	65.17	65.26	50.39	50.24	50.33

Exchange rate assumption: ***Rates based on updates provided by the Treasury Board of the Province of B.C.-May 30, 2017. 1USD = 1.2533CAD***

Inflation assumption: ***CPI from Statistics Canada - updated 2017-01-20. CPI increase in 2016 = 1.4 per cent.***

(i) The market price forecast model results in a forecast where sometimes the Mid C price is set by a CCGT and sometimes it is not. The market price is determined from the ABB PROMOD model, which simulates the operation of each region in North America in order to determine the market clearing price (MCP) at hundreds of locations (referred to as nodes) on an hourly time step. For each region, PROMOD considers:

- **Individual power plant characteristics including heat rates, start-up costs, ramp rates, and other technical characteristics of plants;**
- **Transmission line interconnections, ratings, losses, and wheeling rates;**
- **Forecasts of resource additions and fuel costs over time;**
- **Forecasts of loads for each utility or load serving entity in the region; and**
- **The cost and availability of fuels that supply the plants.**

PROMOD performs an hourly commitment and dispatch algorithm, recognizing both generation and transmission impacts, that minimizes costs. Model outputs include hourly energy prices at each node, unit generation, revenues and fuel consumption, and transmission flows.[8]

BC Hydro subscribes to the ABB reference case database, which is released twice a year (spring and fall), and uses it to model the WECC interconnected area with PROMOD. Over 40 nodes are modelled and the energy price, or MCP, at each node is set by the marginal generating unit at that node (the last unit required to meet load with cost minimized). The MCP varies depending on the season, time of day, transmission constraints, and variations in fuel prices. For example, during the spring freshet, the MCP at the Mid C node can drop to very low levels in some light load hours, indicating that natural gas generation is not the resource type on the margin. At other times prices will be higher, reflecting the fact that CCGT or other resource types are on the margin, or alternatively exports from the Pacific Northwest to other higher-priced regions are on the margin.

The ABB spring 2016 reference case adds significant amounts of variable renewable resources between 2017 and 2030 (about 30,000 MW). However, the reference case also shows significant baseload coal retirements in the Western Interconnect in this timeframe (about 13,500 MW). Given a 25-30 per cent capacity factor for the renewable generation, the energy from the expected renewables is in the same order of magnitude as the

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[8] **Source: *ABB Power Reference Case: WECC Spring 2017 Report*. 2017.**

energy that will be lost by the retiring coal. Thus, while the addition of variable renewable resources is expected to lower the average MCP, this effect is largely offset by expected coal retirements raising the average MCP.

(ii) Actual Mid C prices over the past five years appear to reflect the estimated variable production cost of CCGT generation in most hours. In certain other hours, such as during the spring freshet, as well as other periods of high hydro runoff and high wind generation, Mid C prices were below this value, implying that CCGT generation was not required to meet the load in those hours. In certain other hours, however, Mid C prices exceeded the estimated variable production cost of a CCGT.

The appropriate metric for determining whether Mid C prices generally reflect, on average, the estimated variable production cost of a CCGT is the average Mid C market heat rate. The average Mid C market heat rate is equal to the Mid C price divided by the applicable natural gas price in the region, represented by the Sumas gas index price. Generally speaking, a CCGT can be expected to have a total effective heat rate somewhere between 6 MMBtu/MWh and 10MMBtu/MWh (including all variable costs of production and additional delivery costs of fuel). Going back five years to 2012-2016, the average actual market heat rate at Mid C, using Mid C ICE daily index prices and Sumas daily gas index prices, was 8.6 MMBtu/MWh. Going forward, the ABB spring 2016 reference case predicts power prices that reflect a heat rate of 7.9 MMBtu/MWh for 2020 through 2030. Thus, both the historic prices at Mid C and the ABB model generally reflect the estimated variable production cost of a CCGT.

Also, if the Commission is concerned that the pricing model does not reflect actual market conditions, it should be noted that ABB does back test their model to ensure that the model produces prices that are consistent with historical actuals. Every few years ABB performs a back-cast of a historical year to make sure that the model is behaving as expected. For every data release, ABB compares the forecast prices that the model produces to historical prices and market forwards.

(iii) As noted above, the ABB Spring 2016 reference case adds significant amounts of variable renewable resources between 2017 and 2030 (about 30,000 MW). We expect that, consistent with the ABB spring 2016 reference case, more renewables will be built to satisfy legislated renewable resource objectives (typically referred to as Renewable Portfolio Standards, or RPS), as well as to more generally meet energy needs in the Western Interconnect as significant amounts of coal and other baseload fossil fuel generation retires between now and 2030. As a consequence, we expect there to be more occurrences of lower-priced hours in the future. However, we also expect more occurrences of higher-priced hours, and higher prices in those hours. In other words, the combined impact of replacing coal and other fossil fuel generation resources with variable energy resources such as solar and wind, is *higher price volatility* in the applicable region, not

necessarily higher or lower average prices.

This impact is summarized by EDC Associates, for the Alberta marketplace as follows:

> **The volatility of prices will be much higher across the year (more very low priced hours and much higher high-priced hours), although average pool prices will be relatively unchanged from the Pre-CLP case. Generators will have to earn a larger fraction of their revenues in fewer, higher-priced hours. This higher pool price volatility will change perceived risks for new generator developers and could stall or encourage investment, depending on the developer.[9]**

This price impact of additional variable energy resources has already been experienced in California's organized market, operated by the California Independent System Operator (CAISO). In response to aggressive California RPS objectives, the CAISO market footprint has experienced a rapid installation of renewable variable energy resources, with wind resources now totaling approximately 6,000 MW, utility-scale solar resources now totaling approximately 10,000 MW, and behind-the-meter solar totaling approximately 5,000 MW. To provide perspective, the average daily peak load in the CAISO is just over 31,000 MW, with peak summer load reaching 50,000 MW. This impressive installation of renewable variable energy resources has resulted in hourly prices in the middle of the day often becoming depressed, when solar resources are producing at very high levels. But it has also contributed to higher prices in the morning and early evening hours, as CAISO now experiences very high ramping requirements, largely met by dispatchable generation and imports that must quickly respond to hourly load increases that coincide with hourly solar output decreases. Higher California prices during the hours when solar and wind production is lower have also risen as a result of: 1) the introduction of Greenhouse Gas costs, resulting from California's Cap and Trade program, implemented in 2013, and 2) generation retirements resulting in less dispatchable generation online to respond to higher ramping requirements and higher hours of demand. The net result of these combined impacts to average prices in the CAISO market has been a relatively constant average market heat rate over the past five years and slightly rising average market heat rates in the forward markets for the next five years, despite the significant increases in renewable resource generation in the state over this timeframe.

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[9] **EDC is a well-known consulting firm in Calgary, Alberta who has been producing Alberta power market outlooks for a number of clients, including Powerex, for nearly 20 years. In late 2016 EDC produced a multi-client study steered by most of the generation and ratepayer representatives in Alberta, the AESO and Powerex to assess the future market outcomes of the Climate Leadership Plan adopted by the Alberta government in 2016. At page 21 of the Executive Summary found here. http://www.edcassociates.com/files/ClimateLeadership/EDCA_Abbreviated_Multi-Client_GHG_Study(11.7.2016).pdf.**

The Southern California Heat Rate chart, Figure 1 below, shows actual and forward market heat rates (wholesale electricity price divided by applicable gas price). Historic heat rate charts illustrate how wholesale electricity prices have changed, once the effects of gas price changes have been removed. With the effect of gas prices removed, it can be seen that average wholesale electricity prices have not fallen as a result of adding significant amounts of renewables, nor are they expected to fall going forward as a result of adding more renewables.

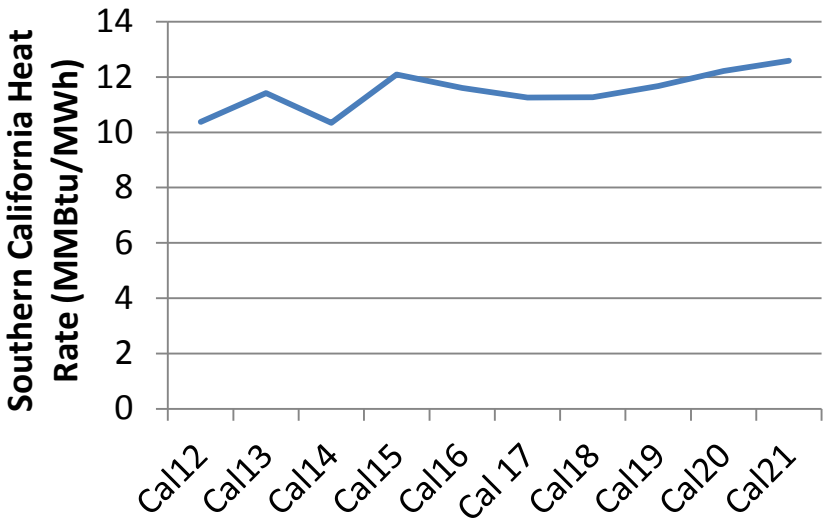


Figure 1 Southern California Heat Rate using CAISO SP15 Day Ahead Locational Marginal Price and Socal Gas Index[10]

Importantly, flexible generation resources are expected to have greater market value than inflexible and/or variable energy resources in the future, because of this continuing trend of increased volatility in hourly prices. Flexible generation resources enable energy to be sold into the market when prices are higher, and also allow sales to be reduced or avoided when prices are low. Conversely, inflexible and/or variable energy resources generally must dispose of their energy at prices that may be equal to, or substantially below, average prices; they generally cannot increase production and sales when prices are high, nor can they reduce output and sales when prices are low.

Finally, it is important to note that the key contributor to the decline in Mid C market prices since 2007 is also the corresponding decline in natural gas prices over this same time period, rather than the addition of renewables. Figure 2 below shows the price of Mid C power alongside the price of

[10] **Historic Prices from CAISO Day Ahead LMP and Intercontinental Exchange (ICE) daily Socal gas index. Forward prices from ICE forward prices for the SP15 and Socal trading hubs.**

Sumas gas from 2007 to 2016. It is clear from this chart that price movements in power have closely followed changes in natural gas prices. The second chart below removes the effect of the natural gas price on the power prices by showing the market Heat Rate at Mid C, which is simply the power price divided by the gas price. This generally stable Mid C heat rate illustrates that once the effects of declining gas prices is removed, average Mid C market prices have remained generally unchanged over the past seven years. It would be incorrect to conclude that average Mid C prices have fallen largely as a result of increased renewable resources.

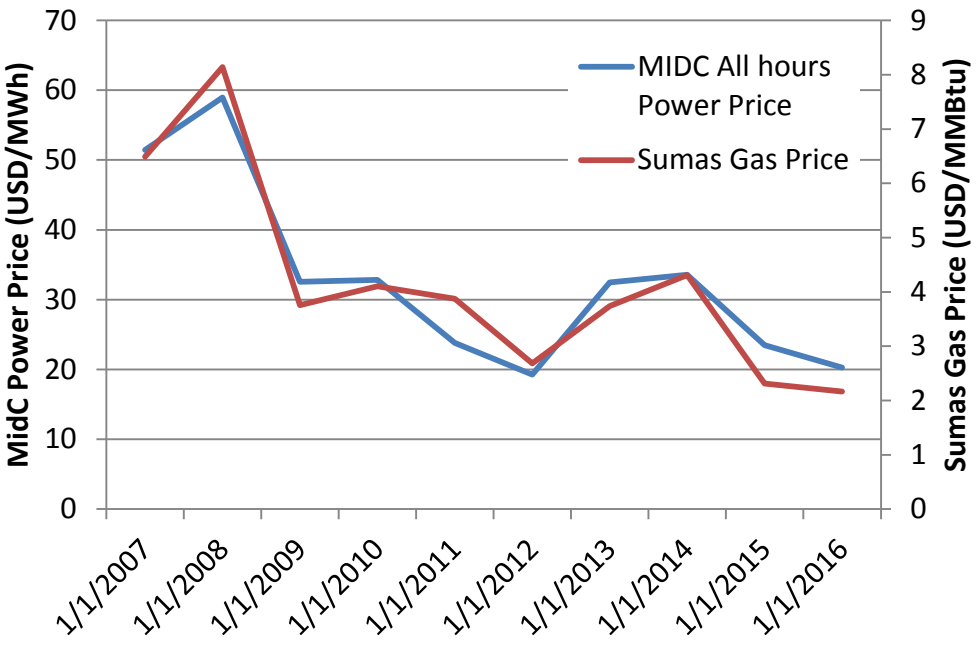


Figure 2 Mid C Power Price and Sumas Gas Price

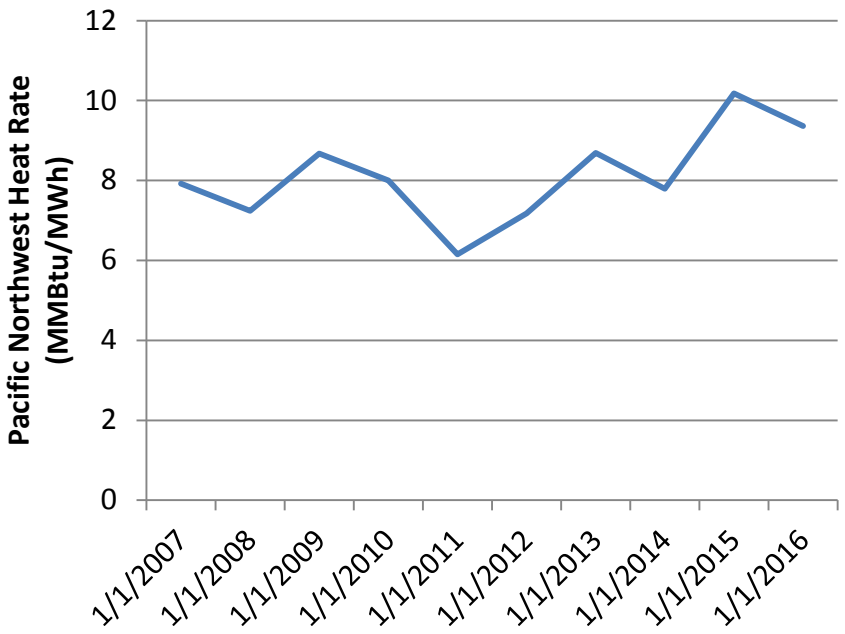


Figure 3 Pacific Northwest Heat Rate, using Mid C Day Ahead Prices and Sumas Gas Index[11]

[11] **Historic Prices from Intercontinental Exchange (ICE) Day Ahead Index and ICE daily MidC gas index.**

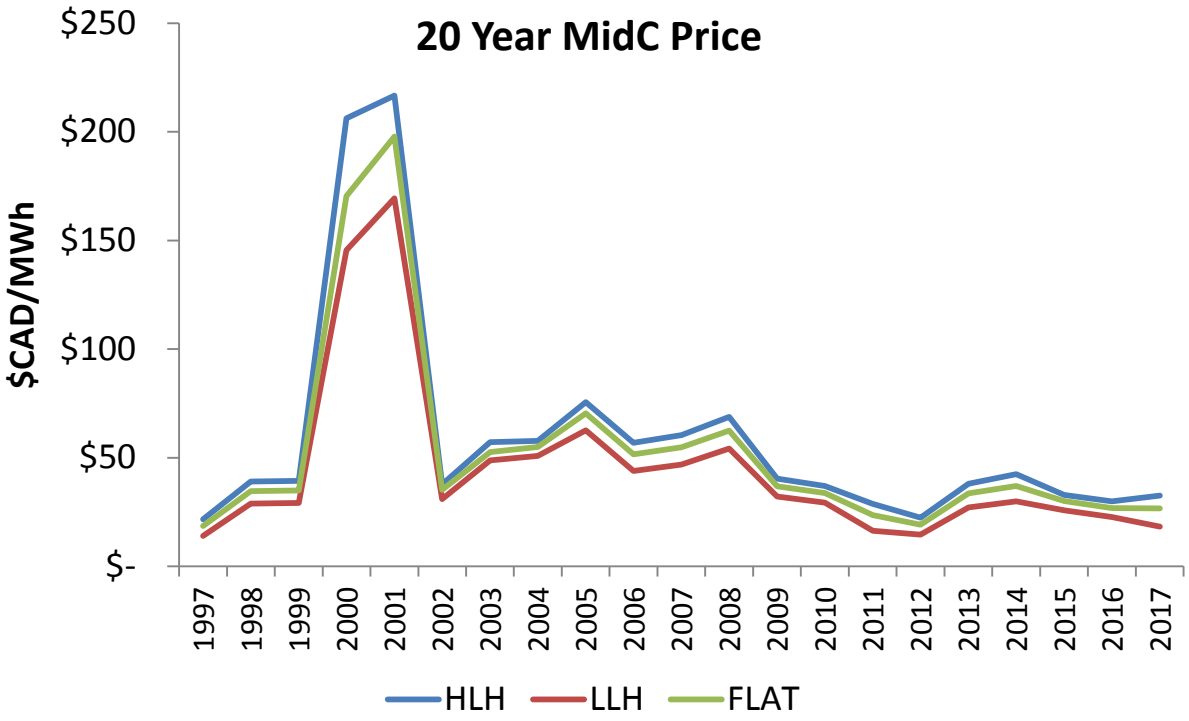
22.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 72-74

2.22.2 BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow. The Panel requests that BC Hydro respond to the following questions:

- Please provide, in graph and table form, the average annual Mid C price (on-peak, off-peak and all hours) for the last 20 years.

RESPONSE:

20 Year Mid C - $CAD/MWh *(Source – [2004-2017] ICE Daily Settles, [1997-2003] Dow Jones)*			
	On-Peak (HLH) ($)	Off-Peak (LLH) ($)	FLAT ($)
1997	21.75	14.10	18.55
1998	39.05	28.85	34.62
1999	39.41	29.25	34.95
2000	206.23	145.57	170.41
2001	216.66	169.36	197.89
2002	37.72	31.01	35.19
2003	57.19	48.79	52.60
2004	57.81	50.91	55.03
2005	75.67	62.61	70.40
2006	56.92	43.87	51.56
2007	60.40	46.93	54.83
2008	68.82	54.25	62.55
2009	40.38	32.16	36.94
2010	37.02	29.40	33.81
2011	28.79	16.41	23.64
2012	22.47	14.70	19.20
2013	38.04	27.17	33.57
2014	42.44	29.91	37.08
2015	32.94	25.87	30.03
2016	29.97	22.72	26.91
2017	32.60	18.31	26.77



(Source – [2004-2017] ICE Daily Settles, [1997-2003] Dow Jones)

22.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 72-74

2.22.3 BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow. The Panel requests that BC Hydro respond to the following questions:

- Please provide in graph and table form, for each year from F2013 to F2017, a comparison of (i) the average all hours Mid C price for that year and (ii) the $/MWh price that BC Hydro received (after transaction costs, such as wheeling and power losses) for the sale of its surplus energy.

RESPONSE:

We provide the information requested below. However, it should be noted that the "price that BC Hydro received" is determined by the Transfer Price Agreement, which only reflects the price at which BC Hydro sells surplus energy to Powerex (at Mid C daily index prices adjusted for transaction costs, such as wheeling and power losses), and does not include any additional value that may be earned by Powerex, and returned to BC Hydro, associated with Powerex selling that surplus energy in premium markets.

The following table compares the day-ahead Mid C price across all hours to the weighted average price that BC Hydro received for its surplus from Powerex. It must be noted that, under the Transfer Pricing Agreement between BC Hydro and Powerex, BC Hydro receives from Powerex the On-Peak or Off-Peak Mid C price, as applicable, adjusted for transmission costs between the BC border and Mid C, for any energy that BC Hydro sells to Powerex each hour.

Powerex sells this energy in various temporal and geographic markets across the western interconnect, attempting to capture the best market opportunities as they arise. Powerex receives the revenue associated with these sales, and pays the actual transmission and other costs associated with reaching these markets. The additional revenue that Powerex is able to earn above the price it pays BC Hydro for its surplus energy (net of transmission and other costs associated with accessing Powerex's various markets) is also returned to BC Hydro's ratepayers as Powerex Net Income.

Importantly, the price at Mid C does not reflect the price of transactions in other geographic markets. Across each year, Powerex will sell energy sourced from the BC Hydro system in virtually every geographic region in the western interconnect, including the Pacific Northwest, Alberta, the Desert Southwest, the Rockies, and California. Accordingly, it would be inaccurate to conclude that the total value returned to BC Hydro's ratepayers associated with BC Hydro's surplus energy was the price Powerex paid BC Hydro for its surplus energy, which is based only

on the Mid C price. In fact, most of the exports from the BC Hydro system during the specific period of F2013 to F2017 were delivered to California.

Nonetheless, in order to provide the Commission with information on prevailing prices in these other markets that Powerex participates in, BC Hydro provides an additional table below that shows average California and Alberta market prices for each fiscal year over this period. A third table shows the California and Alberta prices in the highest priced 50 per cent of all hours in each fiscal year, to provide the Commission with a broad indication of the relative value that can be earned by being able to shape surplus energy sales and associated deliveries into the higher-priced hours. It should also be noted that these energy prices do not generally include any explicit or implicit premiums that Powerex may also receive for other value-added attributes (such as renewable resource attributes, resource adequacy commitments, etc.).

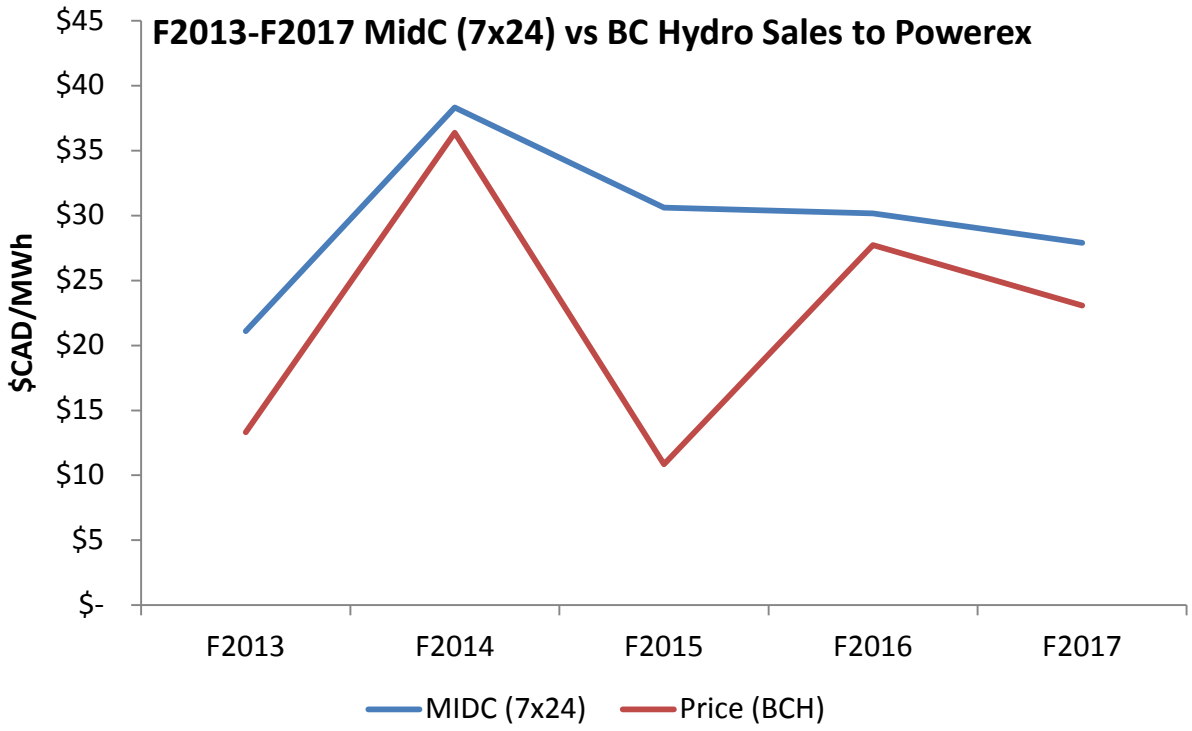
It is also important to identify that the prices reported for F2013 and F2017 may not be directly comparable to the value that can be expected to be earned from surplus energy created by the addition of Site C. This is because surplus energy sales during the F2013 to F2017 period included substantial amounts of surplus sales due to generation resources with limited flexibility and/or storage, often requiring their output to be sold in the same periods that it is produced. For example, much of BC Hydro's Lower Mainland generation, Vancouver Island generation, lower Columbia generation and IPP run-of-river hydro generation occurs during the spring freshet and cannot be stored. This can often result in market sales sourced from the BC Hydro system during relatively low-priced periods of the year. In contrast, Site C generation would benefit from the large upstream storage of the Williston reservoir, and hence surplus energy created by the addition of Site C would generally be able to be stored for sale in more valuable hours.

Mid C Price (7x24) vs. BCH Sales of Surplus to Powerex - $CAD/MWh			
	MID C ($)	**Price (BCH) ($)**	**Domestic Exports (MWh)**
F2013	21.11	13.32	(6,019,503)
F2014	38.31	36.38	(1,008,022)
F2015	30.61	10.84	(14,358)
F2016	30.17	27.73	(6,277,415)
F2017	27.89	23.06	(5,756,393)

Notes: **F2015 domestic export volumes are immaterial, and hence the price in F2015 only reflects a small volume of forced sales in the spring freshet (to deal with an over-supply of run of river generation in a few hours of the period). F2013 volumes reflect a very high water year in B.C. (and the Pacific Northwest) resulting in BC Hydro selling substantial volumes during the spring freshet to avoid system spill in late July, and receiving depressed prices reflective of the very high water in the Pacific Northwest. This resulted in the BC Hydro average sales price in F2013 being uncharacteristically low relative to the average F2013 Mid C price.**

Export Market Prices (7x24) - $CAD/MWh *(Source – CAISO OASIS, AESO)*			
	Southern California ($)	**Northern California ($)**	**Alberta ($)**
F2013	34.99	31.77	65.61
F2014	48.14	46.36	79.05
F2015	46.77	47.18	41.64
F2016	38.67	39.95	30.64
F2017	38.16	39.40	19.33

Export Market Prices (Best 50% Hours) - $CAD/MWh *(Source – CAISO OASIS, AESO)*			
	Southern California ($)	**Northern California ($)**	**Alberta ($)**
F2013	45.00	39.99	115.33
F2014	58.12	55.31	136.38
F2015	56.43	56.18	64.97
F2016	48.10	48.00	45.33
F2017	50.55	50.72	24.18

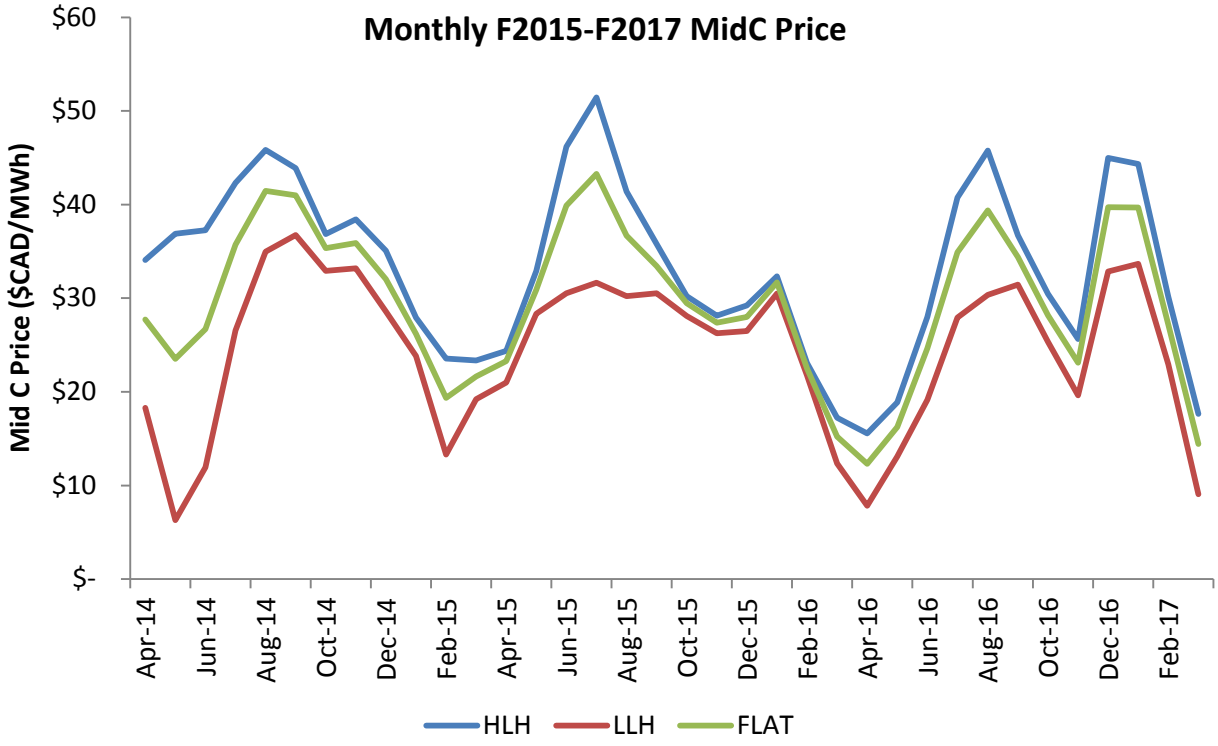

F2013-F2017 MidC (7x24) vs BC Hydro Sales to Powerex
$CAD/MWh
$45
$40
$35
$30
$25
$20
$15
$10
$5
$-
F2013
F2014
F2015
F2016
F2017
MIDC (7x24)
Price (BCH)

22.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 72-74

2.22.4 BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow. The Panel requests that BC Hydro respond to the following questions:

- Please provide, in graph and table form, for each year from F2015 to F2017, the monthly all hours, on-peak and off-peak Mid C price.

RESPONSE:



Monthly Mid C Prices - $CAD/MWh *(Source – ICE Daily Settles)*			
	On-Peak (HLH) ($)	**Off-Peak (LLH) ($)**	**Average (FLAT) ($)**
Apr-14	34.07	18.30	27.73
May-14	36.87	6.29	23.51
Jun-14	37.26	11.95	26.69
Jul-14	42.33	26.54	35.72
Aug-14	45.85	34.97	41.46
Sep-14	43.89	36.75	40.99
Oct-14	36.86	32.93	35.33
Nov-14	38.42	33.20	35.91
Dec-14	35.06	28.58	32.02
Jan-15	27.91	23.81	26.19
Feb-15	23.54	13.31	19.35
Mar-15	23.36	19.21	21.64
Apr-15	24.36	21.00	23.30
May-15	32.91	28.32	30.90
Jun-15	46.17	30.51	39.88
Jul-15	51.45	31.64	43.28
Aug-15	41.38	30.22	36.67
Sep-15	35.79	30.54	33.44
Oct-15	30.22	28.10	29.47
Nov-15	28.13	26.25	27.39
Dec-15	29.24	26.48	28.00
Jan-16	32.33	30.48	31.70
Feb-16	23.06	21.76	22.48
Mar-16	17.22	12.35	15.20
Apr-16	15.56	7.84	12.29
May-16	18.89	13.09	16.23
Jun-16	28.00	19.14	24.66
Jul-16	40.75	27.92	34.90
Aug-16	45.77	30.37	39.37
Sep-16	36.73	31.44	34.37
Oct-16	30.46	25.34	28.17
Nov-16	25.62	19.64	23.10
Dec-16	44.97	32.85	39.71
Jan-17	44.34	33.67	39.69
Feb-17	30.15	22.94	27.19
Mar-17	17.65	9.06	14.42

(Source – ICE Daily Settles)

22.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 72-74

2.22.5 BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow. The Panel requests that BC Hydro respond to the following questions:

- Please describe the energy and capacity markets in the US and Alberta that BC Hydro considers it will be able to participate in.

  Please describe any key difficulties BC Hydro might face in participating in the US and Alberta market, such as access to transmission and regulatory approvals required.

  - Please explain if any of BC Hydro's key export markets (such as California, Alberta) have, or are currently considering, legislative or regulatory requirements that would restrict BC Hydro from selling into their markets (such as self-sufficiency requirements, renewable compliance market), or the price BC Hydro could offer (such as a requirement to bid in at zero).

RESPONSE:

BC Hydro does not participate in external markets. BC Hydro's wholly owned subsidiary, Powerex, is an active participant in external markets.

Please refer to the introduction narrative of the response to BCUC IR 2.22.1 for an explanation of the markets in which Powerex participates and some of the potential challenges it faces.

With regard to concerns associated with a requirement to bid at zero in some markets, BC Hydro does not expect this to have a material effect on BC Hydro's ability to sell any surplus energy, capacity or flexibility. Sales in organized markets are generally paid a market clearing price, not the bid price submitted by the seller. Even participants required to submit a zero bid price can still express their willingness to sell power into the market through the volume of energy offered in each hour, which would be expected to receive the market clearing prices in that hour. For example, the Alberta organized market operated by the Alberta Electric System Operator (AESO) requires that all intertie offers to sell are priced at zero dollars. Accordingly, intertie participants offer a volume of supply reflective of their expectation of the AESO market clearing price. The key impact of this rule is that it can result in a lower volume of sales during those hours in which intertie participants' estimates of the clearing price are too low or are uncertain.

22.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 72-74

2.22.6 BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow.
The Panel requests that BC Hydro respond to the following questions:

- Please provide in table form the percentage of total annual generation expected from Site C for each month of the year.
  - Using the monthly delivery factor adjustments included in BC Hydro's SOP program, please provide an estimate of the seasonally adjusted value of Site C energy, using a starting (pre- seasonally adjusted) value of $45/MWh. Please show supporting calculations.

RESPONSE:

The following table provides the incremental system energy from the addition of Site C to the BC Hydro system.

	Incremental System Energy from the addition of Site C (GWh)	**Incremental System Energy (%)**
January	659	12
February	765	14
March	118	2
April	322	6
May	230	4
June	-80	-2
July	511	10
August	702	13
September	911	17
October	343	6
November	483	9
December	322	6
Total	**5286**	100

Using the monthly delivery factor adjustments from BC Hydro's SOP program, and an average energy price of $45/MWh, the Site C firm energy price has been calculated to

be $42.30/MWh. The negative adjustment means Site C has a favourable profile. The following table shows the SOP weighting factors used. Calculation details for the firm energy price are shown below.

	SOP Weighting Factors		
	Super Peak	**Peak**	**Off-Peak**
January	1.41	1.22	1.05
February	1.24	1.13	1.01
March	1.24	1.12	0.99
April	1.04	0.95	0.85
May	0.90	0.82	0.70
June	0.87	0.81	0.69
July	1.05	0.96	0.79
August	1.10	1.01	0.86
September	1.16	1.07	0.91
October	1.27	1.12	0.93
November	1.29	1.12	0.99
December	1.42	1.20	1.04

Site C monthly energy is shaped into super-peak, peak, and off-peak[1] hours based on hourly time-step modeling conducted for the Site C Environmental Impact Study. Once Site C energy and system energy benefits for each time period[2] are determined for each month, they are summed into monthly time period totals. The firm energy price is then determined as shown in the following formula:

$$Average\ UEC * Average\ Energy = \sum_{month=1}^{12} \sum_{i=1}^{3} Market\ Price_{m,i} * NonFirm\ Energy_{m,i}$$

$$+\boldsymbol{Firm\ Energy\ Price} * \sum_{month=1}^{12} \sum_{i=1}^{3} Firm\ Energy_{m,i} * Weighting\ Factor_{m,i}$$

[1] **Super peak hours are between 4 p.m. and 8 p.m., off-peak hours are between 10pm and 6am, and all other hours are considered peak.**

[2] **Super peak, peak, and off-peak.**

For Site C, we can rely on its average energy for planning purpose. In other words, all energy is firm with no non-firm energy, and market price is therefore not part of the equation. As such, the equation shortens to:

$$\frac{\$45}{MWh} * 5286GWh = \boldsymbol{Firm\ Energy\ Price} * \sum_{month=1}^{12} \sum_{i=1}^{3} Firm\ Energy_{m,i} * Weighting\ Factor_{m,i}$$

Multiplying the energy in each time period[4] for each month by the appropriate weighting factors shown in the table above, and summing, gives 5628 GWh. The equation then becomes:

$\frac{\$45}{MWh} * 5286GWh = \boldsymbol{Firm\ Energy\ Price} * 5628GWh$**, and**

$$\boldsymbol{Firm\ Energy\ Price} = \frac{\$45}{MWh} * \left(\frac{5286GWh}{5628GWh}\right) = \frac{\$42.30}{MWh}$$

22.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 72-74

2.22.7 BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow. The Panel requests that BC Hydro respond to the following questions:

- Please provide additional details on the transmission line to (a) the US and (b) Alberta, including (i) the maximum rating (for BC exports), (ii) the extent to which it is constrained to a lower level (and if so what is the lower level); (iii) how much firm and non-firm transmission capacity is generally available; and (iii) what percentage of the time the transmission line is on average constrained.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.22.1, specifically the "Transmission Constraints" section.

22.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 72-74

2.22.8 BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow. The Panel requests that BC Hydro respond to the following questions:

- Has BC Hydro considered restoring the capacity of the tie-line to Alberta? Similarly, has BC Hydro considered building additional transmission capacity to the US? Would either of these transmission projects offer additional economic opportunities for the sale of surplus energy/capacity provided by Site C? Please elaborate.

RESPONSE:

The capacity of existing interties to the U.S. and Alberta is sufficient to move any surplus energy from Site C to other utilities as described in BC Hydro's response to BCUC IR 2.76.0. BC Hydro has not, in recent history, considered building additional transmission capacity to the U.S. However, from 2006 to 2011 at the initiative of Pacific Gas & Electric, there was an exploration of building a transmission line to transport power from new renewable resources in British Columbia and the Pacific Northwest to northern California. This was named the Canada to Northern California transmission project (CNC project). The CNC project was to have carried up to 3,000 megawatts (MW) of power from renewable resources along an almost 1,000 mile transmission path running through three states and crossing the international border. The early cost estimates on this project was in the range of $3 billion (2005 US$). However, this project was abandoned by the proponents in 2011 due to the expense of the facilities and an inability to reach a commercial agreement.

The restoration of the capacity of the tie-line to Alberta is being looked at as part of a federal funded study on GHG reductions (https://www.aeso.ca/market/market-updates/regional-electricity-cooperation-and-strategic-infrastructure-initiative-recsi/). BC Hydro is part of this study effort.

Alberta is in the process of shutting down more than 6,000 MW of coal generation capacity and building large volumes of renewables. A significant amount of gas fired capacity will need to be built in Alberta alongside the buildout of renewables such as wind and solar. The gas fired generation is critical to provide the dependable capacity necessary to integrate the renewables and maintain grid stability, given Alberta lacks dispatchable, large hydro facilities that provide a similar function in B.C., albeit without the GHG emissions.

Given the current restrictions on intertie capacity with Alberta, an expanded intertie would allow BC Hydro to provide additional amounts of surplus capacity, flexibility and/or clean energy to Alberta and provide opportunities to displace or defer the building of new gas generation. However, the incremental economic benefits to BC Hydro of an expanded intertie to Alberta may be marginal given the significant capacity of the interties to the U.S. and the market opportunities available in the U.S. An expanded intertie to Alberta could however provide significant GHG reductions in Alberta and assist Canada in meeting its climate action goals. A long-term commercial arrangement between the parties that provided an appropriate sharing of the benefits accruing to Alberta would be necessary to support the costs of new transmission facilities.

22.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 72-74

2.22.9 BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow. The Panel requests that BC Hydro respond to the following questions:

- With regards to the flexibility benefits of Site C, please explain whether technological advances could impact the market value of these flexibility benefits (for example, advancements in smart inverter technology).

RESPONSE:

Yes, technological advances could impact the market value of flexibility benefits, both positively and negatively. Technological advances that may impact the market value of the flexibility benefits, as discussed in Appendix S of our August 30 Filing, can be placed in one of two categories, (1) those that have the potential to enhance the benefits of the flexibility of Site C and (2) those that have the potential to reduce the benefits of the flexibility of Site C.

Aggressive renewable portfolio standards in the United States have led to the mass installation of wind and solar resources over the past decade, and this is expected to continue in both the United States and Alberta as renewable portfolio standards continue to be implemented and/or increased. This rapid renewable resource buildout has contributed to technological advances in these resources, particularly solar technologies, reducing the per-unit total cost of solar energy. Although wind and solar resources have generally been added to the level required to meet prevailing renewable portfolio standards in each jurisdiction, there is the potential that further technological advances could reduce solar and/or wind energy costs to a level that makes them considerably more economic than traditional resources such as coal or natural gas generation. If this happens, it could result in some jurisdictions choosing to add variable energy resources in excess of the required quantity (under prevailing renewable portfolio standards) to meet demand growth and/or replace traditional generation resources, such as coal and natural gas generation resources, when they retire. This would increase the need for capacity and flexibility.

At the same time, flexible resources such as Site C, or more generally, the residual flexible capabilities of the BC Hydro Heritage hydroelectric system, currently face competition in providing flexibility in the external markets from a variety of resources including other hydro resources and systems, natural gas resources, coal resources, pumped-storage hydro resources, demand response, and the gradual emergence of battery technologies. Looking forward, however,

the practical choices for flexible resource additions are likely to be more limited, particularly in the context of expanding GHG reduction policies. Few, if any, western jurisdictions are likely to add coal resources, and there is growing concern over the addition of new natural gas resources, particularly in California.[1] Additions of flexible resources are likely to reflect the growing desire to explore clean flexible resource technologies that are also able to provide storage, for the purpose of shaping excess renewable resource production (in excess of local demand) into hours of lower renewable resource production. The new clean flexible resource technologies that are clearly able to provide both flexibility and storage (other than large storage hydro, such as Site C) are new pumped-storage hydro resources and battery technologies.

It is difficult to accurately forecast how technological advances will impact the cost of any resource technology, including pumped-storage hydro resources and emerging battery technologies. However, there are several important points that indicate that the external demand for surplus flexibility and storage attributes of the BC Hydro system, including the addition of Site C, will continue to be valuable in the future, notwithstanding potential technological advances in pumped-storage hydro and/or battery technologies:

- **The demand for flexibility and storage technologies is already large, and is expected to grow rapidly, likely requiring multiple solutions.**

- **Pumped-storage hydro is not a new technology, there are limited sites where pumped-storage resources may be installed, and thus there may be limited ability to dramatically reduce the cost and/or increase the availability of pumped-storage resources.**

- **Battery technologies will likely experience continued technological advancements that will reduce their costs significantly. However, the timing of these advancements and the magnitude of these cost reductions costs is highly uncertain. Moreover, existing battery technologies can only provide approximately 8 hours of dependable capacity, and are not able to provide the same flexibility and storage attributes as large storage hydro resources, such as the ability to store energy across longer time periods and the ability to provide grid support services such as inertia.**

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[1] **For example, in the California Public Utilities Commission Proposed Reference System Plan, the CPUC envisions no new natural gas resources developed in order to meet California's 2030 carbon emission reduction targets. *Administrative Law Judge's Ruling Seeking Comment on Proposed System Plan and Related Commission Policy Actions*, September 19, 2017 at page 11 available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M195/K910/195910921.PDF.**

BC Hydro's understanding of Smart Inverters:

- **Inverters are electrical equipment that converts DC to AC and are typically found as part of a small generation resource installation (e.g., rooftop solar installation for a residential home).**

- **Smart inverters have additional communications and control capabilities.**

- **Smart inverters enable an owner of the generation source to see the energy being generated and often control the device remotely or give control of the device to a third party.**

At this time, BC Hydro is not aware of any evidence that smart inverter technologies will be able to provide the attributes, or scale to the required level, to provide the flexibility, storage and capacity that are expected to be required to meet the rapidly growing needs associated with renewable resource integration.

22.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 72-74

2.22.10 BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow. The Panel requests that BC Hydro respond to the following questions:

- Please describe rough load zones, no run zones and minimum generation constraints (e.g. transmission reliability, hydraulic balance, fisheries requirements, ice flows etc…). Is Site C or its generators expected to have these restrictions? If so, what are they and how will they effect Site C's operations and flexibility? If not, why not? Please elaborate.

RESPONSE:

Hydro generating units, plants and reservoirs will have a variety of operating constraints that are implemented to limit wear and tear, and manage environmental and social issues. The following terms are defined, along with how they will effect Site C's operations and flexibility:

- **Rough Load Zones: There will be bands of the generation operating range that results in high vibration levels in the generating unit that can reduce the life expectancy of the unit or increase maintenance requirements. These bands of operation are called "rough load zones". To avoid the wear that occurs within these zones, when a unit is ramped from one generating level to another, it will be transitioned through rough load zones quickly. Based on studies, it is anticipated that the rough load zone for the generating units at Site C will occur at outputs below approximately 120 MW, therefore operation between about 0 – 120 MW will be minimized;**

- **No run zones: The term "no run zone" is not typically used at BC Hydro, however it likely refers to either rough load zones, or a range of generation from a plant that would result in other undesirable impacts;**

- **Fisheries Requirements: The minimum flow, as per the water license, is 390 m3/s (about 175 MW), for protection of aquatic and riparian habitat downstream. This can be provided by generation discharge and/or spill release;**

- **Ice Flows: Ice flows refer to the restrictions on operations currently at Peace Canyon, and later at Site C, where flows are restricted to specific ranges to ensure that the potential for ice jam flooding downstream is being managed.**

Ice flows that will be specified for Site C are anticipated to be similar to that which is currently being specified for Peace Canyon. These can occur during freeze-up or break-up. For freeze-up this would include a period of a few weeks each winter, where flows are set at a day-average discharge of about 1,450 m3/s (about 650 MW) to ensure that a stable river ice sheet is formed at Town of Peace River, A.B. While the day-average discharge must be maintained, there is also some flexibility for the plant to generate for a few hours at higher levels to serve the daily peak load. With Site C, the start of ice control would be delayed by about five days on average but the duration of ice control would be similar. For ice control during break-up (in April) studies indicate that timing of break-up would not change as a result of the Site C project and therefore the ice flow restrictions during this time would be the same as they are now. This restriction lasts from three to seven days and would limit Site C to flows between 390 m3/s (about 175 MW) to 900 m3/s (about 400 MW) depending on local inflows between Site C and the Town of Peace River, A.B.;

- **Minimum Generation Constraints: The term typically refers to a system wide condition where all flexible generation facilities within the system has been reduced to minimum levels, while not incurring additional spill from the facilities. Minimum generation constraints are most common in the freshet, driven by high generation from non-dispatchable IPP's and BC Hydro's non-storage projects. Under a minimum generation constraint, large basin flexible storage projects, such as GMS, and Peace Canyon (and Site C when it is in service), are reduced to minimum generation levels;**

- **Minimum Generation at Site C: The Site C project will have a licensed minimum flow limit of 390 m3/s. If this minimum flow is released through the Site C powerhouse, then it will result in about 170 MW of generation at the plant;**

- **Transmission Reliability: Transmission reliability is comprised of both adequacy and security. Adequacy is the ability of the transmission system to supply the total amount of electricity required to meet the needs of its customers at all times, taking into account any scheduled and/or reasonably expected unscheduled outages of system elements. Security is the ability of the system to withstand any sudden disturbances such as an electric short circuit or an unanticipated loss of a system element. Transmission reinforcements are planned to enable the Site C project. With these reinforcements, there is no significant transmission reliability issues expected; and**

- **Hydraulic Balance: Hydraulic balance refers to the comparison of hydraulic capacity in a downstream plant, as it relates to the combination of hydraulic capacity of an upstream plant plus the local inflow between the two plants. In the case of Site C and Peace Canyon Dam, assuming a Site C plant hydraulic capacity of about 2500 m3/s, with Peace Canyon full powerhouse capacity of**

about 2,000 m3/s, then the plants would be considered to be in hydraulic balance when local inflow was about 500 m3/s. With all units available at Site C, the plant will usually be able to exceed the combined release of Peace Canyon powerhouse plus local inflows. Based on the above, hydraulic balance constraints are not expected for Site C.

All the plant related restrictions that are described above will to some extent impact Site C operations and flexibility. These constraints have been included in the operational modeling of Site C. As such, the impact of these constraints has been factored into the capability of the Project as a source of energy and dispatchable capacity.

22.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 72-74

2.22.11 BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow. The Panel requests that BC Hydro respond to the following questions:

- Please describe synchronous condense. Are any features of synchronous condense related to the ability to make adjustments from high generation levels to no generation without a start/stop? If so, what are they? Please elaborate.

RESPONSE:

"Synchronous condense" (S/C) is a mode of operating a synchronous machine that allows the machine to contribute reactive power (dynamic voltage control) and inertia to the system without generating real power. When a synchronous machine is operating in S/C mode it is basically operating as a synchronous motor, taking a small amount of power from the system to overcome friction, windage, iron and copper losses in the machine. In S/C mode the generator can control the voltage in the region by automatically producing or absorbing reactive power just as it would do when operating in generate mode.

To make the Site C units capable of operating in S/C mode, draft tube dewatering facilities would be needed to allow the units to operate efficiently. Typically, when the wicket gates are completely closed, the water level in the draft tube covers the turbine, so simply shutting the wicket gates to operate in S/C mode would result in high losses from the turbine runner churning up the water lying in the draft tube. The dewatering equipment consists of a compressed air system that pressurizes the draft tube to lower the water level to below the turbine runner, allowing the turbine to spin freely in air.

Switching from generate mode to S/C mode would not require the generating unit to be shut down, but switching between modes would take several minutes.

22.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 72-74

2.22.12 BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow. The Panel requests that BC Hydro respond to the following questions:

- Please elaborate on how the design decision to include synchronous condense in all six generating units is related to the opportunity to sell the capacity and flexibility afforded by Site C.

RESPONSE:

The design decision to include synchronous condense (S/C) in all six units was driven by the need to meet system reliability requirements and by the desire to maximise the economic value of Site C's capacity and flexibility.

Installation of synchronous condense on six units enables these objectives in the following ways:

- **Units with S/C capability can be cycled from generating to zero power output with minimal wear and tear on the units, thereby giving them more ability than S/C incapable units to follow the variations in load and renewables in B.C. and price swings in nearby power markets;**

- **Regional minimum units on-line requirements can be met with units operating in generation or S/C mode. When market prices are low and system import is high, S/C capable units at Site C can be run in S/C mode to help meet the regional minimum units on-line requirements without having to generate, thereby maximizing total system imports;**

- **Units capable of S/C at Site C will provide flexibility in satisfying system-level rotating inertia requirements for system stability at low power generation levels;**

- **The period of time for most S/C use in the BC Hydro system is in May to June as this is often when maintenance is performed on the transmission and substation components as well as the generating units. Installation of S/C on all Site C units provides flexibility to schedule maintenance in a least-cost manner during these times and in response to any unplanned outages. This is of particular value when scheduling maintenance on the common transformer shared by each two Site C units given that minimum units on-line requirements**

can increase when transmission and/or substation components are out of service (e.g., Southbank reactor outage increases units on-line requirement by one); and

- **The cost of installing S/C on all six units during initial construction is expected to be cheaper than a staged approach.**

For reference, the Peace regional minimum units on-line requirement is five units, with the requirement increased in certain specific circumstances. Currently, there are only three units in the Peace region (all at GM Shrum) that have S/C capability.

22.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 72-74

2.22.13 BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow. The Panel requests that BC Hydro respond to the following questions:

- Has BC Hydro analyzed selling Site C's surplus energy and capacity within BC at discounted rates to incent incremental consumption (i.e. similar to the Freshet Rate pilot)? If so, please elaborate. If not, why not?

RESPONSE:

With BCUC approval, BC Hydro implemented a pilot industrial freshet rate (Rate Schedule 1892) to encourage incremental energy consumption by industrial transmission service rate customers, by providing them access to market prices for surplus energy during the annual Freshet Period of May 1 to July 31. During the Freshet Period the BC Hydro system is subject to a seasonal load resource imbalance (energy oversupply). The freshet rate provides eligible customers with access to market prices for incremental energy purchases.

A preliminary evaluation of the freshet rate indicated that it was successful in terms of customer participation, incremental energy sales and positive ratepayer impact. However, a key concern with surplus rates is accurately determining the surplus, or incremental consumption. Failing to accurately determine the surplus energy that is eligible for the discounted rate could result in revenue losses and impacts to non-participants. BC Hydro is assessing this issue as part of its final evaluation of the freshet rate, as directed in Appendix A of Commission Order No. G-17-16 regarding the 2015 Rate Design Application.

As part of the process of developing the freshet rate proposal for industrial transmission service rate customers, BC Hydro discussed the potential for extending a freshet rate to general service customers at some future date. The outcome of these discussions was the determination to use the learnings from the freshet rate pilot evaluation to inform future consultation on a potential surplus rate for general service customers.

If BC Hydro were to pursue any other such surplus rates, revenues earned would be similar to the modelled market recoveries and would not impact the analysis although this may have ancillary economic development benefits for B.C.

22.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Pages 72-74

2.22.14 Please discuss the potential implications and impact of Powerex joining, or potentially not joining, the Energy Imbalance Market and how that relates to the value of Site C energy and capacity. Include an analysis and discussion of the potential impact resulting from an expansion of Energy Imbalance Market.

RESPONSE:

The Western Energy Imbalance Market (EIM) is a voluntary intra-hour wholesale electricity market located in the U.S. Powerex's participation in the EIM will complement its continued participation in other wholesale electricity markets in the western interconnect, including the forward, next day and hourly bilateral energy markets, as well California's next day and hourly organized markets and Alberta's hourly organized market. Powerex expects to continue to decide its level of participation in each of its available markets, including the EIM, based on the relative opportunities in each market.

The EIM enables the purchase and sale of energy in 15-minute and five-minute increments. The EIM provides a new opportunity to monetize the residual capabilities of the BC Hydro system and affords several key advantages over other market opportunities that are available to monetize sub-hourly flexibility. First, the EIM removes transmission hurdle rates that generally exist today in other U.S. markets, through its transmission reciprocity framework, thereby lowering the cost of delivering energy across the EIM footprint. Under this transmission reciprocity framework, each participating entity voluntarily brings transmission rights ahead of each applicable hour to connect to the EIM footprint, with no further fixed transmission charges applying to EIM transactions within the applicable hour. Second, the EIM allows the automated purchasing and selling of sub-hourly energy, through the EIM's sophisticated software processes. This is an important improvement over the bilateral sub-hourly markets, due to the limited time available to identify trading counterparties, and to negotiate and schedule transactions for each sub-hourly period. While Powerex expects to continue to negotiate longer-term bilateral contracts that also monetize the hourly and sub-hourly flexibility of the BC Hydro system, the EIM presents a new and growing opportunity to do this for discrete intra-hour transactions.

The EIM is one of the last temporal markets available for Powerex to participate in, as it operates after energy has been transacted in the larger forward and day ahead markets in the western U.S. As such, the volume of energy transacted in the EIM is generally limited by the residual U.S. transmission rights voluntarily made available to the EIM each operating hour, as well as by the residual

purchase and sale capabilities of the participants voluntarily offered into this sub-hourly market. Powerex anticipates that its participation, scheduled to commence in April 2018, will typically include approximately 300 MW of import and export transmission rights to and from B.C., as well as approximately 300 MW of purchase and sale bids and offers, which will be supported by the residual capabilities of the BC Hydro system. Although Powerex may increase its level of participation as opportunities arise, it is currently expected that Powerex's level of participation in the EIM will not frequently be limited by the capacity or flexibility of the BC Hydro system, but rather by the level of market opportunities and transmission transfer capability in the EIM. Therefore, at this time, there is no direct connection between Powerex's participation in the EIM and Site C.

With respect to future market evolution, the EIM is likely to continue to grow both in terms of its geographic footprint as well as the volume of voluntary bids and transmission transfer capability. This growth could afford Powerex greater opportunities to monetize the residual flexible capabilities of the BC Hydro system in the future. Nonetheless, the EIM is expected to continue to remain just one market amongst several by which Powerex can monetize the residual flexible capability of the BC Hydro system.

24.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 86

2.24.0 BC Hydro is requested to provide each of these two adders without the effect of the energy increase, and to provide a separate adder for the effect of this energy increase.

RESPONSE:

There have been two points at which the expected average annual energy generation and/or capacity from Site C have increased.

1. **A change was made to the project design to reduce the project tailwater level, increasing project head. This resulted in an increase in the annual energy expected from Site C to 5,196 GWh/year. There was no change to the project capacity.**

2. **The design submitted by the successful proponent as part of the turbine generator procurement process demonstrated higher turbine efficiency resulting in an increase in the annual energy to 5,286 GWh/year and the project capacity to 1,132 MW. This increased output was confirmed through independent model testing.**

The first change above happened prior to the Site C FID, while the second change happened after the Site C FID.

The changes to the UEC at FID and to the current estimates are provided below. This table provides further break out of the change in generating capability at each stage, as shown in the highlighted rows.

	$/MWh
Site C Cost to Ratepayers in 2013 IRP	$83
Change to project capital and operating costs	+2
10-year rates plan: net income now tied to inflation and no longer increases when new assets like Site C added to the system	-26
Change in annual energy to 5,196 GWh/year	-1
Site C Cost to Ratepayers at Final Investment Decision (December 2014) at Point of Interconnection (F2013$)	$58
Updated financing rates (F2013$) – Cost of debt decreases from 4.7% to 3.43%	-9
Change in energy from 5196 GWh to 5286 GWh and capacity from 1100 MW to 1132 MW (F2013$)	-1
Adjustment for Delivery to Lower Mainland and annual shape adjustment (F2013$)	+9
Conversion to F2018$ *	+0
Site C Cost To Ratepayer Today Delivered to Lower Mainland in F2018$	$58

*** The conversion to F2018$ is non-zero, but rounds to $0.**

Note that some adjustments in the table have compounding effects – i.e., the combined effect of two changes may not be equal the sum of the individual changes. BC Hydro has applied the changes in a "top to bottom" order such that compounding effects are included.

25.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 86

2.25.0 BC Hydro is also requested to provide this adder without the effect of the energy increase, and to provide a separate adder for the effect of this energy increase.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.24.0.

30.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 87

2.30.0 The Panel notes the submission of the David Suzuki Foundation regarding the economic impact of the Site C project on "natural capital". However, there is no analysis of the impact of the alternative portfolio so there is no way for the Panel to include this in its economic assessment. The DSF is invited to provide further evidence on this issue. The Panel is unclear how, or whether, this is a direct cost to ratepayers. It appears to the Panel that this is a cost that would be borne by taxpayers. We invite further comment on this issue.

RESPONSE:

In its submission to the Commission, the David Suzuki Foundation ("DSF") suggests that they have presented information directly relevant to the Site C project area. They submit, and the Commission cites, that the "ecological services provided by farmland and nature in the Peace River Watershed are conservatively worth an estimated $7.9 billion to $8.6 billion a year", of which they estimate approximately 85 per cent are derived from "the total annual value for carbon stored in the forests, wetlands and grasslands of the Peace River Watershed" .[1] In making this submission DSF suggests that this would be the annual cost of lost natural capital if Site C is completed, and that this value is largely due to the loss of carbon storage due to the Project.

The DSF submission does not assist the Commission in its Inquiry as it is not relevant to the Project area, and is based on flawed assumptions and key omissions. In particular:

- **The "natural capital" cost estimates provided by DSF are derived from a massive study area about 1,000 times larger than the land that will be inundated by Site C, and do not account for the specific features of the Site C project area;**
- **The project area (without Site C) is a low net carbon emitter, not a carbon storage area;**
- **DSF incorrectly asserts in their cover letter that the forest and river were "given no value at all" in the decision as to whether the Site C project should proceed; and**

[1] **David Suzuki Foundation's submission to the Commission Site C Inquiry, cover letter, and The Peace Dividend, page 8.**

- **DSF has not included in their methodology the value of hydroelectric energy produced within the project area, or the net benefit the Project provides to the reduction of GHG emissions.**

DSF's "Natural Capital" Estimates Are Based on an Area about 1,000 times the Area of the Land Inundated by Site C

The estimates provided by DSF related to "natural capital" are not relevant to the Project or to this Inquiry. The submission by DSF is based on a study area approximately 1,000 times larger than the inundated area. It is not an estimate of natural capital or carbon emissions of the Site C project area, but of a much larger area with considerable diversity.

The total area of the BC portion of the "Peace River Watershed" used in the DSF report to derive their estimates is approximately 5.6 million hectares.[2] The total area of the Site C reservoir will be 9,330 hectares, and of this, 5,557 hectares is land that will be inundated and 3,773 hectares is the existing river channel. Thus the DSF submission cannot and should not be used to draw conclusions regarding the effect of Site C, when it covers an area 1,000 times larger than the land that will be inundated by the Site C Project.

The Site C Project Area is a Net Emitter of Carbon, Not a Carbon Storage Area

The DSF suggestion that the Site C Project will eliminate net carbon storage value is not only based on a study area that is almost entirely not affected by Site C, it is also not supported by area-specific carbon modeling of the Site C project area conducted as part of the environmental assessment for the Project. That model demonstrates that the area that will be permanently affected by the Project is in fact a net carbon emitter of greenhouse gas emissions, as opposed to a net carbon storage area.

The carbon balance model for the Project area of the specific aquatic and terrestrial areas affected by the Site C Project was developed by independent consultants, and presented as part of the Environmental Impact Statement prepared for the environmental assessment of the Project. In that analysis, GHG emissions, including emissions from the reservoir and land clearing activities, were quantified using methods described by the Intergovernmental Panel on Climate Change (IPCC, 2003), and an area-specific carbon model to account for the substantive carbon stocks, processes and fluxes within the Project area.[3] The analysis demonstrates that, while the reservoir area is a small net sink for carbon, emissions from the pre-impoundment Site C Project area (i.e., prior to dam construction) are approximately 5,700 tonnes CO_2e/yr. The carbon storage that

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[2] **EIS, section 11.3, Table 11.3.1, available at http://www.ceaa.gc.ca/050/document-eng.cfm?document=93686.**

[3] **Greenhouse Gases Technical Report, Stantec Consulting Ltd., EIS Volume 2, Appendix S, available at http://www.ceaa.gc.ca/050/document-eng.cfm?document=93686.**

does exist in the project area is offset by agricultural activities in the area (crop production and livestock) that produce CH_4 and N_2O emissions, resulting in net greenhouse gas emissions (not storage).

The model and analysis were reviewed by Environment Canada who agreed with its conclusions.[4]

The Joint Review Panel also agreed, and in its report, concluded:

> **"Environment Canada (EC), in their written submission to the Panel, found the calculations of GHG emissions associated with construction and operation of the Project to be reasonable. EC agreed with the Proponent's determination that the adverse residual effects of the Project on GHG emissions would be low.**
>
> **EC also agreed that the GHG emission intensity would be substantially lower than other electricity generation options, as supported by the 2012 special report of the Intergovernmental Panel on Climate Change, Renewable Energy Sources and Climate Change Mitigation."[5]**

The Environmental Assessment Took into Account the Project Area's Ecological Features and the Recreational Use of the Project Area

It is not accurate to state that the value of the forest and the river were "given no value at all" in the review of Site C. The environmental assessment included thousands of pages on the effect of the Project on land and resource use within the Project area, as well as effects on wildlife, vegetation and ecological communities, and fish and fish habitat.[6]

Moreover, DSF's report does not take into account mitigation measures that will be implemented as part of the development of the Project. Specifically:

- **Other than carbon storage, DSF states that the next highest ecosystem value in the Peace River Watershed relates to wetland habitat. Pursuant to condition 11 of the Decision Statement, BC Hydro will be replacing lost wetland function and area, so that there will be no net loss of wetland ecosystem value in this area.[7]**

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[4] **Environment Canada's Written Submissions to the Joint Review Panel, November 25, 2013, available at http://www.ceaa.gc.ca/050/documents/p63919/96418E.pdf.**

[5] **Joint Review Panel Report, page 42.**

[6] **Environmental Impact Statement, available at http://www.ceaa.gc.ca/050/document-eng.cfm?document=93686.**

[7] **Decision Statement, condition 11; refer also to Environmental Assessment Certificate, condition 12.**

- **After wetland habitat, the third highest value of the Peace River Watershed, according to the DSF report, is recreation. However, DSF does not consider the new reservoir-based recreation setting in its analysis, enabled by public access that BC Hydro will be building both to the reservoir and downstream for recreational purposes.**

- **With respect to agriculture, BC Hydro is required to establish a $20 million agricultural investment fund for improving agricultural land in the region.[8] The Joint Review Panel concluded that "the current annual value of crops from the portion of the valley that would be inundated is but $220,000", and that the "proposed $20 million agricultural investment fund, to be spent on improvements outside the inundation zone, is generous by comparison".[9] The Joint Review Panel concluded that "the highest and best use of the Peace River valley would appear to be as a reservoir."[10]**

DSF Does Not Attribute Any Value to the Hydroelectric Energy that Will Be Produced by the Project Area or Acknowledge the GHG Benefits of Site C

BC Hydro ratepayers will derive considerable value from the hydroelectric services provided by the Site C project, which DSF does not acknowledge. Furthermore, with very low GHG emissions during project operations, it is unlikely that the Project would result in future cost risk associated with increasing regulation of GHG emissions over time. In fact, as affirmed by Environment Canada and the Joint Review Panel, the project provides a net GHG benefit as compared to any other electricity generation option.[11] The Project will produce the lowest greenhouse gas emission intensity of any other resource option.[12]

In conclusion, the costs submitted by DSF and cited by the Commission Panel (at page 84), are not reflective of the Project and are not relevant to this Inquiry.

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[8] **Environmental Assessment Certificate, condition 30.**
[9] **Joint Review Panel Report, page 149.**
[10] **Joint Review Panel Report, page 149.**
[11] **Joint Review Panel Report, pages iv, 242-243; Environment Canada's Written Submissions to the Joint Review Panel, November 25, 2013, page 67, in which Environment Canada writes: "EC also agrees with BC Hydro that the electricity produced as a result of the Project will have a substantially lower GHG emission intensity in relation to most other electricity generation options. This finding is consistent with the 2012 special report of the Intergovernmental Panel on Climate Change (IPCC) entitled "Renewable Energy Sources and Climate Change Mitigation." The IPCC report re-affirms the importance of renewable energy supply choices such as hydropower that will be an important element of any strategy aimed at stabilizing and reducing GHG levels in the future."**
[12] **BC Hydro August 30 Filing, Appendix G.**

36.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 92

2.36.0 BC Hydro is requested to explain in more detail the calculations for cost of incremental firm transmission and line losses.

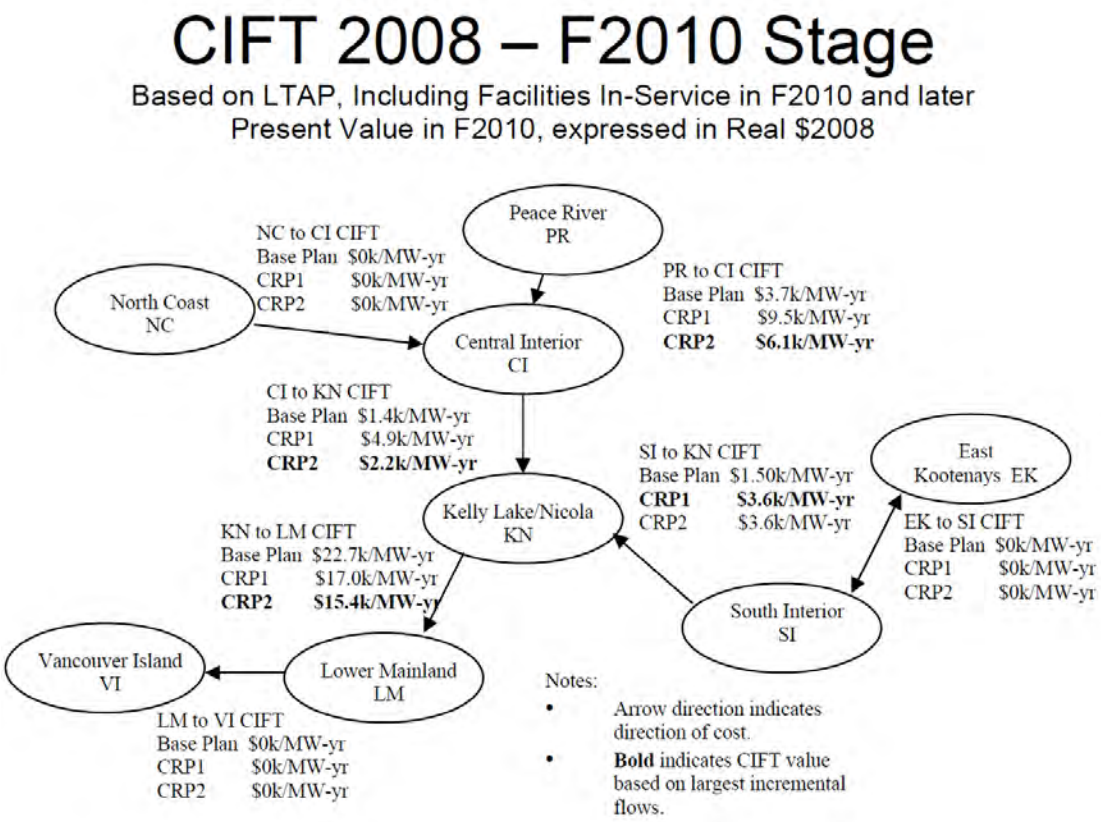
RESPONSE:

<u>Cost of Incremental Firm Transmission (CIFT):</u>

Over time, BC Hydro incurs additional bulk transmission reinforcement costs as a result of acquiring additional resources that are largely needed to be delivered to the Lower Mainland. BC Hydro uses CIFT in its UEC calculations to provide a price signal for locating in different areas of the province. Note that in portfolio analysis CIFT is not used, rather specific transmission upgrade requirements and their associated costs are modeled in the portfolio analysis. This provides a more granular assessment of potential transmission requirements.

For UEC adjustments we calculate a CIFT using the BC Transmission Corporation (BCTC) report titled: Bulk Transmission System Cost of Incremental Firm Transmission for BC Hydro's 2008 LTAP Base Plan and Contingency Resource Plans CRP1 and CRP2 (January 15, 2009) attached to BC Hydro response to BCUC IR 2.26.0 The calculation is based on the location of the resources and their generation characteristics. This report provides a general indication of the long-term unit cost of bulk transmission system reinforcements from one transmission region to the next. The diagram below is taken from this report.

For a project located in the Peace River region, the CIFT adjustment to Lower Mainland will be the $23.7/kW-year in F2008 dollars (the sum from Peace River to Central Interior at $6.1/kW-year, Central Interior to Kelly Nicola at $2.2/kW-year and Kelly Nicola to Lower Mainland at $15.4/kW-year), or about $27/kW-year in F2015 dollars. The CIFT adjustment was then converted to $/MWh by multiplying by the Effective Load Carrying Capability of the wind project and divided by its firm energy. Using Wind_PC18 as an example, the CIFT adjuster = $27/kW-year * 36,000 kW/524,000 MWh = $1.86/MWh.



<u>Line Losses Adjustment:</u>

Resources that BC Hydro acquires incur losses to deliver energy to the load centre, largely the Lower Mainland. To calculate UECs, BC Hydro uses the methods described below to estimate losses for a particular resource. Note that in portfolio analysis, this line loss adjustment is not used but rather the software calculates system losses based upon the portfolios modelled.

- **The calculation carried out to determine losses associated with delivering energy of each resource option to the Lower Mainland is based on the location of the resources and their generation characteristics. Energy losses were calculated based on the methodology described in the BCTC report titled: Peak Load Incremental Losses for the Bulk Transmission System (January 2010) attached to BC Hydro's response to BCUC IR 2.26.0.**

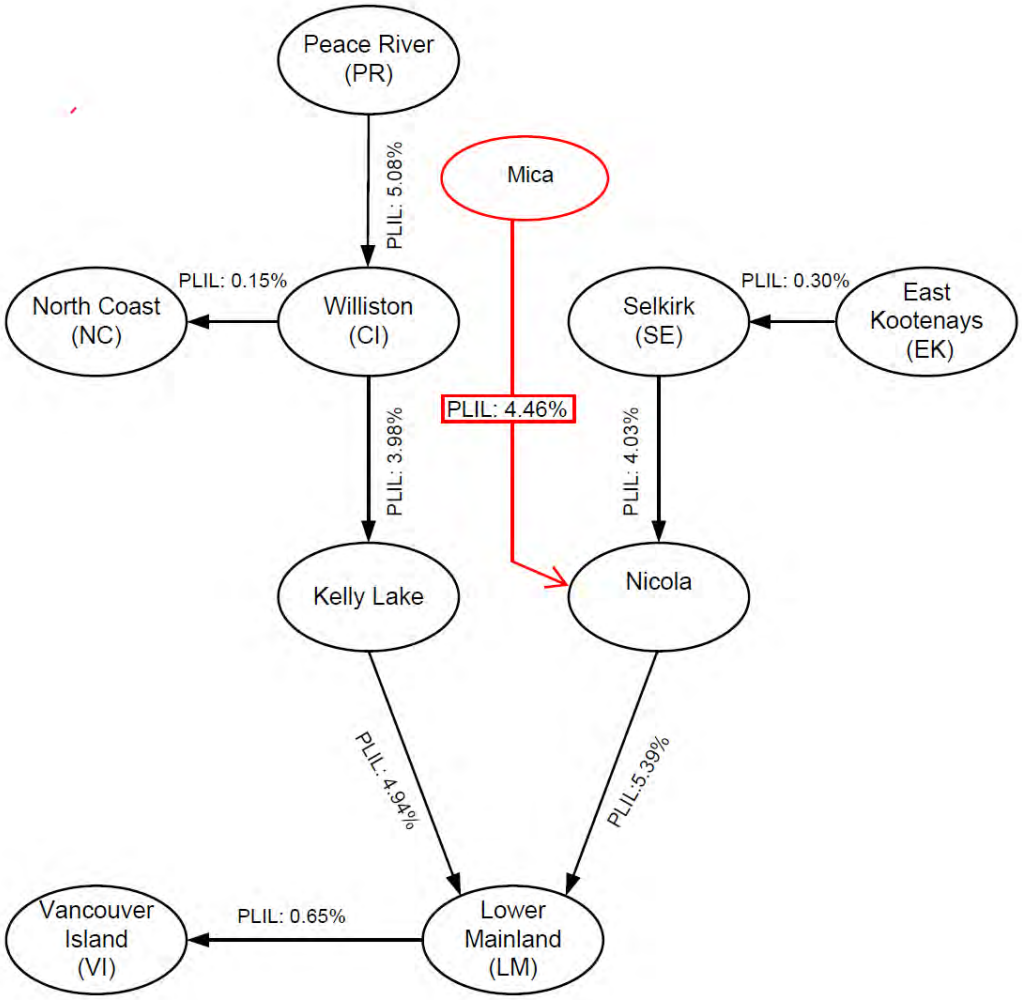
- **For the UEC adjustment shown in the spreadsheet provided to BCUC (Filing F1-4) and referenced in the question, the line losses adjustment is estimated using the information for year 2014-2015 from the report which is**

copied below for ease of reference. The line losses adjustment was estimated based on the peak load incremental losses for bulk transmission paths converted to energy losses using system loss load factors for year 2014-2015.

- **For a project located in the Peace River region, the total incremental losses to the Lower Mainland are 14 per cent (the sum of 5.08 per cent from Peace River to Central Interior, 3.98 per cent from Central Interior to Kelly Nicola, and 4.94 per cent from Kelly Nicola to Lower Mainland). The average load factor and loss load factor are 0.65715 and 0.47575 for year 2014/2015, respectively.**

- **The energy losses (GWh) = total incremental losses * installed capacity * 8760 * loss load factor * generation capacity factor/average load factor. The UEC after taking into consideration of the energy loss would be UEC_POI * average energy/(average energy – energy losses), and the line loss adjuster will be the difference between UEC_POI and the UEC after energy loss. Simplifying the formula, the line losses adjustment = UEC_POI * (1/(1 – total incremental losses * loss load factor/average load factor) - 1). Using Wind_PC18 as an example, the line loss adjuster = 77.84 * (1/(1-0.14 * 0.47575/0.65715) - 1) = $8.78/MWh.**

BCTC Bulk transmission system Peak Load
Incremental Losses (PLIL) for the year 2014-2015



42.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 93

2.42.0 In contrast to the low financing costs for Site C, it appears that full rate base financing applies to the Alternative Block. If so, this assumption results in an apples-to-oranges comparison. If any capital project undertaken by BC Hydro is also financed by interest, this differential in financing assumptions of Site C vs the alternative portfolio implies that BC Hydro would not build any of the projects in the alternative portfolio. It is not clear why there is this implicit assumption. Further, if this is the case, outsourcing generation projects may result in differences in assumptions about project risk, and may affect the assessment of UEC.

BC Hydro is requested to clarify its assumptions underlying financing costs.

RESPONSE:

<u>Role of the Utility</u>

BC Hydro's mandate is to safely deliver reliable, affordable and clean power in accordance with the objectives in the *Clean Energy Act*. This has been achieved with the legacy backbone of hydroelectric Heritage Assets, as shown in Schedule 1 of the *Clean Energy Act*, which BC Hydro has developed, maintained and operated. The Heritage Assets are to be retained by BC Hydro for the benefit of its ratepayers and that role includes the potential construction of Site C. BC Hydro's analysis shows that there is a requirement for dependable capacity assets to augment the Heritage Hydro backbone that has provided benefits to BC Hydro ratepayers for decades.

BC Hydro does not have a mandate to explore and develop alternative energy resources. The role to develop other sources of clean and non-clean energy is that of Independent Power Producers. In the 1980s, BC Hydro acquired its first run-of-river hydro contracts. In the 1990s, BC Hydro acquired gas-fired generation contracts and biomass contracts. BC Hydro's role was formalized in the 2000s with the 2002 and 2007 Energy Plans. The 2002 Energy Plan Policy Action #13 states that "the private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants." This was later confirmed in the 2007 Energy Plan that built upon the framework of the 2002 Energy Plan.

The IPP industry has played a useful role in the development of these many varied resources in B.C. The innovation and exploration that has been undertaken by the IPP industry has provided B.C. with a broad range of clean resources and is increasingly expected to deliver those resources on a cost-effective basis. The

benefit of the IPP industry undertaking these exploration and development activities is their ability to raise capital where investors are willing to assume those risks for the return of an EPA with a reasonable return on equity. If IPPs pursue a risky undertaking that does not become a project, the costs do not flow to ratepayers.

BC Hydro is not well positioned to undertake the risks associated with the exploration and development activities for the many smaller resources and believes the IPP industry should continue to play a similar role. Were BC Hydro to undertake those activities, normal financial processes would have those costs be recovered from ratepayers. Conversely, BC Hydro is well able to undertake the development of large hydro facilities in terms of the longer term approach to development and to spend the time and effort to obtain the necessary permits and approvals. Large utilities are best able to develop large projects of this nature and take on the associated risks on behalf of ratepayers. BC Hydro has the historical perspective of large hydro development and has been developing significant projects such as the John Hart Refurbishment.

BC Hydro's past attempts (including the geothermal development attempts at South Meager Creek) have been costly failures. The best option for the ratepayer is for BC Hydro to seek these alternative resource options from IPPs. BC Hydro has undertaken all of its recent planning and acquisitions on that basis and continues to be of the view that those relative roles are appropriate and largely beneficial for the ratepayer.

In order to meet our mandate, BC Hydro also undertakes cost-effective demand-side management and was one of the early leaders in demand-side management in Canada.

<u>Financial Analysis and Ratepayer Impact</u>

The Commission is correct that BC Hydro has applied different financing costs to different resources. This is appropriate in light of the different developers as discussed above. BC Hydro's approach recognizes that the Terms of Reference focus on ratepayer impact. It uses the financing costs that would actually be paid by ratepayers for particular resources. Specifically:

- **IPPs have a materially higher cost of capital than BC Hydro, and customers will pay that higher cost of capital when BC Hydro acquires the resources. Where resources are likely to be developed by IPPs, we have used an IPP's cost of capital. This is true for the portfolio including Site C and the portfolios without Site C; and**

- **BC Hydro is regulated to finance Site C with debt, rather than a mix of debt and equity. This is the cost that will be recovered from ratepayers, and the Commission is required to look at the impact on ratepayers.**

Artificially assuming all resources can be financed at the same rate as BC Hydro is effectively assuming that BC Hydro will develop all future resources in the portfolios. In other words, the Commission would be assuming that there is no real place for the IPP industry in British Columbia for some time into the future. As described above, we regard this to be a highly unrealistic assumption given it is at odds with the current approach to resource development.

In the context of the ratepayer analysis required by the Terms of Reference, using the costs of financing that ratepayers would pay across all portfolios provides an "apples to apples" comparison. Making assumptions that are unlikely to reflect real ratepayer impacts would be inconsistent with the Terms of Reference, and would introduce significant risk of understating the cost of an alternative portfolio to Site C. As contained in the Commission's decision concerning BC Hydro's 2006 Integrated Electricity Plan/Long-term Acquisition Plan (pages 183 to 208):

- **For purposes of comparing BC Hydro and IPP projects, there should be recognition that BC Hydro will have a lower cost of capital given its access to the Province's high credit rating. For IPP projects, the relevant costs are the costs that reflect payments IPPs receive from BC Hydro and what ratepayers will pay.**

46.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 103

2.46.0 BC Hydro is requested to model a reduction in the capital cost of wind energy as follows:

Table 56: Percent Reductions in Capital Cost of Wind Energy

2020	2025	2030	2035	2040
10%	25%	30%	40%	45%

RESPONSE:

The Commission has raised a number of questions regarding BC Hydro's 70-year analysis of portfolios that include and exclude Site C and asked for additional sensitivity analysis regarding these questions.

BC Hydro has undertaken the analysis requested by the Commission below (referred to here as "Commission Portfolio Sensitivities") including additional sensitivities and finds that completing the Site C project is still in the ratepayers' best interest under the full range of requested sensitivities. Even under a scenario in which Site C's costs increase by 50 per cent, and when Site C is compared to alternative resources using highly optimistic assumptions regarding futures costs, and where BC Hydro is assumed to be the developer and financier of all alternative resources in the province, completing Site C remains a lower cost option than alternatives.

The Commissions specific requests include:

- **On page 103 of the Preliminary Report, the Commission found that geothermal, solar, biomass and battery storage may be alternatives that should be included and asked for the portfolio analysis to be rerun with these options.**
- **In BCUC IRs 2.46.0, 2.47.0 and 2.48.0, the Commission requested reductions in the costs of wind, solar and battery storage of 45 per cent, 60 per cent and 50 per cent by 2040 to be reflected in this analysis.**
- **In BCUC IR 2.40.0, the Commission questioned the IPP EPA renewal costs in the study.**
- **In BCUC IR 2.42.0, the Commission questioned whether BC Hydro should be building and financing IPP Projects.**

- **In the BCUC IR 2.22 series, the Commission raises a number of issues related to market value for surplus energy.**

- **In BCUC IR 2.15.0, the Commission asked for an assessment of the cost outcome scenarios identified by Deloitte in their Report #1.**

BC Hydro has also addressed the risks of the Commission's requested sensitivities in BCUC IRs 2.50.1 and 2.42.0.

In order to be responsive to the Commission's request for BC Hydro's view of future resource costs, BC Hydro has created additional alternative portfolio sensitivities that we believe would be reasonable as a test of Site C's cost effectiveness under more optimistic assumptions regarding alternative resources (referred to here as the "BC Hydro Optimistic Portfolio Sensitivities").

In the portfolio analysis results shown below, BC Hydro has included portfolio UEC results as well as the PV results (refer to the response to BCUC IR 2.45.0 for a discussion of portfolio UECs). The portfolio UECs show the overall cost of each portfolio over the analysis period and are not comparable to the resource-specific UECs provided as part of the Block UEC analysis in section 5.6 of our August 30 Filing.

The portfolio data sheets that show the results of the resources chosen by portfolio will be provided in our response to BCUC IR 2.44.0. Note that Site C sunk, termination and remediation costs have been included in the Alternative Resources portfolio being recovered over ten years.

Table 1 Project Overrun Cost Sensitivities (August 30 Filing Assumptions)

August 30 Filing Cost Overrun Sensitivities	Benefit Site C Portfolio vs. Alt. Resources Portfolio (PV - $ billion)	Site C Portfolio Unit Energy Cost ($/MWh)	Alternative Resources Portfolio UEC ($/MWh)
BC Hydro August 30 Filing Mid Gap	7.3	76	110
+10% Site C Project Cost	7.0	78	110
+20% Site C Project Cost	6.6	79	110
+50% Site C Project Cost	5.5	84	110

August 30 Filing Cost Overrun Sensitivities	Benefit Site C Portfolio vs. Alt. Resources Portfolio (PV - $ billion)	Site C Portfolio Unit Energy Cost ($/MWh)	Alternative Resources Portfolio UEC ($/MWh)
Small Gap[1]	6.1	36	83
+10% Site C Project Cost	5.7	45	83
+20% Site C Project Cost	5.4	47	83
+50% Site C Project Cost	4.3	55	83
Large Gap	10.6	129	158
+10% Site C Project Cost	10.2	130	158
+20% Site C Project Cost	9.9	131	158
+50% Site C Project Cost	8.7	134	158

Table 1 shows project cost sensitivities using the alternative portfolio assumptions BC Hydro provided in the August 30 Submission. Table 1 shows the impact of project cost overruns consistent with those identified in Deloitte Report #1. The cost sensitivities right up to a 50 per cent cost overrun would not change the results that a portfolio with Site C is the most cost-effective option. The higher project cost does increase the Site C portfolio UEC, especially in the small gap case. However, the costs to ratepayers of recovering the sunk, termination and remediation costs still outweigh the project completion.

[1] **The PV benefit under the small gap for BC Hydro's August 30 Submission has changed to $6.1 billion from $6.4 billion as BC Hydro had the opportunity to run proper portfolios for its DSM modelling in the small gap case. The underlying assumptions have not changed.**

Table 2 BC Hydro Optimistic Portfolio Sensitivities

BC Hydro Optimistic Portfolio Sensitivities	Benefit Site C Portfolio vs. Alt. Resources Portfolio (PV - $ billion)	Site C Portfolio Unit Energy Cost ($/MWh)	Alternative Resources Portfolio UEC ($/MWh)
Mid-Gap w/ BCH UEC Assumptions	6.5	69	90
Mid-Gap w/ BCH UEC Assumptions + Low Market Prices	6.4	68	97
Mid-Gap w/ BCH UEC Assumptions + Low Market Prices + BCH Financing of Alternatives	4.7	59	80
Mid-Gap w/ BCH UEC Assumptions + Low Market Prices + BCH Financing of Alternatives + Low Cost Wind Renewal Assumptions	4.6	58	79
+10% Site C Project Cost	4.2	60	79
+20% Site C Project Cost	3.8	61	79
+50% Site C Project Cost	2.7	66	79

Note: The three project cost sensitivities are applied to the "Mid-Gap w/ BCH UEC Assumptions + Low Market Prices + BCH Financing of Alternatives + Low Cost Wind Renewal Assumptions" scenario.

Table 2 includes the following changes to the August 30 Submission analysis:

- **Common to all of the Commission Portfolio Sensitivity runs:**
  - **GMS Units 1 to 5 Resource Smart project is assumed to be available as a resource as discussed in BCUC IR 2.59.0.**
  - **A very early assessment of capacity focused DSM has been added as per BCUC IR 2.73.0.**
  - **Renewing the other 50 per cent of existing IPP biomass EPAs and making biogas available as a resource – refer to BCUC IRs 2.66.0 and 2.67.0.**
  - **200 MW of geothermal has been assumed to be available – refer to BCUC IR 2.61.0.**
- **BCH UEC Assumptions:**
  - **BC Hydro's estimates of optimistic future cost reductions for wind, solar, and battery storage as discussed in BCUC IRs 2.46.0, 2.47.0 and 2.48.0.**

- **Low Market Prices: As described in section 8.6.2 of the Aug 30 Filing using the lower market price scenario shown in Figure 15 of the submission.**

- **BCH Financing of Alternatives: Alternative resources normally built by IPPs were assumed to be financed by BC Hydro at 3.43 per cent (nominal) cost of debt.**

- **Low Cost Wind Renewal Assumptions: BC Hydro's estimate of reducing costs of renewals as discussed in BCUC IR 2.40.0.**

The BCH UEC Adjustment includes an optimistic assessment of future cost reduction in alternative resources, but one that is possible given the uncertainty in future markets. As shown in Table 2, the impact of this BCH UEC Adjustment on the portfolio PVs is not large.

The assumption that BC Hydro becomes the developer and financier of alternative resources has a much greater impact on the PV comparison. As BC Hydro has stated in BCUC IR 2.42.0, BC Hydro does not have a mandate to develop alternative resources. In addition, the analysis undertaken does not make a provision for the additional development costs that BC Hydro would assume if it were to develop these resources.

When BC Hydro tests all of the issues raised by the Commission including the upper range of Deloitte's identified project cost overruns, the Site C portfolio PV benefit drops considerably to a benefit of $2.6 billion but continues to show a net benefit of completing Site C compared to alternative resources.

Table 3 Commission Portfolio Sensitivities

Commission Portfolio Sensitivities	Benefit Site C Portfolio vs. Alt. Resources Portfolio (PV - $ billion)	Site C Portfolio Unit Energy Cost ($/MWh)	Alternative Resources Portfolio UEC ($/MWh)
Mid Gap - UEC Sensitivities	6.2	73	96
+10% Site C Project Cost	5.8	75	96
+20% Site C Project Cost	5.4	76	96
+50% Site C Project Cost	4.3	81	96
Mid Gap - UEC Sensitivities + Low Market Prices	6.0	75	99
Mid Gap - UEC Sensitivities + BCH Financing of Alternates	4.7	62	79
Mid Gap - UEC Sensitivities + BCH Financing of Alternates + Low Cost Wind Renewals	4.6	61	78
Mid Gap - UEC Sensitivities + BCH Financing of Alternates + Low Cost Wind Renewals + Low Market Prices	4.1	65	81
Small Gap – UEC Sensitivities	6.1	35	73
Small Gap – UEC Sensitivities + Low Market Prices	4.7	38	70
Small Gap – UEC Sensitivities + Low Market Prices + BCH Financing of Alternates + Low Cost Wind Renewals	3.8	34	59
+10% Site C Project Cost	3.4	35	59
+20% Site C Project Cost	3.0	37	59
+50% Site C Project Cost	1.9	43	59
Large Gap – UEC Sensitivities	9.7	128	154

Note: The three project cost sensitivities are applied to the: "Mid Gap - UEC Sensitivities" and "Small Gap – UEC Sensitivities + Low Market Prices + BCH Financing of Alternates + Low Cost Wind Renewals" scenarios.

Table 3 shows sensitivity requests made by the Commission as follows:

- **Common to all of the Commission Portfolio Sensitivity runs:**
  - **Renewing the other 50 per cent of existing IPP biomass EPAs and making biogas available as a resource – refer to BCUC IRs 2.66.0 and 2.67.0;**

- **200 MW of geothermal has been assumed to be available – refer to BCUC IR 2.61.0;**

- **The Commission's UEC sensitivities:**
  - **Commission's estimates of future cost reductions for wind, solar, and battery storage as discussed in BCUC IRs 2.46.0, 2.47.0 and 2.48.0;**

- **Low market prices: As described in section 8.6.2 of the Aug 30 Filing using the lower market price scenario shown in Figure 15 of the submission.**

- **BCH Financing of Alternates: Resources normally built by IPPs were assumed to be financed by BC Hydro at 3.43 per cent (nominal) cost of debt;**

- **Low Cost Wind Renewals: BC Hydro's estimate of reducing costs of renewals as discussed in BCUC IR 2.40.0.**

BC Hydro has provided a number of steps within this analysis to provide the Commission with some granularity in terms of what the impacts of the sensitivities are. Again, BC Hydro financing alternative resources, even without accounting for development cost requirements, shows a considerable impact.

Table 3 provides an "all-in" test for the Commission's requested assumptions by combining the various sensitivity tests in the small gap case and included project cost overrun scenarios. With an assumed 50 per cent project cost overrun scenario, the Site C portfolio PV benefit drops below $2 billion. However, there remains a significant benefit to the ratepayers of completing Site C compared to alternative resources, even in this very remote set of circumstances.

Table 3 also shows the large gap case that continues to show a significant benefit to completing Site C. As discussed in BCUC IR 2.20.0, the electrification potential as the world addresses climate change is not another typical economic variability assessment and should be given significant weight in the Commission determinations.

Table 4 Site C Completed Early

Other Commission Portfolio Sensitivities	Benefit Site C Portfolio vs. Alt. Resources Portfolio (PV - $ Billion)	Site C PortfolioUnit Energy Cost ($/MWh)	Alternative Resources Portfolio UEC ($/MWh)
BCUC IR 2.55.0 – Site C 1 Year Early			
Mid Gap	7.4	75	111
Small Gap	6.3	35	83
Large Gap	11.1	127	157

The Site C early sensitivity does show a slight benefit of completing the project ahead of schedule.

48.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 104

2.48.0 BC Hydro is requested to update the current battery cost and to incorporate the assumption that the cost of battery storage falls by 50% by 2040.
For these analyses, BC Hydro may focus on the following scenarios:

- Low Load forecast with IRP DSM plan. Site C terminated
- Mid Load forecast with IRP DSM plan. Site C terminated
- High Load forecast with IRP DSM plan. Site C terminated

RESPONSE:

Battery systems are assumed to be Lithium-Ion batteries at 100 MW size and 1,000 MWh energy storage capacity. Lithium-Ion technology is selected due to the dominance in the North American battery system market since 2015 (for a discussion of different storage technologies, please refer to section 6.4.5 of Appendix L of Aug 30 Filing).

Below are current costs of battery energy storage, based on a mid-estimate of costs from Lazard and Enovation Partners' analysis (2016).

Attribute	Cost ($US)	Cost ($CAN)	Comment
Installed Capital Cost	**$743,000,000**	**$921,000,000**	**Mid-estimate cost of $US743/kWh of stored energy. Costs include capital systems, battery management systems and installation. Does not include Interconnection, land costs or shipping.**
Fixed OMA	**$16,000,000**	**$20,000,000**	**Based on $US330 million replacement of batteries at year 10, spread over 20-year life**
Variable OMA (not related to charging)	**$8/MWh**	**$10,000,000**	**Based on $8/kWh of stored energy**
Round Trip Efficiency	**93%**	**93%**	

As per the Commission's request, the current capital costs have been assumed to be reduced by 50 per cent by 2040. Considering the fixed OMA costs for battery systems are based largely upon a replacement of battery modules at year 10, the

fixed OMA declines at a similar rate. The variable OMA remains constant over the projected timeframe. The input parameters are detailed below:

Project Name	Installed Capacity MW	Total Capital Cost	Project Life Years	Fixed OMA	Variable OMA (not including energy costs)
2016Li-Ion Battery	1000	$ 921,000,000	20	$ 20,000,000	$ 10,000,000
2017Li-Ion Battery	1000	$ 901,812,500	20	$ 19,583,333	$ 10,000,000
2018Li-Ion Battery	1000	$ 882,625,000	20	$ 19,166,667	$ 10,000,000
2019Li-Ion Battery	1000	$ 863,437,500	20	$ 18,750,000	$ 10,000,000
2020Li-Ion Battery	1000	$ 844,250,000	20	$ 18,333,333	$ 10,000,000
2021Li-Ion Battery	1000	$ 825,062,500	20	$ 17,916,667	$ 10,000,000
2022Li-Ion Battery	1000	$ 805,875,000	20	$ 17,500,000	$ 10,000,000
2023Li-Ion Battery	1000	$ 786,687,500	20	$ 17,083,333	$ 10,000,000
2024Li-Ion Battery	1000	$ 767,500,000	20	$ 16,666,667	$ 10,000,000
2025Li-Ion Battery	1000	$ 748,312,500	20	$ 16,250,000	$ 10,000,000
2026Li-Ion Battery	1000	$ 729,125,000	20	$ 15,833,333	$ 10,000,000
2027Li-Ion Battery	1000	$ 709,937,500	20	$ 15,416,667	$ 10,000,000
2028Li-Ion Battery	1000	$ 690,750,000	20	$ 15,000,000	$ 10,000,000
2029Li-Ion Battery	1000	$ 671,562,500	20	$ 14,583,333	$ 10,000,000
2030Li-Ion Battery	1000	$ 652,375,000	20	$ 14,166,667	$ 10,000,000
2031Li-Ion Battery	1000	$ 633,187,500	20	$ 13,750,000	$ 10,000,000
2032Li-Ion Battery	1000	$ 614,000,000	20	$ 13,333,333	$ 10,000,000
2033Li-Ion Battery	1000	$ 594,812,500	20	$ 12,916,667	$ 10,000,000
2034Li-Ion Battery	1000	$ 575,625,000	20	$ 12,500,000	$ 10,000,000
2035Li-Ion Battery	1000	$ 556,437,500	20	$ 12,083,333	$ 10,000,000
2036Li-Ion Battery	1000	$ 537,250,000	20	$ 11,666,667	$ 10,000,000
2037Li-Ion Battery	1000	$ 518,062,500	20	$ 11,250,000	$ 10,000,000
2038Li-Ion Battery	1000	$ 498,875,000	20	$ 10,833,333	$ 10,000,000
2039Li-Ion Battery	1000	$ 479,687,500	20	$ 10,416,667	$ 10,000,000
2040Li-Ion Battery	1000	$ 460,500,000	20	$ 10,000,000	$ 10,000,000

The estimated cost of capacity (unit capacity cost) for battery storage systems in 2040 is $651/kW-year ($2018), not including a cost of energy lost during charging/discharging inefficiencies. A portfolio analysis has been done that included the above battery storage systems (using a minimum project size of 100 MW) as well as pumped storage (using a minimum project size of 1,000 MW), however the model selects pumped storage as a lower cost option than batteries. Please refer to BC Hydro's response to BCUC IR 2.46.0 for further sensitivity analysis.

50.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 104

2.50.1 BC Hydro is requested to explain whether it has considered the relative risk of the projects in the alternative portfolio.

RESPONSE:

We have considered the relative risk of the projects in the alternative portfolio. BC Hydro has also, in this response, provided a similar risk assessment of the alternative portfolio under the scenarios contemplated by the Deloitte Report. The results of this analysis, summarized at the end of this response and in Table 1, are very important in the context of the task the Commission has been given under the Terms of Reference to perform a relative assessment of how the Site C construction cost and risk assessment compares against the cost and risk of termination and suspension scenarios.

BC Hydro's Assessment of Alternative Resource Portfolio

BC Hydro provided an assessment of risk associated with alternative resource options in the 2013 Integrated Resource Plan (2013 IRP) (section 4.3.3). That assessment looked at the risks inherent in the portfolios, including both those risks specific to resources as well as systematic risks such as load variability and market price variability. In the 2013 IRP, BC Hydro reflected the relative risks of the differing projects through the use of portfolio sensitivity analysis. We took a similar approach in our August 30 Filing to the Commission in this Inquiry. Section 8 of the August 30 Filing included sensitivities on the costs of Site C, the future need for electricity, changing electricity market prices and the potential for lower costs for alternative resources. This sensitivity analysis showed that Site C was preferred under the full range of sensitivity scenarios.

In order to provide additional detail on the risks of potential alternative portfolios, BC Hydro has conducted a high-level analysis of the comparative risks of the portfolios currently under consideration.

This risk assessment is:

- **Relative, in that risks are assessed as compared to the other portfolios, rather than an absolute and individual risk assessment. We have performed the risk assessment on a relative basis because that is the essence of the Commission's examination under the Terms of Reference - to compare the ratepayer implications of continuing with Site C as planned or terminating.**
    - **For example, characterization of Site C procurement risk as low does not mean there is minimal risk associated risk associated with**

procurement. This only indicates that the risk is low compared to the other considered portfolios.

- **Qualitative in that the assessment here is not numerical. The qualitative analysis is based on assessments of quantitative factors, such as the required capital expenditures associated with portfolios or the results of sensitivity analysis.**

- **Post-mitigation, in that the relative risk assessment includes our assessment of the potential mitigation opportunities and the likelihood of the success of this mitigation. For example, assessment of the risk impact of LRB variance includes BC Hydro's assessment of the ability to mitigate these impacts through market exports.**

We have reviewed three potential portfolios in this assessment:

- **A portfolio including Site C completed under the expected schedule.**

- **A portfolio of alternative resources consistent with those proposed by BC Hydro in our August 30 Filing. This would replace Site C with a combination of wind and pumped storage resources.**

- **A portfolio of alternative resources consistent with that proposed by Deloitte in their Report #2. This would replace Site C with a combination of geothermal, wind and biomass resources.**

    - **Deloitte's portfolio provided some capacity from upgrades at BC Hydro facilities. However Deloitte has acknowledged they relied on outdated or inaccurate information (refer to Exhibit A-17). This results in only approximately 90 per cent of the expected portfolio capacity likely being available based on current engineering studies. BC Hydro has considered further geothermal, batteries, or pumped storage to replace this missing capacity in our risk assessment.**

Summary of Our Assessment

Our analysis demonstrates the following points, which are also presented in the risk assessment in Table 1:

- **BC Hydro's portfolio with Site C has risks associated with project construction. Portfolios with Site C have comparatively low risks around project availability and procurement, due to the significant work and procurement complete to date on the project. Portfolios with Site C also have very low risks around operations and expiry, due to the long project life.**

- **An alternative portfolio with BC Hydro's expected alternative resources (such as the portfolio described in the August 30th Filing) would have a risk profile generally as follows:**

    - **IPP availability risks due to the required site investigation and permitting work.**

    - **Pricing risk resulting from IPP procurement. There is $5.1 billion remaining to spend on Site C, but there would be $7.0 billion of capital expenditures to procure and spend on IPP resources under the alternative portfolio (both values 2018 real dollars, excluding IDC).**

    - **The IPP portfolio would transfer some construction risk to IPPs. However, BC Hydro would retain attrition and restructuring risk associated with IPPs running into financial difficulties.**

  Overall, alternative portfolios such as the portfolio in the August 30 Filing would have a higher risk profile than Site C, but still tolerable.

- **Both the portfolio with Site C and any alternative portfolio have risk associated with load being less than forecast and the creation of a system surplus. Site C is a large resource with approximately six to seven years remaining in construction. However, the procurement and construction lead times for IPP resources (averaging eight years based on BC Hydro's previous calls) are also substantial. BC Hydro's experience is that it is difficult to reduce IPP purchase volumes following procurement, resulting in the potential to create a system surplus.**

    - **While Site C may have the potential to create a comparatively larger surplus to a portfolio of IPP contracts, there are more options to mitigate the impact of this surplus through market activities and/or customer incentives due to the capacity and flexibility-rich nature of Site C generation.**

- **The portfolio proposed by Deloitte relies on a number of assumptions that are unlikely and even implausible. An alternative portfolio with implausible assumptions around resource availability, financing, and future costs imposes an intolerable level of risk to ratepayers. Ratepayers would effectively be crossing their fingers and hoping for a combination of low probability outcomes, subjecting ratepayers to high risk of substantially higher costs.**

TABLE 1 SUMMARY OF RISK ASSESSMENT

Risk Category	Site C Portfolio	BC Hydro Alternatives (Wind, Pumped Storage)	Deloitte Alternative Assumptions[1] (Geothermal, batteries, and upgrades)
		Portfolio Composition	
Portfolio Composition	Site C 1,132 MW 5,286 GWh/year	Wind 6,119 GWh no dependable capacity Pumped Storage Net loss of 811 GWh 1,200 MW	Geothermal – 84% of energy, 68% of capacity BCH Facility Upgrades – 14% of energy, 28% of capacity Wind & Biogas – <5% of energy and capacity
Developer/Finance	BC Hydro builds and finances Site C	BC Hydro builds and finances any system upgrades. IPPs build and finance alternative resources	BC Hydro builds and finances any system upgrades. BC Hydro builds and finance alternative resources
Direct Capital Costs (F2018 real dollars)	$5.1B (Site C direct capital costs, excluding inflation, interest and sunk costs)	$8.1 billion total ($1.1B Site C termination costs, $7.0B for alternative resources)	$7.1 billion total ($1.1B Site C termination costs, $6.0B for alternative resources)
Annual Operating Costs (F2018 real dollars)	$47 million per year (Site C Operating Costs)	$150 million per year upon completion of full block (IPP operating costs, excluding taxes)	$169 million/year upon completion of full block
		RISK ASSESSMENT	
Availability Risks	Very Low	Low to Moderate	Very High
	• Site C is a hydroelectric facility, utilizing a proven, mature technology. Generation levels have been confirmed through independent model testing of the vendor's turbine design.	• Wind is a proven resource in BC with a substantial level of site investigation. • Pumped storage has a slightly increased level of availability risk as there have been no commercial implementations in BC to-date and only limited implementations in Canada. This risk is partially mitigated by substantial site investigations in BC. Pumped storage is also similar in construction requirements to proven hydroelectric resources.	• There have been no viable geothermal sites identified in BC despite substantial investment by BC Hydro and the private sector over the past decades. The amount of geothermal proposed by Deloitte is implausible over the considered timeframe. • The Deloitte portfolio entirely relies on a capacity from BC Hydro facility upgrades up to 2026. Deloitte's assumptions of the available capacity and associated costs are based on outdated or inaccurate assumptions. As a result, this missing capacity must be replaced from a different source. • Replacing the missing capacity with pumped storage will have risks aligned with the BC Hydro alternative portfolio. Replacing the missing capacity with other resources such as batteries would have a substantially higher level of risk – such technologies are currently not commercially competitive with other resources and the likelihood of prices declining to the point where they are cost effective by the early 2020s (when capacity is required) is low

[1] **BC Hydro has utilized the composition of the Deloitte portfolio from the Deloitte Report #2, including the amendments to the annual costs provided by Deloitte in their response to BC Hydro questions (Exhibit A-17). BC Hydro has utilized the composition and costs of the Deloitte portfolio as of 2034, which represents the timing where the Deloitte portfolio has replaced the energy and capacity of Site C.**

Risk Category	Site C Portfolio	BC Hydro Alternatives (Wind, Pumped Storage)	Deloitte Alternative Assumptions[1] (Geothermal, batteries, and upgrades)
Procurement Risks	Low	Moderate	High
	• BC Hydro has procured the majority of the Site C direct costs. BC Hydro has several contracts remaining to procure, which will be subject to risk in cost escalation and competitive pressure. • BC Hydro's has contingency in place to address some variation in bid prices from BC Hydro estimates.	• BC Hydro will need to negotiate or procure an estimated $8.1B (F18 real $) of capital works and other contract costs. This procurement and negotiation activity has substantial risk: o The total cost to terminate Site C contracts and procure contractors to undertake the Site C and remediation work is $1.1B. There is substantial uncertainty with this amount due to risks including scope variance, bid price variance, schedule uncertainty, and the outcome of contract termination negotiations. o BC Hydro will need to procure alternative resources through IPPs. The estimated capital expenditure component of this procurement is $7.0B. There is substantial uncertainty in the cost of this procurement due to variance in market conditions and site availability. o The schedule for delivering 1000MW of pumped storage capacity by 2025 is very aggressive and contributes substantially to the procurement risk of this portfolio.	• BC Hydro will need to negotiate or procure an estimated $7.1B (F18 real $) of capital works and other contract costs. This procurement and negotiation activity has substantial risk: o The total cost to terminate Site C contracts and procure contractors to undertake the Site C and remediation work is $1.1B. There is substantial uncertainty with this amount due to risks including scope variance, bid price variance, schedule uncertainty, and the outcome of contract termination negotiations. o BC Hydro will need to investigate, develop and procure alternative resources, with an capital expenditure estimated by Deloitte of $6.0B. There is a high level of risk regarding the cost of unproven resources such as geothermal, and a high likelihood that BC Hydro would have to procure other resources at a higher price if geothermal fails to deliver. o It is uncertain what Deloitte would propose to replace the missing capacity resources. Pumped storage would have similar risks to the BC Hydro alternative portfolio, while other technologies such as batteries would have higher level of risk._
Design/Permitting/Construction	Moderate	Low to Moderate	Very High
	• Substantial design, permitting and construction work has been completed on Site C to date. • BC Hydro retains risk associated with the remaining design, permitting, and construction work on Site C.	• BC Hydro will retain substantial risk associated with the design, permitting, and construction work associated with Site C remediation activities. • BC Hydro will experience attrition / volume delivery risk during the design and permitting phase of IPP projects. This could result in too little or too much of the desired product being acquired. • IPPs generally take on construction cost risk, however when IPPs encounter financial difficulties they may approach BC Hydro to restructure the contract.	• BC Hydro would retain risk for design, permitting and construction work on the portfolio of alternative resources. • BC Hydro has negligible experience in the development of geothermal and other alternative resources. As a result, there will be a very high level of risk associated with the implementation of this portfolio.
Operations	Very Low	Low	High
	• BC Hydro has extensive experience in operating large hydro facilities, and has existing regional expertise in the Peace. • Large hydro is "fuel secure" in that it does not rely on a distant, or remote fuel supply, nor a fuel supply that is subject to substantial variation in price.	• IPPs generally take on operations risk, however when IPPs encounter financial difficulties they may approach BC Hydro to restructure the contract. • Pumped storage is an unknown entity on the BC Hydro system and it is not clear how a run/pump cycle could best fit into system operations. • Both wind and pumped storage are "fuel secure" in that it does not rely on a distant, or remote fuel supply, nor a fuel supply that is subject to substantial variation in price.	• BC Hydro would have to decide whether to retain risk for the operations of the portfolio of alternative resources or to subcontract the operations activities to a third party. • There is no experience in BC or Canada with operations of geothermal facilities, resulting in a high level of operational risk • Geothermal facilities tend to have an uncertain project life, as water loss from the formation can result in a lack of available generation.
Expiry Risk	Very Low	Moderate	Undetermined
	• There is negligible risk associated with "expiry" of Site C. The project has a 70-year economic planning life and is expected to operate for well beyond 100 years.	• IPP contracts tend to have an EPA life of up to 30 years. There is risk associated with the electricity market conditions at the time of IPP contract expiry. Tight market conditions may increase contract renewal prices or require BC Hydro to build greenfield energy resources instead.	• BC Hydro has not completed an assessment of potential procurement methods for this alternative portfolio and cannot make a judgement on the potential impacts of any contract expiry.

Risk Category	Site C Portfolio	BC Hydro Alternatives (Wind, Pumped Storage)	Deloitte Alternative Assumptions[1] (Geothermal, batteries, and upgrades)
Impact of Load Variance	Moderate	Moderate	Moderate
	• While Site C may have the potential to create a comparatively larger surplus to a portfolio of IPP contracts, there are more options to mitigate the impact of this surplus through market activities and/or customer incentives due to the capacity and flexibility-rich nature of Site C generation.	• While an IPP portfolio may have the potential to create a comparatively smaller surplus to a portfolio with Site C, there are fewer options to mitigate the impact of this surplus through market activities and/or customer incentives due to the capacity and flexibility-poor nature of the IPP Alternatives.	• While an IPP portfolio has the potential to create a comparatively smaller surplus to a portfolio with Site C, there are fewer options to mitigate the impact of this surplus through market activities and/or customer incentives due to the capacity and flexibility-poor nature of the IPP Alternatives.

62.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 - A-16

2.62.0 BC Hydro is requested to provide any forecasts or estimates of future wind energy costs.

RESPONSE:

BC Hydro assumed the wind energy costs from its 2015 Resource Options Update for the analysis in its August 30 Submission. That estimate reflected interested party participants' future outlook on the wind turbine markets.

In order to determine a reasonable estimate of further potential price drops, BC Hydro relied upon the Median Scenario discussed in the 2016 IEA Wind Task 26 Report "Forecasting Wind Energy Costs & Cost Drivers". We adjusted the estimates provided there based upon the updates that BC Hydro has already made to wind resource assessment in 2015.

BC Hydro estimates that future B.C. onshore wind unit energy costs at gate could drop by 16 per cent, 22 per cent and 27 per cent by 2030, 2040 and 2050, respectively (The corresponding capital and operating costs are shown in BC Hydro's response to BCUC IR 2.63.0 and the corresponding UECs are shown in BC Hydro's response to BCUC IR 2.46.0).

The IEA Wind Task 26 study is based on a global elicitation survey with input from 163 of the world's foremost wind energy experts. Based on this elicitation survey, the median levelized cost of energy (LCOE) (similar to BC Hydro's UEC) from the Median Scenario is expected to drop 24 per cent from the 2014 baseline by 2030, and 35 per cent by 2050. Based on the "Relative Impact of Drivers for Median-Scenario LCOE Reduction in 2030" on page 6, the 24 per cent drop in LCOE is due to 8.6 per cent from capital expenditures, 2.6 per cent from operating costs, 3.4 per cent from project life, and 9.4 per cent from capacity factor.

BC Hydro applied the four drivers in the IEA report to arrive at its 2030 estimate of the UEC drop. BC Hydro applied IEA's reductions in capital expenditures and operating costs at 8.6 per cent and 2.6 per cent, respectively. We did not make a cost reduction adjustment for project life because longer project life has already been accounted for in our 2015 update (we assumed 25 years). For the capacity factor, a comparison of the IEA and BCH 2015 assumptions show that half of the impact of improvements in turbine technology has already been accounted for in our 2015 update, and accordingly we only applied half of IEA's cost reduction from capacity factor (i.e., 4.7 per cent). As a result, a reduction of approximately 16 per cent in the at-gate UEC from our 2015 estimate is expected by 2030. For price reductions beyond 2030, BC Hydro uses the additional LCOE reduction for the Median Scenario (i.e., an additional 11 per cent reduction from 2030 to 2050).

BC Hydro notes that there is uncertainty surrounding these future cost reduction scenarios. The wind turbine markets have shown significant price volatility in the past as shown in Figure 1 of CEABC's Submission Exhibit F18-3, Appendix 1, page 4. This graph of the levelized costs of PPAs shows that the prices had declined significantly in 2002 and 2003, however, by 2009 and 2010, wind turbine prices had climbed significantly particularly in the western region and this coincided with BC Hydro's EPA awards in the Clean Power Call. While BC Hydro expects that the $100/MWh prices from the Clean Power Call are not likely representative of the price in future calls, these higher prices demonstrate the uncertainty in prices and that current low market prices may not reflect future costs. The CEABC report does note that the costs shown in this graph are after the U.S. production tax credits that add about US$15/MWh to the costs shown.

63.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 - A-16

2.63.0 The Panel therefore seeks input from BC Hydro and other parties on the following questions:

1. What is the current BC installed capacity cost of a 100MW onshore wind project ($/kW) and operating cost ($/year and $/MWh)? What would a reasonable forecast of the cost be in F2025 and F2035?
2. Where are the best locations in BC to install wind farms from the perspective of (i) wind levels, and/or (ii) available transmission capacity?
3. What would be a reasonable assumption regarding maximum capacity levels in these locations, and the wind farm capacity factor?
4. Please provide BC Hydro's 2016 Wind Integration Study, or indicate when it will be available.

RESPONSE:

1. **For a 100MW onshore wind project in B.C., the current capital cost at gate is estimated to be $2,360/kW for an ideal site, and $2,830/kW for a complex site (in the 2015 Wind Resource Options Update, 36 per cent of projects are considered complex). The operating cost is $73/kW-yr (or between $17/MWh and $32/MWh depending on the capacity factor) for onshore wind projects in B.C.**

   As discussed in BCUC IR 2.62.0, BC Hydro has selected the 2016 IEA Wind Task 26 Report "Forecasting Wind Energy Costs & Cost Drivers" as being a reasonable estimate of how much prices could drop. Based on this study, it is estimated that capital costs at gate would be $2,170/kW / $2,600/kW for a 100MW ideal/complex site in 2025, and $2,030/kW / $2,430/kW for a 100MW ideal/complex site in 2035. The operating cost is estimated to be $69/kW-yr in 2025 and $66/kW-yr in 2035.

2. **According to our analysis the best location in B.C. to install wind farms is currently the Peace Region. While our study shows that the Peace Region has the highest quality wind resource (with the lowest UEC at plant gate and a capacity factor ranging from 26 per cent to 49 per cent), there is a trade-off between "better resource in Peace Region that needs to be delivered to load centre and incurs cost for transmission losses and infrastructures" versus "less ideal wind resource but much closer to the load centre that has less transmission costs". This trade-off is further complicated by the fact that once**

the best sites in Peace Region are developed, the next best sites there might not be as windy as the best sites in another region. The model used in our portfolio analysis was given options to choose between wind resources in different regions of B.C. It selects the optimal portfolio of resources recognizing transmission constraints and losses, and it generally selects wind resources in Peace Region before ones in other regions.

3. **In our portfolio where Site C is terminated, the model picks up rough 1,000 MW and 3,800 GWh of wind resources in Peace Region before needing incremental transmission capacity by additional reactive power support. It assumes no other new resources in Peace Region. It should also be noted that the need for transmission reinforcement is not solely determined by the amount of new resources (such as installed wind). The type of new resources, amount of local load, forecast demand and DSM levels would affect need as well.**

4. **The 2016 Wind Integration Study is expected to be available for BC Hydro's next Integrated Resource Plan, scheduled for November 2018.**

68.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 - A-27-A-28

2.68.1 The Panel therefore seeks input from BC Hydro and other participants on the following questions:

- What is the current BC installed capacity cost of a 5MW utility solar PV instillation ($/Watt) and operating cost ($/year and $/MWh)?
  - What would a reasonable forecast of the cost be in F2025 and F2035?

RESPONSE

There are currently no utility scale solar projects in B.C. with a capacity of at least 5 MW, therefore all estimates for utility scale solar are based on currently reported costs for utility-scale solar in the U.S. adjusted to the B.C. context. Our current estimates for utility-scale solar in B.C. are reported below, along with projected costs in F2025 and F2035.

Our original estimates were done through a consultative process in 2015 by Compass Renewable Energy Consulting Inc during our resource options update process. The estimates of realized and projected future cost reductions in both installed costs and OMA are based on the projections of the National Renewable Energy Labs' (NREL) 2016 Annual Technology Baseline Report. The NREL estimate for future cost reductions is based on an average of 20 system price projections from ten separate institutions, offering a more robust long term estimate of price reductions. The NREL projection of cost declines selected by BC Hydro is a reasonable forecast from the point of view of long-term energy planning, representing a moderate estimate between more aggressive and conservative projections.

	Current Costs ($2018)	In F2025 ($2018)	In F2035 ($2018)
Installed Cost ($/W)	1.69	1.13	1.02
Annual OMA ($/MWh)	20.60	12.12	12.12

The resulting unit energy cost based on these cost assumptions are shown in BC Hydro's response to BCUC IR 2.46.0.

68.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 - A-27-A-28

2.68.2 The Panel therefore seeks input from BC Hydro and other participants on the following questions:

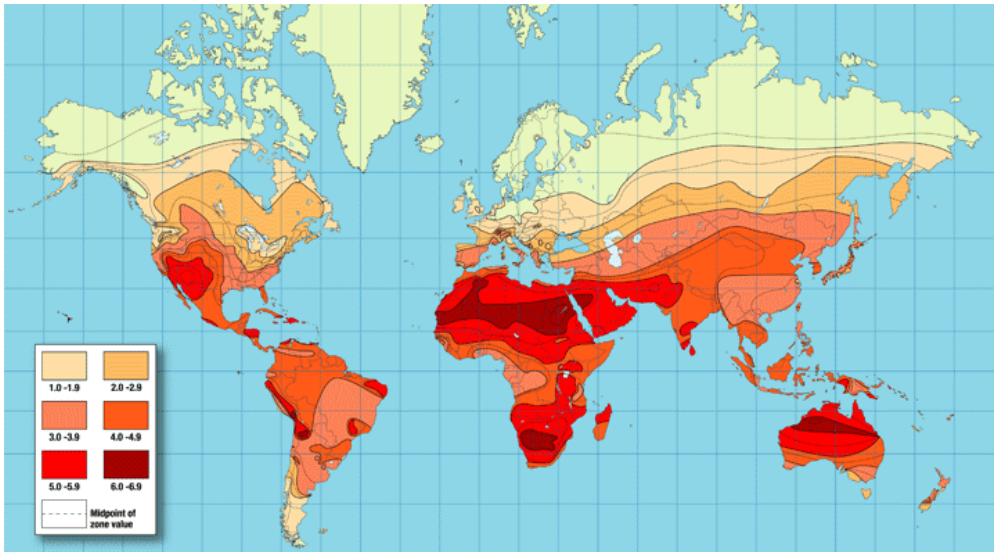
- What are the regional solar radiation levels in BC, and how do they compare to other jurisdictions with higher levels of solar PV penetration (Arizona, California, Germany)?
  - Where are the best locations in BC to install utility scale solar from the perspective of (i) regional solar radiation levels, and/or (ii) available transmission capacity?

RESPONSE:

Solar insolation – a measure of the solar energy available per square meter over a given period – varies around the world. Figure 1 below shows the range of daily solar insolation averaged over a year around the world if measured by a flat 1 m^2 plate facing south tilted at an angle consistent with the position's latitude. This shows the range of solar resources:

- **in parts of Africa and Australia, ~2,550 kWh/m^2 per year are available;**
- **In the sunniest parts of Germany generation is ~1300 kWh/m^2 per year;**
- **Pheonix, Arizona averages 1963 kWh/m^2 per year;**
- **Los Angeles, California averages 1971 kWh/m^2 per year; and**
- **in most parts of B.C. less than 1,100 kWh/m^2 per year.**

Figure 1



Some jurisdictions with weak solar insolation have developed significant solar generation resources. Germany has an installed solar generation resource of 41 GW as of the end of 2016, despite a solar insolation comparable to that of Alaska.

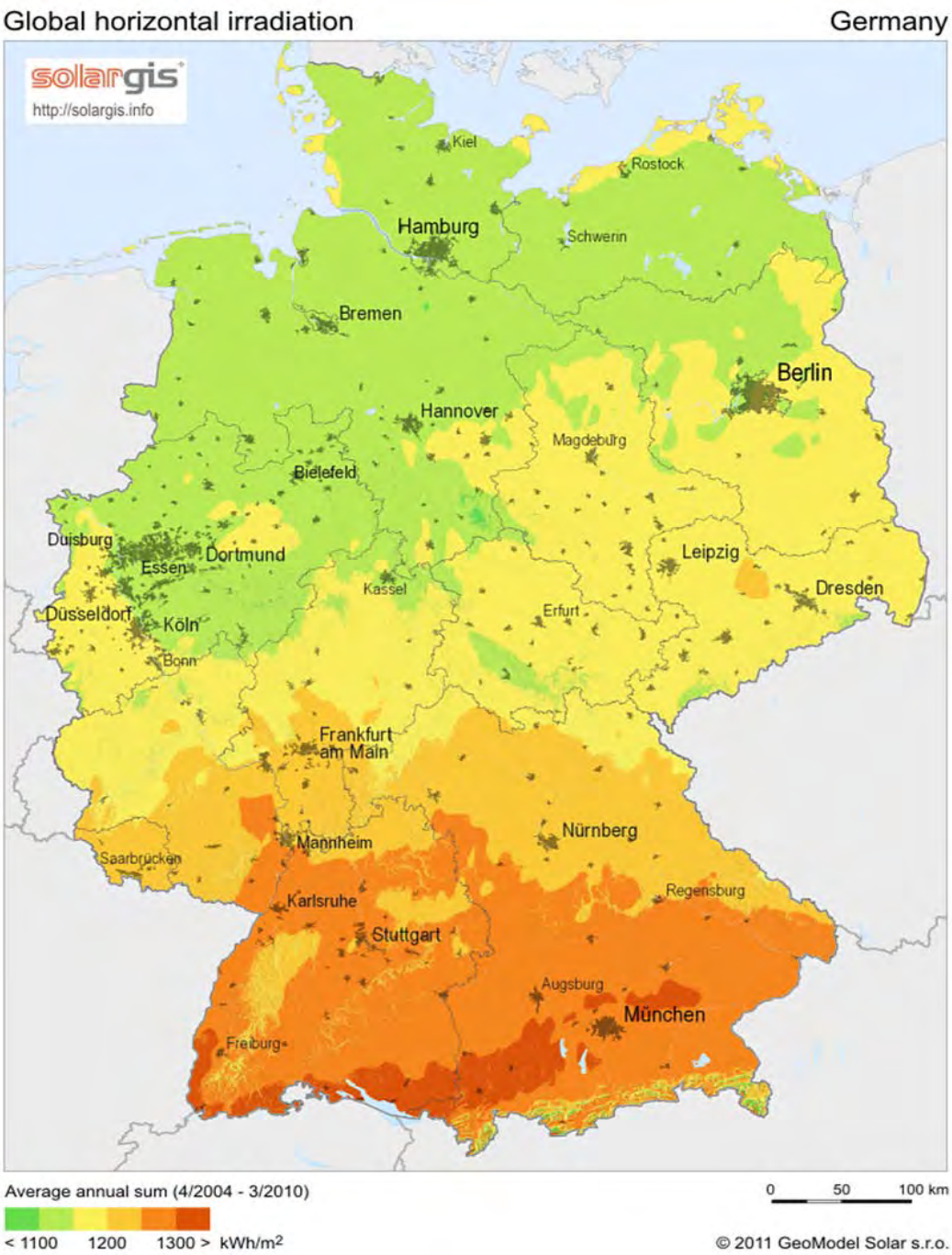
Figure 2 below shows the average annual solar insolation across Germany measured from a flat horizontal plan. The primary reason for Germany's growth of solar installations is the policy of Feed-In Tariffs that provide a guaranteed fixed purchase price for all solar electricity generated sufficient to incent rapid private sector development. Germany's 1991 Electricity Feed-In Act was the first green energy feed-in tariff scheme in the world. It was refined in successive acts after 2000 to stabilize the price. The feed-in price for solar between 2004 and 2012 are presented below in Table 1. This shows a cost of $CAN 264/MWh for utility-scale solar in 2012 throughout Germany.

Table 1

Feed-in tariffs for newly installed photovoltaic systems paid over 20 years [¢/kWh]

Type		2004	2005	2006	2007	2008	2009	2010	July 2010	October 2010	2011	January 2012
Rooftop-mounted	up to 30 kW_p	57.40	54.53	51.80	49.21	46.75	43.01	39.14	34.05	33.03	28.74	24.43
	above 30 kW_p	54.60	51.87	49.28	46.82	44.48	40.91	37.23	32.39	31.42	27.33	23.23
	above 100 kW_p	54.00	51.30	48.74	46.30	43.99	39.58	35.23	30.65	29.73	25.86	21.98
	above 1000 kW_p	54.00	51.30	48.74	46.30	43.99	33.00	29.37	25.55	24.79	21.56	18.33
Ground-mounted	conversion areas	45.70	43.40	40.60	37.96	35.49	31.94	28.43	26.16	25.37	22.07	18.76
	agricultural fields	45.70	43.40	40.60	37.96	35.49	31.94	28.43	—	—	—	—
	other	45.70	43.40	40.60	37.96	35.49	31.94	28.43	25.02	24.26	21.11	17.94

Figure 2

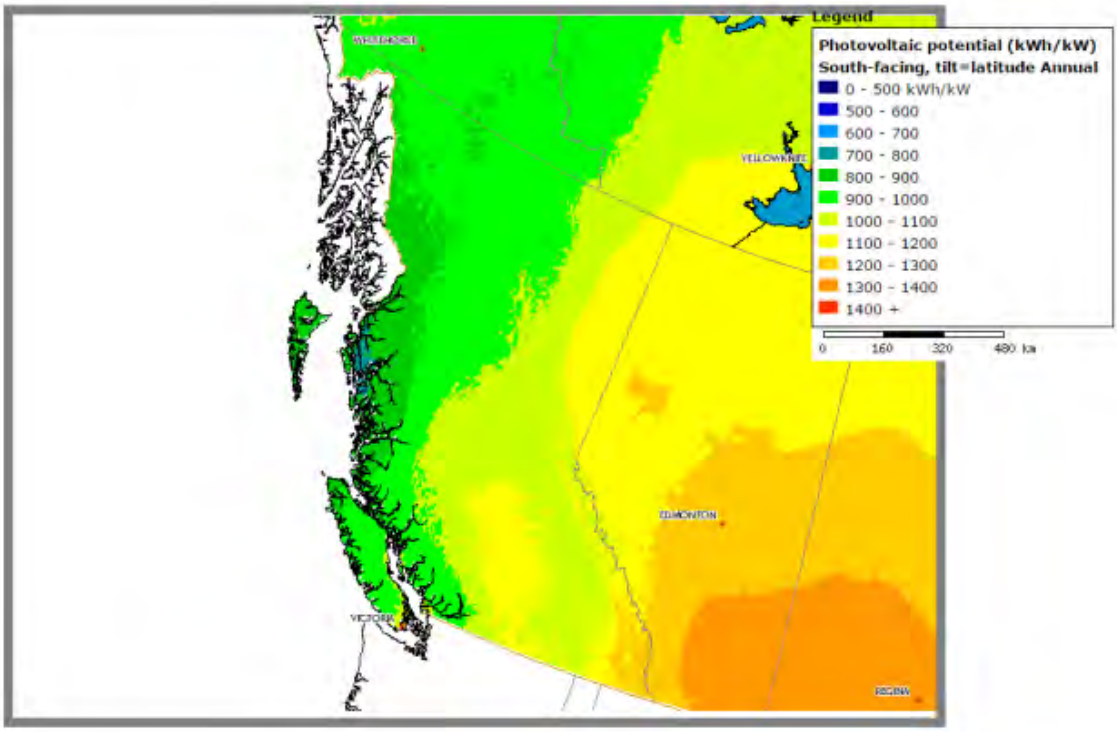


Within B.C., the best solar resources are found in the South East and Southern Interior of the province, as shown in the Figure 3 below. In the South-Eastern most corner of B.C., 1 kW of solar can generate 1300 kWh per kW per year, while solar

systems on the North Coast will generate less than 900 kWh per kW per year. In B.C., solar generation on summer days is approximately four times greater than on winter days – a mismatch for a winter peaking region. For further detail of solar generation in various B.C. cities, refer to BC Hydro's response to BCUC IR 2.68.3.

BC Hydro has assessed Cranbrook as being among the best locations for solar within the BC Hydro service territory by virtue of the relatively strong solar resource and expected low transmission and road costs for first projects (considering there is flexibility in siting solar projects). BC Hydro has therefore assumed the cost of solar at Cranbrook is a proxy for the most cost effective generic solar development in B.C. and have used this in our analysis.

Figure 3



68.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 - A-27-A-28

2.68.3 The Panel therefore seeks input from BC Hydro and other participants on the following questions:

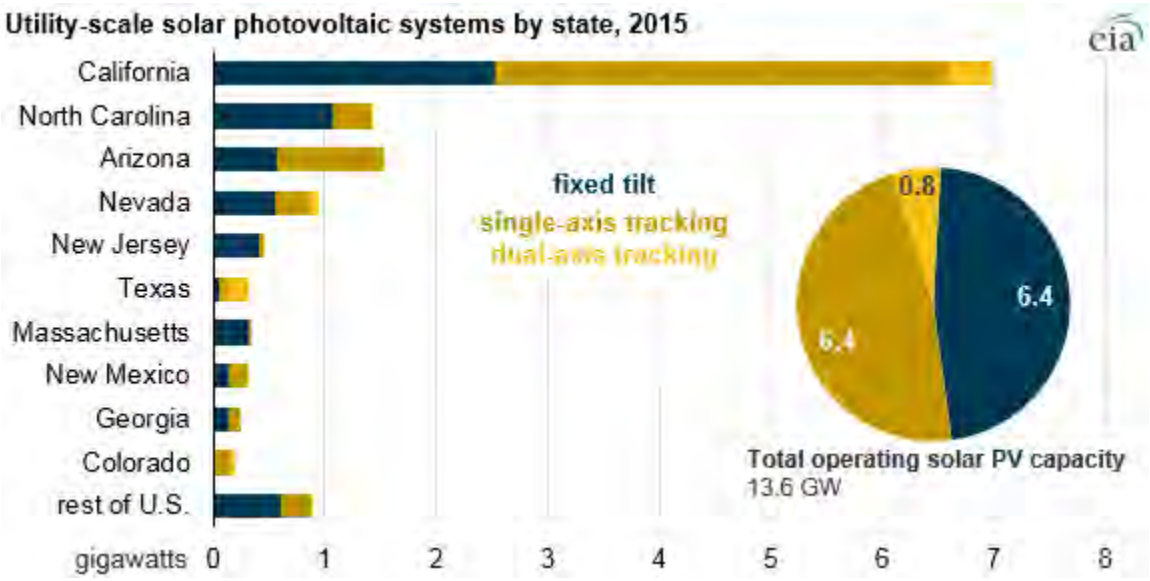
- What would be a reasonable assumption regarding utility scale solar PV capacity factor and life?

RESPONSE:

Capacity factor of solar projects is dependent on the quality of the solar resource (sunnier regions produce more kWh per kW per year) and the configuration of the facility (fixed angle vs single-axis tracker vs dual axis tracker). Below is a chart showing the range of annual energy production for different B.C. locations with different configurations.

Analysis Site	Solar Potential with Fixed System (kWh/kW/a)	Solar Potential with Single-Axis Tracker (kWh/kW/a)	Percent Increase from Fixed System with Single-Axis Tracker	Solar Potential with Dual-Axis Tracker (kWh/kW/a)	Percent Increase from Fixed System with Double-Axis Tracker
Vancouver	1010	1224	21.2%	1386	37.2%
Victoria	1092	1364	24.9%	1570	43.8%
Kamloops	1157	1429	23.5%	1640	41.7%
Fort St. John	1157	1421	22.8%	1658	43.3%

Regarding operating utility-scale solar projects in the U.S., they are fairly evenly split between fixed-tilt and single-axis tracking systems. The figure below shows that 6.4 GW in the U.S. use fixed-tilt, and 6.4 GW use single-axis tracker systems as of the end of 2015.



Emerging practice in 2017 for solar installers in North America is to tend toward a Single-Axis Tracker system, especially in areas with a stronger solar resource. As per the advice of industry experts consulted during the 2015 Resource Options Update, BC Hydro assumed Single-Axis Tracker systems for all utility-scale solar installations. This produces a capacity factor of 14 per cent (DC) in regions like Vancouver, or 16 per cent (DC) in regions like Kamloops. For Cranbrook – the region noted by BC Hydro to have among the best solar resources in the province and selected for further study in portfolio analysis – the capacity factor is 17 per cent.

Solar facility lifetime is influenced by the type of equipment selected, which can range from 20 to 30 years. BC Hydro has assumed a 25-year lifetime, based on the advice of industry experts consulted during the 2015 Resource Options Update.

68.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 - A-27-A-28

2.68.4 The Panel therefore seeks input from BC Hydro and other participants on the following questions:

- Assuming the solar investment was financed by BC Hydro, and using a 6 percent discount rate, what is the estimated levelized cost in today's dollars of a 5MW utility solar PV investment made in in (a) F2025 and (b) F2035, assuming delivery at (i) the plant gate and (ii) delivered to the Lower Mainland. Please show supporting assumptions (including capital cost assumptions, real power losses etc.) and calculations.

RESPONSE:

BC Hydro has no mandate to investigate and develop alternative energy resources. Please refer to BC Hydro's response to BCUC IR 2.42.0.

The following set of assumptions has been made in responding to this IR:

- **Location: Based on the 2015 Resource Options report analysis of potential solar sites in B.C., Cranbrook presents the lowest unit energy cost of all potential solar sites by virtue of a strong solar resource relative to the rest of the province and a minimal cost of incremental transmission and road construction to the point of interconnection. For this analysis, Cranbrook has been selected as a representative site;**

- **System configuration: As per BCUC IR 2.68.3, utility scale solar projects are assumed to be equipped with a single-axis tracker system and a 25-year project life today, in 2025 and in 2035;**

- **Capital and OMA Costs: As described in BCUC IR 2.68.1;**

- **UEC calculation and UEC adjustments methodologies are consistent with the calculation done for other resource options in BC Hydro's August 30 Filing. Further explanations of the line losses adjustments are also provided as response to BCUC IRs 2.26.0 and 2.36.0.**

- **Financing Rate: The Unit Energy cost calculation uses BC Hydro's cost of financing (weighted average cost of debt of 3.43 per cent). As discussed in the response to BCUC IR 2.42.0, a scenario where BC Hydro builds and finances all electricity resources in B.C. including solar is not realistic.**

The resulting UEC in $2018 at gate and adjusted to delivery to the lower mainland is as follows:

	UEC at gate ($/MWh)	UEC delivered to lower mainland ($/MWh)
5 MW Cranbrook solar in 2025	**48.04**	**59.04**
5 MW Cranbrook solar in 2035	**44.31**	**54.72**

Note that the above UECs do not include the cost of additional capacity that would be required by ratepayers, and are thus not a direct comparator to the Site C UEC.

68.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 - A-27-A-28

2.68.5 The Panel therefore seeks input from BC Hydro and other participants on the following questions:

- Please describe any recent developments in utility solar PV that have the potential to significantly decrease costs, increase efficiency and/or increase flexibility (for example, through the use of smart inverters).

RESPONSE:

BC Hydro expects that:

- **Solar technologies still have potential for further advancement as solar manufacturing and installations continue to grow, which may translate to lower capital costs, lower costs of installation or reduced maintenance;**
- **Manufacturing costs are typically estimated to reduce by a certain percentage for every doubling of manufacturing output and this will inherently become a slower rate of cost reduction as the market saturates;**
- **The recent US International Trade Commission finding that US solar panel manufacturers have been injured by solar panel imports that may result in as much as a $0.40/watt import tariff. A floor price of $0.78/watt may be an indication that solar panel pricing has been predatory and the future price decline assessments in North American markets should be tempered; and**
- **Solar costs need to consider both panel prices and installation and maintenance costs. As installation and maintenance costs have a significant labour component, these are not expected to reduce to the same degree as panel costs.**

Some potential contributions to cost reductions may be:

- **Increased module efficiencies**
- **Development of new semi-conductor materials**
- **Developing larger manufacturing facilities in low-cost regions**
- **Developing simple but robust racking systems**

- **Improved power electronics e.g., micro-inverters**
- **Reduced supply chain margins**
- **Streamlining installation practices**
- **Lower frequency of component replacement.**

Refer to the response to BCUC IR 2.46.0 for BC Hydro's assessment of the range of potential future price declines.

76.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 72

2.76.0 CEABC have also raised the issue of available transmission capacity. BC Hydro is requested to address whether this will result in the need for additional transmission capability to move surplus energy from Site C to other utilities.

RESPONSE:

BC Hydro has sufficient transmission capacity to the United States and Alberta to move surplus energy from Site C to other utilities.

The rating of the B.C. to U.S. export path is 3,150 MW and the rating of the B.C. to Alberta path is 1,200 MW. While the operational export capability of these paths are closer to 2,500 MW and 450 MW respectively, the combined operational export capability is still more than what is necessary to support a very large volume of surplus energy. For example, for the 2,500 MW intertie, moving 5,500 GWh of energy in a year would require about 25 per cent of the tie line space or for the tie line space to be used 25 per cent of the time.

The capacity of the interties to export markets can however be constrained from time to time. This can be due to transmission outages and also during times such as the freshet when large volumes of non-dispatchable resources in the region compete for transmission.

The advantage of a dispatchable resource such as Site C is that its energy can be scheduled into high value periods avoiding such constraints that occur periodically. This is in marked contrast to non-dispatchable resources such as run-of-river, wind, and solar. BC Hydro has no control over the output of these resources regardless of whether there are constraints on the interties, or if exports market prices are severely depressed or negative due to excess energy in the region. As CEABC correctly points out in its submission, there are limits on BC Hydro's energy storage capability and as such BC Hydro has had to resort to measures such as spilling energy or forced exports during times of high non-dispatchable generation combined with intertie constraints or unfavorable market conditions.

79.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 86

2.79.0 The Panel is concerned that if BC Hydro is not applying the same assumed project financing rate to the Alternative Portfolio, the result will not be comparable and furthermore, it assumes that BC Hydro will not be constructing and owning the Alternative Portfolio. This results in an "apples to oranges" comparison. BC Hydro is requested to clarify its financing assumptions

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.42.0.

80.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 103

2.80.0 The Panel finds that geothermal , biomass, solar and battery storage may be viable alternatives and requests that BC Hydro rerun its portfolio analysis with these alternatives included

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.46.0.

81.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 39

2.81.1 In order to allow the Panel to reach a conclusion on these additional costs, BC Hydro is requested to readdress the additional $1.7 billion estimate for restarting the project and provide a much more fulsome description of the costs and any assumptions made as to estimated amounts and the likelihood of their being required.

RESPONSE:

As noted in the Cost Estimate Synopsis provided in Appendix O, the total estimated cost for the Project Suspension estimate, including resumption of activities is $2.25 billion plus a provision of $0.5 billion to account for risks of re-starting the project, for a total of $2.75 billion. In addition, as noted on page 15 of the Cost Estimate Synopsis, BC Hydro notes that, "(t)he suspension alternative presents a risky scenario for BC Hydro due to the fourteen year length of time that project will be open a rough range of impacts that these variables could reasonably impact the suspend alternative by five hundred million to two billion."

Table 1 Project Suspension Cost Estimate

Cost Category	Cost ($ million)
Project Suspension Costs, including Maintenance of Site until F2023	**1,090**
Project Reactivation Costs	
Project Reactivation Costs, excluding Special Provision	1,160
Special Provision for Reactivation Costs	500
Subtotal – Project Reactivation Costs	**1,660**
Total Estimated Costs for Project Suspension	**2,750**

Presented in Table 2 below is a comparison of BC Hydro's estimate of Suspension, Maintenance and Reactivation costs to that of Deloitte.

Table 2 Comparison of Estimated Costs for Project Suspension: BC Hydro and Deloitte

Description	BC Hydro ($ million)	Deloitte ($ million)[1]	Variance ($ million)
Reactivation Costs			
Direct Costs	341	195	146
Indirect costs	66	5	61
Contingency	168	327	(159)
Reactivation Costs before Inflation and Management Reserve	**575**	**527**	**48**
Inflation (both during suspension and required to complete construction)	585	-	585
Management Reserve (risk provision)	500	-	500
Project Reactivation Costs (Including Management Reserve)	**1,660**	**527**	**1,133**
Project Suspension Costs, including Maintenance of Site until F2023	1,090	891	199
Total Estimated Costs for Project Suspension	**2,750**	**1,418**	**1,332**

Table 2 above confirms that the estimates of Reactivation Costs before inflation and Management Reserve for both BC Hydro and Deloitte are relatively close, with a variance of $48 million, or 8 per cent. Furthermore, the estimates of Project Suspension Costs, including the Maintenance of the Site until F2023, vary by only $199 million, or approximately 18 per cent.

The two significant differences between the estimates are:

(i) Deloitte's estimate specifically excludes the expected inflation impacts of post-suspension costs to complete the Site C Project; and

(ii) BC Hydro has included a Management Reserve (or risk provision) to cover potential higher inflation costs, potential higher interest costs, potential changes in regulatory conditions, a potential change in the Engineer of Record and other unknown risks inherent in a suspension of seven years. Deloitte has not included any provision for these types of risks beyond their contingency provision calculated based on 30 per cent of costs estimated.

[1] **Per page 65 of Deloitte's Report #1.**

A more fulsome breakdown of the Reactivation costs of $1.7 billion ($1,660 million) is provided in Table 3 below, with a discussion of each type of cost following the table:

Table 3 Project Suspension Cost Estimate, with Detail of Reactivation Costs

Category	Description	($ million)
Direct Costs		
R1	Remobilization Costs	180
R2	[redacted]	[redacted]
R3	[redacted]	[redacted]
R4	[redacted]	[redacted]
R5	Construction Management during Reactivation	14
R6	Procurement costs (indirect)	7
Subtotal – Direct Costs		**341**
Indirect Costs		
R7	Engineering	26
R8	Legal Fees	7
R9	Project Management and Other	31
R10	[redacted]	[redacted]
R11	First Nations Impacts	Excluded
Subtotal – Indirect costs		**66**
R12	Contingency	168
R13	Inflation	585
Subtotal – Project Reactivation (Excluding Management Reserve)		**1,160**
R14	Management Reserve	500
Subtotal – Project Reactivation Costs (Including Management Reserve)		**1,660**
Project Suspension Costs, including Maintenance of Site until F2023		1,090
Total Estimated Costs for Project Suspension		**2,750**

Further detail on each cost presented in the table above is as follows:

R1: Remobilization Costs

Upon reactivation and prior to the Project reaching the equivalent level of readiness and production, Contractors will need to re-perform work already completed under existing, active contracts to develop plans and submissions, hire their management team and workforce, deploy personnel, vehicles and

equipment to site, [redacted]

The bulk of such costs would be attributable to a new Main Civil Works contractor, as at the assumed time of suspension this will be the largest contractor on site. [redacted]

In addition to the Main Civil Works contractor, other Contractors associated with quarrying, road building, clearing, transmission line construction, site support services and worker accommodation would also incur a second remobilization where such Contractors have already begun work. [redacted] was carried as an estimate for the costs for all other contractor remobilizations.

R2: [redacted]

[redacted]

[redacted]

[redacted]

R3: [redacted]

[redacted]

[redacted]

R4: [redacted]

[redacted]

[redacted]

[redacted]

R5: Construction Management During Reactivation

While BC Hydro would maintain a small workforce to oversee the site during the care and maintenance period, during the period of reactivation the Construction Management team at site would need to be re-established prior to resumption of planned construction activities on January 1, 2025.

A new Construction Management leadership team would need to be engaged, who would be responsible for developing a new Construction Management Plan, workforce planning, review and input on procurement processes, and management of any activities needed to return the site from the state of suspension.

The estimate of costs for the reactivation period was based on an analysis of current burn rate and imputed full time equivalent staff (including consultants) by work package, with a factor applied to represent the incremental effort required, recognizing that such costs would be lesser than the current burn rate as the contractors would not be in production for the base project scope. Overall, these costs represent approximately 30 per cent of the current Construction Management expenditures by month.

R6: Procurement

BC Hydro included an additional $7 million to reflect additional honorariums associated with new procurement processes for Main Civil Works, Generating Station and Spillways Civil, and Generating Station and Spillways Hydromechanical contracts. In the case of the Main Civil Works, new honorariums would be required for all compliant bids received to partially offset the significant cost of preparing such a large bid.

[redacted]

R7: Engineering

[redacted]

During reactivation, the broader Engineering team would need to be reconstituted and new plans and processes put in place to assess the current site conditions and design any required remediation, update technical specifications and other procurement documents, participate in new construction planning and regulatory activities, and review submissions from new contractors preparing to begin site works.

Similar to the Construction Management item above, the costs during reactivation were based on an assessment of the current burn rate of applicable work packages, factored to reflect the anticipated work required to revise and re-issue procurement and contract related information and documentation. Based on this reassessment, the average burn rate for the period of reactivation would be approximately 29 per cent of the current engineering expenditures by month.

R8: Legal Fees

Legal costs associated with reactivation would include costs associated with supporting new procurement processes as well as [redacted], and represent approximately 66 per cent of current monthly expenditures.

R9: Project Management and Other

The BC Hydro Site C project team includes employees and consultants supporting all aspects of project planning, execution and control. During reactivation, the project team would be reconstituted, with new staffing plans, project planning, environmental and regulatory permit applications, procurement and contract management planning, Aboriginal consultation and engagement, community and stakeholder relations planning and all other aspects required of a major construction project. Based on this reassessment, the average burn rate for the period of reactivation would be approximately 79 per cent of the current Project Management and other expenditures by month.

R10: [redacted]

R11: First Nations Impacts

[redacted]

BC Hydro staff and consultants involved in ongoing discussions with First Nations are captured under cost item R9, above.

R12: Contingency

As noted in the Cost Estimate Synopsis, a contingency model was developed for the full cost of project suspension and re-activation. In the presentation of figures above, the contingency has been split between the suspension period and the reactivation period, with a 29.9 per cent contingency applied to the suspension portion (based on the Monte Carlo model for termination), and the balance of the contingency for suspension being carried in the reactivation period.

Overall, the contingency associated with the suspension estimate is 33.7 per cent, as described in the Cost Estimate Synopsis previously filed. Contingency is relatively high due to the fact that this is a Class 5 estimate.

R13: Inflation

The total cost of inflation in the suspend scenario was estimated at $624 million, which was derived using an inflation calculation model maintained by BC Hydro's Estimating Department. In presenting the costs above, such figures have been split between the inflation costs associated with suspending the site works and maintaining the site during the suspension period ($39 million), and the cost to complete the project upon reactivation ($585 million). The bulk of this amount is to account for inflation of the remaining work to be constructed, as the current budget does not include inflation for the deferral of all remaining works by seven years. This appears to be a significant source of variation between BC Hydro's estimate and that prepared by Deloitte.

The anticipated inflation was based on two per cent per year, compounded annually, in accordance with BC Hydro's corporate rate assumptions and the annual MMK Consulting report on projected inflation.

R14: Risk Provision

A special provision for increased costs excluded from the estimate to suspend was identified in the Cost Estimate Synopsis, and the lower bound value was carried in the anticipated cost to suspend the project. While these costs may each have a lower likelihood of materializing, BC Hydro does not believe it would be prudent to assume all such excluded costs would be avoided.

While BC Hydro was not able to reliably estimate the exact likelihood and consequence of the changes described below, they each present a plausible scenario of cost increase. Any one of the key risks for which the special provision was included in BC Hydro's suspension cost analysis could independently exceed the $500 million carried as a special provision.

- **Escalation will not occur beyond the 2 per cent assumed rate of inflation**

  Due to the extraordinary project duration resulting from a seven year suspension, the project budget is highly sensitive to small differences in inflation rates. If actual inflation is one per cent greater than forecast, the impact on the project budget would exceed the $500 million special provision line item.

- **Interest Rates will be constant**

  Changes in interest rates can impact the project's interest during construction budget, although BC Hydro has mitigated this risk

substantially by securing long-term debt instruments that minimize the impact of future rate changes.

- **Regulatory conditions will not change**

  Laws and regulations with respect to safety, environmental protection and consultation and engagement with First Nations and stakeholders may be amended by the relevant provincial and federal authorities, as well as through clarification of the law by the courts. Such changes can impact the means and methods of construction, introduce new requirements for environmental and safety mitigation and impact schedule performance as contractors adapt to new regulations. It is not possible to accurately quantify the impact of regulations when the timing, nature and new requirements of such changes are unknown and in any case subject to revision based on stakeholder input, scientific advancement and policy changes.

- **Design parameters and the Engineer of Record will not change**

  [redacted]

  [redacted]

  Further, changes in key design parameters, such as the Maximum Credible Earthquake or the Probable Maximum Flood could have a significant impact on the overall project budget, as such changes would need to be analyzed against the current design and changes to existing and future

construction contracts would be required. These design parameters may arise as a result of [redacted], or by new information from studies or other project sites being incorporated into the design during the period of suspension.

In addition to the four potential sources of variance, there are many other unknowns or stated exclusions which cannot be demonstrably confirmed to not present future cost pressures. BC Hydro reiterates its opinion that a suspension of seven years followed by reactivation presents a very high risk of additional cost drivers that cannot be conclusively assessed or costed at this time.

81.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 39

2.81.2 BC Hydro has stated that there are substantial risks with the assumption "that it would be possible to restart the project should a decision be made to resume construction in the future."
BC Hydro is requested to confirm whether it believes there is any plausible circumstance which would restrict its ability to complete the project and if so provide details.

RESPONSE:

It has been BC Hydro's experience that it will take time to assemble a qualified and experienced team to take responsibility for all areas of the integrated execution plan for a large project such as Site C. Once assembled the project team and execution plan needs to consider technical, procurement, construction, environmental, social, permitting, and public and Aboriginal group consultation requirements. These considerations would also have to align with regulatory and other requirements at the time of project recommencement.

The above work is complex and items are interrelated (i.e. site investigations are an input to engineering design and construction sequencing, which defines the project for the environmental assessment and other permitting, which is then consulted on with Aboriginal groups and other stakeholders, followed by procurement of construction contracts and construction execution). BC Hydro's success in managing these scopes of work over the ten-year development period and into construction was due to ensuring there was an integrated project team, with robust knowledge of the project design, schedule, environmental requirements, and ongoing consultation commitments, (composed of BC Hydro and its consultants and contractors) capable of managing these interrelated issues.

Most of the project team would not be maintained for any multi-year delay period. It should therefore not be assumed that the level of complex work can simply be "paused" for a number of years and then taken up again without substantial challenges to execution. These challenges would likely result in schedule delays and/or additional costs, as contemplated in the "special provision for reactivation costs" provided for in our estimate provided in Appendix O to our August 30 Filing and further discussed in the response to BCUC IR 2.81.1. However, in extreme cases these challenges to execution can rise to the level that they compromise BC Hydro's ability to deliver the project. These challenges could include an inability to find and hire sufficient expertise to carry out the project, or an error in execution that prevents completion of the project.

In addition to the more general risk associated with the stop-and-start of a major capital project, specific circumstances could arise and compromise BC Hydro's ability to successfully complete the project on time and on budget. These include:

- **A determination from either the provincial or federal government that a new environmental assessment is required for the re-started project. Such a determination would substantially increase the costs and risks of proceeding with the project.**

- **A change in the project engineer of record. Based on BC Hydro's experience a new engineer of record will likely require new technical work (site investigations and design work) to satisfy their design accountability. This may prevent BC Hydro from recommencing the project under the expected timeline.**

- **A substantial increase in interest rates. Due to the lengthy construction period the capital cost of Site C is sensitive to fluctuations in interest rates. BC Hydro is currently benefitting from historically low interest rates, which reduce the cost to ratepayers of major capital construction such as Site C. Suspension of the project has the potential to forego this benefit, and may impact the economic rationale to complete the project in the future.**

    - **BC Hydro has an existing hedging program to mitigate the risk of increased interest rates for the current activity on the project. However, the hedges would be ineffective for the suspended and recommenced project due to the change in project timing. Further, without certainty on restarting the project after the period of suspension BC Hydro would not enter into new hedges for the potentially recommenced Site C project.**

- **A period of high activity in the construction market, which would increase the costs of capital projects such as Site C. BC Hydro is currently benefitting from relatively high labour and equipment availability and low to moderate commodity prices. Suspension of the project has the potential to forego this benefit, and may impact the economic rationale to complete the project in the future.**

- **Loss of credibility of BC Hydro's authority to enter future procurement of major construction contracts. Given that, in this scenario the project had been suspended following two years of construction, contractors may view work to recommence the project with some skepticism. This has the potential to result in a lack of credible bids to construct the project and/or large increases in bid prices due to risk assessment or lack of competitive tension. If BC Hydro is unable to obtain credible bids to construct the project, the project may not proceed.**

- **Increased cost or risk of completion of land acquisition necessary to complete Site C. Government decisions that would change existing land use within the future Site C reservoir area, remove the existing flood reserve over Crown land, or urge BC Hydro to sell fee simple land back to original owners, descendants or the general public, would negatively impact BC Hydro's ability to acquire land rights necessary to complete Site C.**