Chris Sandve
Chief Regulatory Officer
Phone: 604-623-3726
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

June 27, 2022

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

Dear Patrick Wruck:

RE: Project No. 3698674
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
John Hart Generating Station Replacement Project
PUBLIC Project Completion and Evaluation Report

BC Hydro writes BC Hydro writes in compliance with Commission Order No. C-2-13, to provide its public Project Completion and Evaluation Report (**PCER**) for the John Hart Generating Station Replacement Project (**the Project**). This submission responds to the Commission's reporting requirements, as set out in Directive No. 5 of the Order.

As required under the 2018 Capital Filing Guidelines (per BCUC Order No. G-313-19), BC Hydro is filing the completed PCER within three months of the date of the Board of Directors review of the PCER summary, which occurred in June 2022.

The PCER includes the content that was directed to be included in the final Project report, content directed to be included in the methodology for semi-annual reporting, and additional content required in accordance with BC Hydro's current PCER template.

Regarding the first point, Order No. C-2-13 included the following directions:

- The final report should include an assessment of the Design-Build-Finance-Rehabilitate (**DBFR**) methodology relative to a Design-Bid-Build (**DBB**) approach, lessons learned in implementing the Project and recommendations for the use of Design-Build-Finance-Rehabilitate in future projects; and
- The final report will be filed within six months of the end or substantial completion of the Project. The final report is to include a complete breakdown of the final costs of the Project, a comparison of these costs to the DBFR P50 Expected Amount in the Application, and an explanation and justification of all material cost variances.

The assessment of the Design-Build-Finance-Rehabilitate methodology relative to a Design-Bid-Build approach, lessons learned in implementing the Project and recommendations for the use of DBFR in future projects are included in the PCER. In addition, the PCER reporting on final cost and variance information follows the same approach as that provided in the semi-annual progress reports.

BC Hydro is providing the confidential Report to the Commission only. A public version of the Report is being filed under separate cover redacting commercially sensitive and contractor-specific information. BC Hydro seeks this confidential treatment pursuant to section 42 of the *Administrative Tribunals Act* and Part 4 of the Commission's Rules of Practice and Procedure.

For further information, please contact Joe Maloney at 604-623-4348 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Chris Sandve
Chief Regulatory Officer

bh/rh

Enclosure

Copy to: BCUC Project No. 3698674 (BC Hydro John Hart Generating Station Replacement Project) Registered Intervener Distribution List.

John Hart Generating Station Replacement Project

Project Completion and Evaluation Report

F2022

February 2013 to March 2022

PUBLIC

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1 Summary

The John Hart Generating Station Replacement Project (the Project) replaced the original powerhouse and water conveyance system operating since 1947 with a new underground powerhouse and water conveyance system. The objectives of the Project were to address the seismic, safety, environmental and reliability risks of the deteriorating facility. The original generating units were in poor condition, the powerhouse and water conveyance systems were unable to withstand a minor earthquake and generator outages caused significant downstream flow reductions, endangering fish and fish habitat.

The British Columbia Utilities Commission issued the Certificate of Public Convenience and Necessity in February 2013. The Board of Directors then approved full Implementation phase funding of $1,050 million (Expected) and $1,118 million (Authorized) in December 2013. In February 2014, the Board approved the execution of a contract referred to as the Project Agreement and associated commitments with Project Co to construct the Project under a Design-Build-Finance-Rehabilitate model.

Construction began in the summer of 2014 and Commercial Operation of the first new asset, the Low Level Outlet, was achieved 12 weeks ahead of the original schedule on May 2, 2018, followed by the first generating unit on July 21, 2018. Generating units 2 and 3 started operating on October 26, 2018 on November 5, 2018, respectively. The new generating units provide 3.3% more energy and 5.2% more capacity than the values in the CPCN Application. Total Completion was achieved on 22 May 2020 and the Services Period[1] began June 6, 2019. As a result of the COVID-19 pandemic, non-essential work, including correction of some of the deficiencies remaining after Total Completion, were

[1] **Services Period** starts at Service Commencement and ends on October 9, 2033. During this period, Project Co provides asset management services and retains asset quality risk.

deferred. These deficiencies were addressed in summer and fall 2021 and there are no outstanding construction related deficiencies.

The estimate at completion as at March 31, 2022 was $1,001 million, $49 million or 5% under the Expected amount, and $117 million, or 10% under the Authorized amount.

The Project met its objectives and is delivering the planned benefits.

1.1 Background Information

The John Hart hydroelectric facility is the farthest downstream of the three-station Strathcona-Ladore-John Hart hydroelectric development on the Campbell River. Located on Vancouver Island within the boundaries of the City of Campbell River, it is approximately 6 km from the river's mouth at the Strait of Georgia.

The John Hart facility is one the largest of BC Hydro's generating stations on Vancouver Island and is classified as a strategic facility because it is on Vancouver Island, where generation capacity is scarce and because it is one of the cascading generating stations on the Campbell River system.

The original John Hart facility had an installed capacity of 126 megawatts, representing 17% of the total dependable capacity of BC Hydro and independent power producers' facilities located on Vancouver Island. The generating station produced an average of 778 gigawatt hours/year.

The reliability of the old generating equipment, in commercial operation since 1947, was critical for maintaining flow continuity in the lower Campbell River. Approximately 95% of the Campbell River's flow passed through the old powerhouse. Since the old generating units could not be bypassed, any generating unit forced outage immediately decreased downstream flow by 95%, until the water released through the spillway could reach the downstream fish habitat.

1.2 Project Objectives

The Project met all of its objectives, being to:

- Comply with current seismic requirements, including improving the seismic withstand capability of the powerhouse and replacing wood stave penstocks in the water conveyance system;
- Extend the life of this strategic generating asset by at least 50 years, increase its efficiency and reliability, reduce maintenance and operating costs and modernize operating controls; and
- Minimize potential adverse impacts to fish and fish habitat from unplanned flow reductions.

Many of the original John Hart facility's components such as the intake, penstocks, powerhouse superstructure and generating equipment were in poor condition and/or had low seismic withstand capability.

The original John Hart facility posed significant environmental and safety risks in addition to generation reliability issues. The facility provided fish flow water management on the lower Campbell River and the domestic water supply to the City of Campbell River and several First Nation communities. Loss or failure of the old penstocks could have caused significant damage to fisheries, loss of domestic water supply and downstream flooding.

Without investment, the powerhouse and water conveyance system would no longer be fit for their intended purpose given the condition of these assets.

1.3 Scope and Scope Variance

The Project scope included replacing the above-ground powerhouse and most of the water conveyance system. No changes were made to the dam, except those needed for the new intake and flow bypass system. The six generating units and the associated equipment in the original powerhouse were replaced with three new higher-capacity units in a new underground powerhouse.

The original water conveyance system of intakes, wood-stave and steel penstocks and surge towers was replaced by an underground tunnel system fed by an intake located on bedrock at the existing main concrete dam and a new surge tower. A flow bypass facility to maintain continuous flow and water levels in the lower Campbell River was also installed.

Under the Project Agreement, the new Facility was required to:

- Generate at least 128 megawatts from the existing 124 cubic metres per second Water License diversion flow;
- Have a design service life of 100 years for all major civil components and industry standard service life for specified equipment components, systems and sub-systems;
- Remain safely operable during and after an Operating Basis Earthquake with an Annual Exceedance Frequency of 425 years and be capable of 128 megawatts of generation immediately after such an earthquake;
- Retain the water barrier and all key Dam Safety functionalities within the Project scope after the Maximum Design Earthquake (Annual Exceedance Frequency of 10,000 years); and
- Comply with all existing Water Use Plan requirements in the Campbell River below the powerhouse.

There were minor scope changes, but they were managed within the Project cost and schedule during the Implementation phase of the Project. The scope approved by the Board in December 2013 remained materially unchanged.

1.4 Procurement Strategy and Outcomes

The Project was built under a Design-Build-Finance-Rehabilitate procurement model where the successful proponent, referred to as Project Co, was responsible for the design in accordance with performance specifications, construction, partial financing, maintenance and life cycle rehabilitation under the Project Agreement with BC Hydro. This was a new procurement model for BC Hydro and significant effort was invested in establishing a contract that would provide BC Hydro cost and performance certainty and transfer of risk. After examining different procurement approaches, BC Hydro chose the Design-Build-Finance-Rehabilitate procurement model. The investigation was guided by the BC Ministry of Finance's Capital Asset Management Framework, where capital projects greater than $50 million were to be assessed for their suitability for alternative procurement approaches.

Project Co was responsible for all project risks except those specifically assigned to or shared with BC Hydro under the Project Agreement. Project Co is also accountable for planning the maintenance of the new assets for Services Period - the 15 years following the Service Commencement Date. This approach predominantly transfers asset quality and availability risk to Project Co during the Services Period.

An Affordability Ceiling, established before the Request for Proposals was issued, was the maximum net present cost of all payments made during construction, decommissioning and the Services Period. The Affordability Ceiling ensured that the Project was delivered at a lower cost than the Reference Case Expected Amount.[2] When the initial proposals exceeded the Affordability Ceiling, BC Hydro increased its financing from 40% to 60% as the risk of reduced financed debt was offset by the

[2] Reference Case Expected Amount described in section 4.3.1 Appendix C2 to the Board May 2012 Update Materials found in Appendix A-3 of the CPCN Application.

benefit of overall cost savings to ratepayers during Project construction and the operating period.

Relative to the traditional Design-Bid-Build model, the main benefits realized from the Design-Build-Finance-Rehabilitate model were: (1) cost certainty – described in the Cost Variance section below; (2) more schedule certainty – while some milestones were not met and Availability Payments[3] foregone as a result, the flow bypass was ahead of schedule; and (3) a pay-for-performance structure that provided an incentive for Project Co to consider long-term project performance requirements beyond the typical warranty period available under the Design-Bid-Build model.

1.5 Schedule Variance

The Project in-service date was 9 November 2018, which was when all Project risk drivers were met, and all generating, and water conveyance assets were energized and producing revenue. This was ahead of the February 1, 2019 Project baseline in-service date.

Despite tunnelling delays and changing turbine/generator supplier, Project Co managed to complete the tunnel, the low-level outlet and the first unit on schedule, and only missed the target in-service date for the second and third units, by 16 days and 26 days, respectively. The impact of the delay was minor, since the original John Hart generating station continued to be available until the new generating units went into service.

Subsequent milestones such as Service Commencement and Total Completion were not met due to delays in completing the balance of plant work and satisfying documentation requirements. These delays resulted in a loss of $4.3 million in

[3] Availability Payments are the payments from BC Hydro to Project Co during the Availability Term to repay the costs financed by Project Co during the Implementation (construction) Phase and for asset management fees. These payments started when the first commercial asset attained Commercial Operation in May 2018 and they will end in October 2033.

Availability Payments to Project Co. The Low-Level Outlet flow bypass system was put in-service 12 weeks ahead of schedule.

Table 1 shows the original contractual In-Service Dates, the schedule revised in accordance with Innovation Proposal No. 1 and the dates achieved.

Table 1 Planned and Actual Schedule Completion Dates

Original Contractual In-Service Dates	Revised Contractual In-Service Dates & Assets Per Innovation Proposal No. 1	Actual Commercial Operation Dates	Status and Comments
May 2, 210	May 2, 210	May 2, 210	Met
First Unit	Tunnel and Water-up with first Asset which was either: • Low Level Outlet; OR • First Unit	Tunnel and LLO	
July 21, 2018	July 21, 2018	July 21, 2018	Met
Second Unit	Second Asset which was either: • First Unit, if Low Level Outlet was first asset in service; OR • Second Unit, if Low Level Outlet not in service	First Unit	
October 10, 2018 Third Unit AND Service Commencement	October 10, 2018 Remaining unit(s) & Service Commencement	October 26, 2018 Second Unit	16 days late
		November 5, 2018 Third Unit	26 days late
		March 29, 2019 Interim Service Commencement	N/A Service Commencement excluding generator efficiency tests was re-named Interim Service Commencement.
		June 6, 2019 Service Commencement	239 days late Service Commencement was delayed, but operation of the new generators was unaffected. Service Commencement revised to include generator efficiency test completion
February 1, 2019	October 10, 2018	November 9, 2018	29 days late/84 days early
By-Pass In-service			February 1, 2019 was also the Project baseline In-Service Date.
August 13, 2019	August 13, 2019	May 22 2020	283 days late
Total Completion			Total Completion marked the end of construction and decommissioning - the delay did not affect project benefits, since new generators were operating.
October 9, 2033	October 9, 2033	October 9, 2033	Fixed end-date under PA
Service Period Ends			

Innovation Proposal No. 1 offered to put the full Low-Level Outlet capability and the automated flow bypass system into service earlier than originally scheduled. By doing so, BC Hydro's environmental risks were reduced earlier than planned. The proposal also included an increase in committed energy and capacity value guarantees.

In exchange, BC Hydro granted Project Co the flexibility to re-sequence work (without adjusting the Service Commencement date) and provided financial compensation for the increased energy and capacity guarantees.

1.6 Cost Variance

The construction of the replacement facility was done under a fixed price contract where Project Co designed, constructed and partially financed the Project.

The Estimate at Completion for the Project is $1,001 million, 5% less than the Expected Amount, or 10% under the Authorized amount. No Reserve draws were required for the Project.

Table 2 below, and accompanying notes, provides the Project cost variance information.

Table 2 Cost Variance Table

	($ million)	A	B	C	D	E	F	G
Line	Description	First Full Funding (FFF)	Estimate at Completion (EAC)	Variance [EAC - FFF]	Variance [Column C/A] (%)	Notes	Actuals to March 31, 2022	% Complete [Column F/B] (%)
1	Project Co Costs							
2	Project Co Costs (Direct)	673	673	0	0		673	100
3	Project Co Costs (Ineligible and Decommissioning Costs, net of Remittances)	48	43	(5)	-10	1	43	100
4	Project Co Interest During Construction	60	56	(4)	-7	2	56	100
5	Total Project Co Costs	781	772	(9)	-1		772	100

	($ million)	A	B	C	D	E	F	G
6	Pre-construction (completed)	86	86	-	0		86	100
7	Minor Interface Work	8	11	3	36		11	100
8	Management and Engineering	49	53	4	8	3	53	99
9	Mitigation and Compensation	19	18	(1)	-4		18	100
10	Taxes and Fees	6	2	(4)	-67	4	2	100
11	Allocated Contingency	19	0	(19)	-100	5	-	0
12	BC Hydro Loadings	82	59	(23)	-29	6	59	100
13	Total Owner's Costs	269	229	(40)	-15		229	100
14	Current Forecast before Unallocated Contingency	1,050	1,001	(49)	-5		1,001	
15	Unallocated Contingency	-	-	-	0		-	0
16	Expected Project Cost (P50)	1,050	1,001	(49)	-5		1,001	-
17	Project Reserve	68	-	(68)	-100		-	0
18	BC Hydro Authorized Amount	1,118	1,001	(117)	-10		1,001	100

Notes to Cost Variance Table

1. Addition errors may occur due to rounding.
2. The Total Expected Amount and Authorized Amount include the costs to decommission existing John Hart facilities and exclude Net Book Value write-offs and costs related to First Nations Impact Benefits Agreements.

Cost variances exceeding $3 million are noted in column E of the table above and explained in the notes below:

Note 1: Project Co Costs (Ineligible and Decommissioning Costs, net of remittances) (line 3) have a favourable variance due to Remittances[4] from Project Co to BC Hydro excluded from the original Project Cost forecast including:

(a) Asset availability impacts during construction and commissioning [redacted], and

(b) Contaminated soil amounts being less than the baseline in the Project Agreement, a credit [redacted].

[4] Remittances are payments from Project Co to BC Hydro for specific events – for example, the non-availability of the GU/LL assets during the Bridging Period.

Note 2: The $4 million favourable variance in Project Co's Interest During Construction (line 4) was caused by Project Co's financing rate at financial close being lower than forecast.

Note 3: The $4 million unfavourable variance in Management and Engineering costs (line 8) are due to: a. an [redacted] increase to settle the November 2015 Differing Site Condition Notice for additional rock bolting throughout the tunnel; b. a prior [redacted] reduction due to budget reallocation to cover the Minor Interface increases (line 7); c. a [redacted] reduction in various small work package items which came in under budget; and d. A [redacted] cost increase due to the COVID-19 pandemic.

Note 4: Actual taxes and fees (line 10) on the Project were $4 million less than forecast, a favourable variance.

Note 5: The Project risk profile was reduced, and the original contingency (line 11), as well as net savings from other work packages, were removed from the Forecast, resulting in an $19 million favourable variance.

Note 6: The $23 million favourable variance in BC Hydro loadings (line 12) is due to the lower base cost forecast compared to plan, differences in timing in the actual spend against plan, and actual corporate rates being lower than forecast.

1.7 Deficiencies

Total Completion was achieved May 22, 2020 and required that the value of remaining deficiencies as certified by the Independent Certifier to be less than a threshold amount.

An Independent Certifier was retained by BC Hydro and Project Co to review and certify progress of the work for payment and to determine whether contract milestones such as Service Commencement, Bypass System Completion and Total Completion had been achieved.

Completion of some of the deficiencies remaining after Total Completion were deferred as a result of the COVID-19 pandemic. The most significant deferred deliverable was the completion of the generator Sudden Short-Circuit Test. The test was completed in July 2021 and certified by the Independent Certifier in October 2021. The other deferred deficiencies were addressed in summer and fall 2021, and all project construction related deficiencies were completed by the end of March 2022.

No permanent deficiencies were identified or are expected. Project Co is required to assess equipment condition four, eight and 12 years after Service Commencement. The Facility must also meet certain condition requirements at the end of the 15-year Services Period.

1.8 Ongoing Commitments

There are ongoing commitments to Project Co and to the British Columbia Utilities Commission.

Until the end of the Services Period in October 2033, the Project Agreement requires BC Hydro to make monthly Availability Payments to Project Co which repay Project Co's construction financing and for asset management services.

British Columbia Utilities Commission Order No. C-2-13 directed BC Hydro to provide semi-annual progress reports to the end of the Services Period on the amounts paid under the Project Agreement, and the amounts and reasons for any deductions made to availability payments.

There are no other ongoing commitments resulting from the Project.

1.9 Regulatory Approvals

On May 25, 2012, BC Hydro filed an application for a Certificate of Public Convenience and Necessity for the Project with the British Columbia Utilities Commission, which was issued by Order No. C-2-13 dated February 8, 2013.

The Order noted that BC Hydro had correctly identified the First Nations asserting Aboriginal rights and/or title in the Project area, and that BC Hydro's consultation was adequate to the time of the Decision. As directed, BC Hydro also worked with the interveners and British Columbia Utilities Commission staff to develop a detailed methodology of semi-annual reporting and the final report.

Conditional Water Licence was received from the Comptroller of Water Rights and the Leave to Commence process was followed through all the stages of construction and commissioning. The Decommissioning Summary Report was submitted to and accepted by the Comptroller of Water Rights Office in September 2020.

1.10 Indigenous Relations

The Project is within the boundaries of K'ómoks First Nation, Homalco First Nation, Laich-Kwil-Tach Treaty Society, Nanwakolas First Nation Referrals Office, We Wai Kai First Nation, and Wei Wai Kum First Nation.

Collaborative planning during the early stages of the Project allowed BC Hydro time to work with First Nations to address First Nations environmental and traditional use concerns during the life of the Project. BC Hydro addressed First Nations environmental concerns during construction by coordinating First Nations to participate in hands-on environmental monitoring. BC Hydro also provided regular environmental updates and reports and incorporated First Nations comments into environmental plans as the Project progressed.

As part of the Project, BC Hydro made a commitment to First Nations to improve fish passage on the Salmon River. BC Hydro met this commitment by removing the Salmon River diversion dam. This was a significant accomplishment in addressing We Wai Kai and Wei Wai Kums' traditional use concerns, as the Project is located in their core territory. The successful conclusion of the Project helped advance the relationships with all First Nations.

BC Hydro, Project Co and First Nations worked together to provide direct and indirect First Nations contract spending of [redacted], including services and employment opportunities. This effort resulted in more than 120,000 employment hours. The North Vancouver Island Aboriginal Training Society (**NVIATS**) reported that there were 104 First Nation workers employed on the Project.

1.11 Environment and Archaeology

The Project area includes the John Hart Reservoir and the Campbell River. The Reservoir is the primary drinking water source for the City of Campbell River and the Campbell River supports populations of several salmonid and non-salmonid fish species.

Key areas of environmental management included drinking water quality monitoring, sediment and erosion control, oil spill prevention, and wildlife management including some listed amphibian species.

Seventeen minor environmental incidents were reported over the Project's construction period, 12 incidents for which reporting was required, and five reported as a courtesy. Four of the reported environmental incidents were river flow ramp rate violations and eight were related to water quality. There were no impacts to drinking water.

The Archaeological Resource Overview prepared in March 2011 concluded that the potential for the presence of archaeological resources in the Project area was low and no further archaeological work was required.

There were no archaeological incidents reported.

1.12 Stakeholder Engagement

There was extensive stakeholder engagement during the Project's planning and construction. Activities included establishing and operating an interpretive centre, upgrading the City of Campbell River's water supply system, trails, bridges, roads, and parking lots in the surrounding area. Annual open houses, tours and the formation of the BC Hydro Liaison Committee consisting of local government, agencies and other stakeholder groups complemented the above.

The Project had strong public support, but some issues relating to potential impacts were raised. The issues included access to the Campbell River and nearby trails during construction, the City of Campbell River's domestic water supply, fish habitat and river flows downstream of the generating station and economic opportunities during construction. BC Hydro committed, and adhered to its commitment, to maintain access to the river and trails on a best-efforts basis and upgrading trails after completion. On the City of Campbell River domestic water supply, BC Hydro worked with and partially funded relocation of the water supply intake. Flow modeling was done to understand downstream river flows and aquatic impacts and events were held to identify project economic opportunities during construction.

1.13 Safety

Project Co was responsible for compliance with the *Workers Compensation Act* and therefore ultimately responsible for the safe performance of the work.

All sub-contractors on-site had proven safety records and strong safety cultures.

The work included activities in many industrial sectors, such as mining, surface excavation, heavy and civil engineering construction, and utility system construction, so no single industry safety comparator was directly applicable. Regardless of which industry-specific safety comparator was used, the Project's safety record was in the top quartile.

As of Total Completion in May 2020, there were no lost time injuries on the Project.

1.14 Key Lessons Learned

The lessons learned log for the Project includes over 100 items in addition to the learnings from the Design-Build-Finance-Rehabilitate model. The key lessons learned include:

Design-Build-Finance-Rehabilitate – This procurement model delivered cost, schedule, and performance certainty, and allowed proponent innovation. For example, in the design of the intake/powerhouse facility configuration and water bypass, Project Co proposed an underground facility resulting in a land footprint that was significantly reduced and providing incremental energy and capacity benefits. The model also predominantly transferred project risks, such as geotechnical risk, to Project Co. The model is suitable for large projects with long-lived assets, where asset performance can be clearly measured and where there is little overlap with existing BC Hydro assets.

Safety – Safety performance benefitted from the Major Civil constructor (Aecon SNC-Lavalin Joint Venture), sub-contractor to Project Co, being responsible for selecting all their sub-contractors. Due to the experience of having constructed many hydro projects in BC, Aecon SNC-Lavalin Joint Venture was able to select superior sub-contractors and perform the work in a safe, efficient manner.

First Nations Involvement and Communications – Building the flow bypass system,[5] designed to ensure that fish were unaffected by varying flows through the generating station, was a key element in building trust as protecting fish in the Campbell River system continues to be a priority of First Nations. Regular meetings were held to discuss Project updates, environmental activities and identify corrective

[5] Bypass System - is the automatic system that controls three pressure reducing ‘bypass valves’ to restore flow to the river in event of a Unit outage. The term bypasses is used to refer to the individual bypass valves which were initially manually operable.

actions. These meetings included project team members and senior management. In addition to employment and procurement opportunities, involvement included:

- Sharing, seeking input to, and participation in, key environmental matters such as review of Environmental Plans and hands-on environmental monitoring for the duration of the Project;
- Participation in media events, stories, on-site visits and community events;
- Wei Wai Kum, We Wai Kai and BC Hydro worked together to develop a local First Nations work force (Laich-Kwil-Tach Environmental Assessments Limited/A'Tlegay Fisheries) while advancing key components of the Project; and
- Successful implementation of a commitment to co-manage a fish passage solution with BC Hydro at the Salmon River Diversion Dam despite numerous challenges. Co-development and co-management are approaches pursued in implementing the United Nations Declaration on the Rights of Indigenous People, and the Project provided an example of a successful co-management approach.

The Project also served as a catalyst to build relationships with the First Nations that are now formalized in Relationship Agreements with We Wai Kai, Wei Wai Kum and K'omoks First Nations. BC Hydro has built and continues to operate distribution, transmission and generating facilities within the traditional territories of the First Nations and these Relationship Agreements acknowledge a shared past, advance the ongoing process of reconciliation, and develop a positive forward-looking relationship based on trust, understanding and respect.

City of Campbell River Water Supply - The City of Campbell River's water supply was connected to BC Hydro's old penstocks, which were removed as part of the Project. Relocating the infrastructure and obtaining the necessary agreements was more complex and time-consuming than originally anticipated. An increased focus on defining scopes of work involving external shareholders during the planning stage is recommended.

Geotechnical Risk Sharing - The approach using tangible metrics for evaluating differing geotechnical conditions in the Project Agreement, which were successful and should be considered for other applicable projects. Retaining a Tunnel Specialist to monitor and independently map excavations was also beneficial and recommended if applicable.

Safety Reporting - Safety incident reporting requirements in the Project Agreement did not align/integrate with BC Hydro's Incident Management reporting system. BC Hydro’s safety incident severity and type categorizations were different from the ones used by Project Co, contributing to differences between Project Co’s and BC Hydro's safety statistics. Future project agreements should require that the contractor's safety incident reporting aligns with BC Hydro's safety reporting metrics and definitions.

Environment - Regular environmental meetings (twice a week) with Project Co and external agencies are recommended as they:

- Identified upcoming sensitive work for which BC Hydro required oversight;
- Raised concerns in a timely manner;
- Identified emerging issues;
- Improved efficiency;
- Addressed issues pro-actively and allowed for follow-up, enabling discussions between BC Hydro and Project Co;
- Involved the Independent Environmental Monitor in weekly meetings, where the Monitor helped to address any potential concerns from a regulatory perspective and manage issues, resulting in:

- Fewer environmental incidents than expected for a project of this scale and location (domestic water and sensitive fish habitat);
- Work prioritized at the daily meetings, which helped to avoid contractor work interruption/derailment, as questions had been answered at the meetings;
- Improved transparency in project work activities. BC Hydro kept up to date on contractor activities on a weekly basis and timing of key works; and
- Increased clarity in environmental work plans, which helped to avoid potential lengthy back and forth on document reviews.

Standard labour and equipment rates - Standard labour and equipment rates were not included in the Project Agreement. These rates should be stipulated in future Design-Build-Finance-Rehabilitate contracts to allow for more accurate evaluation of contemplated contract changes.

Independent Certifier – The Project used a cost-shared Independent Certifier to review and certify contract payments and milestone-related items. This unbiased perspective was beneficial in resolving contractual matters and should be considered for future similar-sized projects using comparable contract structures.

Environment - A Contaminated Sites Approved Professional oversaw soil remediation along the wood stave penstock corridor. This on-site presence provided assurance that all contaminated soils were properly removed during excavation, handling, weighing, volume surveying and hauling of contaminated soils. As a result, the goal of remediating to Wildland Reverted Standard was met and an application for Certificate of Compliance from the Ministry of Environment could be made.

BC Hydro retained an independent environmental consultant, to ensure soil weights and volumes were accurately measured in the field, tracked by truck and soil class and summarized in regular reports to BC Hydro. This oversight and independent reporting were essential to ensure that the cost sharing was in accordance with the terms of the Project Agreement.

Successful implementation was achieved by:

- BC Hydro Environmental Auditor acting in an oversight role by overlapping field visits to learn and confirm observations made by the independent environmental consultant; and
- Weekly progress meetings between Project Co, BC Hydro's Environmental Representative and Auditor.

Fire Safety Risk – Design and performance of the fire safety system, including independent system integration (e.g., fire protection and Heating, Ventilating and Air-conditioning), were Project Co's responsibility. BC Hydro included only certain performance-based requirements in the Project Agreement. As a result, obtaining information on integration and functioning of the fire protection and Heating, Ventilating and Air-conditioning systems was difficult and afforded a limited ability to recommend improvements. Future contracts, where design is delegated to contractors should consider 1) requiring a fire protection/Heating, Ventilating and Air-conditioning system design review; 2) requiring an integration design and/or construction manager; 3) requiring a Design Basis Memo for the fire protection/ Heating, Ventilating and Air-conditioning system operation be provided for Review and be continuously updated/Reviewed with changes made; and 4) requiring a Fire Safety Plan for Operations, as one of the conditions precedent for Service Commencement.

2 BCUC Application, Decision and Progress Reporting

BC Hydro filed an application pursuant to sections 45 and 46 of the *Utilities Commission Act* for a Certificate of Public Convenience and Necessity (**CPCN**) for the Project on May 25, 2012 (**CPCN Application**).

The CPCN Application and responses to Information Requests (**IRs**) set out: (1) a Design-Bid-Build (**DBB**) P50[6] Reference Case[7] capital cost estimate of $1,014.3 million; (2) a DBB Reference Case Authorized Amount of $1,158.9 million; and (3) a Design-Build-Finance-Rehabilitate (**DBFR**) P50 estimate of $940 million.

On February 8, 2013, the British Columbia Utilities Commission (**BCUC** or **Commission**) issued a CPCN by Order No. C-2-13, concluding that the Project was needed to address seismic, environmental, and reliability risks at the water conveyance system and powerhouse. The BCUC also found that the "…John Hart Generating Station Replacement Project is necessary and in the public interest as it is the most cost-effective long-term solution." Order No. C-2-13 further stated that the "Project…aligns with and advances several of British Columbia's Energy Objectives. First Nations consultation and public engagement have been adequate to the point of our Decision."

The CPCN was subject to a maximum amount of $940 million based on the DBFR P50 Expected Amount, with an In-Service Date (**ISD**) of November 2018. In addition to granting a CPCN, Order No. C-2-13 contained directions regarding the Project Agreement (**PA**), reporting and Project schedule as described in section 2.1.

2.1 Commission Directives and Applicable Actions by BC Hydro

Order No. C-2-13 Directives (cited in quotations below) and applicable BC Hydro's actions with respect to each directive are listed below:

1. "A Certificate of Public Convenience and Necessity is granted to BC Hydro for the Project as set out generally in the Application."

[6] P50 or Expected Amount is where actual costs will not exceed the Expected Amount 50% of the time.

[7] Unless otherwise indicated or defined, the capitalized terms have the same meaning as defined or used in the CPCN Application and/or in section 3.2. BC Hydro has not attempted to provide the definition of each capitalized term. Where helpful, we may refer to the relevant section in the CPCN Application, final arguments or the BCUC decision. For instance, the use of DBB Reference Case was discussed in the BCUC's decision (section 6.2) accompanying Order No. C-2-13.

2. "The Certificate of Public Convenience and Necessity is granted for a maximum amount of $940 million based on the Design-Bid-Finance-Rehabilitate P50 Expected Amount and having an in-service date for total project completion of November 2018."

3. "BC Hydro shall not obtain a recovery through rates of any cost overrun exceeding $940 million until the Commission determines whether those costs have been incurred prudently or, alternatively, determines that a prudency review could be waived because that waiver is in the public interest and is otherwise in accordance with the *Utilities Commission Act*."

   Action: The procurement process was completed in November 2013, after the CPCN was issued in February 2013. Following completion of the procurement process, BC Hydro updated the Project cost estimate to a P50 Expected Amount of $1,050 million and an Authorized Amount of $1,118 million to reflect procurement results. This new range was narrower than, and compared favourably with, the CPCN Application DBB Reference Case range, but the updated P50 Expected Amount was higher than the DBFR P50 $940 million capital cost estimate. The following considerations informed the BC Hydro Board of Directors' (**Board**) November 2013 approval:

   - The P50 Expected Amount of $1,050 million resulting from the lowest bid price submitted in a competitive, fair and transparent procurement process. BC Hydro engaged a Fairness Reviewer, John A. Singleton, to monitor the selection process;
   - Fixed-price contract in place with more cost and schedule certainty backed by private finance;
   - Potential high cost of switching to a DBB or Design-Build (**DB**) procurement process, with an expected one-year schedule delay and outcome uncertainty, and no assurance that switching to a DBB or DB procurement model would yield a lower cost;

- Incremental energy (+2.9%) and capacity (+3.3%) benefits;
- Technical innovation in the design of the intake/powerhouse, facility configuration and water bypass. The John Hart facility land footprint was significantly reduced, which provided social/environmental benefits; and
- A Unit Energy Cost (**UEC**) of $80 per megawatt hour (MWh), which is within the UEC range of $75/MWh to $82/MWh presented in the CPCN Application.

4. "BC Hydro is to file with the Commission a copy of the Project Agreement contract with the successful Proponent within two weeks of finalizing the contract."

   Action: The Project Agreement was executed February 25, 2014 and filed on March 6, 2014 as Appendix A to Semi-Annual Progress Report No. 1 – February 2013 to February 2014, dated March 6, 2014.

5. "BC Hydro is directed to comply with the following Commission directives with respect to reporting:

   - "Following BC Hydro Board approval of the Project Agreement and no later than the fall of 2013 BC Hydro is to host a workshop with interveners of this proceeding and with BCUC staff to develop a detailed methodology of semi-annual reporting. The methodology developed must be submitted to the Commission for approval no later than December 1, 2013."

     Action: Semi-Annual Progress Report No. 1 – February 2013 to February 2014 provided the BCUC and interveners with information to facilitate discussion at the Project reporting workshop concerning the semi-annual progress report methodology.

A Project reporting workshop was held on March 25, 2014.[8] After that workshop, BC Hydro circulated a draft Project reporting methodology to all interveners for comment. The methodology was submitted to the BCUC on April 30, 2014. By Order No. G-68-14, dated June 6, 2014, the BCUC accepted the methodology, but required that safety and environmental incidents be reported, as well as risks that could impact the Project by $3 million or more.

- "BC Hydro will provide semi-annual progress reports in the form approved by the Commission. The semi-annual progress reports will be filed within 45 days of the end of each reporting period."
- "During the 15-year availability term, the reports must specify, at a minimum, the amounts paid under the Project Agreement, the amounts and reasons for any deductions made to availability payments."

  Action: All semi-annual progress reports relating to construction have been filed in the approved form. Since the beginning of the availability term, each report has also included the amounts and reasons for any deductions made to Availability Payments, asset availability, and Condition Assessment outcomes as applicable.

- "BC Hydro, either concurrently with the semi-annual report workshop or in a separate workshop, is to host a workshop with interveners of this proceeding and with BCUC staff to develop a detailed methodology for the final report to be filed with the Commission upon Project completion. The methodology developed is to be submitted to the Commission for approval."

  Action: BC Hydro submitted the proposed final report template to the BCUC on February 11, 2021. A web-based workshop with BCUC staff and

8 BC Hydro requested an extension to the date for filing the Project Agreement and for submitting the methodology of semi-annual reporting for approval. This request was granted in Order No. G-199-13.

interveners of the CPCN Application proceeding was held on March 2, 2021, followed by a written comment period to obtain input and feedback on the proposed Project Completion and Evaluation Report (**PCER**).

The template was based on previous PCERs filed with the BCUC for other BC Hydro projects. On April 30, 2021, the BCUC issued Order No. G-132-21 approving the proposed final report methodology.

- "The final report should include an assessment of the Design-Bid-Finance-Rehabilitate methodology relative to a Design-Bid-Build approach, lessons learned in implementing the Project and recommendations for the use of Design-Bid-Finance-Rehabilitate in future projects. The methodology developed is to be submitted to the Commission for approval. The final report will be filed within six months of the end or substantial completion of the Project. The final report is to include a complete breakdown of the final costs of the Project, a comparison of these costs to the DBFR P50 Expected Amount set out in the Application, and an explanation and justification of all material cost variances."

  Action: The assessment of the Design-Bid-Finance-Rehabilitate methodology relative to a Design-Bid-Build approach, lessons learned in implementing the Project and recommendations for the use of DBFR in future projects are provided in section 13 of this report. As noted above, this final report methodology was approved by the BCUC by Order No. G-132-21. The cost breakdown and variances are also provided in section 5 of this report.

6. "BC Hydro is directed to prepare and file with the Commission a Project Schedule once the Project Agreement has been finalized."

   Action: A summary of the Project Schedule was filed with the Commission on March 6, 2014 (see section 2.2.5 of the Semi-Annual Progress Report No. 1).

3 Procurement

3.1 DBFR Procurement Approach

BC Hydro had chosen DBFR, recognizing the overall DBB/DBFR trade-off, which was higher private finance costs versus the cost savings and benefits secured through the execution of DBFR.[9]

Under the DBFR procurement model, BC Hydro entered into a contract, the Project Agreement, with the successful proponent (**Project Co**), for a 20-year term consisting of a five-year construction/commissioning period and a 15-year maintenance period two (referred to as the Availability Term).[10] The following are some key provisions of the DBFR model:

- Project Co was made responsible for the design in accordance with performance specifications, construction, partial financing, maintenance and life cycle rehabilitation under the Project Agreement;
- Project Co was responsible for all project risks except those specifically assigned to or shared with BC Hydro under the Project Agreement. Project Co is also accountable for planning the maintenance of the new assets for Services Period - the 15 years following the Service Commencement Date. This approach predominantly transferred asset quality and availability risk to Project Co during the Services Period; and
- An Affordability Ceiling, established before the Request for Proposals was issued, was the maximum net present cost of all payments made during construction and decommissioning and the Services Period. The Affordability Ceiling ensured that the Project was delivered at a lower cost than the Reference Case Expected Amount. When the initial proposals exceeded the

[9] BC Hydro Final Written Submission, page 55, line 17 - 18

[10] A more detailed description of the DBFR procurement model was provided in BC Hydro Final Written Submission, section 4.3.3.

Affordability Ceiling, BC Hydro increased financing from 40% to 60%, as the risk of reduced financed debt was offset by the benefit of overall cost savings to ratepayers during the Project construction and operating period.

A full assessment of the DBFR outcomes as compared to the expected benefits can be found in section 13 below.

The Project procurement process from the CPCN Decision in February 2013 to the Board's Project approval in November 2013 was as follows:

Request for Proposals

As described in Semi-Annual Progress Report No. 1,[11] the three proponents receiving the Request for Proposals (**RFP**) represented a range of Canadian and international organizations experienced in design, construction, maintenance and financing of major public infrastructure projects. The information on key members of each team is set out in Table 3.

Table 3 Shortlisted RFP Proponents

Elk Falls Energy Partners	SNC	Salmon River Hydro Partners
Ontario Pension Board / Brookfield Financial Flatiron Construction Canada / Hochtief Fiera Axium Infrastructure Connor, Clark & Lunn Gvest Traditional Infrastructure LP / Gracorp Capital Advisors Ltd. Jacobs Associates & Graham Construction Knight Piesold Consulting Alstom Power & Transport Canada Inc.	SNC-Lavalin Inc. IMPSA Frontier-Kemper Constructors ULC-Tunnelling AECON Alberta Treasury Branch Bank of Nova Scotia National Bank Financial	Bilfinger Berger Acciona Barnard Construction Klohn Crippen Berger Voith Hydro F&M Installations HMI Construction Siemens

11 Section 3.1, page 9

BC Hydro conducted three collaborative sessions and two special topic meetings with each proponent, where BC Hydro could test the proposed terms and conditions, verify cost and schedule estimates, clarify requirements and exchange ideas.

For the proponents, the meetings articulated technical and performance requirements, provided additional guidance on acceptable solutions and clarified the draft Project Agreement.

Technical Proposals

In April 2013, the technical proposals were submitted by all three proposals, with each containing non-compliant areas which required clarification and additional information before further evaluation. BC Hydro requested supplemental information from the proponents and extended the submission deadline to August 30, 2013.

In July 2013, one of the proponents, Salmon River Hydro Partners notified BC Hydro that they were unable to continue in the RFP process.

On August 30, 2013, BC Hydro received supplemental technical submissions from the remaining two proponents.

Financial Proposals

BC Hydro completed financial evaluation in two stages.

Stage 1 – 6 September 2013 Submissions

The financial evaluation involved: (1) verifying compliance with mandatory requirements; and (2) adjusting (for evaluation purposes only) for risk, performance guarantees and specific technical valuations to arrive at the evaluated price. The evaluation adjustments considered were:

- Plant capacity and energy guarantee;
- Subsurface risk adjustment (total ownership of tunnel geotechnical risk);

- Construction outage requirements (timing, frequency and duration);
- Free draining tunnel;
- Bypass innovation and excellence;
- Passive hydraulic transient management design;
- Facility safety and maintainability; and
- Retention of existing site office building.

The financial proposals received from SNC and Elk Falls Energy Partners were non-compliant, as they both failed to meet the Affordability Ceiling.

In the CPCN Application, BC Hydro stated that management would return to the Board if all proponents signalled that the Affordability Ceiling was not achievable.

BC Hydro management returned to the Board for review of the following options:

1. Terminate the DBFR procurement process and switch to a DBB or DB procurement model;
2. Terminate the DBFR procurement process and negotiate concurrently with both proponents;
3. Accept the lowest bid proposal; or
4. Amend requirements and request a “best and final offer” from both proponents.

BC Hydro amended the requirements and requested a “best and final offer” from both proponents.

Stage 2 – October 29, 2013 Submissions

SNC and Elk Falls Energy Partners submitted revised financial proposals on October 29, 2013. SNC had the lowest adjusted price and was designated the preferred proponent.

Innovation

The SNC proposal was technically superior, incorporating innovations in the areas of intake and powerhouse design, facility configuration and water by-pass integration with generating units located in a provincial park. These elements provided public use, employee and public safety benefits.

The Project Agreement was executed between BC Hydro and InPower BC (i.e., the Project Co) on February 25, 2014. InPower BC is a special-purpose entity created by SNC-Lavalin to design, build, finance and maintain the John Hart generating station.

Risk Mitigation

Consistent with the CPCN Application, the Project Agreement had a total term of approximately 20 years; a construction term of four to five years and a service term of 15-years.

During construction, BC Hydro made monthly progress payments up to 60% of the construction value on work completed by Project Co and Project Co financed the remainder.

Following Service Commencement, Project Co assumes most of the operating performance-related risks and is also responsible for meeting the asset condition requirements during and at the end of the Project Agreement's term.

BC Hydro will continue to make monthly Availability Payments according to a schedule set out in the Project Agreement. Availability Payments repay costs financed by Project Co (the 40% amount) and pay for asset management services over the 15-year Services Period, but deductions are made for non-availability/non-performance of the Facility.

Under the Project Agreement, project cost, schedule, design integration, construction and asset performance risks were predominately transferred to

Project Co. Risks retained by BC Hydro were a limited share of the geotechnical risk in the power tunnel; a share of the financing rate risk; and a subset of potential risks prescribed in Schedule 28 of the Project Agreement and “Supervening Events”, defined in the Project Agreement as those which could impact design, cost and schedule such as:

- Changes to project scope, performance requirements;
- Changes due to operational requirements or policies;
- Adverse weather conditions; and
- Changes in law which would require a variation in the design and construction of the facilities.

These retained risks were analysed, and mitigation plans developed to determine the contingency provision of $19 million (loaded) in the BC Hydro revised P50 Expected amount of $1,050 million, consistent with retained risk responsibilities.

The original John Hart generating station continued to operate during construction, but Project Co was entitled to certain outage periods for construction and cut overs. For additional outages, BC Hydro’s compensation was based on the number of affected units, outage duration and time of year.

The key Implementation phase risks and their respective responsibilities are summarized in Table 4. Except for BC Hydro’s financing (which increased from 40% to 60%), the risk profile is consistent with what was discussed in the CPCN Application.

Table 4 Risk Transfer/Ownership

Implementation Phase Risks	Ownership
Successful proponent default	Retained
Financing	Shared (BC Hydro 60%; Successful proponent 40%)
Cost	Expected – Predominantly transferred (Fixed price bid). Costs held in Authorized Amount for Change in Law, Force Majeure and undisclosed environmental conditions. These are categorized as Retained Risks.
Schedule, Construction, and Integration	Predominantly Transferred
Outage and Failure (existing facility)	Damage from construction - Transferred
Outage and Failure (new Facility)	Shared (pre-defined outage windows for maintenance and rehabilitation work)
Geotechnical tunnel conditions	Share with respect to tunnel conditions. All other geotechnical risks (Intake, Drop Shaft, Portal, Powerhouse/Tailrace) - Predominantly Transferred
Construction worker safety	Predominantly Transferred
Public safety	Shared (construction site – Successful proponent; existing operations – BC Hydro)
Environmental	Shared (BC Hydro retained risk on undisclosed liabilities and baseline)
First Nations	Shared

Cost Considerations

With project risks predominantly transferred to Project Co as described above, BC Hydro was able to narrow the Project cost range to $68 million ($1,050 million to $1,118 million) from the earlier $145 million range submitted in the CPCN Application ($1,014 million to $1,159M).

3.2 Key Contractual Terminology

Contractual terminology and acronyms used in this report are:

Actual Commercial Operation Date is the later of the Target Commercial Operation Date and the date on which all the conditions precedent to Commercial Operation of the applicable Commercial Asset(s) have been satisfied as certified by the Independent Certifier.

Availability Payments are the payments from BC Hydro to Project Co during the Availability Term to repay the costs financed by Project Co during the Implementation (construction) Phase and for asset management fees. These payments started when the first commercial asset attained Commercial Operation in May 2018 and they will end in October 2033.

The **Availability Term** is the period when Availability Payments are made, and it encompasses both the Bridging and the Services Periods. It started in May 2018 and ends in October 2033.

Bridging Period is the interval between 1) the time that the first Generating Unit/ Low Level (**GU/LL**) Asset attains Commercial Operation; and 2) the time that the last GU/LL Asset is in Commercial Operation and all Conditions Precedent to Service Commencement have been met. During the majority of the Bridging Period, both the Existing and the new Facilities were in operation.

Bypass System - is the automatic system that controls three pressure-reducing 'bypass valves' to restore flow to the river in event of a Unit outage. The term bypasses is used to refer to the individual bypass valves which were initially manually operable.

Commercial Assets are the GU/LL Assets, the conditions precedent to Service Commencement, and automatic operability of the Bypass System.

A Commercial Asset**'s Operation Date** is the later of when the relevant Commercial Asset is completed and the Target Date for that asset. This is the date that the Ramp Rate percentage increment of the Availability Payments related to that asset can start being paid to Project Co.

Comptroller means the British Columbia Comptroller of Water Rights.

Conditions Precedent to Service Commencement are conditions to be satisfied before the Services Period starts. This includes all assets being in service, Balance of Plant work, BC Hydro staff training, and submittal of key documentation.

Condition Assessment means the assessment of the Facility carried out during years four, eight and 12 after Service Commencement in accordance with Appendix 7D [Condition Assessment] of the Project Agreement.

CPCN means the Certificate of Public Convenience and Necessity issued by the BCUC.

DBFR (Design-Build-Finance-Rehabilitate) is the Procurement Model for the Project. Under this model, BC Hydro contracts with Project Co (the InPower BC consortium) which then has subcontracts with the suppliers and vendors. Under this model, Project Co finances a portion of the construction costs which are repaid over the 15 years following construction. The ‘Rehabilitate’ component of this model is that Project Co retains a significant amount of the asset quality risk during the first 15 years and must meet specific asset condition assessment criteria every four years. Project Co will also provide asset management services during this 15-year period.

Effective Date means the date of the Project Agreement between BC Hydro Power Authority and InPower BC General Partnership of February 25, 2014.

Eligible Costs are all costs properly and reasonably invoiced by the Design-Builder to Project Co for design and construction for the original scope of work.

EFRS means The Environmental Flow Release System, providing flows of 4 cm to 10 cms into the Elk Falls Canyon to meet operational Water Use Plan obligations.

Existing Facility means the original John Hart Generating Station, including the Existing Powerhouse, Existing Penstocks, Existing Intake, Existing Surge Towers, Existing Tailrace, Existing Intake Control Building (Concrete), Existing Intake Control

Building (Steel), Existing Intake Gates, Existing Site Office Building, Existing Units, Substation, Dams, Spillway and all associated buildings, structures, facilities, systems, monitoring instruments and other infrastructure, as it existed on the Effective Date.

Existing Units are the old generating units in the Existing Facility.

Facility means the new hydro-electricity generating facilities, including the Power Intake, Water Conveyances, Generating Units, Powerhouse, any modifications to the Dams, any modifications or improvements to other portions of the Existing Facility (to the extent incorporated into the design of the Facility), and all associated buildings, structures, tunnels, shafts, roads and infrastructure and all other civil, structural, mechanical, electrical, instrumentation and other equipment and systems to be designed, constructed, procured or otherwise provided by Project Co pursuant to the Project Agreement.

Generating Units are the new units in the new powerhouse. This term refers to all machinery and equipment making up a new complete and independent hydro-electric generator including the water passages, Turbine, Generator, Unit Transformer, protection and control system and replacements thereof.

GU/LL Asset means any one of the three Generating Units (**GU**s) or the Low Level Outlet (**LLO**) (including the Environmental Flow Release System and manual operability of the bypasses).

Ineligible Costs means the indirect or 'ineligible' costs include bidding fees, insurance during construction, and Project Co overhead costs during construction.

KPI stands for Key Performance Indicator.

LLO refers to the Low Level Outlet valve, which includes the Environmental Flow Release Valve and the bypasses (with manual operability). The Low Level Outlet Valve can provide up to 40 cms into the upper Elk Falls canyon.

The **LLO System** includes the Low Level Outlet, the Environmental Flow Release System and the automated Bypass System.

Project Agreement – the agreement between British Columbia Hydro and Power Authority and InPower BC General Partnership (**Project Co**), dated February 25, 2014.

PPM is Project and Portfolio Management.

Progress Payments are the payments for progression of Implementation works.

The Project is the John Hart Generating Station Replacement Project.

Project Co means InPower BC General Partnership.

The **Ramp Rate** is the percentage increment of the Availability Payments that Project Co becomes entitled to as the Commercial Operation Dates for the Commercial Assets are attained. The Ramp Rate is multiplied by the relevant month's value in the schedule of Availability Payments which is included in the Project Agreement. This determines the Availability Payment amount that Project Co will receive.

Remittances mean the payments from Project Co to BC Hydro for specific events such as non-availability of the GU/LL assets during the Bridging Period.

Service Commencement is when the Bridging Period ends, and the Services Period begins. This occurs either on October 10, 2018 or when all the GU/LL assets are in Commercial Operation and all the Conditions Precedent to Service Commencement are satisfied, whichever is later. Service Commencement occurred June 6, 2019. At Service Commencement, the Facility was handed over to BC Hydro Stations Field Operations and BC Hydro's crews then start to maintain and operate the Facility.

Services Period starts at Service Commencement and ends on October 9, 2033. During this period, Project Co provides asset management services and retains asset quality risk.

Target Commercial Operation Dates (for the Commercial Assets) and the **Target Service Commencement Date** are the earliest possible dates that the percentage of the Availability Payments related to each Commercial Asset can start.

Total Completion marks completion of construction and decommissioning of the Project, with deficiencies or trailing costs as allowed under the Project Agreement.

Total Completion Longstop Date is a milestone date of August 23, 2020 under the Project Agreement.

4 Engineering and Construction Management

Project Co was responsible for design, construction, equipment supply/installation and commissioning/decommissioning. BC Hydro performed quality audits and inspections to ensure the work complied with the terms of the Project Agreement and fully met specifications.

The Project Agreement specified the conditions to be met to achieve Service Commencement and Total Completion. The conditions for Service Commencement and Total Completion were delayed but did not affect operation of the new generators. BC Hydro and Project Co agreed to move Service Commencement to after completion of generator efficiency tests and re-name the original Service Commencement milestone the Interim Service Commencement.

The Project won numerous Canadian and North American awards. An example is the 2018 Canadian Innovation Project of the Year awarded by the Tunnelling Association of Canada. This award is given to a team who has significantly contributed to a project in Canada, and who demonstrates the highest level of engineering skill, insight and understanding of underground construction.

4.1 Design

Below is a summary of the timeline of completion of key design activities:

- In September 2014, Project Co began geotechnical investigations, including borehole drilling and testing needed to confirm the sub-surface conditions for the underground powerhouse;
- By March 31, 2015, the intake physical model testing milestone was achieved;
- By September 30, 2015, design work for the intake physical model and operating gate closure test, the draft powerhouse plans and sections, the intake plans and sections, multiple small design packages related to the powerhouse auxiliary systems, excavation drawings for the power tunnel downstream of the Middle Earthfill dam, surge chamber design, and tailrace outlet and intake excavation drawings were all complete;
- On January 11, 2016, the final turbine generator model test was completed in Alstom's lab in Grenoble, France and certified compliant by the Independent Certifier;
- By September 30, 2016, the general arrangement of all major Facility components including the design of steel liners and first stage concrete, up to and including the main floor in the powerhouse complex were complete. Designs for underground excavations, except for the Middle Earthfill Dam Zone of the power tunnel, had also been received;
- By March 31, 2017, the design of turbine / generator components, major mechanical gates and valve design was substantially complete;
- By September 2018, protection/control designs including those for staging of the substation interconnection, were complete, as was the balance of plant/auxiliary equipment design; and

- By September 30, 2019, design activities were complete, excluding documentation such as commissioning reports, as-built drawings, operations and maintenance manuals.

4.2 Procurement and Manufacturing

Below is a summary of key procurement and manufacturing activities:

- Project Co initially sub-contracted the turbine and generator supply to IMPSA,[12] an Argentinian company. IMPSA was unable to comply with the terms of the contract and was replaced by Alstom on December 5, 2014. Alstom was subsequently purchased by General Electric (**GE**) in November 2015;[13]
- By September 30, 2015, Alstom had developed a hydraulic turbine model; but it did not fully meet the performance specifications and guarantees. As such, Alstom manufactured additional turbine models for testing and for optimizing the design to ensure that the final model would meet all contractual requirements. The turbine generator model test was certified compliant in January 2016;
- By March 31, 2016, the medium voltage switchgear, power transformer, unit transformer and the AC station service (transformers and switchgear) contracts were awarded;
- By July 11, 2016, fabrication, and installation of temporary construction bridge cranes for the powerhouse were completed;
- On October 4, 2016, the first scroll case and stay rings, draft tube cones, and upper pit liners were delivered to site. Factory testing of the intake operating gate was completed later that month; and

[12] Industrias Metalúrgicas Pescarmona S.A.
[13] "GE Completes Acquisition of Alstom Power and Grid Businesses", Press Release, November 3, 2015

- By March 31, 2018, all major turbine and generator components and unit transformers had been delivered to site.

4.3 Quality Management

Project Co was responsible for procurement and quality of materials, equipment, installation and long-term performance of the assets. BC Hydro independently managed quality control by establishing and monitoring compliance with quality specifications. Below is a summary of key quality management work undertaken by BC Hydro.

Starting in late 2015, BC Hydro conducted quality audits/inspections of major equipment suppliers, manufacturers and fabricators. Welding quality issues were found on an inspection of the main supplier to GE Hydro China, and the issues were resolved by correcting the welds and increasing supplier surveillance by Project Co.

By September 30, 2017, BC Hydro's equipment supplier, manufacturer and fabricator audits were, with the completion of manufacturing, complete, and monitoring of installations started.

In March 2018, quality assurance activities focused on commissioning. Problems with the bearings on all generating units were found during commissioning, repaired by Project Co and accepted after re-testing.

After commissioning was completed and the service commencement certificate issued in June 2019, quality management activities focused on receipt of completion documentation and monitoring the completion of deficiencies.

As a result of the COVID-19 pandemic, non-essential work, including correction of some of the deficiencies remaining after Total Completion, was deferred. These deferred deficiencies were addressed in summer and fall 2021, and no construction related deficiencies remain as of March 31, 2022.

4.3.1 Innovation Proposals

An Innovation Proposal describes modifications to the Facility or services that achieve efficiencies, reduce costs to BC Hydro or realize other benefits such as operating improvements.[14] Project Co submitted Innovation Proposal No. 1, as permitted under the Project Agreement for consideration by BC Hydro in November 2016. This Innovation Proposal offered to place the full Low Level Outlet capability (124 cm) and the automated flow bypass system into service earlier than originally scheduled. An increase to the energy and capacity guarantees under the Project Agreement of 2.9 GWh and 2.4 MW[15] respectively was also offered. In exchange, BC Hydro agreed to provide: 1) flexibility to re-sequence work (without adjusting the service commencement date under the Project Agreement); and 2) some financial compensation.

Innovation Proposal No. 1 was accepted and resulted in key public safety, environmental, and seismic Project risks being addressed earlier than originally scheduled, by allowing downstream flow and fish habitat to be maintained during generator outages. For Project Co, the increased flexibility allowed the overall Project timeline to be met. The compensation was funded from existing work package budgets; no draw on contingency or reserve was required.

Another Innovation Proposal was accepted by BC Hydro in April 2018. The new generating units were to be fitted with additional instrumentation allowing for enhanced data acquisition and analysis of each unit’s operating conditions.

4.3.2 Changes

In addition to Innovation Proposals, BC Hydro must pay Project Co for Design Development Changes and for Change Notices accepted by BC Hydro.

14 Innovation Proposal(s) were reviewed and approved by senior BC Hydro management.

15 The Plant Capacity Guarantee was increased to 134.6 MW from 132.2 MW and the energy from 859.3 MW to 862.2 GWh. The specifications required 128 MW capacity and 835 GWh of energy.

The net cost of Project Changes and Design Development Changes to March 31, 2022 was approximately $2.6 million and were paid within the Project forecast amount.

4.3.3 Claims Resolutions

Twelve Supervening Event Notices[16] (**SEN**s) and two major Differing Site Condition[17] (**DSC**s) notices were issued by Project Co. Settlement agreements were executed in June 2019, December 2019, May and July 2020 resolving these claims, which totalled [redacted]. There are no claims outstanding as at March 31, 2022.

The June 2019 Settlement Agreement closed four SENs (4, 6, 8, and 10) and one DSC claim [redacted]. The other DSC was settled in the December 2019 Settlement Agreement [redacted].

The May 2020 Settlement Agreement resolved four additional claims (SEN 5, 7, 9, 11) [redacted].

Project Co issued SEN 12; a claim related to the COVID-19 pandemic. SEN 12 was settled by the July 2020 Settlement Agreement at no cost by extending the Total Completion Longstop date in the Project Agreement by 10 days. This extension caused the shift of a key date in agreements with Project Co's lenders and avoided a technical default.

More specifically, the settlement agreements for the 12 Supervening Event Notices and two major Differing Site Conditions are as follows:

Differing Site Conditions:

[16] A Supervening Event is defined in the Project Agreement as any of a Compensation Event, Relief Event, Excusing Event, Force Majeure Event or Eligible Change in Law Event, which are events beyond Project Co's control.

[17] Differing Site Conditions are defined in the Project Agreement as Baseline Condition Exceedances encountered by Project Co during construction of the Tunnel Work that causes an increase in Project Co's cost or time required to complete the Tunnel Work

1. Differing Site Condition 6 - Notices For Additional Rock Bolting Throughout The Tunnel: Initially raised by Project Co in late 2015, this issue was settled for [redacted] on December 20, 2019; and
2. Differing Site Condition 8 - Groundwater Inflow Event raised in July 2017 and settled in June 2019 for [redacted].

Supervening Event Notices:

1. Supervening Event Notice 1 was received in May 2015 when a geotechnical feature was found while excavating the main access tunnel. It was settled through the formal referee process but deemed ineligible for compensation because it was in an area identified as being 100% Project Co geotechnical risk. Project Co did not pursue this further;
2. Supervening Event Notice 2 was also received in May 2015 when unexpected rock elevations and soil conditions were encountered while establishing the Service Tunnel and Main Access Tunnel portals. Project Co chose not to pursue the claim due to its similarities to Supervening Event 1;
3. Supervening Event Notice 3 was received in August 2017 for a Force Majeure event caused by Hurricane Harvey which forced the supplier of the pipe spools for the LLO / EFRS to close. The components were received on schedule and the claim closed [redacted];
4. Supervening Event Notice 4 was received in November 2017. Project Co alleged that BC Hydro had not disclosed that asbestos was contained in the black mastic lining of the existing penstocks. The claim was resolved by the June 2019 Settlement Agreement [redacted];
5. Supervening Event Notice 5 was submitted in January 2018. Project Co claimed BC Hydro failed to disclose underground utilities after an excavator contacted a buried 13.8 kV cable in the switchyard. The contact caused a

ground fault that tripped Generator 6. The claim was resolved by the May 2020 Settlement Agreement [redacted];

6. In October 2018, Project Co issued Supervening Event Notice 6 related to the availability of water for testing and commissioning. It was resolved by the June 2019 Settlement Agreement [redacted];

7. October 2018, Project Co also issued Supervening Event Notice 7 related to the availability of water for testing and commissioning. This claim was resolved by the May 2020 Settlement Agreement [redacted];

8. Supervening Event Notice 8 City Water Tie-in was submitted in November 2018 and resolved by the June 2019 Settlement Agreement [redacted];

9. In December 2018, Project Co issued Supervening Event Notice 9 related to cancellation of an approved generator commissioning outage due to water availability and operating requirements. It was closed by the May 2020 Settlement Agreement [redacted];

10. In February 2019, Project Co issued Supervening Event Notice 10 related to the postponement of performance and acceptance tests by BC Hydro due to Campbell River water conditions in January 2019. It was resolved by the June 2019 Settlement Agreement [redacted];

11. In April 2019, Project Co issued Supervening Event Notice 11 related to a Discriminatory Change in Tax Laws. It was resolved by the May 2020 Settlement Agreement [redacted]; and

12. In March 2020, BC Hydro received a Supervening Event Notice, requesting 10 days of relief to the Total Completion Longstop Date[18] due to the COVID-19 pandemic. The extension was granted, and the claim settled in the July 2020 Settlement Agreement [redacted].

[18] Total Completion Longstop Date is defined in the Project Agreement as “August 13, 2020, as adjusted in accordance with this Agreement.”

5 Project Implementation Cost Variance Explanation

Table 5 below provides a cost summary of the Board approved plan, forecast and material variances.

Table 5 Project Cost Variance against the First Full Funding ($ million)

	($M)	A	B	C	D	E	F	G
Line	Description	First Full Funding (FFF)	Estimate at Completion (EAC)	Variance [EAC - FFF]	Variance [Column C/A]	Notes	Actuals to March 31, 2022	% Complete [Column F/B] (%)
1	Project Co Costs							
2	Project Co Costs (Direct)	673	673	0	0%		673	100
3	Project Co Costs (Ineligible and Decommissioning Costs, net of Remittances)	48	43	(5)	-10%	1	43	100
4	Project Co Interest During Construction	60	56	(4)	-7%	2	56	100
5	Total Project Co Costs	781	772	(9)	-1%		772	100
6	Pre-construction (completed)	86	86	-	0%		86	100
7	Minor Interface Work	8	11	3	36%		11	100
8	Management and Engineering	49	53	4	8%	3	53	99
9	Mitigation and Compensation	19	18	(1)	-4%		18	100
10	Taxes and Fees	6	2	(4)	-67%	4	2	100
11	Allocated Contingency	19	0	(19)	-100%	5	-	0
12	BC Hydro Loadings	82	59	(23)	-29%	6	59	100
13	Total Owner's Costs	269	229	(40)	-15%		229	100
14	Current Forecast before Unallocated Contingency	1,050	1,001	(49)	-5%		1,001	
15	Unallocated Contingency	-	-	-	0%		-	0
16	Expected Project Cost (P50)	1,050	1,001	(49)	-5%		1,001	-
17	Project Reserve	68	-	(68)	-100%		-	0
18	BC Hydro Authorized Amount	1,118	1,001	(117)	-10%		1,001	100

Notes to Project Cost variance against First Full Funding

1. Addition errors may occur due to rounding.
2. The Total Expected Amount and Authorized Amount include the costs to decommission existing John Hart facilities and exclude Net Book Value write-offs and costs related to Impact Benefits Agreements.

The Notes shown in column E of Table 5 explain the material variances (those exceeding $3 million) between the approved amount (First Full Funding or FFF) and the forecast at completion (Estimate at Completion or EAC):

Note 1: Project Co Costs (Ineligible and Decommissioning Costs, net of remittances) (line 3) have a favourable variance due to Remittances[19] from Project Co to BC Hydro excluded from the original Project Cost forecast, and include:

(a) Asset availability impacts during construction and commissioning totaling [redacted], and

(b) Contaminated soil amounts being less than the baseline in the Project Agreement, a credit of [redacted].

Note 2: The $4 million favourable variance in Project Co's Interest During Construction (line 4) was caused by Project Co's financing rate at financial close being lower than forecast.

Note 3: The $4 million unfavourable variance in Management and Engineering costs (line 8) are due to: a. an [redacted] increase to settle the November 2015 Differing Site Condition Notice (DSC6) for additional rock bolting throughout the tunnel; b. a prior [redacted] reduction due to budget reallocation to cover the Minor Interface increases (line 7); c. a [redacted] reduction in various small work package items which came in under budget; and d. A [redacted] cost increase due to the COVID-19 pandemic.

Note 4: Actual taxes and fees (line 10) on the Project were $4 million less than forecast, a favourable variance.

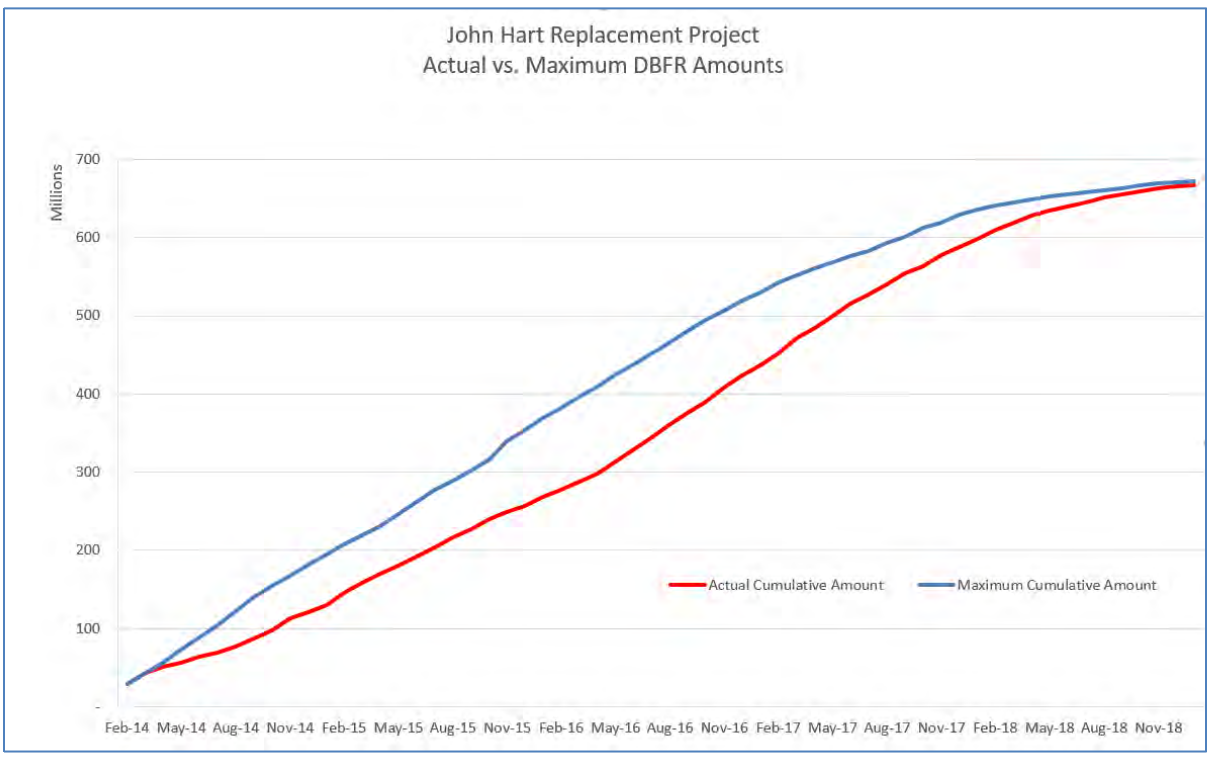
[19] Remittances are payments from Project Co to BC Hydro for specific events – for example, the non-availability of the GU/LL assets during the Bridging Period.

Note 5: The Project risk profile was reduced, and the original contingency (line 11), as well as net savings from other work packages, was removed from the forecast, resulting in an $19 million favourable variance.

Note 6: The $23 million favourable variance in BC Hydro loadings (line 12) is due to the lower base cost forecast compared to plan, differences in timing in the actual spend against plan, and actual corporate rates being lower than forecast.

Figure 1 shows the Project Co actual direct costs on a monthly cumulative basis (red line) as well as the maximum monthly amounts (blue line) listed in the Project Agreement.

Figure 1 Actual vs. Maximum Cumulative Project Co Direct costs



6 Schedule

Schedule risk was predominantly transferred to Project Co as described in section 3.1 above.

The Project in-service date was November 9, 2018, which was when all Project risk drivers were met, and all generating and water conveyance assets were energized and producing revenue. This was ahead of the February 1, 2019 Project baseline in-service date.

Despite tunnelling delays and changing turbine/generator supplier, Project Co managed to complete the tunnel, the low-level outlet and the first unit on schedule, and only missed the target in-service date for the second and third units, by 16 days and 26 days, respectively. The impact of the delay was minor, since the existing John Hart generating station continued to be available until the new generating units went into service.

Subsequent milestones such as Service Commencement and Total Completion were not met due to delays in completing the balance of plant work and satisfying documentation requirements. The delays resulted in a loss of $4.3 million in Availability Payments to Project Co. The new generating units were then in operation, so the impact on generation was minimal.

Correction of some of the deficiencies remaining after Total Completion was deferred as a result of the COVID-19 pandemic. The most significant deferred deficiency was the completion of the generator Sudden Short-Circuit Test. The test was completed in July 2021 and certified by the Independent Certifier in October 2021. The other deferred deficiencies were addressed in summer and fall 2021 and there is now no outstanding construction related deficiencies.

During construction, the tunnelling delay provided the most significant potential schedule impact. A geotechnical issue was encountered while excavating the main access tunnel, and tunnelling was temporarily halted. While tunnelling was halted, Project Co designed alternate excavation measures and sequences, which would have allowed for continued tunnelling, but would impact project schedule and cost. Upon review by Project Co, it was determined that the section could be safely bypassed, without affecting the project schedule or outcomes.

The schedule was revised after Innovation Proposal No. 1 was accepted and is shown in the second column (Revised Contractual In-Service Dates & Assets Per Innovation Proposal No. 1) of Table 6. Notes following the table explain the schedule variances.

Table 6 Project Schedule

<table>
<tr><th>Original Contractual In-Service Dates</th><th>Revised Contractual In-Service Dates & Assets Per Innovation Proposal No. 1</th><th>Actual Commercial Operation Dates</th><th>Status and Comments</th><th>Notes</th></tr>
<tr><td>May 2, 2018</td><td>May 2, 2018</td><td>May 2, 2018</td><td>Met</td><td></td></tr>
<tr><td>First Unit</td><td>Tunnel and Water-up with first Asset which was either:
• Low Level Outlet: OR
• First Unit</td><td>Tunnel and LLO</td><td></td><td></td></tr>
<tr><td>July 21, 2018</td><td>July 21, 2018</td><td>July 21, 2018</td><td>Met</td><td></td></tr>
<tr><td>Second Unit</td><td>Second Asset which was either:
• First Unit, if LLO was first asset in service; OR
• Second Unit, if LLO not in service</td><td>First Unit</td><td></td><td></td></tr>
<tr><td rowspan="4">October 10, 2018
Third Unit
AND
Service Commencement</td><td rowspan="4">October 10, 2018
Remaining unit(s) & Service Commencement</td><td>26 October 2018
Second Unit</td><td>16 days late</td><td>1</td></tr>
<tr><td>November 5, 2018
Third Unit</td><td>26 days late</td><td></td></tr>
<tr><td>March 29, 2019
Interim Service Commencement</td><td>N/A
Service Commencement excluding generator efficiency tests was re-named Interim Service Commencement.</td><td>2</td></tr>
<tr><td>June 6, 2019</td><td>239 days late</td><td></td></tr>
</table>

Original Contractual In-Service Dates	Revised Contractual In-Service Dates & Assets Per Innovation Proposal No. 1	Actual Commercial Operation Dates	Status and Comments	Notes
		Service Commencement	Service Commencement was delayed, but operation of the new generators was unaffected. Service Commencement revised to include generator efficiency test completion	3
February 1, 2019	October 10, 2018	November 9, 2018	29 days late/84 days early	4
By-Pass In-service			February 1, 2019 was also the Project baseline In-Service Date.	
August 13, 2019	August 13, 2019	May 22, 2020	283 days late	5
Total Completion			Total Completion marked the end of construction and decommissioning - the delay did not affect project benefits, since new generators were operating.	
October 9, 2033	October 9, 2033	October 9, 2033		
Service Period Ends			Fixed end date under PA	

Schedule variance notes:

1. **Commercial operation of the 2nd and 3rd generating units** – were delayed by 16 days and 26 days (two and three weeks) respectively, when compared with Project Co's revised contractual in-service dates. These delays were attributable largely to mechanical problems encountered on the units during pre-commissioning and commissioning.

2. **Interim Service Commencement** – the original requirements for Service Commencement, the date when Project Co was to begin providing asset management services and assumes asset quality risk, did not include completion of Generator Efficiency Tests. Project Co and BC Hydro agreed to

re-define Service Commencement to include completion of the Generator Efficiency Tests.

The requirements for Service Commencement were re-defined as the Interim Service Commencement and were completed on March 29, 2019.

Since key generating and water conveyance assets were already in-service, there were no negative impacts to BC Hydro from the delay. Completion of the balance of plant work, key documentation, and BC Hydro staff training were factors contributing to the delay.

3. **Service Commencement** – Completion of the Generator Efficiency Tests was not originally a condition for Service Commencement. The parties agreed to delay Service Commencement until the Generator Efficiency Tests were complete. The original Service Commencement Date was October 10, 2018 and the conditions were satisfied 239 days (34 weeks) later, on June 6, 2019.
4. **Bypass** – The Bypass System was originally scheduled for completion February 1, 2019 and Innovation Proposal No. 1 shifted completion to October 10, 2018. The Bypass System went into service on November 9, 2018, 29 days (four weeks) late compared to the October 10, 2018 target and 84 days (12 weeks) earlier than the original schedule.
5. The **Total Completion** target date of August 13, 2019 was missed due to ongoing work related to decommissioning, deficiencies, and outstanding documentation. Correction of some deficiencies was delayed due to the COVID-19 pandemic. Total Completion was achieved on May 22, 2020. However, there was little negative impact to BC Hydro from these delays.

7 Indigenous Relations Engagement Activities

The Project is within the boundaries of K'ómoks First Nation, Homalco First Nation, Laich-Kwil-Tach Treaty Society, Nanwakolas First Nation Referrals Office, We Wai Kai First Nation, and Wei Wai Kum First Nation.

Concerns expressed by First Nations included impacts to fish, incremental project effects such as the potential for water contamination, economic benefits, access to lands and traditional use, training/employment, impacts to archaeological sites and potential flooding. Collaborative planning during the early stages of the Project allowed BC Hydro time to work with First Nations to seek input into and address First Nations environmental and traditional use concerns during the life of the Project. BC Hydro addressed First Nations environmental concerns during construction by coordinating First Nations hires to participate in hands-on environmental monitoring. BC Hydro also provided regular environmental updates and reports and incorporated First Nations' comments into environmental plans as the Project progressed.

The BC Hydro Salmon Diversion Facility Fish Passage Improvement Co-management Project Commitment in the John Hart Project Consultation and Benefits Agreement with We Wai Kai and Wei Wai Kum was a significant accomplishment in addressing We Wai Kai and Wei Wai Kums' traditional use concerns as the Project is located in their core territory. The successful conclusion of the Project helped advance the relationships with all First Nations.

Capacity funding and Impact Benefit agreements were entered into with, and letters of support were received from, Wei Wai Kum, We Wai Kai and K'ómoks First Nations.

BC Hydro, Project Co and First Nations worked together to provide direct and indirect First Nations contract spending of [redacted], including services and employment opportunities. This effort resulted in more than 120,000 employment hours. The North Vancouver Island Aboriginal Training Society (**NVIATS**) reported that there were 104 First Nation workers employed on the Project.

8 Stakeholder Engagement

Extensive stakeholder engagement started in 2007 on the Project rationale, planning and design, mitigation opportunities, and construction.

Initial engagement involved the Campbell River Hydroelectric Facilities Liaison Committee, which met three times per year starting in fall 2007. The Committee consisted of about two-dozen stakeholders, made up of local government, government agencies, and other stakeholders. Community and local government presentations, open houses, letters, e-distribution lists, and proactive media updates complemented the Committee meetings.

As the Project shifted to construction, engagement expanded to include the John Hart Project Interpretive Centre, business and contractor introductions, monthly construction reports, annual site construction event tours, virtual reality tours, Twitter posts, and on-line videos of project construction activities.

The John Hart Project Interpretive Centre, which was renamed the Campbell River Hydroelectric Facilities Discovery Centre in 2019, had 89,622 visitors from fall 2013 to the end of 2019 and continues to operate. There was excellent feedback about the Project from visitors locally and around the province.

About 600 people met over two days with Project Co to discuss jobs and subcontractor opportunities in the initial stage of the Project.

The annual construction open house event was held four times and had 4,540 participants in total. The 2018 open house featured a tour of the underground powerhouse which required a ticket. Proceeds of approximately $7,000 from the strong public demand for tickets were donated to the North Island College for their apprenticeship scholarship program.

Since 2013, the Project has averaged about 60 stories per year in local and regional media, which was primarily positive. BC Hydro issued 65 monthly construction reports, which helped tell the Project story and provide transparency to stakeholders and the public.

The Project contributed towards the construction of the Elk Falls Suspension Bridge, which opened in May 2015 and currently receives about 200,000 visitors per year. In addition, trail upgrades on BC Hydro property, and the reclamation of land after the old powerhouse was demolished improved public access to the Canyon View Trail.

During construction, BC Hydro required additional land from BC Parks on a temporary basis. Following Total Completion, BC Hydro and BC Parks rationalized their land holdings by exchanging and amalgamating small land parcels, resulting in a net increase in the size of Elk Falls Provincial Park.

The City of Campbell River now has an improved domestic water supply and treatment facility due to the Project. Before the Project, the City withdrew its domestic water supply from the old penstocks which were demolished as part of the Project. BC Hydro contributed [redacted] towards the City's construction of a new water system consisting of a new water intake, pumping and treatment facility on the shore of the John Hart Reservoir.

The Project has also provided an excellent community engagement foundation for future dam safety projects planned for the Campbell River system.

9 Environmental and Archaeological Management

The environmental setting around the Project site is characterized by two main waterbodies in the Project area - the John Hart Reservoir and the Campbell River. The Reservoir is the primary drinking water source for the City of Campbell River and supports populations of several salmonid and non-salmonid fish species.

Key areas of environmental management included drinking water quality monitoring, sediment and erosion control, oil spill prevention, and wildlife management including some listed amphibian species. An Environmental Assessment (**EA**) including archaeological and traditional use studies was completed by the Project which identified potential risks related to these issues. The Project Agreement included plans to address the potential risks.

Environmental risks during construction were managed through Project Co's Construction Environmental Management Plans (**CEMP**) and associated site-specific Environmental Work Plans (**EWP**), Drinking Water Quality Management Plan (DWQMP), Commissioning Environmental Management Plan (**CO-EMP**) and Decommissioning Environmental Management Plan (**D-EMP**).

Key objectives of these plans included:

1. Identifying elements of the Project work that could present a risk to the environment and drinking water supply;
2. Describing work procedures to be undertaken to minimize and mitigate adverse impacts to the environment and drinking water supply; and
3. Describing work procedures to be undertaken in the event of an incident to contain and limit impacts to the environment and drinking water supply.

The EWPs outlined site-specific procedures to ensure the requirements of the CEMP, CO-EMP and D-EMP were met. The EWPs identified Project Co's approach to ensure compliance with regulatory obligations and BC Hydro's requirements for all activities conducted by Project Co and their subcontractors.

During the Decommissioning phase, key components of environmental risk management included remediation of contaminated sites around the penstock corridor and areas behind the old powerhouse. The contaminated sites remediation task was successfully completed, and the sites were remediated to the Wildland Reverted Standard.[20]

9.1 Project Permits and Approvals

BC Hydro was responsible for obtaining these Key permits and approvals required for the Project, summarized in Table 7, including associated amendments, orders, and Leaves to Construct.

Table 7 Project Regulatory Requirements and Approvals Schedule

Permit	Act	Agency	Permit Number	Issuance Date	Summary
Project CPCN	*Utilities Commission Act*	British Columbia Utilities Commission	Order No. C-2-13	May 25, 2012	
Conditional Water License (**CWL**)	*BC Water Sustainability Act*	FLNRO[21]	C130984	January 6, 2014	Authorized diversion and use of a maximum of 38.45 m3/s. Authorized works for construction
CWL	*Water Sustainability Act*	FLNRO	C130985	January 6, 2014	Authorized diversion and use of a maximum of 85.55 m3/s. Authorized works for construction.
CWL	*Water Sustainability Act*	FLNRO	C131060	January 6, 2014	Authorized water storage in the John Hart Lake Reservoir. Authorized works for construction.
LCC No. 1 – Leave to Commence Construction - Civil Works	*Water Sustainability Act*	FLNRO	LCC No. 1	July 8, 2014	Scope of work included construction of access and service tunnels amongst others.
LCC No. 2 – Intake	*Water Sustainability Act*	FLNRO	LCC No. 2	October 24, 2014	Scope of work included construction of the intake coffer dam, drop shaft, intake structure, EFRS, and LLO.

20 Reverted Wildlands were introduced in the Stage 10 Amendment to the BC Contaminated Sites Regulation

21 FLNRO is Forests, Lands and Natural Resource Operations, a provincial agency.

Permit	Act	Agency	Permit Number	Issuance Date	Summary
LCC No. 2 - Amendment	*Water Sustainability Act*	FLNRO	LCC No. 2 - Amendment	April 21, 2015	Approval of the updated construction design; the design no longer required removal of block No. 2 of the Main Dam and the new intake was constructed by tunneling beneath block No. 2.
LCC No. 3 – Tailrace Rock Plug	*Water Sustainability Act*	FLNRO	LCC No. 3	July 13, 2015	Scope of work included the design of the tailrace rock plug and tailrace channel excavation downstream of the rock plug.
LCC No. 4 – Tailrace Rock Plug Removal	*Water Sustainability Act*	FLNRO	LCC No. 4	December 13, 2016	Scope of work included first construction of the tailrace rock plug berm (Component 1) and then drilling, blasting, and removal by excavation of the tailrace rock plug (Component 2).
LCC No. 5 – Intake Coffer Dam Removal	*BC Water Sustainability Act*	FLNRO	LCC No. 5	April 27, 2017	Scope of work included flooding the intake, removal of the intake coffer dam steel piles by use of divers, drilling and blasting of the intake rock plug and approach channel to the design elevations and shape, and removal of the blast rock.
LTCD No. 1 – Leave to Commence Diversion	*BC Water Sustainability 12*	FLNRO	LTCD No. 1	February 21, 2018	Scope of work included watering-up of the water conveyance facilities, and commissioning of the generating units, the unit transformers, the bypass system, the LLO, and EFRS.
Decommissioning Order	*BC Water Sustainability 12*	FLNRO		December 19, 2008	Scope include decommissioning old JHN facility
LCO – Leave to Commence Operation (section 93)	*BC Water Sustainability 12*	FLNRO		June 19, 2019	Scope includes commissioning all components of the new JHN facility

Permit	Act	Agency	Permit Number	Issuance Date	Summary
Section 8 – Short Term Use Approval	*Water Sustainability 12*	FLNRO	A1-1571	April 8, 2014	Authorized diversion and use of water from John Hart Lake for general construction use. An amendment approved March 26, 2015 changed the diversion point from the area adjacent to the existing penstocks to a point adjacent to the existing dam structure.
Section 10 – Short Term Use Approval	*BC Water Sustainability 12*	FLNRO	1003352	March 29, 2016	Change in the *BC Water Act*; replaces former Section 8 – Short Term Use Approval.
Water Act Section 34 Order	*BC Water Act*	FLNRO	-	January 6, 2014	Authorized diversion and use of max 124 m3/s for powerhouse purpose in the existing powerhouse during Project's construction period.
Crown Use Tenures					
LOO – Licence of Occupation	*BC Water Act* and *BC Land Act*	FLNRO	27783	January 6, 2014	Authorized the occupation of Crown land by flooding associated with storage of water.
Park Boundary Adjustment	*Protected Areas of British Columbia Amendment Act*	Legislature	OIC 1877-13	March 27, 2013	Authorized the removal of land from Elk Falls Park.
Land Exchange	*Protected Areas of British Columbia Amendment Act*	Legislature	Bill 17	October 7, 2021	Authorized transfer of lands between BC Hydro and BC Parks.
PUP – Park Use Permit Amendment	*Park Act*	BC Parks	102948	January 13, 2022	Authorized Generation works
PUP – Park Use Permit Amendment	*Park Act*	BC Parks	102872	December 14, 2021	Authorized Distribution works
PUP – Park Use Permit Amendment	*Park Act*	BC Parks	102040	December 14, 2021	Authorized Transmission works
Crown Land Grant	*Land Act*	BC Parks	CA9584083	December 15, 2021	Crown Land Grant of District Lot 1738 from BC Parks to BC Hydro
Crown Land Grant	*Land Act*	BC Parks	CA9584085	December 15, 2021	Crown Land Grant of District Lot 1739 from BC Parks to BC Hydro

Permit	Act	Agency	Permit Number	Issuance Date	Summary
Crown Land Grant	*Land Act*	BC Parks	CA9584087	December 15, 2021	Crown Land Grant of District Lot 1740 from BC Parks to BC Hydro

The Project was completed in compliance with the Project Agreement, applicable permits, provincial and federal legislation, regulations and standards.

9.2 Environmental Management and Outcomes

An Environmental Monitoring Plan (**EMP**) was developed by Project Co and implemented throughout the Project's construction, commissioning and decommissioning phases. The EMP outlined environmental monitoring requirements to inspect, evaluate, and report on the effectiveness of work practices and environmental mitigation measures throughout the Project. The monitoring plan included specific directions with respect to the aquatic and terrestrial monitoring programs and reporting. In addition to Project Co's environmental monitoring activities, BC Hydro implemented its own environmental auditing measures as part of its environmental quality assurance measures. Further, the Provincial Comptroller of Water Rights retained an Independent Environmental Monitor (**IEM**) to provide an environmental monitoring oversight throughout the Project's implementation.

There were seventeen minor environmental incidents reported over the Project's construction period, 12 incidents for which reporting was required, and five reported as a courtesy. Four of the 12 reported environmental incidents were river flow ramp rate violations and eight were related to water quality. All reported environmental incidents were resolved to the satisfaction of the appropriate authority.

9.3 Archaeological Management and Outcomes

The Archaeological Resource Overview prepared in March 2011 concluded that the potential for the presence of archaeological resources in the Project area was low and no further archaeological work was required. An archaeological management plan was developed at the start of the Project that provided chance find procedures for heritage or archaeological artifacts.

No chance finds were made during the Project.

10 Safety Activities

10.1 Safety Risk Management

Project Co was responsible for compliance with the *Workers Compensation Act* and therefore ultimately responsible for the safe performance of the work.

All sub-contractors on-site had proven safety records and strong safety cultures.

The work included activities in many industrial sectors, such as mining, surface excavation, heavy and civil engineering construction and utility system construction, so no single industry safety comparator was directly applicable. Regardless of which industry-specific safety comparator was used, the Project's safety record was in the top quartile.

As of Total Completion in May 2020, there were no lost time injuries on the Project.

10.2 Safety Inspections and Orders

WorkSafeBC conducted 147 inspections and issued thirty-eight Orders. Twenty-one of the Orders were administrative and related to documentation and procedural requirements, while the remainder were process-related. All Orders have been completed and closed.

10.3 Incident Summary

There were no lost time injuries in the more than 3.80 million hours worked on the Project until Total Completion, but there were some major and moderate safety incidents.

A lost time injury is one where a worker misses work due to their injury. A major safety incident is one where medical attention is required and a moderate incident requires first aid.

Major incidents – there were six incidents such as a cut on the leg, a worker being struck by a shotcrete hose, a sore back and two incidents where fingers or hands were pinched.

Moderate Incidents – a total 233 incidents including muscle strains, twisted ankles and sore shoulders occurred where first aid was required

11 Risk Management

The sub-set of risks applicable to BC Hydro during and after Project design and construction are presented in Table 8 below. Risks arising during the Services Period are described below in section 11.2.

11.1 Implementation Risk Management

In accordance with BCUC Order No. G-68-14, Project risks with impacts of $3 million or more are tabulated below in Table 8 and are those filed with the Commission in the Semi-Annual Progress Reports.

All Project risks are now closed and are shown shaded in Table 8 below.

Table 8 Project Risks

Item	Risk Event Description	Risk and Response Summary
1.	Change in Requirements and/or Performance Specifications	There was a risk that policies and procedural changes could change the requirements /performance specifications of the Project, which may have resulted in a compensation event, increased Project Cost and/or schedule delays. To manage this risk, all changes to the Project Agreements were reviewed and accepted by the BC Hydro Representative. Approval by BC Hydro President & CEO was required for scope changes greater than $100,000. All communications were managed through document control processes and BC Hydro Representative review. This risk has passed, and the residual consequence reduced.

Item	Risk Event Description	Risk and Response Summary
2.	Event triggers operational requirement during construction	BC Hydro operated the original plant through the majority of the Project and has and will continue to manage reservoir levels throughout the Project's life, there was a risk that BC Hydro operational requirements could or will impact Project Cost and schedule. BC Hydro's implementation plans addressed internal communications to manage this risk. Regular discussions between site Project and Vancouver Island Generating Station staff occurred. BC Hydro Generation System Operations (**GSO**) and Fraser Valley Operations (**FVO**) were engaged on an ongoing basis as the Project Construction progressed. Further, the Project Agreement provided specific requirements for Project Co to be able to handle potential significant operating conditions. This risk is closed; the two Supervening Event Notices relating to lack of water for commissioning have been resolved.
3.	Integration Risk with Existing Facility Asset	Due to interfaces and integration of new assets, including protection and control interconnections with the existing assets, there was a risk of delays to the Project schedule, safety or environmental incidents, a compensation event, lost opportunity costs, and/or Project Cost increases. To treat this risk, BC Hydro specifications required Project Co to develop a commissioning and cutover plan, reviewed through the consent procedure. GSO was briefed on an ongoing basis as construction progressed. Damage to BC Hydro's existing plant that was not Project Co's responsibility was covered under BC Hydro's insurance program. The Project Agreement also provided financial mitigation for outages that may occur. Vancouver Island Generation staff also provided ongoing mitigation to deal with issues that could have arisen. The implementation project plan for transmission and distribution work ensured delivery of BC Hydro obligations on time. The existing Facility has now been removed. The residual consequence has been reduced accordingly.
4.	Retained Scope of Work	BC Hydro retained work including the Transmission & Distribution Telecom and Protection & Control Interconnections as well and reviewing submittals. There was a risk of BC Hydro failing to meet its obligations under the Project Agreement resulting in Project Cost increases, schedule delays, and possible compensation events. To treat this risk, work package budgets were comprehensively reviewed, and each work package manager developed a work package specific Implementation Plan. A Project Manager managed Transmission & Distribution Telecom and Protection & Control Interconnection Package activities and a detailed plan specific to this integration work was implemented. The Project also developed a document management system to manage submittals. The Owner's Engineer Implementation Plan details review methodologies through a team approach. The residual consequence has been reduced as the work is complete.
5.	City of Campbell River (City) Water Infrastructure	There was a risk the City's water infrastructure would not be ready when the penstock was decommissioned. This risk was closed when the City completed commissioning and testing of their water project in early April 2018 (which is ahead of the May 1, 2018 date in the Memorandum of Understanding with BC Hydro). Completion of the City water project means that the City will no longer be taking drinking water from BC Hydro's infrastructure.

Item	Risk Event Description	Risk and Response Summary
6.	Environmental event during Implementation or Decommissioning	There was a risk of an environmental event during implementation or Decommissioning due to weather events or operational requirements requiring the John Hart facility to spill, a Project Co non-compliance with environmental regulations, undisclosed contamination, contamination baseline exceedance along the penstock corridor, unknown ground water contamination, or the discovery of a provincially / federally listed species. The consequences included environmental contamination, delays, fines, penalties, increased costs, reputational impacts, and possible contamination of public drinking water. These risks were largely transferred to Project Co through Schedule 8 of the PA. Under the PA, Project Co developed, maintained and continually improved environmental management processes including management plans, work plans, monitoring, and auditing. In addition, performance mechanisms in the PA addressed non-compliance and non-performance by Project Co. Under these mechanisms, BC Hydro assigned points for non-performance events. A financial deduction is applied to Project Co based on accumulated points above the tolerance level ($/day per point) and if the event was outstanding beyond the rectification period. Further treatment included environmental monitors: An independent environmental monitor reported to the Comptroller; An independent environmental monitor reported to Hydro; and BC Hydro audited site work to ensure consistency with Project Co plans and to perform its role as Owner.
7.	Geotechnical Issue	There was a risk that site geotechnical conditions could be determined to be outside expectations. This risk was treated for horizontal sections of water conveyance tunnels, by the PA outlining a baseline of rock conditions. Exceedance of these conditions in the horizontal water conveyance tunnels would have resulted in a differing site condition compensation event. For all other areas (intake, powerhouse, tailrace, adits, and access tunnels) Project Co carried the risk of as-found conditions if geotechnical conditions encountered were outside expectations. In this event, the Project schedule would have been delayed and risking Project Co default or a formal dispute as defined in the PA. With the years of operations and the monitoring and inspections to date, the probability of this risk is significantly reduced.
8.	Owner's Costs (Management of contract dispute / resolution, and/or step-in)	Due to the cost of managing a contract dispute and/or managing BC Hydro's step-in rights under the PA, increased owner's costs and/or Project schedule delays were possible. This risk was managed through the procurement process by selecting an experienced Design-Builder with the competence to deliver large hydropower projects. The risk was further mitigated by lenders, providing 40% of the design-build costs, had step-in rights to remedy a Project Co default. The Independent Certifier reviewed and signed off on monthly progress payments and the Commissioning Notice to Operate. BC Hydro is a knowledgeable owner who proactively managed the contract and submittals to mitigate claims. This risk continues through the Services Period, although at a significantly lower consequence level.
9.	Supervening Event Occurs (e.g., Change in Law)	A supervening event may have occurred due to a compensation, relief, excusing, force majeure, or a change in law. This could have resulted in a schedule delay, higher Project Cost, and continued exposure to existing John Hart plant environmental, safety, and reliability risks. Construction risks and impacts are closed but this risk continues and will need to be managed through the Services Period

Item	Risk Event Description	Risk and Response Summary
10.	Permits and/or Approvals Denied	BC Hydro retained risk for delays or denial of LCC approval beyond three months, *DFO Fisheries Act* Authorization beyond six months, and tailrace Parks Use Permit (**PUP**) beyond six months. The PUP covering any parts of the New Works (i.e., tailrace structure and any in-stream works located in the Elk Falls Provincial Park permit area) required BC Parks review and acceptance of final design drawings for the New Works. This could have resulted in a compensation event claim, schedule delay and/or cost increases. The PA transferred the risk of obtaining authorizations to Project Co for the first three months for LCCs and six months for Tailrace PUP and *Fisheries Act* Authorization. The Impact Benefits Agreements ensured that First Nation consultation was complete with respect to authorizations. All required permits were received, and the risk closed.

11.2 Residual Risks Related to the Services Period

The Services Period started with the Service Commencement date of 6 June 2019 and continues to October 2033. During this period, Project Co provides asset management services and assumes asset quality risk. BC Hydro's risks during the Services Period are below:

Supervening Event Claim: An excusing and/or a relief claim could still occur for compensation or relief for incremental costs or lost Availability Payments. Supervening Events could be triggered during the Services Period by external events such as fires, health orders or transportation shortages, or by BC Hydro's actions such as labour lockout or execution of significant other works on the site.

Risk Transfer from BC Hydro actions: A BC Hydro capital project or major maintenance work within the site, which modifies equipment, elements or infrastructure under the responsibility of Project Co, could result in the responsibility for the equipment, element of the Facility being transferred back to BC Hydro, and making BC Hydro responsible for any associated risks and costs.

Changes in Regulatory Requirements: Under the terms of the Project Agreement, BC Hydro remains responsible for the costs of implementing the requirements from a "Change in Law" which includes changes in requirements from Mandatory Reliability Standards or safety legislation.

Public Safety Incident: Due to hazards around public use trails near or around the generating station, there is a continued risk of a public safety incident. To treat this risk, Public Safety Management Plans are in place for both BC Hydro and Project Co. Non-Conformity Reports and Non-Performance Events are used to capture non-conformance.

BC Hydro site audits included public safety and measure performance against requirements in the Project Agreement and Project Co's Public Safety Management Plan.

BC Hydro Obligations – Labour Availability: BC Hydro is responsible for providing enough electricians trained with Work Protection Practices (**WPP**) for the Facility during the Services Period, so there is a risk that BC Hydro could fail to meet its contractual obligations, resulting in claims.

Availability Payment (Indexing Portion) O&M Cost variances: Through the Services Period, Project Co must maintain insurance coverage. Availability Payments may be adjusted if comparative insurance cost indices increase more than [redacted] from the preceding year. Due to the potential for Project Co's insurance premiums to increase more than this amount, there is a risk that BC Hydro will be responsible for paying more than the expected amounts, resulting in unbudgeted O&M payments.

Unauthorized Access to Site: As a result of any security breach, vandalism, theft, or terrorism, there is a risk of a loss or damage to new or existing BC Hydro or Project Co property.

[redacted]

Quality Subpar Requiring Rework: Due to new assets and controls, complex interface components, overall Project complexity, performance-based specifications and limited availability of BC Hydro quality assurance resources, there is a risk that the assets may not meet the performance requirements of the Project Agreement and/or the endorsed Final Designs. The design or installation, commissioning and condition assessments may not provide components that fully meet the design service life of the asset and/or leave the Facility with deficiencies when it is returned to BC Hydro asset management responsibility at the end of the Services Period.

This could result in BC Hydro incurring costs to replace assets or correct deficiencies, causing the loss of generating efficiency, creation of safety risks and/or reputational impacts.

While the Project Agreement provides multiple avenues to mitigate this risk during Construction and Commissioning, there are ongoing mitigations to help manage long term quality risk during the Services Period, including:

- Availability Payment impacts with increased costs for forced outages due to equipment failure, over planned outages for maintenance; and
- Mandated and independently checked detailed Unit and equipment inspections in years four, eight and 12, with holdback provision on any defects in the final 12-year inspection to ensure the defects are rectified prior to returning responsibility for the Facility at the end of Services Period;

Risks that BC Hydro is unable to test include:

- The long-term quality of corrosion protection and civil work such as the soil nail wall of the entrance roads and concrete & steel structures. While these items may meet the Project Agreement requirements at Handback, they can’t be fully tested economically to confirm long-term performance; and

- The ability of the new Facility to meet the seismic requirements described in the Project Agreement.

Environmental Incident: Due to the proximity of generation assets to the Campbell River, there is a continued risk of an environmental incident during the Services Period which could result in:

- Fish kills and habitat destruction;
- Regulatory investigations and fines; and
- Reputational impacts.

During the Services Period, the risk of an environmental incident is shared by BC Hydro and Project Co. Environmental work plans are developed by Project Co and implemented by BC Hydro. Environmental issues resulting from work plan implementation rest with BC Hydro. BC Hydro is also responsible for operating the Facility and related environmental consequences.

The most significant risk mitigation is the proven performance of the Bypass System created by the Project, which ensures flow is maintained in the river in event of forced unit outages or unplanned flow events. BC Hydro mitigates environmental performance risk contractually by applying significant financial payment in the event of response failure of the Bypass System, and more generally by assigning points for Non-Performance Events, if Project Co fails to comply with the Project Agreement. For Non-Performance Events, a financial deduction is applied to Project Co based on accumulated points ($/day per point) above a threshold if the situation remains outstanding beyond the rectification period. Further, a dedicated BC Hydro resource is managing the Project Agreement during the Services Period and supported by BC Hydro's Environmental team per normal Environmental management operational processes and procedures.

Safety Incident: There is a risk of a safety incident that could result in a WorkSafeBC order, serious worker injury or fatality.

During the Services Period, BC Hydro is the Prime Contractor responsible for coordination of work and worker safety and for following BC Hydro's safety procedures and requirements as part of the Project Agreement.

12 Availability Payments

Under the DBFR procurement model, Project Co financed 40% of direct construction costs and their management costs during construction. These Project Co costs are paid back to Project Co via monthly Availability Payments over the Services Period. There are two components to the Availability Payments: the first is repayment of the costs financed by Project Co during construction, and the second is for asset management services.

Availability Payments started in May 2018 when the first new GU/LL Asset entered service and will end in October 2033. This repayment period is called the Availability Term.

There are two parts to the Availability Term. The Bridging Period (the Bridging Period) was the first part followed by the Services Period. The Bridging Period started at the beginning of the Availability Term, when the first GU/LL Asset went into service and ended in June 2019 at Service Commencement. Service Commencement is contractually defined as the transition from construction to the Services Period. After Service Commencement, BC Hydro staff began performing the Project Co prescribed maintenance of the Facility. The Services Period continues until the end of the Availability Term in October 2033.

12.1 Bridging Period

During the Bridging Period, Project Co received an increasing percentage of the maximum Availability Payment depending on the number of assets in operation.

This arrangement provided an incentive for Project Co to meet the target commercial operation dates shown in column C of Table 9 below. Missing these dates resulted in loss of Availability Payments shown in column B2 of Table 10 below.

Table 9 below outlines the applicable percentage or Ramp Rate in column A, the originally scheduled dates in column B, the Innovation Proposal No. 1 revised dates in column C, and the actual dates achieved in column D

Table 9 Availability Payments during Bridging Period

<table>
<tr><th>Applicable Ramp Rate (%)[22]</th><th>Original Target Commercial Operation Dates and GU/LL[23] Assets</th><th>Revised Target Commercial Operation Dates and GU/LL Assets per Innovation Proposal No. 1</th><th>Actual Commercial Operation Dates</th><th>Status and Comments[24]</th></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td><td>E</td></tr>
<tr><td>50%</td><td>May 2, 2018
1st GU</td><td>May 2, 2018
Tunnel and LLO OR Tunnel and 1st GU</td><td>May 2, 2018
Tunnel and LLO</td><td>Met</td></tr>
<tr><td>70%</td><td>July 21, 2018
2nd GU</td><td>July 21, 2018
1st unit (if LLO 1st) OR 2nd unit (if a GU was 1st)</td><td>July 21, 2018
1st GU</td><td>Met</td></tr>
<tr><td rowspan="3">90%</td><td rowspan="3">October 10, 2018
3rd GU & Service Commencement</td><td rowspan="3">October 10, 2018
Remaining unit(s) & Service Commencement</td><td>October 26, 2018
2nd GU</td><td>Late</td></tr>
<tr><td>November 5, 2018
3rd unit</td><td>Late</td></tr>
<tr><td>March 29, 2019
Completion of the Original Conditions Precedent for Service Commencement (Renamed ‘Interim Service Commencement’)</td><td>Late</td></tr>
</table>

22 The Ramp Rate percentage is multiplied by the value, in the relevant month, in the schedule of Availability Payments which is included in the Project Agreement.

23 Generating Unit/ Low Level (**GU/LL**) Assets

24 ‘Met’ means attained on or before the Target Date, ‘Late’ means completed but not attained on or before the Target Date, “On Track” means it is forecasting to occur on or before the Target Date, ‘Missed’ means not completed and the Target Date has passed.

Applicable Ramp Rate (%)[22]	Original Target Commercial Operation Dates and GU/LL[23] Assets	Revised Target Commercial Operation Dates and GU/LL Assets per Innovation Proposal No. 1	Actual Commercial Operation Dates	Status and Comments[24]
100%	February 1, 2019 Bypass System	February 1, 2019 Target Bypass System Completion Date for the last Ramp Rate Increment Remained Unchanged	February 1, 2019 = the later of Bypass System completion (November 9, 2018) and February 1, 2019	Met

Table 10 below shows the Availability Payments paid to Project Co to March 31, 2022:

Table 10 Availability Payments ($ million)

[redacted]

Columns B1 to B4 apply to the repayment of Project Co's construction financing, and columns C1 to C4 to the asset management fee.

Each column is described in the table below:

Table 11 Availability Payment Details

Column	Description
B	**Non-Indexing (Debt Repayment)**
B1	Non-Indexing Payment
B2	Non-Indexing cost of Delays to In-Service Dates
B3	Availability Deductions
B4	Actual Net Non-Indexing Portion
C	**Indexing (Asset Management Fees)**
C1	Indexing Payment
C2	Indexing cost of Delays to In-Service Dates
C3	Immediate Callout Billable Hours Deductions
C4	Actual Net Indexing Portion

13 Assessment of DBFR and Recommendations

This section fulfills the requirements specified in Directive #5 of British Columbia Utilities Commission's Order No. C-2-13 which reads in part "The final report should include an assessment of the Design-Bid-Finance-Rehabilitate methodology relative to a Design-Bid-Build approach, lessons learned in implementing the Project and recommendations for the use of Design-Bid-Finance-Rehabilitate in future projects…"

Section 13.1 provides the assessment of the Design-Bid-Finance-Rehabilitate methodology relative to a Design-Bid-Build approach, section 13.2 discusses the lessons learned, and section 13.3 includes the recommendations.

13.1 Assessment

BC Hydro's assessment is that the DBFR procurement approach operated as intended. The Project objectives and timeline were achieved, and the procurement approach provided the expected cost and schedule certainty, while allowing proponent innovation through the use of performance specifications. Project risks were predominantly transferred from BC Hydro to Project Co. BC Hydro expects that for the remaining term of the Project Agreement, the pay-for-performance structure of the DBFR arrangement will continue to act as intended.

In particular, the following is noted:

1. Cost-certainty was achieved as shown by actual costs compared to the overall project forecast shown in Figure 1 of section 5 above. As forecast, 60% of the planned construction progress payments of $673 million were paid out. In BC Hydro's experience, for a project of this size and complexity, managing several contractors under the DBB approach would not likely have achieved this result;
2. The DBFR model drove valuable technical innovation. With Project Co's responsibility for designing and building, their initial proposal provided 2.9% more energy and 3.3% more capacity than the values in the CPCN Application. Innovation Proposal No. 1 provided a further increase to 3.3% more energy and 5.2% more capacity than the values in the CPCN Application. A DBB arrangement provides much less opportunity for a contractor to influence the design through technical innovations. The resulting energy and capacity values from a DBB approach would likely have closely matched the values in the CPCN Application;
3. Project Co's response to the potential schedule impact following the discovery of the geotechnical issue while excavating the main access tunnel demonstrated the effect of incentives under a DBFR arrangement.

   Project Co determined that changing the tunnel alignment would bypass the geotechnical issue without affecting the project schedule or outcomes. In contrast, BC Hydro would have had to coordinate a significant change in design and schedule between the separate Designer and Builder in a DBB model. Unlike DBFR, there would be no financial incentive linked to schedule performance for either the Designer or the Builder. Increases in direct costs, claims and schedule delays would have resulted;

4. The DBFR approach provided additional schedule certainty. Missing Project milestones resulted in [redacted] unrecoverable loss to Project Co of Availability Payments. Additionally, the private-sector finance performance measures were aligned with BC Hydro's. The potential of unrecoverable loss of Available Payments and the alignment of financial performance measures provided greater incentives for Project Co than Liquidated Damages provisions commonly used under a DBB approach.

   Liquidated Damages are usually expressed as a rate per day or week of delay but are capped at a maximum dollar amount. When the cap is reached, the contractor or supplier faces no further increases, reducing the urgency and schedule certainty. DBB approaches usually don't have the participation of private-sector financial entities and related performance measures;

5. Under DBFR, Project Co was responsible for procurement, which would be BC Hydro's risk and responsibility under the DBB form of procurement. An example of the benefit of DBFR over DBB was experienced during the Project when IMPSA,[25] the initial turbine and generator supplier, encountered financial difficulties. This eventually led Project Co to replace IMPSA with Alstom (now GE). A DBB arrangement would have required BC Hydro to organize a replacement supplier and take contractual responsibility for identifying and managing interfaces between the turbine and generator scope and the rest of the Project. All of this would have caused an inevitable delay and cost impact. Under the DBFR contract, the responsibility falls under Project Co; and

6. Since BC Hydro builds and operates assets with long economic lives, the quality of design and construction affects the operability, reliability, and cost

[25] Industrias Metalúrgicas Pescarmona S.A.I.C. y F. (**IMPSA**)

over the operating lifetime, which are thus very important considerations for BC Hydro. BC Hydro attempts to improve supplier and contractor design and implementation by design reviews, witness testing, quality assurance plans, inspections, and other measures; however, the ultimate guarantee of facility performance comes from contractual equipment warranties and performance provisions.

In BC Hydro's experience, it is difficult to obtain and enforce warranties under the DBB model for terms longer than four to six years (depending on market conditions and equipment type), monetary compensation is limited (typically to 10% of the contract value), and recovery is limited to replacement parts only (i.e., not outage time or generation losses).

By comparison, Availability Payments and the associated Non-Availability Event Deductions from unit outages or reduced power rating of the generating unit provide partial mitigation of equipment condition issues over the 15-year Services Period. Periodic Condition Assessments and criteria for handback are additional measures that reduce the risk of the Facility's functioning being compromised at the end of the Services Period. BC Hydro believes that this arrangement provides better mitigation than any arrangements available under a DBB model.

13.2 Lessons Learned

- Due to DBFR, the proponent proposed an innovative design that resulted in more energy at a reasonable price. If BC Hydro were to implement DBFR again, then BC Hydro would again allow for innovative bids.
- Due to the DBFR, the geotechnical issue encountered while excavating the main access tunnel did not result in massive overruns/schedule delays. If BC Hydro were to implement DBFR again, then BC Hydro would contemplate similar geotechnical risk transfer and risk sharing mechanisms in the contract.

- Due to the time and cost needed to organize the DBFR procurement process, the contemplated project must be large enough to justify these impacts.
  BC Hydro would take the project size into consideration when considering the use of DBFR. Longer-lived assets that will allow the private sector participant to earn a return on the financing component are also a consideration.
- Due to the need for alignment between asset performance metrics and risks managed by the private-sector participant, the metrics should be clear and easily understood. For example, asset availability is a good measure for the Project, since it exposes the private participant to risks they can (and are expected to) manage through quality of design and construction and appropriate asset management practices. Conversely, using generating output as a metric exposes the private participant to hydrology risks and BC Hydro’s dispatch decisions.
- Due to the constraints of doing a project within an operating plant, the private participant could be limited by BC Hydro’s operating requirements, unless the project was physically separate from operations. If physical separation is not possible, operational needs may delay the private participant from doing the work. These delays would lead to claims, reallocation of risks back to BC Hydro and jeopardize schedule certainty. For project to be considered for DBFR in the future, the degree of physical separation from operations achievable should be taken into consideration.

13.3 Recommendations for Future Projects

BC Hydro recommends that the use of a DBFR approach on future projects be evaluated on a case-by-case basis depending on the nature of the project, market conditions and BC Hydro’s requirements.

DBFR is more likely to be used on future projects that are large and complex, where BC Hydro is seeking additional cost and schedule certainty and an effective transfer of risk. The potential for technical innovation in the design and construction of the project also indicates the use of DBFR. A DBFR also provides incentives for long-term quality in design and construction, which reduces costs in the longer-term.

14 Photographs

Photographs are provided in Appendix A.

John Hart Generating Station Replacement Project

Project Completion and Evaluation Report

Appendix A

Photographs

Index of Photos

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Figure A-21 Main Access Tunnel Geotechnical Feature Encountered (May 2015)

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Figure A-23 Powerhouse Cavern (August 2016)

1 **Figure A-24 Powerhouse Cavern (December 2018)**

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2 Left to right:
3 Tommy Hunt, Carver for Wei Wai Kum; Chief Chris Roberts, Wei Wai Kum;
4 Max Chickite, Carver for We Wai Kai; Allister Mclean, BC Hydro; Chief Brian Assu, We Wai Kai and Stephen
5 Watson, BC Hydro