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April 30, 2019

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

Dear Mr. Wruck:

RE: Project No. 3698568
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Gordon M. Shrum (GMS) Units 1 to 5 Turbine Replacement Project (Project)
PUBLIC Project Final Completion Report (Report)

BC Hydro writes in compliance with Commission Order No. G-1-10 Directive 2(d), to provide its public Report. Commercially sensitive and contractor-specific information has been redacted pursuant to section 42 of the *Administrative Tribunals Act* and Part 4 of the Commission's Rules of Practice and Procedure.

A confidential version of the Report is being filed with the Commission only under separate cover.

BC Hydro has filed 17 GMS Project Progress Reports with the Commission over the course of the Project, commencing in November 2010.

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

Yours sincerely,

Fred James
Chief Regulatory Officer

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Enclosure

GMS Units 1 to 5 Turbine Replacement Project

Final Report

April 2019

PUBLIC

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Appendices

1 Project Completion

As reported in Semi-Annual Progress Report No. 12, the GMS Units 1 to 5 Turbine Replacement Project (the **Project**) final unit In-Service Date (**ISD**) was October 9, 2015, two months after the revised ISD of August 2015 reported in Semi-Annual Report No. 11. The Project remained open after unit ISDs to address deficiencies, in particular, the cavitation issue identified in Semi-Annual Progress Report No. 8, and updated in subsequent reports. These deficiencies were resolved during normally-scheduled unit outages, as the deficiencies did not prevent normal operation, and did not justify outages in themselves. BC Hydro reports a final completed cost of $182.7 million, which is $15.9 million (8 per cent) below the revised Expected Amount (P_{50}) of $198.6 million, and $91.0 million (33 per cent) below the overall Authorized Amount (P_{90} and Management Reserve) of $273.7 million (both after adjustment for adoption of International Financial Reporting Standards (**IFRS**), and excluding book value write-offs of $0.2 million). This total cost is $0.3 million below the forecast of $183.0 million provided in Semi-Annual Progress Report No. 16, as the cost to correct the deficiencies was slightly less than expected.

2 Project Need

The Project was initiated to respond to deficiencies in the existing turbines, extend the turbine maintenance cycle, and increase energy production since a modern turbine design was expected to provide higher efficiency than the existing units. Additionally, BC Hydro expected to benefit by eliminating a ‘must run’ condition that had been applied to the existing turbines to reduce fatigue and extend their life-span, at the cost of reducing the average generating efficiency at GMS. Finally, the Project would provide an opportunity to modify the wicket-gate operating mechanism to avoid sheer-pin failures like the one that occurred on GMS Unit G3 in March 2008, as described further in section 2.4

2.1 Deficiencies in Existing Turbines

The previous GMS Units 1 to 5 turbines were manufactured by Mitsubishi and were placed into service in 1968 and 1969. Each turbine had a nameplate power output of 266 MW at a net head of 165 m (full pool). Major overhauls on the turbines were completed between 1985 and 1993. These turbines had a history of runner and headcover cracking problems which resulted in significant maintenance costs due to increased maintenance requirements (inspection and weld repairs on a semi-annual schedule) and related outage time.

2.2 Turbine Efficiency Gains

The hydraulic efficiency of the original Mitsubishi turbines was estimated to be 92.48 per cent (weighted-average[1]) based on results of field tests conducted in 1995, but model testing in 2004 indicated that this estimate was high by 0.45 per cent (i.e. actual value determined was 92.03 per cent). In planning the Project, and based on preliminary work with equipment manufacturers, BC Hydro expected new turbines to result in a final efficiency in the range of 94.5 per cent to 95.0 per cent, representing an increase of 2.0 per cent to 2.5 per cent. For the purposes of evaluating the project, BC Hydro assumed an increase in efficiency of approximately 2.3 per cent, which was expected to provide an additional 177 GWh of annual energy, as well as the 164 GWh of energy regained by allowing merit-order dispatch, as discussed in section 2.3.

2.3 Turbine "Must Run"

Stresses in a turbine runner are highest during unit start or stop sequences, or in the transition between generation and sync-condense operation and vice-versa. To reduce start/stop stresses, Units 1, 2, 4, and 5[2] were base-loaded (to the extent

[1] Turbine efficiencies differ depending on operating condition (head and power output). Efficiencies are weighted by the expected or actual frequency of different operating conditions.

[2] Unit 3 was significantly re-built following the turbine failure in March 2008. It was excluded from the base-load requirement on the basis that the re-built runner could withstand the start/stop stresses in normal operation until replaced as part of the Project.

possible, run continuously, without starting or stopping), rather than the typical practice of dispatching units from most-efficient to least-efficient to meet the required power output for the plant (merit-order dispatch). This operating mode reduced the average efficiency at GMS because Units 1 to 5 were the least efficient turbines in the plant. Utilization of the inefficient turbines imposed an estimated annual loss of 164 GWh compared to a plant-wide merit-order dispatch capability, which would have seen Units 6 to 10 operating at higher capacity factors, and Units 1 to 5 operating at lower capacity factors. The merit-order dispatch gain resulting from the Project is in addition to the anticipated efficiency gain discussed in section 2.2.

2.4 Wicket Gate Operating Mechanism

A cascade failure in the wicket gate operating mechanism caused GMS Unit 3 to fail in March 2008. The failure forced the unit out of service for over a year and was costly both in cash costs to remediate the failure, and in opportunity costs of lost generation and capacity. The wicket gate operating mechanism was common to Units 1 to 5, and BC Hydro stipulated that the Project scope include modifications to these mechanisms on all five units to prevent a recurrence of the Unit 3 failure.

3 Project Outcomes

The project was initiated to address all of the objectives outlined in section 2 and upon completion each has been met as described below and summarized in Table 1.

3.1 Turbine Deficiencies

The runners show no signs of cracking or cavitation damage, and are expected to operate with a long duty cycle with either no, or infrequent, weld repairs required. The operating ‘must run’ restrictions have been eliminated, with the result that the GMS plant is now dispatched on a merit-order basis, and the energy lost to base-load operation has been regained.

3.2 Turbine Efficiency

The supply and installation contract for the runners, headcovers, and associated turbine components was structured in two stages: Stage 1 allowed for engineering and equipment design, and culminated in a model turbine which was tested at an independent laboratory; Stage 2 was the fabrication and installation of the five new prototype turbines at GMS. Two proponents, Andritz Hydro Canada Inc (**Andritz**), and Voith-Siemens Hydro Power Generation Inc (now Voith Hydro Inc.– **Voith**), were selected to participate in Stage 1.

This two staged approach allowed BC Hydro to select between the two proponents based on the tested efficiency of their turbine design, rather than relying on an efficiency guarantee and possible financial compensation if the guarantee was not met. The tested weighted-average efficiency for the Andritz turbine was 94.57 per cent, while the Voith turbine was slightly higher at 95.48 per cent (both after adjustment from model results to prototype results). Although Voith's contract price was higher than Andritz's, the higher turbine efficiency, as well as technical advantages of the Voith turbine[3], led BC Hydro to select Voith as the turbine supplier.

On testing the Voith turbine after installation, the measured efficiency is 95.97 per cent ± 1.24 per cent, representing a positive efficiency variance of 0.49 per cent ± 1.24 per cent. For context, GMS Units 1 to 5 generation has averaged just over 6,400 GWh for the three calendar years since the last unit ISD, and an improvement of 0.49 per cent in turbine efficiency represents almost 33 GWh of plant output annually.

[3] In a report to the British Columbia Utilities Commission dated January 18, 2011, BC Hydro reported the model test results for both Voith and Andritz and the reasons for selecting Voith as the turbine supplier, as well as the analysis of the accelerated schedule alternative for the Project.

3.3 Wicket Gate Mechanism

The wicket gate operating mechanism was replaced for all five units. The new design includes a new link pin and friction brake which will maintain control of the wicket gate in the event of a failed shear pin. BC Hydro believes that this design will be effective in preventing a wicket gate failure such as that experienced on Unit 3.

3.4 Summary of Project Outcomes

The project outcomes are summarized as follows:

Table 1 Project Impact and Benefits Realization

Impact / Benefit Name	Project Objective	Measure	Baseline Value	Forecast or Estimated Value	Actual Value Measured	Variance	Measurement Report & Timing
Turbine Efficiency	Improve Efficiency	Weighted Average Efficiency	~92.48%[1]	95.48%[2]	95.97%[3] ±1.24%	+0.49% ±1.24%	Prototype (G4) Efficiency Test, May 2015
Weld Repair	Eliminate the need for weld repairs to the runner	Eliminated or reduced needs (in days per unit per year)	Pre-replacement the GMS runners needed annual weld repairs requiring 93 welder days[4]	Not expected	To be observed over life – no weld repairs required to date	n/a	Ongoing
Unit Dispatch	Remove Dispatch Restrictions	Removed or Retained	Dispatch Restricted reducing plant output by estimated 164 GWh/Yr,	Restriction Removed	Restriction Removed, additional 164 GWh available,	n/a	Removal of Unusual Conditions Orders
Wicket Gate Operating Mechanism	Remove Interference between Adjacent Gates	Removed or Retained	Interference is possible	Interference Removed	Removed	n/a	Acceptance of Design

Notes:

Please refer to sections 2.2 and 3.2 for discussion of turbine efficiency

1. Value based on 1995 field tests. This was overstated by 0.45 per cent, with actual pre-project efficiency of 92.03 per cent
2. Model efficiency based on 2010 independent test results, adjusted for model-to-prototype step-up. This was the anticipated minimum efficiency when BC Hydro made the decision to continue to Stage 2 with Voith. This

was an improvement of 0.45 per cent over the efficiency guaranteed in Voith's tender of 95.03 per cent. By comparison, Andritz's tendered efficiency was 94.57 per cent, also after adjustment for model-to-prototype step-up.

3. Testing was conducted on Unit 4, after the runner had been modified in response to cavitation issues. The modifications increased the model efficiency by 0.11 per cent (from 95.48 per cent to 95.59 per cent, both adjusted for model-to-prototype step-up).
4. Due to the complicated stainless steel overlay and significant runner cracking, each of the 17 blades required approximately five to six days of a welder's time each year.

4 Project Schedule

The initial Project plan and the Certificate of Public Convenience and Necessity Application both anticipated a schedule in which one unit would be installed annually, generally between March and October of each year. This schedule was intended to preserve maximum generating capacity at GMS over BC Hydro's annual system peak demand from November through February. At the same time, it was recognized that if system capacity loads and resources allowed it, a faster back-to-back installation schedule could be adopted.

The turbine supply and installation contracts had been awarded on the basis of the one-unit-per-year schedule. A discussion regarding any alternate schedule could not be initiated until the successful Stage 2 proponent had been identified after the conclusion of model testing in June 2010. In July 2010, Voith was selected as the preferred proponent to continue, and the contract with Andritz was terminated. Evaluation at that point indicated that system loads would be lower than previously thought, and full GMS capacity would not be required to meet peak loads over the project term. As a result, BC Hydro approached Voith to propose an accelerated schedule, which was adopted.

The original and accelerated schedules, as well as the actual milestone achievements, are shown in Table 2 below:

Table 2 Project Schedule

Description	Original Schedule	Accelerated Schedule	Actual Completion	Variance[1] (Months)
U1-5 Turbine Replacement Board Update	Nov 2008	n/a	Feb 2009	(3)
Implementation Stage 1 Funding Approval	Nov 2008	n/a	Nov 2008[2]	0
BCUC Application Submitted	Aug 2009	n/a	Aug 2009	0
BCUC Decision Received	Feb 2010	n/a	Jan 2010	1
Implementation Stage 2 Funding Approval	May 2010	n/a	May 2010	0
Implementation Stage 2 Notification to Supplier	July 2010	n/a	July 2010	0
Accelerated Schedule Adopted				
First Unit (Unit 4) – ISD	Nov 2012	Nov 2012	Feb 2013	(3)
Second Unit (Unit 1) – ISD	Nov 2013	Aug 2013	Oct 2013	(2)
Third Unit (Unit 2) – ISD	Nov 2014	Apr 2014	Jun 2014	(2)
Fourth Unit (Unit 5)- ISD	Nov 2015	Nov 2014	Jan 2015	(2)
Fifth Unit (Unit 3) – ISD	Nov 2016	Jun 2015	Oct 2015	(4)
Identified Deficiencies Addressed[3]	n/a	n/a	Dec 2018	n/a
Project Close Out	Mar 2017	Dec 2015	Mar 2019	(39)

Notes:
1. Schedule difference between schedule (Original or Accelerated) and actual completion, in months. Negative values indicate delays between schedule and actual.
2. Represents EAR approval date. Board approval was granted at the Board Meeting in February 2009.
3. No milestone was established for deficiencies in either the Original or the Accelerated Schedule. Deficiencies did not prevent normal operation, and were addressed in planned outages to maintain unit availability.

The accelerated schedule reduced project costs, including the Voith contract price and BC Hydro's project management costs and Interest During Construction (**IDC**). In addition, the accelerated schedule allowed both Voith and BC Hydro to maintain better crew continuity since there were no long idle periods between installations.

5 Project Costs

The Project actual and expected costs, and the variance between them, are summarized in Table 3 below:

Table 3 Project Costs

Description	$000s[1]			Explanation
	Actual Cost[2]	**Expected Amount[3]**	**Variance (Actual Cost – Expected Amount)**	
Seed, Identification, Definition and Early Implementation (Contract Stage 1)	11,806	11,279	527	Direct costs below estimate by $1.2 million, offset by Overhead and IDC which were above estimate
Implementation Phase				
Implementation Stage - General Activities	30,587	12,738	17,849	Includes engineering and contractor costs to remedy identified deficiencies, particularly in relation to the cavitation issue, and added scheduling and planning resources
Supply and Installation – First Unit (U4)	32,425	32,490	(66)	Expected and Actual Unit costs declined with experience. Actual Cost includes remediation of minor deficiencies
Supply and Installation – Second Unit (U1)	27,603	25,012	2,591	
Supply and Installation – Third Unit (U2)	26,522	24,449	2,073	
Supply and Installation – Fourth Unit (U5)	25,570	24,013	1,557	
Supply and Installation – Fifth Unit (U3)	28,182	23,256	4,926	Increased commissioning costs due to unrelated equipment issues
Contingency	0	45,386	(45,386)	Contingency draws were below estimate
Sub-total – Implementation	*170,889*	*187,344*	*(16,455)*	
TOTAL	**182,695**	**198,623**	**(15,928)**	

Notes
1. All cost figures exclude book-value write-offs of $0.2 million
2. Actual costs to March 2019, at which time the Project was closed.
3. Expected Amount adjusted for reduction of overhead on transition to IFRS, and adoption of accelerated schedule

The cumulative Project cash flow is shown in Appendix A. The costs by year and unit, as well as variances between actual and expected costs, are shown in Appendix B.

6 Project Contracts

The Project entered into two contracts to design, fabricate, supply and install five new turbines at GMS. The contract with Andritz was terminated at the end of Stage 1 at a cost to-date of $[redacted]. The contract with Voith continued to Stage 2, with a total contract value of $[redacted].

As a result of adopting an accelerated contract delivery schedule, the Voith contract was reduced to $[redacted]. Over the course of the contract, Equitable Adjustments in the amount of $[redacted] were awarded to address unanticipated site and equipment conditions; runner cavitation issues; shaft seal cooling water filtration improvements to meet site conditions; improvements to equipment safety, and other minor modifications as required.

Table 4 Contracts over $3 million

No.	Description Supplier and Scope of Supply	Initial Contract Value[1] ($ million)	Accelerated Contract Value[1] ($ million)	Equitable Adjustment ($ million)	Contract Cost ($ million)	Expended to Date ($ million)
1	Voith Hydro Contract[2] – Stages 1 and 2	[redacted]				

1. [redacted]
2. [redacted].

7 Project Challenges

7.1 Schedule

The Project was three months late bringing the first unit (Unit 4) into service, which was due to unanticipated resource constraints during commissioning. This schedule slip was partially recovered on subsequent units as both the Project and site staff worked to improve communication and resource coordination, and both BC Hydro and Voith personnel gained experience on the equipment and installation processes.

The final unit ISD was affected by equipment issues unrelated to the turbine which delayed the unit being placed into service.

7.2 Runner Cavitation

As discussed in prior Semi-Annual Reports to the BCUC, cavitation damage was noted during the first scheduled warranty inspection on the Unit 4 runner (the first unit installed). This damage was unexpected as there had been no indication of cavitation during model testing. Subsequent investigation revealed that the cavitation was linked to operating at low flow rates under high reservoir elevations, and the damage was occurring in a part of the runner that could not be observed in the model testing configuration.

Voith developed a modification to the runner that was intended to remove the cause of the cavitation, but it proved to be ineffective. Voith then developed a second modification which was successful. The modified runners have shown no evidence of cavitation since the modification was completed and BC Hydro does not expect that cavitation will be an issue with the new turbines.

The Voith contract included a cavitation warranty which required Voith to pay BC Hydro liquidated damages in the amount of $[redacted] and complete periodic weld repairs for the duration of the warranty period, if cavitation damage exceeded allowable thresholds and Voith was unable to rectify it. BC Hydro considered that resolution of the cavitation problem was a better solution for long-term asset health than a payment for liquidated damages and an ongoing program of runner weld repairs. As a result, BC Hydro and Voith negotiated a cost-sharing agreement for the application of the runner modifications.

The cost-sharing agreement was structured so that BC Hydro's contribution was, in part, contingent on the results of the cavitation test on Unit 2. The cavitation test compared blades with a weld repair with Cavitec; blades with a weld repair with native material; blades with a slightly roughened surface, and blades modified with the second modification. The result of the cavitation test was that blades modified with the second modification showed no cavitation damage, while blades repaired with Cavitec showed damage that was narrowly within the contractual limits.

BC Hydro considers the runner modifications to be a better long-term technical solution than on-going weld repairs with Cavitec. BC Hydro requested Voith apply the second modification to all five units which, under the cost sharing agreement, resulted in a total cost of $[redacted] to BC Hydro.

Development and implementation of the second modification represents the only known case of *in-situ* cavitation correction in the hydropower industry, and both BC Hydro and Voith Hydro are pleased with the accomplishment.

7.3 Turbine Humming

All five of the new turbines experienced an unidentified low humming noise when operating at some combinations of head and flow rate. The problem was resolved by injecting air into the turbine chamber through the headcover. After testing on Unit 4, this solution was applied to all five units, with additional air handling piping installed, as required, to serve all five units. The scope of this work was primarily the installation of additional piping and control cables, which was completed for less than $0.1 million. Future costs of operating and maintaining the additional equipment are not expected to be material.

7.4 Wicket Gate Face-Plate Galling

On initial inspections, the first three units installed (Units 4, 1, and 2) exhibited galling, or damage caused by adhesion between sliding surfaces, primarily on the wicket gate upper face plates. After re-machining the face plates to restore their flat surfaces, the problem was resolved by slightly shimming up the headcovers to reduce the frictional load between the face plates and the wicket gates. This solution was applied proactively to the last two units installed, Units 5 and 3. BC Hydro and

Voith shared the cost of this modification; BC Hydro's share was slightly less than $0.15 million, and there are not expected to be any operating cost implications.

7.5 Shaft Seals

The shaft seals are wearing faster than originally anticipated, likely due to higher than expected silt levels in the water. While the expectation was for a 10-year life, it appears that they may only have a three year life-span. BC Hydro has raised a warranty claim with Voith, who will investigate during an upcoming outage, and BC Hydro expects that Voith will propose a harder seal material. If Voith does not present a solution which is acceptable to BC Hydro, the increased frequency of replacement will increase average annual maintenance costs by approximately $0.03 million per machine, or a total of $0.15 million annually for all five units. The seal wear increases cooling water leakage, which in turn increases the demand on the cooling water filters, as discussed below.

7.6 Shaft Seal Cooling Water Filters

The Project installed two filter skids for cooling water, but the automatically-actuated valves wore out faster than anticipated due to frequent cycling between filtering and cleaning (backwash) mode. The problem was traced to 1) high silt loads in the reservoir due to low reservoir elevations, which required frequent cleaning, 2) errors in the logic BC Hydro applied in the programmable logic controllers (**PLCs**) that operate the skids, and 3) Voith's valve specification which did not consider the higher silt loads experienced. The problem was exacerbated by the high cooling water leakage rates at the shaft seals resulting in the two skids operating in parallel, rather than the intended deployment of one operating skid and one fully redundant skid as a back-up.

BC Hydro identified more robust valves, but as they were not immediately available from the manufacturer, Voith performed a like-for-like replacement of the original valves at their cost, as a short-term solution. These valves have now been replaced by the more robust BC Hydro specified valves at BC Hydro's cost.

BC Hydro has also developed and applied new logic for the PLCs, and the rate of cycling has returned to more normal levels. The skids will continue to operate in parallel until the wearing issue with the shaft seals is rectified.

8 Lessons Learned

8.1 Plant Coordination

The Project imposed high demands on plant staff which were not initially recognized in Project or plant planning and staffing. The difficulty in obtaining plant resources led to schedule slips, particularly on the first unit replaced (Unit 4).

Lessons Learned: It is critically important to coordinate activities with existing plant schedules. Resource availability and schedule performance dramatically improved after the Project provided dedicated scheduling resources to improve coordination with the plant. This approach has been adopted for other facilities with multiple concurrent projects underway.

8.2 Embedded Parts

The condition of many embedded parts could not be assessed until unit disassembly. In some cases, the required refurbishment was more extensive than anticipated, putting the work onto the critical path, or extending the outage schedule.

Lessons Learned: The condition of embedded or obscured parts should be assessed as early as possible in the refurbishment cycle to provide the maximum time to respond to unanticipated deficiencies. Allow extra contingency time if the project implementation will rely on refurbishing embedded or obscured parts.

8.3 Inspection and Survey

The concurrent Rotor Pole Upgrade project required separation of the thrust block and thrust runner (this was added scope for the Project). The two components were not adequately surveyed prior to the separation, and as a result the re-assembled thrust block and thrust runner were out of tolerance. The components had to be separated a second time with the thrust runner sent out for urgent machining.

Lessons Learned: It is essential to conduct thorough inspections of key components before, during, and after refurbishment work. Ensure suppliers, installers, and their sub-contractors have the tools and procedures to conduct and document the required work and inspections.

8.4 Interpretation from Drawings

The air admission housing was found to create a confined space around the brushgear, which would reduce access to frequently-maintained parts. This was not identified until the installation on the first unit (Unit 4) was complete because it was difficult to identify from the two-dimensional drawings available for review.

Lessons Learned: Three-dimensional visualization may be helpful to illustrate complicated components, particularly when old and new components will interface. Three-Dimensional CAD and similar tools have been adopted on other BC Hydro projects.

8.5 Cavitation

Entrance-edge cavitation was missed during the design phase and model testing.

Lessons Learned: Frozen-rotor Computational Fluid Dynamics analysis does not adequately model all clock positions, and thus cannot be relied-upon to identify all potential cavitation. Model testing is intended to overcome that limitation, but in this case the runner blade and spiral case geometry prevented observation of the entrance edge during model testing. The visibility of the entrance edge should be confirmed on models before testing begins, and new techniques like the wicket-gate window or submerged boroscope should be implemented to provide that visibility.

8.6 Lifting Certifications

Existing plant lifting devices were not certified for the required lifts. On several occasions extraordinary measures were required to certify lifting devices in time for major lifts.

Lessons Learned: Obtain copies of all lifting device certifications at the start of a Project. If certifications are not available, undertake the work required to enable certifications for the anticipated lifts required over the Project term.

8.7 Water Testing

Several shaft seal cooling water filtration skids failed shortly after installation. On review of the failures, it was apparent that the silt levels in the water were higher than anticipated and as a result, the shaft seal cooling water filtration skids were not robust enough for the application.

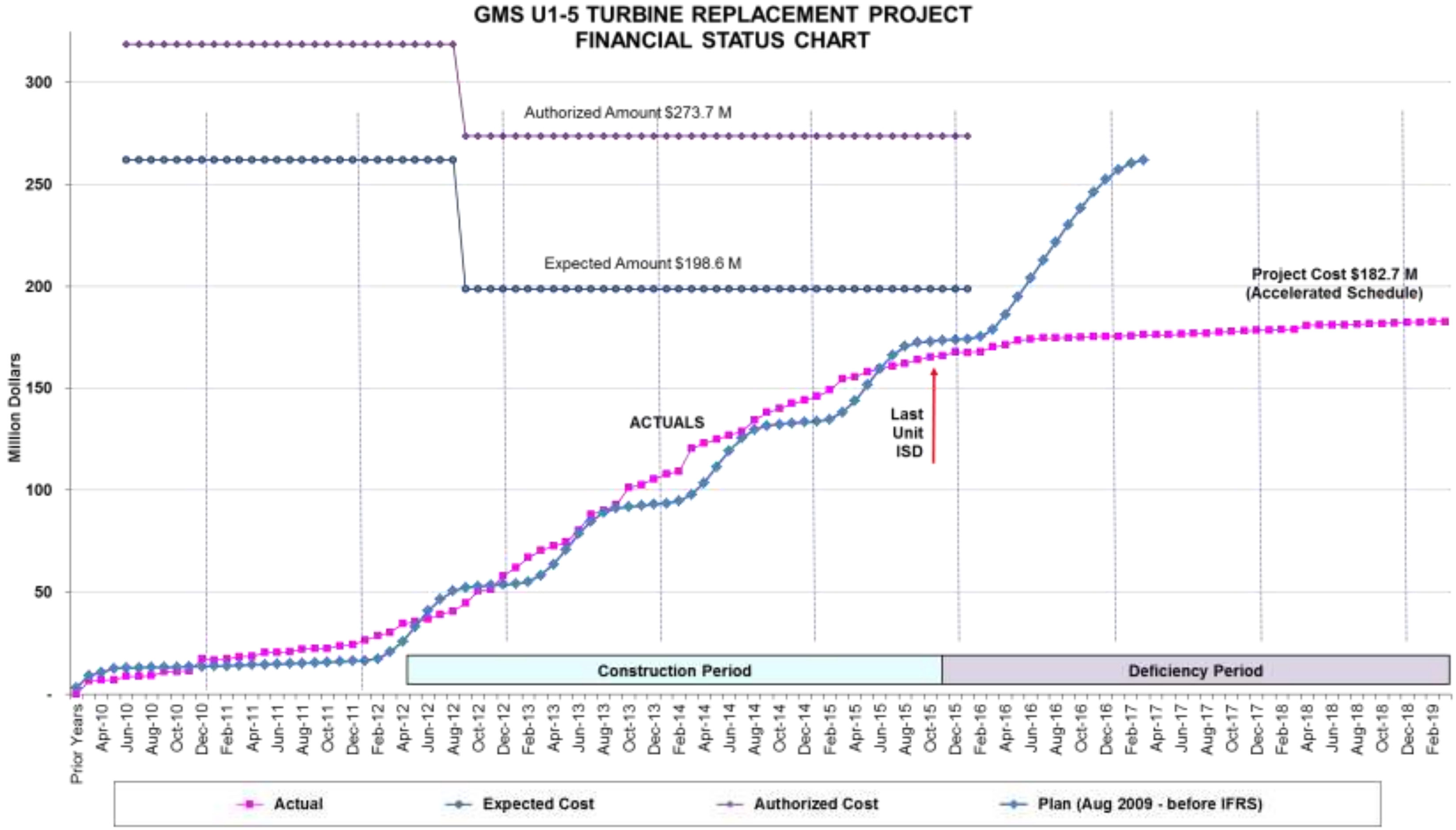
Lessons Learned: Increase the scope and frequency of water testing to improve the understanding of water quality. Perform detailed reviews of systems which will require regular ongoing maintenance and thoroughly investigate experience and references for sub-suppliers and sub-contractors.

GMS Units 1 to 5 Turbine Replacement Project

Final Report

Appendix A

Project Expenditure Plot


GMS U1-5 TURBINE REPLACEMENT PROJECT
FINANCIAL STATUS CHART
Authorized Amount $273.7 M
Expected Amount $198.6 M
Project Cost $182.7 M
(Accelerated Schedule)
ACTUALS
Last
Unit
ISD
Million Dollars
Construction Period
Deficiency Period
Actual
Expected Cost
Authorized Cost
Plan (Aug 2009 - before IFRS)

GMS Units 1 to 5 Turbine Replacement Project

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Appendix B

Project Cash Flows by Unit and Variance Explanations

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Variance Explanations

The total cost of the Project is $182.7 million, $15.9 million below the Expected Amount (P_{50}) of $198.6 million[4] and $91.0 million below the Authorized Amount of $273.7 million ($P_{90}$ and Management Reserve). The reduction in costs was primarily due to lower-than-anticipated draws on Project contingency.

Explanations for variances between the Project actual costs and the Expected Amount are provided below. The letter beside each variance explanation below corresponds to the reference column in the table above.

(a) The allocation of FY10 and prior period costs has been changed due to improvements in financial and project management systems to account for these pre-system conversions costs;

(b) Project management costs in the Implementation phase increased by $1.6 million, from $2.5 million to $4.1 million, reflecting additional costs for GMS site security, and increased project controls and monitoring costs;

(c) Engineering costs have increased by $2.0 million, from $4.3 million to $6.3 million, resulting from an increase in Quality Assurance work for the Project, and the efforts devoted to the cavitation issue and runner modifications;

(d) BC Hydro has created a new cost category to capture the costs to remedy identified deficiencies, including cavitation issues. These costs, totalling $15.9 million, were allocated between units as part of asset detailing at Project completion;

(e) Construction Indirect and Safety costs decreased by $2.1 million, from $3.6 million to $1.5 million, reflecting a lower cost for temporary construction infrastructure due to efficiencies gained as the Project progressed.

4 All figures exclude book value write-offs of $0.2 million.

(f) Direct costs for the Supply, Installation and Construction of Units 1 to 5 increased by a total of $13.3 million, from $116.7 million to $130.0 million, due to unanticipated site and equipment conditions, improvements to equipment safety, and other minor modifications as required. These increases were funded by contingency draws.

The Project contingency in the Expected Amount was $45.4 million, including $7.1 million for overhead and IDC on contingency. Of the total amount, $31.2 million was used to cover cost increases noted above. The remainder of $13.4 million was not required and was removed from the project forecast, reducing the undrawn balance to nil.