BC hydro
FOR GENERATIONS

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August 5, 2009

Ms. Erica M. Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
Gordon M. Shrum Generating Station (GMS) Units 1 to 5 Turbine Replacement Project

BC Hydro encloses its application filed pursuant to section 44.2(1)(b) of the *Utilities Commission Act*, seeking a BCUC Order accepting that the expenditures associated with the GMS Units 1 to 5 Turbine Replacement Project are in the public interest.

BC Hydro proposes to hold a workshop on August 20, 2009 as the first step of the regulatory review process.

All communications with respect to the application should be directed to:

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and to:

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For further information please contact Lyle McClelland at 604 623-4306.

Yours sincerely,

for Joanna Sofield
Chief Regulatory Officer

Enclosure

c. BCUC Project No. 3698500 (BC Hydro F2009/F2010 Revenue Requirements Application) Registered Intervenor Distribution List.

Halfway River First Nation
Kwadacha First Nation
McLeod Lake Indian Band
Treaty 8 Tribal Association
Tsay Keh Dene First Nation
West Moberly First Nations

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BC hydro

Chapter

1

Introduction

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1.1 Introduction

This application (the **Application**), filed pursuant to section 44.2(1)(b) of the *Utilities Commission Act* (the ***UCA***), contains a schedule of capital expenditures that British Columbia Hydro and Power Authority (**BC Hydro**) anticipates making for implementation of the Gordon M. Shrum Generating Station (**GMS**) Units 1 to 5 Turbine Replacement Project[1] (the **Project**). BC Hydro seeks, pursuant to section 44.2(3)(a) of the *UCA,* that the British Columbia Utilities Commission (**BCUC**) accepts that the expenditures referred to in the schedule of capital expenditures are in the public interest.

In considering whether the expenditures are in the public interest, according to section 44.2(5) of the *UCA* the BCUC must consider: the Government's energy objectives; BC Hydro's most recent long term resource plan; whether the expenditure schedule is consistent with sections 64.01 and 64.02 of the *UCA* in respect of electricity self-sufficiency and clean and renewable resources; and the interests of present and future ratepayers.

1.1.1 B.C. Government Energy Policy

The Project is consistent with Policy Action Item #17 of the British Columbia (**B.C.**) Government's updated energy policy, "*The BC Energy Plan: A Vision for Clean Energy Leadership* (**2007 Energy Plan**), regarding investment in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the Province.

As well, the Project is consistent with sections 64.01 and 64.02 of the *UCA* in that the Project contributes to electricity self-sufficiency and generates clean electricity.

1.1.2 Revenue Requirement and Service Plan Cost Estimates

BC Hydro identified the Project in a number of applications to the BCUC including, the 2005 Resource Expenditure and Acquisition Plan (**2005 REAP**), the 2006 Integrated

[1] In the BC Hydro F09/F10 Revenue Requirements Application, the Project is entitled the G.M. Shrum Unit 1 to Unit 5 Turbine Rehabilitation Project.

Electricity Plan and Long-Term Acquisition Plan (**2006 IEP/LTAP**), the F2007 and F2008 Revenue Requirements Application (**F07/F08 RRA**), and the F2009 and F2010 Revenue Requirements Application (**F09/F10 RRA**). In the capital plan submitted as part of the F09/F10 RRA BC Hydro forecast it would incur capital expenditures of $6.4 million to the end of F2010 in respect of the Project. BC Hydro also estimated that the cost for the Project would fall within a range of cost of $170 million to $240 million. Since the time of these estimates, the scope of the Project was updated to reflect the results of analysis of the GMS Unit 3 failure and BC Hydro entered into a supply and install contract with two possible suppliers of the turbines after a competitive procurement process. The Project Expected Cost is now $262 million and the Authorized Cost is $319 million. BC Hydro's project estimating methodology including an explanation of Expected and Authorized Costs is described in Appendix C.

1.2 Project Highlights

1.2.1 GMS Description

GMS is an essential part of BC Hydro's generating system. With a current capacity of 2,730 megawatts (**MW**), GMS accounts for about one quarter of BC Hydro's generating capability. GMS has ten generating units. GMS Units 1 through 5 are late 1960's vintage Mitsubishi Francis turbines with General Electric generators. Each of these units has a rated maximum unit capacity of 261 MW. Together they provide 1,305 MW of capacity, currently representing about 12 per cent of BC Hydro's installed capacity. Units 1 to 5 generate an average of 6,600 gigawatt hours (**GWh**) of energy per year.

1.2.2 Project Description

The Project involves replacing the Units 1 to 5 turbines. Specifically, this will include designing and manufacturing new turbine runners, wicket gates, wicket gate operating mechanisms and head covers and overhauling the remaining turbine components.

On February 27, 2009, two contract awards for the Project were approved by BC Hydro and award notices were issued to Voith Hydro Inc. (**Voith**) and Andritz Hydro Limited (**Andritz**). The contracts and Project implementation have two stages:

- the turbine model design and testing (**Implementation Stage 1**) – at this stage, the turbine designs submitted by the two potential suppliers will undergo Competitive Model Testing (**CMT**) where their turbine designs are tested and evaluated before the turbine upgrade supply and install work is awarded to the successful supplier; and
- the turbine construction and installation (**Implementation Stage 2)** - this stage includes the final design, manufacturing, overhaul and installation of the new and overhauled turbine equipment by the successful supplier.

1.2.3 Project Schedule

BC Hydro expects to implement the Project in stages. A staggered In-Service Date (**ISD**) schedule is planned. The target ISD for the first unit is November, 2012, with the installation of all five units to be completed by November, 2016. BC Hydro expects the entire Project to be complete by March, 2017. Installation and commissioning of each unit will take place at the site during a six-month outage per unit over five consecutive years until all five units are replaced.

1.3 Project Justification

1.3.1 Need

The primary justification for the Project is the unsatisfactory asset condition of the GMS Units 1 to 5 turbines and the associated high business risks. The turbine runners in these units have exhibited ongoing cracking problems since 1972 and also suffer from cavitation[2] problems. The runners have defects and residual stresses introduced by a high number of weld-repairs that have been completed to address these ongoing issues. The headcovers have ongoing cracking problems as well. BC Hydro concludes that one of the root causes of the cracking problems is the original design and therefore repairs or overhaul will not eliminate or reduce the potential impact of additional cracking. There are also design deficiencies in the wicket gate operating mechanisms that necessitate their replacement.

[2] A process where a void or bubble in a liquid rapidly collapses, producing a shock wave. In a turbine, this shock wave can cause damage to the surface of equipment through the formation of pits. The pits increase the turbulence of the fluid flow and create crevasses that act as nucleation sites for additional cavitation bubbles. The pits also increase the components' surface area and leave behind residual stresses making the surface more prone to stress corrosion.

Overall, the runners, headcovers, wicket gates and wicket gate operating mechanisms must be replaced as part of the Project to address inherent design problems and to ensure no adverse interaction between these turbine components. The remaining components must be overhauled to extend their service life.

These design issues, defects and residual stresses increase the probability of unit failures. In the short term, to manage the current high level of unit risk, BC Hydro has adopted a six-month inspection and maintenance cycle on GMS Units 1 to 5 and has placed operating restrictions on GMS Units 1, 2, 4 and 5. The operating restrictions reduce the plant operating efficiency and also impact the ability for BC Hydro to economically optimize the system with market purchases. BC Hydro will monitor asset condition with these restrictions in place but considers that comparable restrictions will remain in place until the turbines are replaced.

BC Hydro considers it unacceptable to continue to address the risk of unit failures with increased maintenance and operating restrictions. Rather, a more permanent, robust solution as proposed in this Project is required.

1.3.2 Project Benefits

In addition to addressing unsatisfactory asset condition, implementation of the Project will also provide additional benefits, including:

- low cost, incremental energy gains through improved efficiency from a new runner design and other modifications;
- low cost, incremental energy gains as a result of removal of the operating restrictions on unit operation that currently constrains generation from GMS Units 1, 2, 4 and 5;
- avoided future outage costs and future inspection and maintenance cost increases as a result of operating Units 1 to 5 without ongoing cracking and equipment health issues and the requirement for frequent inspections and maintenance;

- an option for a future capacity rating increase from 261 MW per unit to 305 MW per unit. The Project will not result in a capacity increase as future work is required. A capacity increase is not within the scope of the Project; and
- machine and worker safety improvements arising from design features that improve the safety of the machine and reduce the risk of a significant failure in the future.

BC Hydro is of the view that implementation of the Project is in the best interests of persons in B.C. who receive or may receive service from BC Hydro.

1.3.3 Cost-Effectiveness

The Project has a positive Net Present Value (**NPV**) and is the most cost-effective alternative to address the condition of the GMS Units 1 to 5 turbines. Specifically:

- Replacement of the turbines will eliminate the need for the operating restrictions currently in effect. This will allow GMS to run units in “merit order” (most efficient dispatched first and most often, through to least efficient dispatched last), improving overall plant efficiency. This improvement will regain approximately 164 GWh per year;
- There is an expected increase in efficiency of the turbines associated with a new runner design. The level of efficiency improvements will not be known until after the CMT stage of the Project. However, BC Hydro expects that the efficiency gain will translate into increased energy production of approximately 177 GWh per year and will be achieved while BC Hydro operates within the parameters of the current water license; and
- The Overhaul and Status Quo alternatives would require frequent outages going forward in order to carry out inspections and maintenance. The cost of these outages includes both direct costs and opportunity costs. Only the Project will allow the inspection and maintenance cycle of GMS Units 1 to 5 to return to a cycle frequency that would be consistent with healthy turbine assets, as only the replacement alternative reduces the residual risk to an acceptable level for this to occur.

1.4 First Nations and Public Consultation

BC Hydro has undertaken consultation with First Nations and the public to identify issues specific to the Project. BC Hydro expects the Project will have minimal potential for environmental or social impacts as works will occur within the existing GMS facility footprint on BC Hydro property and will not result in flow changes outside of normal operation variation in the Williston reservoir or the Peace River. Taking into the consideration these factors and the consultation activities undertaken, listed in sections 5.2 and 5.3, BC Hydro is of the view that consultation efforts conducted for the Project have been adequate.

Details of the consultation that has taken place can be found in Chapter 5 and Appendix G.

1.5 Project Risks

Consistent with BC Hydro's standard project management practices and procedures, risk screenings have been conducted to identify major Project risks and their associated control and mitigation strategies. A summary of the material risks, plans to manage these risks, and levels of residual risks are provided in Chapter 6.

1.6 Order Sought

BC Hydro is applying for a BCUC Order that accepts that this expenditure schedule to complete the Project is in the public interest according to subsection 44.2(3)(a) of the *UCA*. Specifically, the Project proposes the replacement of turbines for GMS Units 1 to 5 with a target completion in March 2017 involving staggered unit in-service dates between November 2012 and November 2016. The Project Expected Cost is $262 million and Authorized Cost is $319 million.

BC Hydro intends to file with the BCUC bi-annual progress reports on the Project schedule, costs and any variances or difficulties the Project may be encountering. The form and content of the bi-annual progress reports will be consistent with other BC Hydro capital project quarterly reports filed with the BCUC. Within six months of the end or substantial completion of the Project, BC Hydro will file a final report. The final report will include a complete breakdown of the final costs of the Project, a comparison of these costs to the Project Expected Cost estimate and provide a detailed explanation and justification of material cost variances.

As directed per BCUC Letter No. L-78-06, BC Hydro has included in Appendix B of the Application a draft final order.

1.7 Proposed Review and Approval Process

BC Hydro proposes a written hearing process consisting of:

- Application filed on Wednesday, August 5, 2009.
- BCUC issues an Order establishing the regulatory timeline and notice of workshop by Friday, August 7, 2009.

Workshop

- Workshop on the Application presented by BC Hydro on Thursday, August 20, 2009.

Information Requests (**IRs**)

- BCUC IR Round 1 issued by Tuesday, August 25, 2009;
- BC Hydro responds to BCUC on Tuesday, September 15, 2009.
- BCUC IR Round 2 and Intervenor IR Round 1 issued Tuesday, September 22, 2009
- BC Hydro responds to BCUC IR Round 2 BCUC and Intervenor IR Round 1 IRs Tuesday, October 13, 2009

Written Submissions/Reply

- BC Hydro final written submission by Tuesday, October 27, 2009;

- Intervenors' final written submissions by Tuesday, November 3, 2009; and
- BC Hydro written reply by Tuesday, November 10, 2009.

To complete the Project by the end of March 2017 (including an ISD of November 15, 2012 for Unit 4, the first replaced turbine unit), BC Hydro is filing this Application with the expectation that the proposed process will support BCUC approval being granted no later than February 2010.

1.8 Structure of the Application

The Application consists of six chapters and has been structured to be consistent with the BCUC's March 2004 CPCN Application Guidelines (Letter No. L-18-04).

Chapter 2 contains details on BC Hydro including the Project team.

Chapter 3 contains a detailed description of the Project, including costs, schedule and rate impact. The chapter describes the impact of the Project on the Bulk Transmission System and describes the impact of the construction market on the Project. Chapter 3 also addresses the social and environmental impacts of the Project and the position of the Project with respect to Federal, Provincial and Municipal approvals.

Chapter 4 details the Project justification, including the need for the Project, Project benefits and a comparison of the Project to alternatives.

Chapter 5 details the First Nations and public consultations conducted by BC Hydro with respect to the Project.

Chapter 6 identifies the various risks to the Project and describes BC Hydro's risk management strategies. The chapter also identifies the NPV impacts of cost and benefit uncertainties.

Appendix A is a glossary of terms and acronyms and a list of key assumptions used in this Application.

Appendix B contains a draft of the requested final order for the Project.

Appendix C includes a description of BC Hydro's Project Lifecycle Management and Project Cost Estimating Practices.

Appendix D is the GMS Generating Station G3 Runner Failure Technical Analysis and Recommendations Report.

Appendix E contains the most recent Equipment Health Rating Technical Prescription Reports for GMS Units 1 to 5.

Appendix F contains a copy of the existing GMS Water Licence.

Appendix G contains materials used for First Nations Consultation and Public Consultation.

Appendix H contains the Project Expenditures.

Appendix I provides supporting information for BC Hydro's Net Present Value analysis.

Gordon M. Shrum Units 1 to 5 Turbine Replacement Project

Chapter

2

Applicant

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2.1 Name and Address of Business

BC Hydro is a Crown Corporation established in 1962 under the *Hydro and Power Authority Act*. BC Hydro is mandated to generate, distribute and sell electricity; upgrade its power sites; and purchase power from, or sell power to, a firm or person. BC Hydro is the largest electric utility in B.C., serving over 94 per cent of the Provincial population. BC Hydro is charged with the responsibility of, among other things, owning and operating heritage resources, which are prescribed under the *BC Hydro Public Power Legacy and Heritage Contract Act* and which include the GMS Units 1 to 5 turbine assets.

BC Hydro's head office is located at 333 Dunsmuir Street in Vancouver, B.C.

2.2 Financial and Technical Capacity of the Applicant

2.2.1 Financial Capacity

Pursuant to section 3 of the *Hydro and Power Authority Act*, BC Hydro is an agent of Her Majesty the Queen in right of the Province. The B.C. Minister of Finance is the fiscal agent of BC Hydro. BC Hydro has constructed some of the largest projects in the Province undertaken by a single corporation and has the financial capacity to undertake the Project and other large projects by means of: borrowing guaranteed by the Province, borrowing directly from the Province, and by funds generated internally from the operation of its business.

Moody's Investors Service and Standard & Poor's Corporation, two major financial rating agencies in the United States of America (**U.S.**), have rated BC Hydro bonds as Aaa and AAA respectively. The rating from the Dominion Bond Rating Service in Canada is AA High.

2.2.2 Technical Capacity

BC Hydro has been responsible for the planning, design and construction of generation and distribution facilities since 1962. BC Hydro was also responsible for these functions with the transmission system until 2003. In 2003, British Columbia Transmission Corporation (**BCTC**) was formed. Under the *Transmission Corporation Act* and a number of designated agreements between BC Hydro and BCTC, BCTC currently has the responsibility to operate, plan and manage the BC Hydro owned transmission system. BC Hydro currently owns and operates 30 grid-connected hydroelectric generating stations within the Province. The existing GMS Units 1, 2 and 3 were commissioned into service in 1968 and Units 4 and 5 were commissioned into service in 1969.

In recent years, BC Hydro has undertaken other projects similar in scope to the Project. These projects include:

- GMS G3 Runner Repair Project (ISD 2009);
- GMS Units 6 to 8 Runner Replacement Project (ISD 2004-2006);
- Bridge River Units 1 to 6 Turbine Upgrade Project (ISD 2001-2003); and
- Kootenay Canal Units 1 to 4 Turbine Upgrade Project (ISD 1994-1996).

These projects have provided BC Hydro with experience and technical knowledge that will benefit the Project.

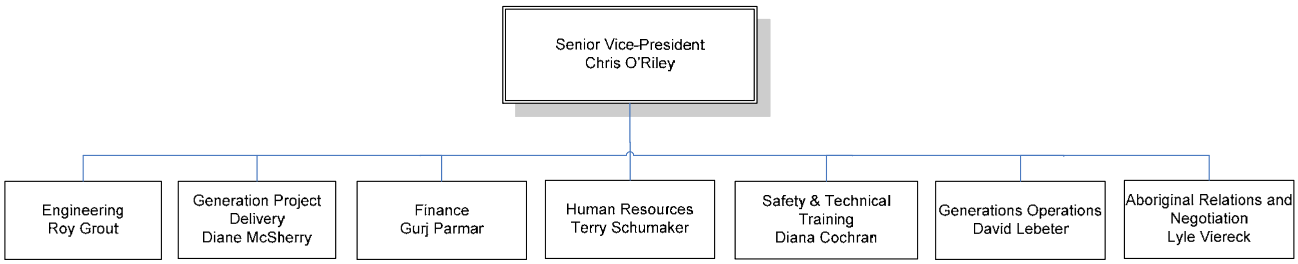
BC Hydro does not expect any significant transmission interconnection or bulk system impacts as a result of the Project as there is no associated increase in generating capacity of the units. However, BC Hydro is currently working with BCTC to make a final assessment of any impacts including system operational considerations associated with the new turbines.

Along with BC Hydro staff working on the Project, BC Hydro has retained the services of specialized consultants to advise on various aspects of the Project. RSW Inc. was retained to provide technical opinions on the project. Ecole Polytechnique Fédérale de Lausanne (**EPFL**) will undertake independent laboratory testing and verification of the modelled turbine performance that will be undertaken by Voith and Andritz in Implementation Stage 1 of the Project. Powertech Labs Inc. also provided technical input on the Project. MMK Consulting Inc. provided non-residential construction sector forecast escalation factors used in the capital cost estimate.

2.3 Project Delivery Governance

Figure 2-1 is a functional organization chart of the Engineering, Aboriginal Relations and Generation (**EARG**) business group that is accountable for the delivery of the Project.

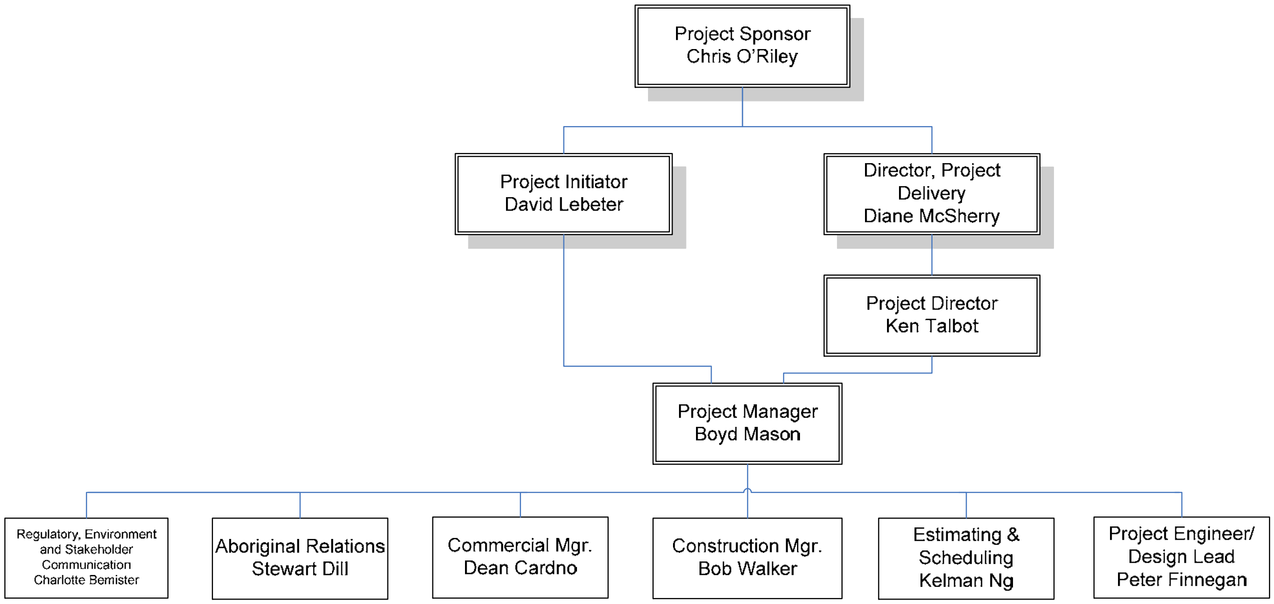
Figure 2-1 EARG Functional Organizational Chart



Chris O'Riley, a Senior Vice-President, leads the EARG line of business. David Lebeter, who reports directly to Chris O'Riley, leads the EARG generation operations group. This group is responsible for operating and maintaining the plants in the fleet, asset and capital planning, and the initiation of EARG projects. The generation operations group also directly delivers some of the smaller projects in BC Hydro's capital plan. Diane McSherry, another direct report to Chris O'Riley, leads the EARG generation project delivery group. This group is accountable for delivery of the majority of the EARG projects in BC Hydro's capital plan. The projects in generation project delivery are organized into five portfolios, each led by a project director accountable for portfolio results. Each portfolio has staff project managers and related project support functions to deliver the projects assigned to the portfolio. Other functional groups in EARG such as Engineering, Aboriginal Relations and Negotiations (**ARN**), and Safety provide staff to support projects; those individuals are accountable to the project manager for the purposes of the project.

Figure 2-2 is the organization chart for the Project.

Figure 2-2 Project Organization Chart



BC Hydro EARG projects are led by a project manager who is accountable to a project initiator and to a portfolio project director. The project manager leads the project team to complete the objectives of the project and is accountable to the project initiator for the definition (statement of objectives, original and revisions) and justification (original and revised business case) of the project. The project initiator defines the problem or opportunity that requires a project to be initiated. The project manager, representing the project team, proposes a set of objectives (statement of objectives) to address the problem or opportunity and a plan to achieve those objectives. Approval of the proposed objectives by the project initiator defines the project to be delivered. The same concept applies to the business case. The project manager is accountable to the portfolio project director for delivery of the project in accordance with the approved definition of the project. In other words, the project manager is accountable for determining how the project will be delivered, including delivery models, procurement strategies, obtaining resources, obtaining all permits and regulatory approvals, putting contracts in place, and managing to the plan to achieve the agreed objectives.

Chris O'Riley, Senior Vice President, EARG is the project sponsor (**Project Sponsor**) of this Project and is responsible for supporting the success of the Project by acting as liaison with

BC Hydro's executive team and approving key decisions. David Lebeter, Director of Generation Operations, as project initiator (**Project Initiator**) is accountable to the Project Sponsor for the definition and the justification of the Project, while Diane McSherry, the Director of Generation Project Delivery, is accountable to the Project Sponsor for delivery of the Project. The Director of Finance, Gurj Parmar, is accountable to the Project Sponsor and BC Hydro's Executive Vice President and Chief Financial Officer for financial due diligence of the Project.

Gordon M. Shrum Units 1 to 5 Turbine Replacement Project

Chapter

3

Project Description and Impacts

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3.1 Description of the Project

3.1.1 Description of GMS

The GMS generating station is located on the Peace River near Hudson's Hope in North Eastern British Columbia (refer to Figure 3-1,Figure 3-2 and Figure 3-3). GMS contains ten generating units with a combined installed capacity of 2,730 MW and is located below ground level next to the W.A.C. Bennett dam that impounds the Peace River to form the Williston Reservoir.

Figure 3-1 Geographic Location of GMS

Figure 3-2 Photograph of GMS

Figure 3-3 Aerial View of GMS

The ten generating units at GMS were installed in groups at different times and by different manufacturers. This has resulted in three generations of units at GMS: Units 1 to 5; Units 6 to 8; and Units 9 and 10. For this reason, BC Hydro has pursued a strategy of replacing major components on all units in a given group as part of the same Project. As the dam has an indefinite life, the powerhouse equipment will continue to be replaced in such a manner and as needed.

GMS Units 1 through 5 are equipped with late 1960's vintage Mitsubishi Francis turbines with General Electric generators. Units 1, 2 and 3 were commissioned in 1968 and Units 4 and 5 were commissioned in 1969. Each of these units has a rated maximum unit capacity of 261 MW. Together they provide 1,305 MW of capacity, currently representing about 12 per cent of BC Hydro's installed capacity and generate an average of 6,600 GWh of energy per year.

3.1.2 Technical Description of a Turbine

A basic overview of the operation and components of a turbine and generator such as those at GMS is shown in Figure 3-4 and Figure 3-5 and is described below. The Project will address the turbine component of a unit. The generator is addressed in this section only to provide a more complete contextual understanding of the Project.

Water from an intake in the Williston Reservoir passes through the penstock to the turbine, where the kinetic energy of the water turns a waterwheel (called a runner) and exits through the draft tube. The runner is connected to the generator by a shaft. The generator consists of two major components, the rotor and the stator. The rotor is a large circular electromagnet connected to the turbine shaft and the stator is a static coil consisting of electrical conductors tightly wound around a metal core, which encircles the rotor.

Figure 3-4 Turbine and Generator Overview

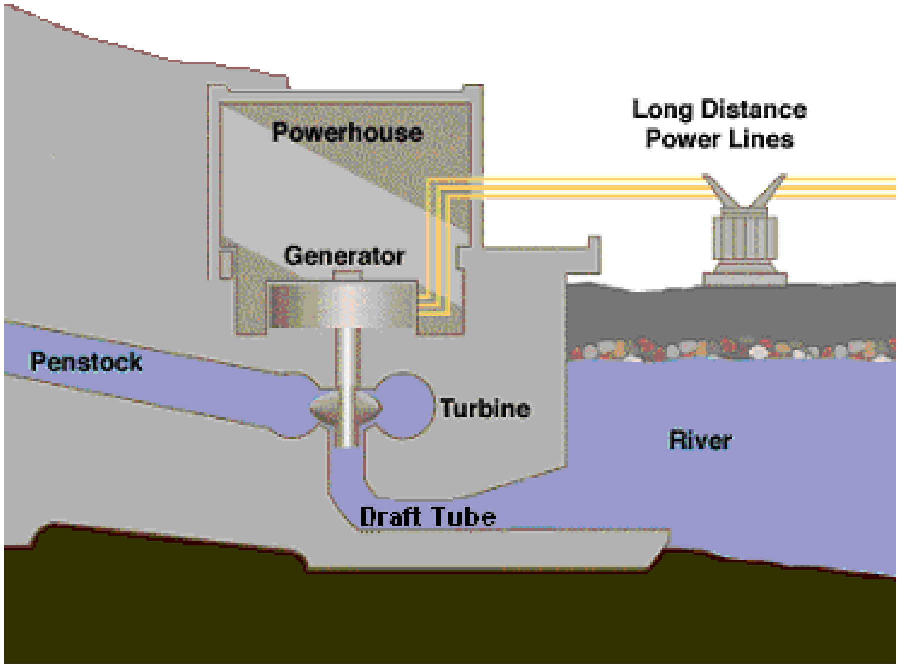
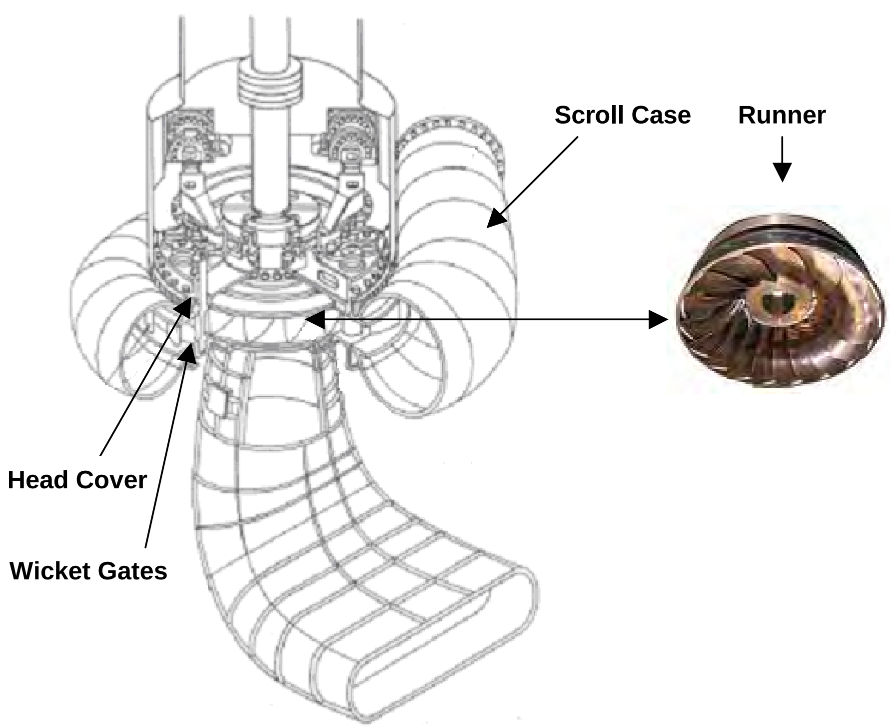


Figure 3-5 Turbine Cut-Away Diagram



Water from the penstock enters the scroll case, a circular, shell-like tube that wraps around the runner. The inner wall of the scroll case is open to the runner, with a set of stationary stay vanes directing the water into and through the runner.

Between the stay vanes and the runner are a set of pivoting wicket gates, which are opened and closed hydraulically by the unit's governor to increase or decrease the amount of water admitted to the runner, and thus increase or decrease the amount of power generated by the unit. The governor is an electro-hydraulic system that constantly monitors the unit's actual power output, compares it to a power setting, and opens or closes the wicket gates accordingly. The wicket gates operate in unison. The runner itself consists of a set of runner blades designed to convert the kinetic energy of the moving water into mechanical energy that rotates the shaft.

3.1.3 Project Description

The Project involves replacing the GMS Units 1 to 5 turbines. Specifically, this will involve designing and manufacturing new turbine runners, wicket gates, wicket gate operating mechanisms and head covers and overhauling the remaining turbine components. The Project Implementation phase is being undertaken in two stages.

Turbine Model Design and Testing (Implementation Stage 1) – CMT will be performed by two potential turbine suppliers and will involve performing hydraulic studies and model work to develop the hydraulic design of the new turbine components, and a model turbine for testing. The turbine efficiency and capacity will be verified by independent testing of the turbine models, which will be conducted at the Hydraulic Machines Laboratory of EPFL, one of the world's leading hydraulic test facilities. Implementation Stage 1 also includes evaluating the CMT results and awarding the turbine upgrade work to the successful contractor.

In February 2009, two contract awards were made to Voith and Andritz for Implementation Stage 1 only. Implementation Stage 2 will be subject to future approval and both contracts include conditions requiring BC Hydro authorization prior to proceeding with any Implementation Stage 2 work.

Turbine Construction and Installation (Implementation Stage 2) –This stage involves final design and manufacturing of the new turbine components, removal of old equipment, overhaul of some existing turbine components, and the installation of new and overhauled equipment by the single selected supplier. The new turbine components will include new runners, new wicket gate operating mechanisms, new wicket gates and new headcovers. All other components of the turbines will be overhauled. Table 3-1 itemizes the specific items included in the Implementation Stage 2 scope of work. The expected service life of the new equipment is 50 years. The expected life extension of the overhauled components will be further assessed in Implementation Stage 2 of the Project. However, BC Hydro estimates the service life of the overhauled components will be extended by either 25 or 50 years depending on the component.

Table 3-1 Equipment List

Equipment	Description	Expected Life - Post Project (Years)
Components to be Replaced with New Equipment		
Runners	Device for transforming potential energy (water stored in reservoir) into mechanical energy. It is constructed of multiple hydrofoil blades fixed to supporting structures (crown and band).	50
Wicket Gates	A series of hydrofoil-shaped baffles that regulate the flow of water from the penstocks to the runners.	50
Wicket Gate Operating Mechanisms	The mechanism that controls the position of the wicket gates.	50
Head Covers	Non-rotating structural component that: 1) supports the wicket gate upper stems and the operating mechanism, 2) acts as a seal between the water passages and turbine pit, 3) is an important part of the system for managing the thrust load created by water passing through the turbine.	50

Equipment	Description	Expected Life - Post Project (Years)
Components to be Overhauled		
Draft Tube	The diffuser through which the water discharges from the turbine;	50
Discharge Ring	Section of the draft tube directly underneath the runner.	50
Bottom Ring	Non-rotating structural component that supports the bottom wicket gate stems.	50
Stay Ring	Structural component of the spiral case that supports the stay vanes.	50
Spiral Case (Scroll Case)	Spiral-shaped water passage that conveys water from the penstock to the runner.	50
Stay Vanes	Stationary hydrofoils that guide water from the spiral case to the wicket gates.	50
Servomotors	Hydraulically-actuated positioning devices that are connected to the wicket gate operating mechanism.	25
Shaft Seal	Mechanical sealing device around the main shaft that minimises water-leakage into the turbine pit.	25
Turbine Guide Bearing	Babbitt bearing for maintaining the radial position of the main shaft.	25
Turbine Pit (General)	Area of the turbine for accessing the top of the head cover, the wicket gate operating mechanism and the turbine guide bearing.	50
Turbine Shaft	Steel shaft for transmitting torque between the runner and the generator-rotor.	50
Turbine Air Admission Device	Device for admitting air directly underneath the center of the runner to stabilise the vortices generated by: 1) part-load operation, 2) overload operation, or 3) transient operation.	25

Equipment	Description	Expected Life - Post Project (Years)
Lower Bracket	Structural component that transfers the weight of the runner and shaft and hydraulic thrust to the powerhouse foundation. Also houses the generator bearing.	50
Generator Bearing and Oil Lift Pumping Unit	Babbitt bearing for maintaining the radial and axial position of the unit. Lubrication is provided during start-ups by the oil lift pumping unit.	25
Brakes/Jacks	Pneumatically-actuated friction devices for bringing the unit to a full-stop.	25
Units 4 and 5 allowance for Synchronous Condense Operation	Additional piping will be added to the head cover and discharge ring to facilitate the future addition of synchronous condense capability to Units 4 and 5 (this capability is currently available on Units 1 to 3).	50

This Project will address only the GMS Units 1 to 5 turbines. The status of the other major components of GMS Units 1 to 5 is:

- Generators – the generators of Units 1 to 4 are being replaced. The work began in 2006 and is scheduled to be complete by the end of 2010. Unit 5 is in good condition and does not require replacement at this time.
- Exciters – The exciters on Units 1 to 5 were replaced between 2002 and 2004.
- Governors – The governor controls on Units 1 to 5 were replaced in 1998. The hydraulic portion of the governors has an expected life of ten to 20 years. Replacement of the governors is not required at this time.
- Unit Circuit Breakers – The Units 1 to 5 circuit breakers are expected to be replaced within five to ten years.
- Unit Transformers – The replacement of Units 1 to 5 transformers in poor or unsatisfactory condition is currently underway. Installation of the new transformers began in 2008 and will be completed in 2011.

3.2 Project Schedule

The Project schedule is summarized in Table 3-2.

Table 3-2 Key Project Dates and Decisions[3]

Decision Points and/or Milestones	Date
Stage 1 Contracts Awarded	February 2009
Application submitted to the BCUC	August 2009
BCUC Decision Issued before:	February 2010
Independent Model Test Completion	June 2010
BC Hydro Board of Directors grant Authorization to proceed to Stage 2	July 2010
First replaced turbine unit In-Service Date	November 2012
Second replaced turbine unit In-Service Date	November 2013
Third replaced turbine unit In-Service Date	November 2014
Fourth replaced turbine unit In-Service Date	November 2015
Fifth replaced turbine unit In-Service Date	November 2016
Project Completion	March 2017

Each unit is being installed over the summer months to ensure that units are operational during the winter peak period and to minimize the value of lost energy. The Project can also accommodate acceleration of the turbine ISDs by year round construction should future system load/resource balance, as well as project critical path items, permit. This could be triggered if there was further and significant deterioration of turbine asset health, even with the operating restrictions and maintenance procedures that have been put in place to address this risk, prior to the planned ISD.

3.3 Project Costs

3.3.1 Construction Costs

The Project Expected Cost estimate is $262 million. This estimate includes costs to date and costs for the turbine contract, turbine contract escalation[4], construction management,

[3] A more detailed project schedule will be developed following completion of Implementation Stage 1.

[4] Both turbine supply contracts are subject to escalation based on commodity and construction cost indices. The Expected Cost includes general inflation as well as anticipated escalation where the specified indices are expected to increase at a rate higher than general inflation. The Authorized Cost includes escalation on the same basis based on probabilistic cost increases, as well as a specific allowance for higher-than-anticipated increases in the relevant cost indices.

services and site support, protection and control (**P&C**) materials and installation, additional equipment and retirement items, indirect BC Hydro support plus contingency, inflation[1], interest during construction (**IDC**) and overhead. An additional allowance is included for escalation risk, to allow some work acceleration in the event of a schedule delay, additional thrust bearings, lead paint removal and painting and other minor items.

To develop an Authorized Cost estimate that provides a higher degree of confidence than the Expected Cost estimate, a Project Reserve was added to the Expected Cost that includes the following adjustments to the Expected Cost estimate:

- the Project contingency was increased based on a detailed review of the range of possible costs for each of the items in the detailed cost breakdown; and
- management reserves were added for:
  - synchronous condense capability on Units 4 and 5 should this be required in the future; and
  - replacement allowance for discharge rings, servomotors and turbine guide bearings, should this work prove necessary on inspection of the existing turbines.

Table 3-3 provides a Project cost estimate indicating the components of the Expected Cost estimate and Authorized Cost estimate for the Project. The detailed Project cost estimates are provided in Table 3-4.

Table 3-3 Project Cost

PROJECT COMPONENT	Nominal Dollars (Millions)
Implementation Stage 2 (Direct Construction Costs)	158.2
Project Management and Engineering	9.5
Project Allowance (Note 1)	8.0
Sub-total: Implementation Stage 2 (Construction, Project Management and Engineering Costs)	175.8
Project Contingency on Expected Cost (Note 2)	18.7
Dismantling and Removal	1.4
Sub-total: Implementation Stage 2 (Direct Cost)	195.9
Corporate Overhead	25.9
Interest During Construction (IDC)	24.1
Sub-total: Implementation Stage 2 (Direct + Loaded Cost)	245.9
Definition and Implementation Stage 1 Cost (Direct)	11.2
Definition and Implementation Stage 1 Loadings (Note 3)	4.9
TOTAL EXPECTED COST	262.0
Project Reserve (Note 4)	56.7
TOTAL AUTHORIZED COST	318.7

Notes

(1) Project Allowance includes allowances for schedule delay risk, additional thrust bearing allowance, lead paint removal and painting allowance, escalation risk and other minor items.

(2) Please refer to Appendix C for an explanation of BC Hydro's project estimating methodology which describes how Project Contingencies are developed.

(3) Loadings include corporate overhead and IDC

(4) The Project Reserve includes three components: 1) an incremental increase in contingency of $30.1 million over an above the expected cost contingency, 2) incremental loadings of $11.2 million on the contingency, and 3) a management reserve of $15.4 million to allow for funding to replace discharge rings, servomotors, and turbine guide bearings should this work prove necessary upon inspection of the existing turbines, as well as to install additional components necessary for synchronous condense capability on Units 4 and 5.

In recent years, BC Hydro has identified the Project in a number of its BCUC applications including the 2005 REAP, 2006 IEP/LTAP, F07/F08 RRA and the F09/F10 RRA. In its most recent biennial capital plan which was submitted as part of its F09/F10 RRA, BC Hydro forecast capital expenditures of $6.4 million would be incurred up to the end of F2010 and estimated that total Project costs would be in the range of $170 to $240 million.

As indicated in Table 3-3, BC Hydro is now indicating an Expected Cost and an Authorized Cost of $262 million and $319 million respectively. The key reasons for the revised costs are:

- a revised Project scope that has been informed by the Unit 3 runner failure analysis; and
- cost details were updated to reflect the awarded contracts resulting from the Project tender process.

3.3.2 Contingency/Risk Allowance

Contingencies have been assigned to take into account the uncertainties and risks identified during the Project Identification and Definition phases. Contingencies are estimated based on the total construction costs.

The Expected Cost includes a contingency of $17.0 million (unloaded) while the Authorized Cost includes additional contingencies of $25.6 million. Inflation, capital overhead and IDC are applied to contingencies such that there is a total contingency of $63.7 million (loaded) included in the Authorized Cost. The contingency for the Expected Cost and Authorized Cost are based on range estimating methods in developing a Monte Carlo risk analysis. Refer to Appendix C for a description of BC Hydro's cost estimating practices. Table 3-4 provides a more detailed breakdown of the Project contingency and reserves.

Table 3-4 Total Contingencies and Reserves

	$ millions			
Description		**Total Contingency on Expected and Authorized Costs**	**Project Reserve**	**Project Cost**
Project Expected Cost	A			**262.0**
Contingency included in Expected Cost	B	17.0		
Inflation, escalation and loadings on Contingency included in Expected Cost (Note 1)	C	5.3		
Incremental Contingency on Authorized Cost	D	25.6		
Inflation, escalation and loadings on Incremental Contingency included in Authorized Cost (Note 1)	E	15.8		
Total Contingency included in Project Authorized Cost	B+C+D+E	63.7		
Incremental Loaded Contingency included in Authorized Cost	F=D+E		41.3	
Management Reserve (Note 2)	G		15.4	
Authorized Project Reserve	H=F+G		56.7	
Project Authorized Cost	A+H			**318.7**

Notes

(1) Loadings on contingency include capital overhead and interest during construction.

(2) Management reserve allows for funding to replace discharge rings, servomotors and turbine guide bearings should this work prove necessary upon inspection of the existing turbines, as well as to install additional components necessary for synchronous condense capability on Units 4 and 5.

3.3.3 Price Escalation Assumptions

The Expected Cost and Authorized Cost estimates for the Project are based on the design-supply-install contract prices negotiated and awarded to Voith and Andritz in February 2009. As part of its normal practice in estimating the cost of future projects, BC Hydro applied escalation factors representing anticipated cost increases in the heavy construction sector, which may be different than expected general inflation due to sector-specific issues. The appropriate escalation factors are updated semi-annually, after internal and external review of industry cost trends and consideration of periodic reports prepared by an independent economist, MMK Consulting.

3.3.4 Non-BC Hydro Project-Related Capital Costs

No non-BC Hydro Project-related costs are foreseen outside of the costs identified in section 3.3.1.

3.4 Construction Market Impacts

3.4.1 Market Conditions

The ongoing global financial crisis and economic conditions have significantly impacted the landscape in many industries. In general, circumstances are such that BC Hydro is in a favourable position to proceed at this time, and in the near future, with capital projects. However, the turbine market is characterized by a small number of suppliers, most of which are still working through order backlogs accumulated in the past four or five years. Current economic conditions have restrained pricing and improved supplier responsiveness, but BC Hydro has not observed general price reductions. BC Hydro believes that the strategy of maintaining competitive pressure on two suppliers has achieved all that can be reasonably expected to take advantage of global conditions.

3.5 Impact on the Bulk Transmission System

BC Hydro does not expect any significant transmission interconnection or bulk system impacts as a result of the Project as there is no associated increase in generating capacity of the units. BC Hydro is currently working with BCTC to make a final assessment of any system impacts associated with the new turbines.

3.6 Public Works Impact

Since the Project does not involve an expansion of the existing GMS facility, no new or expanded public works, undertakings or infrastructure will be required for the Project. As the generating units are located below ground level, no visible surface modifications will result from the Project.

3.7 Social and Environmental Impacts

3.7.1 Environmental Impacts

The Project footprint does not extend beyond existing GMS facilities and will not require the permanent use of any land additional to that already occupied by the existing W.A.C Bennett Dam and GMS.

The Project does allow for increased unit capacity in the future but this will not take place until additional investment is undertaken to remove remaining bottlenecks (upgrading rotor poles, generator circuit breakers, isophase bus and the associated water license revisions) that are not within the scope of the Project.

The Project does not trigger any Federal environmental assessment process. BC Hydro is currently in discussions with the B.C. Environmental Assessment Office (**BCEAO**) to determine if the Project is reviewable under the *BC Environmental Assessment Act* (**BCEAA**). However, the Project does not involve a capacity increase, nor does it have significant environmental, economic, social, heritage or health effects. BC Hydro will continue to operate under the current water license for GMS. No Federal funding, Federal land or Federal authorizations are required.

If BC Hydro decides to implement the additional work to achieve a capacity increase, the associated increase from 261 MW to 305 MW for each unit (for a total increase of 220 MW) will be greater than the 50 MW increase that would trigger a review under the BCEAA.

3.7.2 Social Impacts

Construction of the Project will provide temporary local economic benefits due to the mobilized work force. This short-term increase in workforce may drive a need for housing for these workers in the area.

Due to the scope of the Project and based on First Nations consultation and public consultation, as described in Chapter 5, BC Hydro does not expect any significant adverse impacts on or concerns by First Nations or public stakeholders.

3.7.3 Listing of all Approvals

There are no Federal permits, approvals and authorizations required for the upgrade and subsequent operation of GMS Units 1 to 5 turbines. No amendments are required to the existing Water License for GMS (refer to Appendix F) and no municipal permits are required for this Project. The need for a Provincial Environmental Assessment is currently under review as outlined in section 3.7.1.

3.8 Analysis of Estimated Rate Impacts

The impact that the Project would have on BC Hydro's revenue requirement is discussed in this section. The estimated annual incremental rate impacts resulting from the Project with an ISD for the overall Project of November 2016 at an Expected Cost of $262 million and an Authorized Cost of $318.7 million are shown in Figure 3-6.

The Long Term Rate Increase Forecast filed in the 2008 Long-Term Acquisition Plan (**2008 LTAP**)[5], is the starting point for the analysis of the incremental revenue requirements and rate increase/decrease impacts of the Project.

The Project would affect the following elements of BC Hydro's revenue requirements: cost of energy, operating expenditures, amortization, finance charges and return on equity.

While there would be an initial increase to BC Hydro's revenue requirements in the early years during Implementation Stage 2, this annual increase would be highest at around $6 million based on both the Project Expected Cost and Authorized Cost and then would decline to the point where by F2016 there is a decrease in the revenue requirement for the Project Expected Cost (F2020 for the Project Authorized Cost).

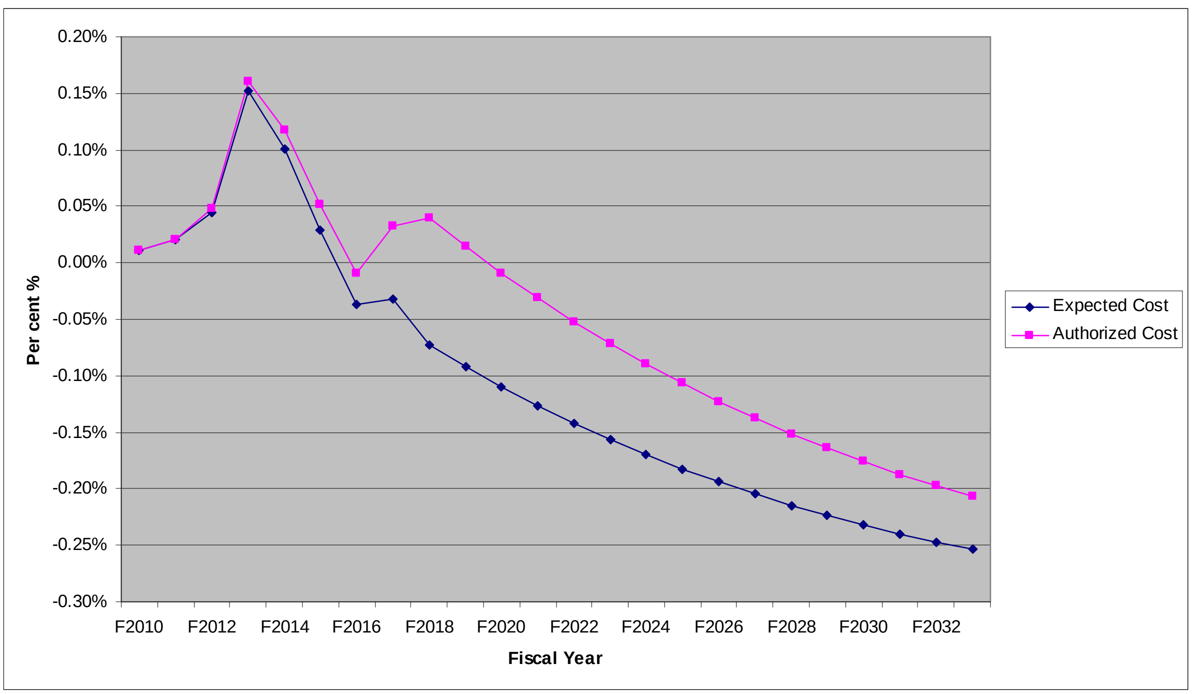
By F2033, the last year of modelling in the analysis, the annual revenue requirement would be about $25 million and $20 million lower for the Project Expected Cost and Authorized Cost respectively. The reason behind the decreases is that the lower cost of energy would outweigh the incremental costs of the Project on the other elements of the revenue requirements.

5 Exhibit B-3, BC Hydro response to BCUC IR 1.7.1

As shown in Figure 3-6 the Project would give rise to incremental annual rate increases in the beginning of the Project resulting from the initial effect of the amortization and financing costs of the project. The changes in rates between F2016 and F2019 for both the Project Expected Cost and Project Authorized Costs are primarily attributed to the increase in finance costs and higher amortization once the fifth and final turbine goes into service.

By F2016 and F2020 for the Project Expected Cost and Project Authorized Cost respectively, rates are positively impacted by the Project; in other words, rates are less than they would be if the Project did not proceed.

Figure 3-6 Annual Estimated Incremental Rate Increase/Decrease Impacts of the GMS Units 1-5 Turbine Replacement Project



Gordon M. Shrum Units 1 to 5 Turbine Replacement Project

BC hydro

Chapter

4

Project Justification

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4.1 Need for the Project

This section addresses the need to proceed with the Project with ISDs of F2013, F2014, F2015, F2016 and F2017 for GMS Units 4, 1, 2, 5 and 3 respectively.

The primary justification for the Project is the unsatisfactory condition of the GMS Units 1 to 5 turbines and the associated high business risks. These turbines have exhibited ongoing cracking problems since 1972 and have defects and residual stresses as a result of a high number of weld-repairs that have been completed to address these ongoing issues. Furthermore, the turbines have cavitation and inherent design problems. These problems result in a high risk of unit failure.

In the short term, to manage the current high level of risk, BC Hydro has moved to a six month inspection and maintenance cycle and placed operating restrictions on the assets such that Units 1, 2, 4 and 5 are to experience no shut downs or synchronous condense transfers except as a last resort for system reliability. Furthermore, operating restrictions have been placed on Unit 3 as a result of the repair following the March 2008 runner failure. While Unit 3 is unrestricted in the number of shutdowns and synchronous condense transfers it may experience, the minimum and maximum power output of Unit 3 is restricted by the cavitation limitations of the repaired runner. BC Hydro will monitor asset condition with these restrictions in place but considers that comparable restrictions will remain in place until the turbines are replaced.

BC Hydro considers it unacceptable to continue to address the risk of unit failures with increased maintenance and operating restrictions. Rather, a more permanent, robust solution as proposed in the Project is required.

In addition to addressing the unsatisfactory asset condition, the Project will also provide low cost incremental energy and has other benefits that result in the Project having a positive NPV based on the Expected Cost and Authorized Cost estimates for the Project. These Project benefits are addressed in more detail in section 4.2.

4.1.1 Life Cycle Asset Management

BC Hydro has applied its Life Cycle Asset Management (**LCAM**) principles and practices and Equipment Health Rating (**EHR**) methodology in its assessment of the need to replace GMS Units 1 to 5 turbines. LCAM and EHR are described further below.

BC Hydro is committed to managing its generation assets through the effective and efficient application of the LCAM principles and practices. The LCAM is used to maximize economic return on physical assets over their life by achieving desired performance outcomes, while effectively managing the risks inherent in owning, managing and operating a large asset base.

LCAM considers several dimensions of business value including: safety; availability and reliability; commercial performance; contribution to revenue; total unit cost of production; and environmental and social performance. The asset management framework enables making trade-offs amongst these value dimensions, leading to optimization of business value.

The LCAM is used for BC Hydro's generation assets to ensure consistency in decision-making processes and to provide transparency to external stakeholders and regulatory agencies[6].

One of the key decisions in asset management is when to refurbish or replace equipment. There are three specific factors that trigger replacement:

1. Below target reliability or availability or declining reliability or availability trend combined with:
    - Maintenance costs that are increasing or can be economically reduced by equipment replacement; or

[6] BC Hydro's LCAM system for generation assets is consistent with the British Standard Institution (BSI) PAS 55 Asset Management Specifications.

- Equipment is obsolete (e.g., spare parts and/or technical knowledge are no longer economically available);

2. Estimated business risk to BC Hydro is too high; or
3. Additional energy or capacity can be produced economically (e.g., Resource Smart opportunity).

Under the LCAM model, BC Hydro uses a standardized condition assessment methodology known as EHR, to assist in identifying when capital investment in major equipment is required.

In assessing the health of specific equipment, the EHR methodology considers:

- the design and original quality of the asset;
- the current condition of the asset;
- the maintainability of the asset, including past performance of the asset and the availability of replacement parts and technical knowledge;
- how the asset has been and will be operating;
- how the asset has been and will be maintained; and
- opportunities for investment to improve the asset.

BC Hydro also uses a risk assessment methodology to assist in making investments in generation assets. Risks are assessed in terms of their frequency or probability of occurrence and in terms of their consequences or severity and are evaluated in four categories: safety, financial, environmental, and damage to reputation.

Finally, BC Hydro’s LCAM requires that alternative solutions be evaluated. This involves, for each of the alternative solutions, balancing the tradeoffs between the risk and performance dimensions and the total lifecycle cost. BC Hydro's objective is to maximize the lifecycle value of its generation assets, while being mindful of the impact on customer rates.

4.1.2 Original Design and Technical Problems with GMS Units 1 to 5

GMS Units 1 to 5 turbines are late 1960's vintage Mitsubishi Francis turbines. Units 1, 2 and 3 were commissioned in 1968 and Units 4 and 5 were commissioned in 1969. These were the first units to be installed at GMS. During their service life, GMS Units 1 to 5 turbines have had one major overhaul each between 1985 and 1993.

Cracks in the runners were discovered in 1972 and have been an ongoing problem since this time. BC Hydro has studied the cracking issue extensively and has concluded that it is primarily due to inherent original design weaknesses[7]. Ongoing cracking problems are also a result of high dynamic stresses, low fatigue strength, defects in original manufacturing, and defects and stresses introduced by multiple weld-repairs. As one of the root causes of the cracking problems is the original design, repairs or overhaul will not eliminate the cracking or reduce the potential impact of additional cracking.

The units have been taken out of service every 6 to 24 months for weld-repairs of cracked runner blade sections, yet the cracking has continued and cavitation has also become an ongoing problem. As a result, these units are now being inspected every six months due to asset health concerns. As Unit 3 has recently undergone a major repair, it is expected to perform somewhat better in the near term although cavitation is still a concern with this unit.

GMS Units 1 to 5 turbines have a history of headcover cracking problems. Modifications to the original baffle assemblies were made when the units underwent major overhauls in 1985 to 1993. Although these modifications addressed the initial headcover cracking problem, since that time, new cracks have been forming in the top radial ribs of the headcover. In addition to this issue, the coupling bolts on the underside of the headcover that retain each half of the inner seal ring have failed on several of the units.

[7] BC Hydro reached a settlement with the manufacturer of BC Hydro's claims with respect to the turbines.

The wicket gate operating mechanism in these units has an inherent design problem that can contribute to cascading closure of de-synchronized wicket gates.

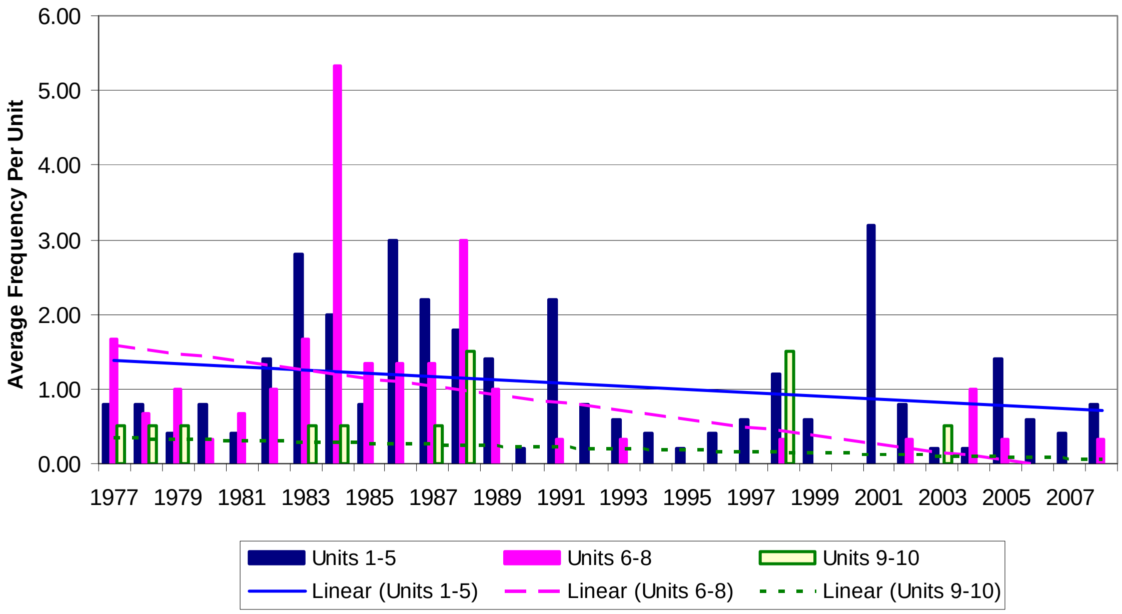
While there are no inherent wicket gate design issues that directly necessitate their replacement, in the context of the Project, the shape of the wicket gate hydrofoil requires modification and optimisation to ensure there is no adverse interaction with the runner. Modifications to the shape of the existing hydrofoil are not feasible due to the fabricated-plate construction of the hydrofoil. Any significant modification to the hydraulic profile would seriously impact the structural properties of the wicket gate.

4.1.3 Forced Outages

As shown in Figure 4-1, the average numbers of turbine-related forced outages for all unit groups[8] have been declining over the past several years. These declines are primarily due to BC Hydro pursuing a more pro-active response to monitoring and maintenance, introducing reliability centered maintenance practices and capital investment. However, the figure also shows that Units 1 to 5 continue to have more turbine related forced outages than the other two unit groups.

[8] Each of these groups represents the different vintage of turbines at GMS.

Figure 4-1 GMS Turbine Forced Outage Frequency

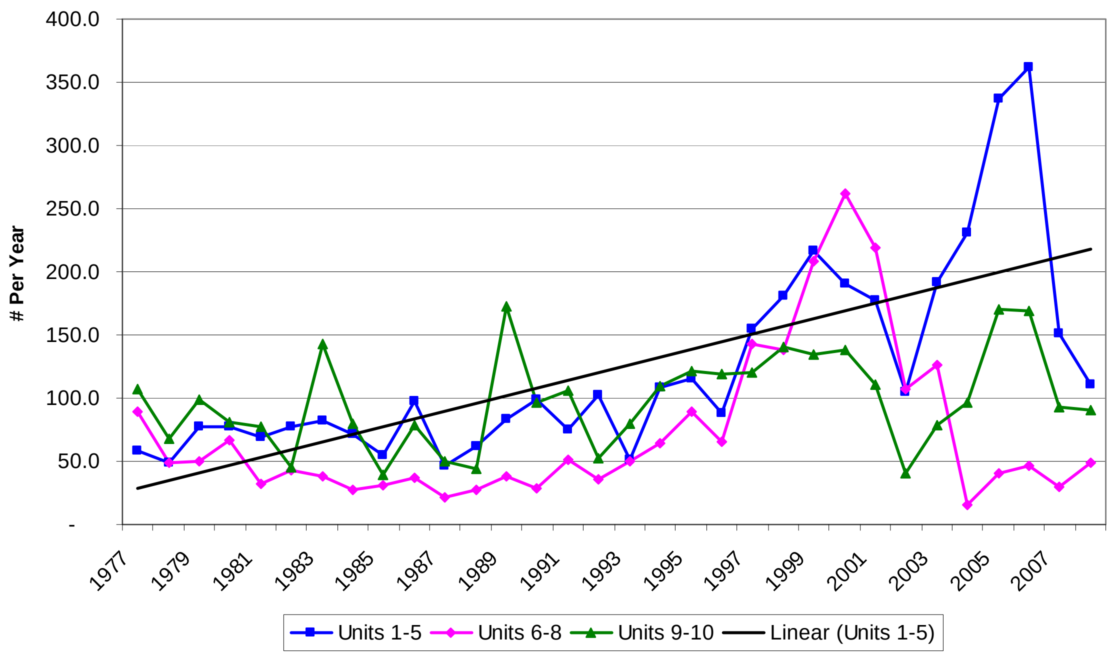


The average unit turbine forced outage frequency over the period 1977 to 2008 for Units 1 to 5, Units 6 to 8 and Unit 9 and 10 was 1.04, 0.73 and 0.20 forced outages per year respectively. As can be seen on each of the linear trend lines in Figure 4-1, all units have experienced lower overall forced outage rates; however, Units 1 to 5 have experienced the least improvement over time. The ongoing higher frequency of forced outages with Units 1 to 5 turbines is indicative of the less than optimal original design and quality of the units and the residual defects and stresses introduced over the years. Improvements in both the design and quality of turbines were made for Units 6 to 8 and further improved upon for Units 9 and 10.

4.1.4 Unit Starts and Synchronous Condense Mode Transfers

Figure 4-2 shows the trend in the total number of unit starts and synchronous condense mode transfers for the turbine groups at GMS. As demonstrated, all GMS units have been operating under a regime of steadily increasing unit starts and synchronous condense mode transfers primarily due to BC Hydro's need for greater operational flexibility. Unit starts place the units under stress, including the turbines, as they force the turbine to run through the "rough load zone" – the operating regime below roughly 65 per cent of rated output, where instability in the draft tube vortex leads to excessive vibration, and pressure surges in the water passages. In addition, each start or stop requires operation of the mechanical components of the turbine (e.g., wicket gates, servomotor and actuators, wicket gate operating ring) to the limit of their operating ranges. Synchronous condense operational mode allows a unit to absorb power to maintain voltage stability and support the bulk transmission system. Running in this mode places a similar demand on a turbine as a stop/start sequence.

Figure 4-2 GMS Total Unit Start and Synchronous Condense Mode Counts



The linear trend line for GMS Units 1 to 5 in Figure 4-2 demonstrates the increasing number of start or stops and synchronous condense mode counts on these units.

4.1.5 GMS Unit 3 Runner Failure

On March 2, 2008, GMS Unit 3 suffered a major runner failure, with significant damage to the wicket gates, runner blades and bearing. Appendix D contains a technical analysis and recommendations report for the GMS Unit 3 Runner Failure.

On May 5, 2009 Unit 3 was returned to service. The repair cost for this outage was approximately $27 million[9]. This value does not include any market opportunity cost associated with this outage. A temporary Unit 3 runner replacement was manufactured and installed. The post-failure strategy was to reconstruct the runner and refurbish other damaged components to extend the turbine life by another ten years until a permanent solution is implemented under the Project. This work has no impact on the scope of work of the Project.

4.1.6 Future Performance Requirements

BC Hydro expects the demands placed upon GMS Units 1 to 5 to increase as a result of potentially higher levels of variable and non-dispatchable electricity on the system and to support future market opportunities. This will require improved operating flexibility with increased start/stop and synchronous condense activity. These start/stop and synchronous condense transfers place more stress on the units when compared with steady-state operation. The Project will address these future unit performance requirements by specifying that Units 1 to 5 turbines are to be designed to withstand these higher forces.

4.1.7 Equipment Health Rating

As indicated in section 4.1.1, BC Hydro uses an EHR methodology to assess the health of generation assets. The EHR is based on a condition assessment of the equipment and provides an objective, repeatable and consistent assessment of the BC Hydro major generation assets (turbines, generators, governors, exciters, transformers, circuit breakers, water passages and coated structures) at the grid-connected hydro generating stations.

[9] BC Hydro expects to recover some of these costs through insurance.

Condition assessments are performed based on the most recent preventative maintenance test and inspection data. For turbines such as at GMS, the condition assessment includes test and inspection data from the following components:

- stationary water passage components;
- wicket gates;
- wicket gate operating mechanism;
- runner; and
- turbine guide bearing.

Equipment health assessments are then based on the condition assessment and also include data trends and operational history. Each equipment health assessment results in a rating of “good”, “fair”, “poor” or “unsatisfactory”.

Technical prescriptions are then prepared that state, from a technical perspective, what should be done to the assets, when to do it, and how much it is estimated to incur in time and cost. This information is used as input into the asset planning process.

The GMS Units 1, 2, 4 and 5 turbines are currently rated as unsatisfactory. The GMS Unit 3 turbine is currently rated as fair. Based upon design criteria used for the Unit 3 repair, it is expected that Unit 3 will be rated as poor or unsatisfactory at the time it is scheduled for replacement.

The technical prescription recommendations for the GMS Units 1 to 5 (refer to Appendix E) are to perform a major rehabilitation of the turbines including replacement of the runners, wicket gates and operating mechanism, head cover and associated components as soon as possible, with Unit 3 being the last unit upgraded as long as the temporary repairs perform well. The specific technical prescriptions for the turbine runners and major ancillary components are shown below in Table 4-1:

Table 4-1 Technical Prescription for GMS Units 1 to 5 Major Ancillary Components

Component	Technical Prescription
Runners	Replace the runners with a modern design in order to eliminate the deficiencies with the existing design.
Headcovers	Replace the headcovers with a modern design in order to: • eliminate the deficiencies with the existing design; • eliminate the risk of adverse interaction between the existing headcover and new runner; and • eliminate the risks (technical, schedule and cost) associated with the Project.
Wicket Gates	Replace the wick gates with a modern design in order to: • eliminate the risk of adverse interaction between the existing wicket gate and new runner; • eliminate the risks (technical, schedule and cost) associated with the Project; • achieve the potential efficiency gains associated with a more modern design; and • increase the sizing of bushings to reduce the currently high pressures placed on them.
Operating Mechanisms	Replace the operating mechanisms with a modern design in order to eliminate the deficiencies with the existing design.

Overall, the runners, headcovers, wicket gates and wicket gate operating mechanisms must all be replaced as a package to address inherent design problems and to ensure there are no adverse interactions between these turbine components. The remaining components must be overhauled to extend their service life.

The result of this work will be improved reliability and efficiency, with improvement to the safety features on the turbine. Not proceeding with the Project increases the probability of another major failure and higher ongoing maintenance costs.

4.1.8 Summary of Need

In summary, the primary justification for the Project is the unsatisfactory asset condition of the GMS Units 1 to 5 turbines and the associated business risks. Overall, the Project is needed because:

- The GMS Units 1 to 5 turbines are an essential part of BC Hydro’s generating system and must be adequately maintained;
- Ongoing problems with the runners and major ancillary components continue and are deteriorating. As a result, there is a significant risk of unit outages. To partially mitigate this risk, BC Hydro has implemented additional monitoring and response requirements, along with operational constraints. However, the measures being taken cannot eliminate the risk and are not considered acceptable long-term solutions; and
- Increasing operating demands in terms of higher availability and operating flexibility, including unit starts/stops and synchronous condense mode transfers, are not supported by the existing turbines.

4.2 Identification of Project Benefits

Section 4.2 addresses the additional benefits of upgrading GMS Unit 1 to 5 turbines. These include efficiency, safety, reliability and financial benefits.

4.2.1 Operating Benefits

Table 4-2 summarizes the annual benefit associated with the Project once the turbines for all five units have been replaced. Sections 4.2.2 through 4.2.5 discuss each of these benefits.

Table 4-2 Incremental Annual Project Benefits

Benefits	Description	$ million ($2009)
	Removal of Operating Restriction – The value of foregone energy production due to current operating restrictions on the existing Units 1, 2, 4 and 5, which can be avoided by replacing the units.	13.8
	Value of Incremental Energy – An estimate of the value of the incremental energy associated with the improved turbine efficiency, delivered to the Lower Mainland, based on the F2006 Call inflated to 2009 dollars (calculated at $93/MWh).	14.9
	Avoided Future Outage Opportunity Costs - Future outage related opportunity costs avoided by replacing the turbines.	1.5
	Avoided Future Maintenance Costs – Increased future maintenance costs avoided by replacing the turbines.	0.3
	Sub-Total Benefits	**30.5**
Costs	**Cost of Energy** – Water Rentals will be charged on incremental system annual energy gains.	(2.1)
Total Incremental Annual Benefit Net of Costs		**28.4**

4.2.2 Incremental Energy From Removing Operating Restrictions

The proposed work on the turbines will remove current restrictions on unit operation, which constrain the energy generation capability at GMS. In order to reduce the probability of turbine failure, GMS Units 1, 2, 4 and 5 are currently operated with the restriction that they not be shutdown or transferred to synchronous condense mode (if so equipped) unless required for system reliability[10]. The intent of these operating restrictions is to avoid the stresses on the wicket gate operating mechanisms and the runner that occur when starting or stopping the turbine, or the transferring between generate and synchronous condense modes in order to reduce ongoing runner blade cracking and reduce the probability of unit failures.

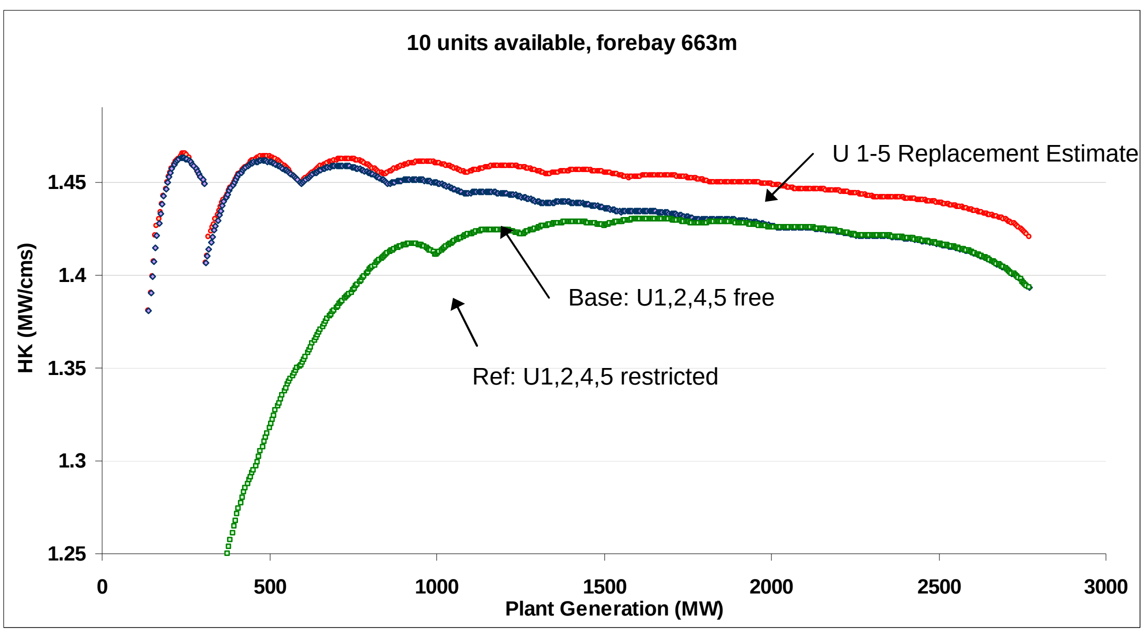
Over the past 40 years, the manufacturer and BC Hydro have proposed and implemented many potential solutions to eliminate runner cracking, all without effect. Even with the

10 Operating Restrictions: GMC #1-48136, June 20, 2008; GMC #1-49043, August 29, 2008; SYS #3-62897, October 7, 2008

restrictions described above in place, cracks continue to develop in the runner blades. On this basis, BC Hydro has no reason to expect that the current operating restrictions, or comparable restrictions, can be removed, without aggravating the blade cracking, unless the turbines are replaced.

As shown in Figure 4-3, the operating restrictions result in a reduction in plant operating efficiency, since it results in the least-efficient units being dispatched in preference to the most efficient units. Compared to “normal” operation, where units can be dispatched in merit-order (from most efficient to least efficient unit) to meet the required output of the plant, this constraint reduces average annual generation by 164 GWh. System modelling shows that the effect of the constrained operation is roughly equal between units: each constrained unit contributes a loss of 41 GWh in annual generation. Given these must-run restrictions, there is also an impact on the ability of BC Hydro to economically optimize the system with market purchases.

Figure 4-3 GMS Plant Efficiency Curves[11]



[11] The term HK is a measure of both head and efficiency, whereby Generation (MW) = HK * (Volume of water passing through the turbine measured in cubic metres per second).

Based on the F2006 Call Adjusted Bid Price of $88 per MWh (in 2006 dollars) for firm generation delivered to the Lower Mainland, this lost output has an annual value of $13.8 million in 2009 dollars, after reflecting transmission losses between GMS and the Lower Mainland. Water rentals would be charged on the regained energy as shown as an incremental cost in Table 4-2.

4.2.3 Energy Gains through Improved Efficiency

As also shown in Figure 4-3, replacing the turbines is expected to provide efficiency gains as a result of a new runner design, an improved surface finish and from water passage modifications outside the runners. Consistent with the 2007 Energy Plan, this incremental energy results in no greenhouse gas emissions.

The expected level of achieved efficiency gain from the Project may vary and will not be finalized until CMT is complete and the final design is confirmed. However, the current expected average annual efficiency gain is 35.4 GWh per unit or 177 GWh for all five units.

Based on the F2006 Call Adjusted Bid Price of $88 per MWh (in 2006 dollars) for firm generation delivered to the Lower Mainland, the increased output from higher efficiency has an annual value of $14.9 million in 2009 dollars, after reflecting transmission losses between GMS and the Lower Mainland. Water rentals would be charged on the increased output as shown as an incremental cost in Table 4-2.

4.2.4 Avoided Future Outage Opportunity Costs

Replacing the turbines in GMS Units 1 to 5 will avoid future outages to address the ongoing cracking and equipment health issues and concerns that would remain if the turbines were not replaced. It is expected that six to nine unit-weeks of outages per year are required for the semi-annual inspection of GMS Units 1 to 5 and any associated repairs. These costs will be avoided as a result of the Project. The opportunity cost of an outage-week is estimated to be at least $250,000, hence the total avoided costs are in the range of $1.5 million to $2.25 million per year.

4.2.5 Avoided Future Operation and Maintenance Cost Increases

Replacing the turbines will avoid the need for higher frequency of turbine inspections and maintenance in the future. Starting in the winter of 2008/09, BC Hydro has increased the frequency of turbine inspections on Units 1, 2, 4, and 5 to address asset health risks and monitor equipment condition, and expects to continue this practice in the future. This inspection regime requires an otherwise unneeded shutdown and imposes incremental costs of $50,000 per year per unit, increasing Operations and Maintenance costs at GMS by a total of $250,000 annually. These incremental costs will be avoided by the Project, since the replacement turbines are not expected to require this higher frequency of inspection and condition monitoring.

4.2.6 Future Potential Capacity Benefits

The Project will provide the potential for a future capacity rating increase from 261 MW per unit to 305 MW per unit for a total capacity increase of 220 MW. However, the Project will not realize this capacity increase, as additional work would be required to realize this capacity rating increase that is not within the scope of the Project. The total incremental cost of replacing the turbines with the increased capacity unit as compared to an equivalent capacity unit is about $3.5 million. BC Hydro is of the view that this incremental cost is negligible relative to the opportunity to have an option of increasing capacity significantly.

4.2.7 Safety

The Project will improve the safety risks associated with maintaining and operating the Units 1 to 5 turbines. Any design feature that reduces the exposure of a major turbine component to failure improves worker safety. This is especially true in an underground powerhouse like GMS, where workers in the vicinity of an operating unit are exposed to the hazards associated with the failure of a major component. Highlights of the safety considerations that will be addressed as part of the Project include the following:

- Eliminating the exposure of the plant workers to the safety hazards associated with runner crack welding. As the new runner design will eliminate the historical issue of cracking, weld-repairs to the runners will no longer be required;

- Reducing the exposure of the plant workers to the safety hazards associated with maintaining the shaft seal and inner head cover. The new head cover will be configured to improve access to these historically difficult-to-access locations;
- Eliminating the risk of a major failure of the turbine resulting from multiple broken shear pins and a cascade closure of multiple wicket gates. The new wicket gate operating mechanism will include a friction device to prevent rapid closure of a wicket gate in the event that its shear pin is broken. Furthermore, protective devices to detect broken shear pins and to initiate the appropriate alarm sequence are included. These will be the same or similar to the ones now installed on Units 1 to 5; and
- Reducing the risk of a major head cover failure that results from metal fatigue or transient event in the water passage. The new head cover will be designed to the requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code Section VIII[12], and BC Hydro's technical specifications for the Project.

4.2.8 Net Present Value of Project

The Project has a positive Net Present Value for both the Expected and Authorized project costs, as demonstrated in Table 4-3.

As shown in Table 4-3, the levelized unit energy cost of the Project based on the incremental energy benefits associated with removing the current operating restrictions and the efficiency gain net of non-energy benefits and losses to the Lower Mainland, is $51 per MWh on an Expected Cost basis and $60 per MWh on an Authorized Cost basis. This is significantly less than the reference cost of energy associated with the F2006 Call of $88 per MWh ($93 per MWh in 2009 dollars).

[12] The Boiler and Pressure Vessel Code is a standard that provides rules for the design, fabrication, and inspection of boilers and pressure vessels. The code is reviewed every three years and consists of 12 volumes.

Table 4-3 Net Present Value of Project

Project Capacity and Energy			
		Per Unit	**Total**
Rated Capacity (No Change)	MW	261	1,305
Average Annual Energy (Constrained Dispatch)	GWh/Year	1,287	6,436
Incremental Energy by Removing Constraints	GWh/Year	33	164
Expected Incremental Energy	GWh/Year	35	177
Total Expected Energy after Replacement	GWh/Year	1,355	6,777
Project NPV and Cost of Energy		**Replacement**	
		Expected	Authorized
Capital Costs (Stage 2 Implementation)	PV $M	133	164
Capital Costs (to end of Stage 1 Implementation)	PV $M	11	11
Installation Outage Opportunity Costs	PV $M	15	15
Cost of Energy (Water Rental)	PV $M	36	36
Avoided Future Outage Opportunity Cost	PV $M	(18)	(18)
Avoided Future Maintenance Cost	PV $M	(3)	(3)
Net Cost	PV $M	175	206
Value of Energy (Net of Transmission Losses)	PV $M	319	319
Project NPV	**NPV $M**	144	113
Energy Benefits	PV GWh	3,418	3,418
Levelized Cost of Energy (Net Cost/Energy Benefits)	$ / MWh	51.3	60.2

4.3 Alternatives to GMS Units 1 to 5 Turbine Replacement

4.3.1 Introduction

There are several alternatives to the Project that have been examined. These alternatives were identified as either not feasible or not as cost-effective as the Project.

4.3.2 Alternatives Not Feasible

4.3.2.1 Cease Operations of GMS Units 1 to 5

It would not be feasible to cease operations of GMS Units 1 to 5. Operation of these units is required to move sufficient water out of the reservoir in order to avoid spilling water and the resulting environmental impacts. This alternative would also have a large negative impact on the value of BC Hydro's integrated system as ceasing operations would lose the benefit of low cost Heritage energy.

4.3.2.2 Overhaul with Runner Modifications

BC Hydro has considered two solutions to address the runner cracking problem that involve modification to the runners, but has concluded that these options are not feasible. These solutions are described below. Additionally, addressing the runner cracking problem alone would not address all problems associated with the existing turbines.

Blade Inserts

A solution to address the turbine runner trailing edge cracking issue is to use an insert welding technique. This solution would replace the blade-to-crown trailing edge of each unit with a steel plate insert (such as duplex stainless steel or High Strength Low Alloy steel) capable of withstanding the operating stresses during generation and at runaway speed. However, the blade insert addition is not feasible because regardless of which insert-material is selected. a post-weld heat treatment of the runner is required to relieve the residual stresses developed during the significant welding associated with installing the inserts. This post weld heat-treated runner would seriously jeopardize integrity for the following reasons:

- During the post weld heat treatment of the runner, the existing duplex stainless steel weld overlay would develop cracks on the blade-to-band leading edges and blade-to-crown trailing edges; and
- The yield stress of the carbon steel casting at 600°C is very low and the locked-in welding induced residual stresses in the runner would translate into permanent strains causing distortion of the blades around 600°C. This would severely compromise the hydrodynamic profile of the blade of the runner. During the operation of this runner, it would suffer from severe cavitation damage and a drastic reduction in efficiency.

Blade Replacement

A solution to address the runner blade cracking issue is to replace the blades on the runners, as done with the Unit 3 repair work. However, BC Hydro does not consider this a feasible long-term solution as it does not address the ongoing cavitation problem nor does it provide the improvement in asset health required for the head cover, wicket gates, wicket gate operating mechanisms or the other components of the turbine that must be addressed to improve the asset health of the entire turbine unit. Additionally, there may be unknown asset health risks associated with the re-use of the existing crown and band.

4.3.2.3 Overhaul with the Installation of Stiffeners (Struts) Between Runner Blades

A potential solution to address the runner cracking issue is to install stiffeners in-between the runner blades. BC Hydro performed a preliminary investigation of this alternative, including a field test on Unit 4 in June 1998. However, the results from this work were not positive. Virtually all of the stiffener welds were found to be broken during the first inspection period, with little reduction in the occurrence and severity of cracks in the runner blades. Furthermore, permanent implementation of this alternative would result in a hydraulic efficiency decrease of at least one per cent, and significant cavitation damage on the runner blades in the wake of the stiffeners. For these reasons, this alternative was rejected.

4.3.3 Alternative Not as Cost-Effective as Replacement

4.3.3.1 Overhaul

This alternative is a complete unit overhaul with no modifications to the runner as part of the overhaul. The alternative includes an extensive overhaul of all components listed in Table 3-1, with no new components purchased. While this alternative is feasible, BC Hydro expects the turbines would still need to be replaced after an additional ten years of operation due to the condition of the equipment and the risk it presents to operating availability. This replacement after ten years would be similar in scope to the Project, and little or no value from an overhaul would be retained in that replacement. BC Hydro has assumed that the cost of this eventual turbine replacement will be the same as the current Project, adjusted for anticipated construction escalation in the intervening period.

As shown in Table 4-4, the NPV of this alternative is lower than the replacement alternative. The residual risks of forced outages associated with this option are higher as well due to the underlying condition of the major turbine components, particularly the runner, even with an overhaul. Also, until the eventual replacement in ten years time, there is no energy gain associated with this alternative to offset the capital cost. For these reasons, BC Hydro rejected this alternative.

Table 4-4 Net Present Value Comparison of Overhaul to Replacement

Project Capacity and Energy					
				Per Unit	**Total**
Rated Capacity (No Change)	MW			261	1,305
Average Annual Energy (Constrained Dispatch)	GWh/Year			1,287	6,436
Incremental Energy by Removing Constraints	GWh/Year			33	164
Expected Incremental Energy	GWh/Year			35	177
Total Expected Energy after Replacement	GWh/Year			1,355	6,777
Project NPV and Cost of Energy		**Overhaul**		**Replacement**	
		Expected	Authorized	Expected	Authorized
Capital Costs (Stage 2 Implementation)	PV $M	110	155	133	164
Capital Costs (to end of Stage 1 Implementation)	PV $M	11	11	11	11
Deferred Replacement of Turbines	PV $M	78	89		
Installation Outage Opportunity Costs	PV $M	24	24	15	15
Cost of Energy (Water Rental)	PV $M	19	19	36	36
Avoided Future Outage Opportunity Cost	PV $M	(10)	(10)	(18)	(18)
Avoided Future Maintenance Cost	PV $M	(2)	(2)	(3)	(3)
Net Cost	PV $M	230	286	175	206
Value of Energy (Net of Transmission Losses)	PV $M	162	162	319	319
Project NPV	**NPV $M**	(68)	(124)	144	113
Energy Benefits	PV GWh	1,735	1,735	3,418	3,418
Levelized Cost of Energy (Net Cost/Energy Benefits)	$ / MWh	132.5	165.0	51.3	60.2

4.3.4 Status Quo

This alternative involves no change in BC Hydro’s current operation but involves maintaining the six-month inspection and maintenance cycle. It does not address risks associated with asset heath. In addition, status quo would result in BC Hydro maintaining the current operating restriction that applies to Units 1 to 5.

The financial analysis in the Application compares the incremental costs/benefits of the Project to status quo. As such, the impact of status quo is the opportunity cost of not achieving the net benefits associated with the Project and will result in the continued deterioration of these assets.

4.3.5 Summary of Alternatives

The advantages of the Project over the alternatives are summarized as follows:

- the Project will significantly reduce the level of business risks associated with the condition of the turbines;
- the Project has a positive incremental NPV while the overhaul alternative has a negative incremental NPV and the status quo alternative has a zero incremental NPV;
- the Project will provide incremental clean energy; and
- the Project will result in lower maintenance and outage related costs compared to the overhaul alternative.

Gordon M. Shrum Units 1 to 5 Turbine Replacement Project

BC hydro

Chapter

5

First Nations and Public Consultation

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5.1 Introduction

This chapter describes the consultation that BC Hydro has undertaken with respect to the First Nations and public stakeholders.

5.2 First Nations Consultation

This section identifies the First Nations that may be impacted by the Project, describes the First Nation consultation activities in support of the Project and describes the consultation that has taken place and proposed activities as the Project proceeds.

The objectives of this consultation are, in respect of those First Nations whose rights or interests are potentially impacted by the Project, to:

- ensure that the First Nations are provided with all appropriate and relevant information associated with the Project so that the First Nations understand the nature and potential impacts of the Project;
- receive any input from the First Nations on the Project;
- ensure that any potential adverse and beneficial impacts on the First Nation's rights or interests are clearly understood by BC Hydro; and
- where First Nations are potentially adversely impacted by the Project, work with the First Nations to identify possible strategies for avoiding or mitigating such impacts and, to the extent avoidance or mitigation of impacts is not possible, discuss and develop with the affected First Nation, other potential accommodation options.

5.2.1 Identification of First Nations

The GMS facility is located in North Eastern British Columbia adjacent to the Williston Reservoir (refer to Figure 3-1). Based on a review of historic treaty boundaries, maps of consultative boundaries provided by the Province, maps of the Statement of Intent (**SOI**) areas submitted by First Nations in the British Columbia treaty negotiation process, and agreements BC Hydro has with First Nations, BC Hydro identified several First Nations which are considered to be relevant for inclusion in consultation activities on the Project.

BC Hydro's review of these maps and agreements indicated that the Project:

(a) Lies within the consultative boundaries and/or SOI area of the following First Nations which are a signatory to Treaty 8:

- i) West Moberly;
- ii) Halfway River; and
- iii) McLeod Lake.

(b) Falls outside of the consultative boundaries of the following First Nations which are a signatory to Treaty 8:

- i) Saulteau;
- ii) Doig River;
- iii) Blueberry River;
- iv) Prophet River; and
- v) Fort Nelson; and

(c) Falls outside of the asserted territories of the following First Nations, but with whom BC Hydro has agreements (discussed below) in place:

- i) Kwadacha; and
- ii) Tsay Keh Dene.

The Fort Nelson, Saulteau, West Moberly, Prophet River, Blueberry River, Halfway River and Doig River First Nations are all signatories to Treaty 8, signed in 1899 with the Federal Crown. Treaty 8 provides hunting, fishing, trapping rights and extends from North Eastern British Columbia into Alberta. The McLeod Lake Band signed an adhesion to Treaty 8 in 2000.

The Treaty 8 Tribal Association of British Columbia represents six Treaty 8 communities (Doig River, Fort Nelson, Halfway River, Prophet River, Saulteau and West Moberly) and is focused on protecting and preserving treaty rights.

The Tsay Key Dene and Kwadacha First Nations are both currently engaged in treaty negotiations with Canada and British Columbia. The Tsay Key Dene and Kwadacha First Nations have also been engaged in negotiations with BC Hydro regarding impacts and historical grievances from the Williston Reservoir. In 2006, BC Hydro and the two First Nations signed the Williston Agreement-In-Principle to address the impacts of flooding from the Williston Reservoir. A final agreement with the Kwadacha First Nation was signed in November 2008. A final agreement with the Tsay Key Dene First Nation has been ratified by the parties and is awaiting signature. Both agreements include a provision that obligates BC Hydro to notify the First Nation in writing of regulatory proceedings relating to the GMS facility.

The Peace Project Water Use Plan (**WUP**) was submitted to the Province in 2006. Eight First Nations were engaged in the WUP discussions and Tsay Keh Dene, Kwadacha and MacLeod Lake participated in the development of the final consensus recommendations.

As the Project will have no downstream effects, BC Hydro determined that consultation with First Nations located downstream of GMS and whose asserted territories the Project lies outside, for example those located in the Peace Athabasca Delta, was not necessary.

5.2.2 Expected First Nation Impacts

It is anticipated that the Project will have minimal, if any, adverse impacts on First Nations for the following reasons:

- The Project will not result in water flow changes outside of normal operation variation in Williston Reservoir or the Peace River ;
- The Project does not extend beyond the existing facility footprint on existing BC Hydro property; and

- There are minimal social impacts and no environmental impacts on surrounding communities. Social and Environmental impacts are addressed in section 3.7.

5.2.3 First Nation Consultation Process

BC Hydro is undertaking a consultation approach commensurate with the minimal level of potential impact that the Project is expected to have on First Nations.

In January 2009, First Nations received information letters (refer to Appendix G) sent from BC Hydro to:

- West Moberly First Nations with a copy sent to the Treaty 8 Tribal Association;
- Halfway River First Nation with a copy sent to the Treaty 8 Tribal Association;
- McLeod Lake Indian Band;
- Kwadacha First Nation; and
- Tsay Keh Dene First Nation.

These letters provided background on the GMS facility, explaining BC Hydro's main reasons for undertaking the Project. The letters provided the schedule of turbine unit replacements and clarified that the existing water license would be adhered to, with no change to water flows or reservoir levels (outside of normal operating variation) anticipated as a result of the upgrades. Additionally, the letters indicated that due to the size of the Project expenditure, BC Hydro would be seeking the approval of the BCUC and that it is anticipated that an application will be submitted to the BCUC in September 2009. The materials included a Fact Sheet on the Project and other work being undertaken at GMS.

In May 2009, the First Nations received a second letter and accompanying fact sheet. These letters reiterated key information from the January 2009 letters and offered the First Nations another opportunity to raise any concerns in respect of the Project.

In June 2009, BC Hydro made phone calls to the First Nations, including the Treaty 8 Tribal Association. As personal contact could not be made in each case, a message was left describing the purpose of the call as being to follow-up on the letters of January 2009 and May 2009, in particular to provide an opportunity to ask questions or raise any concerns in respect of the Project. The Kwadacha First Nation was not contacted as a response letter had already been received from that First Nation (discussed below).

In July 2009 the First Nations received a third letter which provided an update on BC Hydro's plans for submitting an Application to the BCUC, as well as another opportunity to raise any concerns in respect of the Project.

5.2.4 Consultation Feedback

Based on the consultation process, BC Hydro has received a letter from the Chief of the Kwadacha First Nation indicating that Kwadacha has no objection to the planned replacement of GMS Units 1 to 5 turbines (refer to Appendix G).

To date, no additional feedback has been received from First Nations.

5.2.5 Adequacy of First Nations Consultation

In BC Hydro's view, its consultation efforts with potentially affected First Nations is adequate to discharge the honour of the Crown to this stage of the Project.

5.2.6 Ongoing First Nation Consultation Plans

BC Hydro will continue consultation with potentially affected First Nations as the Project is implemented. BC Hydro will provide additional information updates when applicable and will respond to any questions or information requests that may be received regarding the Project. BC Hydro will work to understand and address any concerns or issues that are raised by First Nations and where appropriate, BC Hydro will engage in discussions with First Nations to further identify means to avoid, mitigate, minimize or otherwise accommodate any concerns or issues relating to the Project.

5.3 Public Consultation

This section describes BC Hydro’s public consultation activity regarding the Project. BC Hydro is committed to ensuring interested stakeholders, local residents and government agencies are informed about and understand the need for the Project and have opportunities to provide their feedback.

The specific objectives of the public engagement efforts for the Project are to:

- ensure interested parties, stakeholders and the public are informed about the status of and the need for the Project;
- obtain input from interested parties, stakeholders and the public on potential issues and concerns with the Project for BC Hydro’s consideration and resolution where possible; and
- foster established and develop new relationships in the local area, building on trust from previous interactions; and build the groundwork for future interactions between BC Hydro and the community.

5.3.1 Public Groups Included in Consultation

The GMS facility is located within the municipal boundary of Hudson’s Hope, B.C. about 20 kilometres (**km**) west of the town site. The community is home to most of the employees at both GMS and the Peace Canyon Dam. Hudson's Hope is located approximately 90 km west of Fort St. John and 70 km north of Chetwynd and has a population of close to 1,100 residents. The community is incorporated with a Mayor and Council and is also a member community of the Peace River Regional District.

BC Hydro identified the following public groups, in the vicinity of the GMS facility, to engage through a public consultation process. These groups were identified based on BC Hydro’s experience with past project consultation activities related to the GMS facility:

- Chambers of Commerce;

- Municipal and Regional District Governments;
- Members of Legislative Assembly;
- Peace River/Williston Reservoir Advisory Committee; and
- News and media organizations.

Additionally, the following organizations were included in the communication:

- BC Ministry of Environment – Peace/Williston Fish and Wildlife Compensation Program; and
- British Columbia Transmission Corporation.

5.3.2 Public Consultation Process

BC Hydro has pursued a public consultation approach for public groups within the vicinity of the GMS facility that is commensurate with the level of expected potential impact of the Project. As such, a written public consultation process was undertaken.

In January 2009, May 2009 and July 2009, documents describing the Project (refer to Appendix G) were sent to the local groups and representatives identified in section 5.3.1.

These documents provided background on the Project including the schedule of turbine replacements. Additionally, the documents indicated that due to the size of the Project expenditure, BC Hydro would be seeking the approval of the BCUC.

These documents also indicated that the current maximum capacity per unit is 261 MW and that the new turbines will be limited to the current capacity because of other equipment capacity constraints and water license limitations. The documents clarified that the new turbines will ultimately allow the generating units to operate at 305 MW but that this capacity increase will require additional equipment upgrades not currently planned or scheduled before this increased capacity can be achieved. In addition, in order to realize capacity increases, BC Hydro must apply for a water license revision and receive approval from the Ministry of Environment.

To date, no feedback has been received from this public consultation process.

5.3.3 Future Consultation Plans

BC Hydro will continue public consultation by written communication with groups in the vicinity of the GMS facility as the Project progresses.

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Chapter

6

Project Risks and Risk Management

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6.1 Introduction

This chapter addresses the material risks that have been identified for the Project and BC Hydro's plans to manage these risks.

Over the life of the Project, and consistent with BC Hydro's standard project management practices and procedures, risk screenings are conducted to identify the major Project risks and their associated control and mitigation strategies. This chapter provides a summary of the material risks, plans to manage these risks, and any residual risks.

The risks associated with the Project are identified by the phases and stages of the Project life cycle in which they are introduced. These are the Implementation Stage 1, Implementation Stage 2 and the operations phase. Identification and Definition phase risks are not considered significant at this point in the Project.

6.2 Implementation Stage 1 Risks

Implementation Stage 1 targets achieving a turbine design that will fully restore asset health and that will provide the anticipated energy gains, all within budget and on schedule. There are several risks that could impact achieving these outcomes, which are addressed in the sections below.

6.2.1 Turbine Technical Design Risk

As indicated in Chapter 3, BC Hydro entered into Project Implementation Stage 1 with two suppliers, Voith and Andritz. Each of these suppliers provided targeted turbine design specifications to BC Hydro in response to BC Hydro's tender for the turbine design, supply and install contract. They will compete with each other through the CMT process to be selected by BC Hydro as the single supplier for Implementation Stage 2 of the Project.

There is a risk that the turbine supplier(s) submit a design that does not adequately meet the specifications submitted in their respective tenders. The turbine design(s) could have inherent faults that lead to turbine vibration, cavitation, surging or other limitations. Furthermore, the turbine designs may not support delivering the anticipated efficiency benefits. These inherent faults could be the result of the sub-optimization of a single component of the turbine or incremental component alterations leading to a deficiency in overall design. This risk is increased by BC Hydro's requirement that the new turbines incorporate components of the existing turbines, and by the dimensional restrictions of the existing water passages, which will not be changed. These limitations constrain the designers of the new turbines more than an "all-new" installation, such as the case with Revelstoke Unit 5.

BC Hydro implemented or planned the following controls and mitigation measures for Implementation Stage 1 of the Project to manage this risk

The Implementation Stage 1 procurement process was designed to ensure that BC Hydro selected top suppliers to enter into the CMT process. BC Hydro invited the major suppliers able to perform the required work for the Project to submit tenders. Based on proposals received, BC Hydro selected the top two suppliers to enter the CMT process.

Each of the turbine suppliers will undertake computer and physical model testing in the development of their respective turbine designs.

The Design Basis Memorandum has been created from BC Hydro experience with past projects and current engineering team expertise. Recent lessons learned from the GMS Unit 3 failure were also included in the Design Basis Memorandum.

As the Project involves designing a turbine around embedded components in GMS, and also involves the design of five turbines with a total capacity of 1,305 MW, BC Hydro has pursued a CMT process to maximize the potential for an optimal turbine design to achieve targeted outcomes. The competitive process provides incentive for the two potential turbine suppliers to submit the best possible turbine design. In addition, having two capable suppliers continue the design through to model testing reduces the likelihood of a design failure. If either supplier is unable to realize its anticipated turbine performance, BC Hydro is able to proceed with the other supplier. This process was selected over Single Model Testing (**SMT**) model and no model testing (**NMT**) due to the particular difficulty of designing a replacement turbine.

BC Hydro has engaged EPFL, one of the world's leading hydraulic test facilities to independently test the efficiency and capacity of the turbine physical models.

BC Hydro may terminate the contract at the end of Implementation Stage 1 if neither of the turbine designs are adequate.

6.2.2 Investment at Risk

BC Hydro seeks an order per section 44.2(3)(a) of the *UCA* that the BCUC accepts that the expenditure schedule for the Project is in the public interest. If the BCUC does not accept the expenditure schedule and an order is not granted, this may lead to a delay in awarding the Implementation Stage 2 contract beyond July 2010. Such a contract award delay could result in a delay in the Project schedule by one year with a capital cost impact of $13 million due to increased escalation over the term of the contract and an estimated opportunity cost impact (due to the incremental efficiency benefit of the new turbines being delayed one year) of $19 million.

BC Hydro retains the right to terminate the contract in the event the BCUC does not find the project in the public interest or any other required approval is not granted, although BC Hydro would incur some costs. Specifically, if the contract is terminated in 2010, BC Hydro would incur termination related costs of $9 million with the costs increasing with each day of delay of the termination.

6.2.3 Schedule Risk

There is a risk that turbine suppliers fail to complete the design work on schedule. BC Hydro has put controls and mitigation measures in place to manage this delay risk. These measures include the CMT process itself and supplier contractual penalties for failure to comply with the schedule. BC Hydro has not identified any other significant risks that could delay Implementation Stage 1.

6.2.4 Capital Cost Risk

BC Hydro has a fixed price contract in place with both suppliers to manage the risk of cost increases in Implementation Stage 1.

6.2.5 Environmental Regulatory

The BCEAO may deem the Project to be reviewable. If this is the case, BC Hydro will refer the Project to the BCEAO Executive Director under the B.C. *Environmental Assessment Act* Section 10(1)(b) requesting a determination that no environmental assessment certificate is required for the Project. This may result in a Project schedule delay. BC Hydro is managing this risk by having ongoing discussions with the BCEAO and will continue consultation with First Nations and the public on the Project.

6.2.6 First Nations Risk

Inadequate First Nation consultation is a risk to regulatory approvals and the Project schedule. To mitigate these risks, as described in Chapter 5, BC Hydro has undertaken, and will continue to undertake, consultation with First Nations with respect to the Project.

In BC Hydro’s view, its consultation efforts with potentially affected First Nations have been adequate for this type of replacement project that is not adding capacity. No First Nations have indicated concerns with the Project. BC Hydro has received a letter from the Chief of the Kwadacha First Nation indicating that Kwadacha has no objection to the planned replacement of GMS Units 1 to 5 turbines.

6.3 Implementation Stage 2 Risks

Implementation Stage 2 will target implementation of turbines that fully restore asset health and that provide the anticipated energy gains, within budget and on schedule and with no safety, security or environmental incidents. There are several risks that could impact achieving these outcomes, which are addressed in the sections below.

6.3.1 Commissioning Risk

There is a risk that the quality and performance of the turbines at implementation will not meet contract specifications identified by the independent testing in Implementation Stage 1, leading to turbines that do not fully restore asset health or provide anticipated efficiency gains.

BC Hydro implemented or has planned the following controls and mitigation measures to manage this risk:

- implementation Stage 2 contract warranties that address design, materials, workmanship and cavitation risks are in place. The contract also limits BC Hydro's liability and requires the successful supplier to complete remedial work or compensate BC Hydro to address substandard quality or performance; and
- the Project schedule plans for the staggered installation of the turbines. Implementing the new turbines one at a time will allow BC Hydro to operate each new turbine (as well as all previously-installed turbines) before each subsequent turbine is installed. This running period will allow BC Hydro and the supplier to identify operating problems with the turbines, and will allow the supplier the opportunity to address any issues in subsequent units.

6.3.2 Capital Cost Risk

The risk that the Implementation Stage 2 capital cost is higher than the Authorized Cost amount is addressed with several controls and mitigation measures including:

- a fixed price contract, priced in Canadian dollars, with suppliers, subject to some escalation and exchange rate variances;
- contingencies included in the Authorized Cost amount that address the potential for cost impacts associated with escalation and exchange rates over expected forecasts;
- a clear scope of work is included in the supplier contract;
- BC Hydro will have a construction management team onsite at GMS to manage the execution of the on-site component of the contract with the supplier;
- BC Hydro may terminate the contract for schedule non-compliance and switch to the alternate supplier; and

- BC Hydro has undertaken due diligence on the two potential Implementation Stage 2 suppliers to address the potential for supplier financial default. As well, the potential suppliers have provided BC Hydro with a performance bond and security letter of credit.

6.3.3 Schedule Risk

There is a risk that BC Hydro will not complete the Project within the planned schedule. This may delay achieving the full restoration of asset health and the achievement of incremental energy and other Project benefits.

BC Hydro’s controls and mitigation measures to manage the risk of an Implementation Stage 2 schedule delay risk include:

- the Implementation Stage 2 contract scope is comprehensive to minimize the potential for work outside of scope that may otherwise result in a schedule delay. The contract scope incorporates lessons learned from the GMS Unit 3 failure and BC Hydro engineering expertise;
- schedule requirements and penalties to the supplier, associated with schedule delay, are included in the Implementation Stage 2 contract;
- the Project budget includes a contingency allowance for some schedule acceleration;
- BC Hydro has planned unit outages to accommodate Implementation Stage 2;
- BC Hydro has undertaken due diligence on the potential suppliers to minimize the risk of contractor insolvency or other company specific risks impacting the schedule;
- the supplier assumes the risk of labour unrest and lack of qualified workers, equipment, or materials during construction through the design, supply and installation contract. The contract contains conditions that pass this risk to the supplier and imposes financial penalties for failing to achieve schedule;

- BC Hydro has undertaken, and will continue to undertake, consultation with First Nations and the public with respect to the Project to ensure there are no outstanding issues with the Project that could impact the Project schedule;
- BC Hydro will continue to operate within the water license with the implementation of the Project;
- BC Hydro will continue ongoing discussions with the BCEAO; and
- BC Hydro has considered the Peace WUP and has confirmed there are no WUP impacts as a result of the Project.

6.3.4 Safety Incident Risk

To manage the risk of a significant safety incident occurring, BC Hydro will implement controls and mitigation measures that include:

- a detailed safety management plan (**SMP**) that addresses both BC Hydro and the supplier;
- a construction management team on-site at GMS to ensure safety is addressed;
- safety features incorporated into the design of the new turbines; and
- first aid availability at the GMS site.

6.3.5 Security Risk

During construction there is increased security risk. BC Hydro will assess the risk and develop a plan that will include measures such as:

- training of on-site operations staff and contractors on site-security;
- provision of extra security guards where appropriate;
- provision of visible identification for staff and construction workers; and

- installation of new access locks on gates and doors.

6.3.6 Environmental Incident Risk

To manage the risk of a significant environmental incident occurring as a result of the Project implementation, BC Hydro will implement controls and mitigation measures, including:

- an environmental management plan (**EMP**) that addresses both BC Hydro and suppliers;
- a BC Hydro construction management team onsite at GMS to ensure the environment is protected;
- remedial work clauses relating to environmental impacts in the supplier contracts, including a warranty of remedial work; and
- implementation of the turbines will be undertaken such that BC Hydro will continue to operate within the parameters of the GMS water license.

6.4 Operations Risks

6.4.1 Failure and Outage Risk

There is a risk that the turbines will not deliver the anticipated availability and reliability performance, on an ongoing basis. The controls and mitigation measures that BC Hydro has put in place to manage this risk include:

- contractual design warranty;
- contractual materials and workmanship warranty;
- contractual provisions for rework; and
- contractual performance guarantees and penalties.

6.4.2 Safety Risks

As noted in Chapter 4, the Project will improve safety in several ways. While some reduction in safety risk is a function of turbine design, some risks remain that are related to undertaking turbine inspections and maintenance. Provided the turbines perform as planned, the frequency of inspection and maintenance will be reduced and accordingly the associated safety risks. The controls and mitigation measures to ensure these safety risks are reduced are the same as per the failure and outage risk.

6.4.3 Operating and Maintenance Costs

There is a risk that the anticipated outage reductions and future maintenance cost reductions will not be achieved. These risks are controlled and mitigated as per the failure and outage risk.

6.5 Summary of Material Risks

Table 6-1 summarizes the material risks for the Project, the control and mitigation strategies employed and the level of residual risk remaining after implementation of the control and mitigation strategy.

Table 6-1 Risk Management Summary

Material Risks	Control and Mitigation Strategy Employed	Residual Risk Frequency and Consequence
Implementation Phase – Stage 1		
The turbine suppliers provide a design that does not fully meet their respective targeted specifications as per their proposals in response to the request for proposals for the supply and install of the turbines, leading to an outcome of a design that will not fully restore asset health or provide anticipated efficiency gains	• Implementation Stage 1 tender process • Computer model testing • Physical model testing • Design Basis Memorandum • Independent model performance testing • Competitive model testing • Contract termination clauses	Very low probability High impact

Material Risks	Control and Mitigation Strategy Employed	Residual Risk Frequency and Consequence
A schedule delay puts investment at risk	• Contract clauses address the potential for delay • BC Hydro retains the right to cancel the contract	Low probability Moderate impact
Stage 1 schedule delay risk	• CMT process • Contractual penalties for failure to comply with schedule	Very low probability Low impact
Stage 1 capital cost risk	• Fixed price contract	Very low probability Low impact
Environmental regulatory approval delays result in a project schedule delay.	• BC Hydro is having ongoing discussions with the BCEAO. • BC Hydro has engaged First Nations and public in Project consultations	Medium probability High Impact
Inadequate First Nations consultation leads to a delay in regulatory approvals and the Project schedule	• First Nations consultation during Implementation Stage 1 • Continuing First Nations consultation during Implementation Stage 2	Low probability High impact
Implementation Phase – Stage 2		
Commissioning risk resulting in less than optimal restoration of asset health and less than anticipated efficiency gains.	• Contractual performance guarantees and warranties • Staggered implementation of turbines and BC Hydro acceptance testing	Very low probability High impact
The risk that the Implementation Stage 2 Project costs are higher than anticipated, leading to an outcome that the Project costs exceed the Authorized Cost estimate	• Supplier contract • BC Hydro construction management team will be onsite • BC Hydro Internal Cost Controls	Low probability Moderate impact

Material Risks	Control and Mitigation Strategy Employed	Residual Risk Frequency and Consequence
The risk that the Implementation Stage 2 schedule is delayed	• Supplier contract • Outage plan • BC Hydro construction management team will be onsite • BC Hydro due diligence on suppliers • Supplier contract • First Nations past and continuing consultation • Past and continuing public consultation • Water license compliance • Environmental Regulatory approvals received • Anticipate regulatory approvals completed by commencement of Stage 2 • WUP Review	Low probability Moderate impact
The risk that there is a significant safety incident during the Project leading to an injury	• Safety management plan • Safety regulations • Safety features designed into the new equipment • BC Hydro construction management team will be onsite • Site medical equipment/First Aid	Very low probability High impact
During construction, with the activity of many new people on-site, there is a heightened security risk	• Extra security guards to be put in place • Identifying signage on hard hats to be in effect • New access locks to be installed on gates and doors	Low probability High impact

<table>
<tr><th>Material Risks</th><th>Control and Mitigation Strategy Employed</th><th>Residual Risk Frequency and Consequence</th></tr>
<tr><td>The risk that there is a significant environmental incident during the Project leading to an outcome of environmental damage</td><td>• Environmental management plan
• Contract clauses requiring supplier environmental responsibility
• BC Hydro construction management team will be onsite
• Contractual remedial environmental work requirements
• Warranty of remedial environmental work</td><td>Low probability
High impact</td></tr>
<tr><td colspan="3">Operations Phase</td></tr>
<tr><td>There is a risk that the new turbines do not meet performance expectations when in service, leading to the turbines not meeting anticipated design and availability requirements and not delivering anticipated efficiency gains.</td><td rowspan="3">• Controls in Implementation Stage 1 and Implementation Stage 2
• Ongoing monitoring
• Performance guarantees and warranties
• Contractual remedial work clauses
• Warranty of remedial work</td><td rowspan="3">Very low probability
High impact</td></tr>
<tr><td>There is a risk of a safety incident occurring during ongoing maintenance inspections</td></tr>
<tr><td>The risk that operating and maintenance cost benefits are not achieved</td></tr>
</table>

6.6 Impact of Cost/Benefit Uncertainties on Project Net Present Value and Unit Cost of Incremental Energy

The primary justification of the Project is the need to address the unsatisfactory asset condition and the associated business risks. The additional Project benefits result in a positive NPV. It is acknowledged that there are a number of risks and uncertainties that could affect the NPV. This section demonstrates the sensitivity of the Project NPV and the levelized cost of energy to the uncertainties described below.

6.6.1 Implementation Risks

In part, BC Hydro has developed an Authorized Cost estimate for the Project to ensure the impact of any capital cost overrun is understood. If this level of capital cost were incurred, then the Project NPV would decrease to $113 million from the Expected Cost NPV of $144 million, a reduction of $31 million. The corresponding levelized cost of incremental energy from the Project would increase from $51 per MWh to $60 per MWh. Capital cost savings would make the project correspondingly more attractive: a saving of 5 per cent from the Expected Cost would improve the Project NPV by $7 million to $151 million, with a corresponding levelized cost of incremental energy of $49 per MWh.

6.6.2 Operations

BC Hydro expects that the Project will avoid increased future maintenance costs and outage opportunity costs due to the decreased frequency of required unit inspections and maintenance. Even if such cost avoidance were excluded, the impact on the NPV of the Project is relatively minor, with outage opportunity costs representing $18 million in present value contribution to the NPV of the Project and maintenance savings representing $3 million in present value contribution to the NPV of the Project. If the anticipated savings are excluded entirely the NPV of the Project is reduced from $144 million to $126 million in the case of the outage opportunity costs, or to $141 million in the case of the maintenance savings. By comparison, if those cost savings are doubled, the NPV improves from $144 million to $161 million or $147 million, respectively. The corresponding contribution to the levelized cost of incremental energy from the Project is $5 per MWh for the outage opportunity costs and $1 per MWh for the maintenance savings; the range from completely discounting the savings to assuming double the anticipated amounts corresponds to a levelized cost of energy of $56 to $46 per MWh related to the outage opportunity costs, and of $52 to $50 per MWh related to the maintenance savings.

The achieved efficiency of the turbines will depend on the final outcome of the CMT and supplier selection. The expected energy gains for the Project are 164 GWh per year from eliminating current operating restrictions and 177 GWh from increased turbine efficiency. Based on achieving a 10 per cent increase or decrease in the efficiency gains for the Project, the NPV would increase or decrease by $16 million, moving from $144 million to $160 million or $128 million, respectively. This increase or decrease in realized efficiency gains will reduce or increase the levelized cost of incremental energy from the Project by $2 per MWh, indicating a range from $49 to $54 per MWh, compared to a levelized cost of $51 per MWh at the Expected Cost and anticipated efficiency gain.

6.6.3 Summary of Cost/Benefit Uncertainties

Figure 6-1 and Figure 6-2 provide risk bands that illustrate the impacts of Project cost/benefit uncertainties on the Project NPV and on the levelized cost of incremental energy, respectively. The bands are centered on the Expected Project outcome in each case – either a $144 million positive NPV in Figure 6-1, or levelized cost of $51 per MWh for incremental energy in Figure 6-2, and shown as a heavy vertical line. The range of impact of the uncertainties discussed above, either in terms of NPV or levelized cost, are shown as bars extending on either side of that line, with the horizontal extent of the bars indicating the impact of the uncertainty in appropriate units. The figures are intended to provide an indication of the absolute and relative impact of the identified uncertainties. In no case is the Project NPV negative in Figure 6-2 – the lowest NPV corresponds to expenditures at the Authorized Cost level, with a Project NPV of $113 million. This same outcome corresponds to the highest levelized cost of incremental energy on Figure 6-2, or $60 per MWh.

Figure 6-1 NPV Range of Cost/Benefit Uncertainties ($ million)

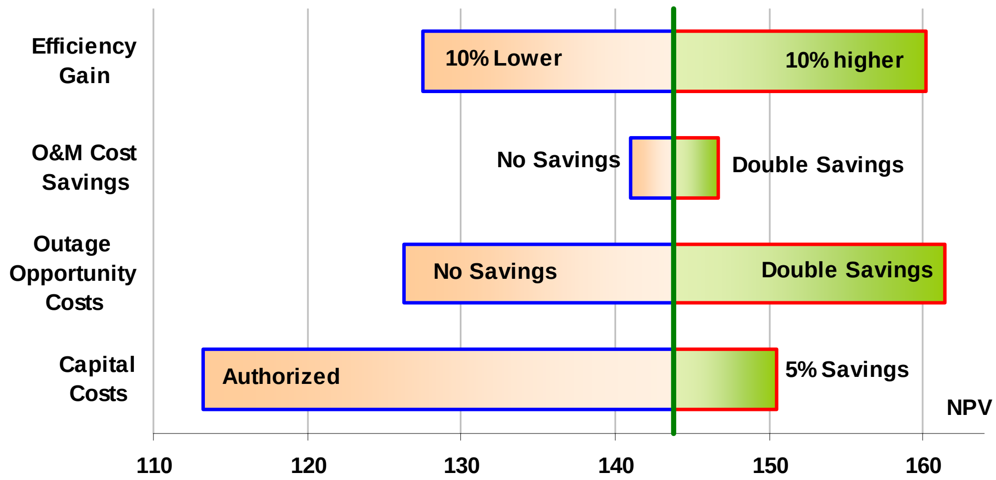
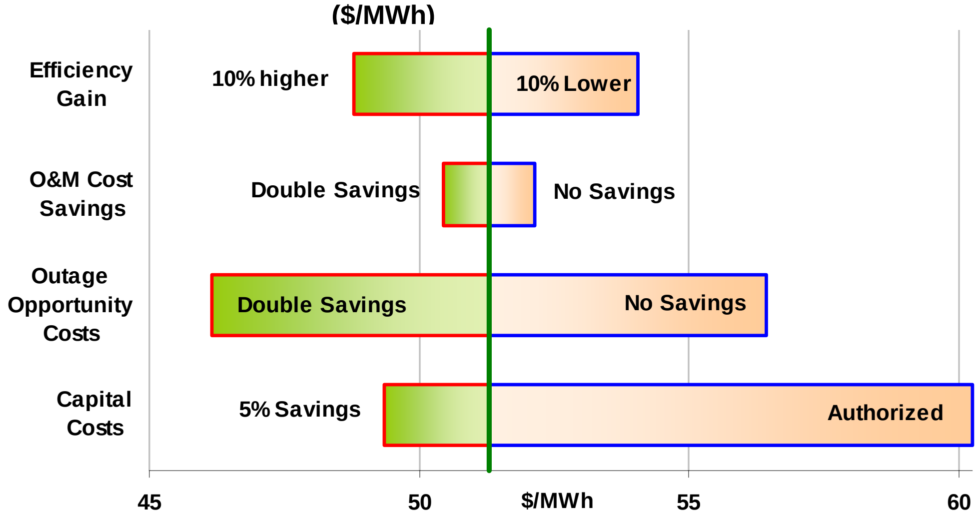


Figure 6-2 Levelized Cost of Incremental Energy Range of Cost/Benefit Uncertainties ($/MWh)



Gordon M. Shrum Units 1 to 5 Turbine Replacement Project

Appendix

A

Glossary and Key Assumptions

Glossary

This Appendix lists defined terms, acronyms and metric units used in the Application.

Authorized Estimate	Authorized Cost is comprised of the Expected Cost and a Project Reserve amount.
BCTC	British Columbia Transmission Corporation
BCUC	British Columbia Utilities Commission
Bulk Transmission System	This is the “backbone” or major high voltage transmission system that carries the majority of the power from the generators to the lower voltage regional systems and carries the interchanges with the U.S. and Alberta.
Capacity	The instantaneous *power* output of a generator at any given time, normally measured in *kilowatts* (kW) or *megawatts* (MW), of a power plant. The instantaneous *electricity* demand at any given time, normally measured in *kilowatts* (kW) or *megawatts* (MW). A *transmission* facility’s ability to transmit electricity, at any instant. Several related terms are commonly used: • **Maximum Capacity:** The highest *generating plant* output or *transmission* loading that can actually be achieved in situ; • **Installed Capacity:** (Also referred to as Nameplate Rating). The maximum rating of a *generator* or *transmission* station equipment identified by the manufacturer under specified conditions; and • **Dependable Capacity:** The amount of megawatts a plant can reliably produce when required, assuming all units are in service. Factors external to the plant affect its dependable capacity. For example, streamflow conditions can restrict the dependable capacity of hydro plants and fuel supply constraints can impact thermal plant dependable capacity. Planned and forced outage rates are not included.
Cavitation	A process where a void or bubble in a liquid rapidly collapses, producing a shock wave. In a turbine, this shock wave can cause damage to the surface of equipment through the formation of pits. The pits increase the turbulence of the fluid flow and create crevasses that act as nucleation sites for additional cavitation bubbles. The pits also increase the components' surface area and leave behind residual stresses making the surface more prone to stress corrosion.
Competitive Model Testing (CMT)	Competitive process for selecting a vendor on the basis of test results from design models developed by the vendors.

Demand	The rate at which electric energy is delivered to or by a system, generally expressed in kilowatts (kW) or megawatts (MW), at a given instant or averaged over any designated time interval. Several related terms are commonly used: • **Instantaneous Demand**: Rate of energy delivered at a given instant; • **Average Demand**: The electric energy delivered over any interval as determined by dividing the total energy by the units of time in the interval; and • **Peak Demand**: The highest electric requirement occurring in a given period (e.g. an hour, a day, month, season or year). For an electric system, it is the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.
EAR Approval	Expenditure Authorization Request
EARG	Engineering, Aboriginal Relations and Generation Business Unit
Efficiency	The effective rate of conversion of a natural resource (e.g. natural gas) to useable energy and capacity or the effective rate of conversion of electricity to an end use (e.g. heating).
Equipment Health Ratings (EHR)	An objective, repeatable equipment health evaluation system. EHR enables comparison of the health of BC Hydro generation assets. The EHR system uses test and inspection data and other information to determine the condition or health of assets. The result is a technical evaluation of the asset resulting in a letter grade; Good, Fair, Poor, Unsatisfactory (G,F,P,U), as follows: • Good no noticeable deterioration/defects; • Fair some deterioration/defects exist (function not affected); • Poor serious deterioration/defects exist in at least some portions of the asset (function affected); and • Unsatisfactory extensive deterioration/defects (no longer functions as required).
Expected Estimate	Expected Cost is comprised of the Cost Estimate, Contingencies, Escalation, Overhead and Interest During Construction (IDC).
Generator	A machine that converts mechanical energy into electric energy.
Gigawatt-Hour (GWh)	One million kilowatt-hours – an amount of electric energy that will serve about 100 residential customers for one year.
GMS	Gordon M. Shrum Generating Facility
Headcover	Non-rotating structural component that: 1) supports the wicket gate upper stems and the operating mechanism; 2) acts as a seal between the water passages and turbine pit; and 3) is an important part of the system for managing the thrust load created by water passing through the turbine.

IDC	Interest During Construction
Integrated Electricity Plan (IEP)	2006 Integrated Electricity Plan.
Interconnection Study	A British Columbia Transmission Corporation (BCTC) study determines the technical feasibility of a customer's facilities connecting to the B.C. transmission system.
IR	Information Request
ISD	In-Service Date
LCAM	Life-Cycle Asset Management
Long Term Acquisition Plan (LTAP)	BC Hydro's action plan to cost effectively meet growing customer electricity requirements. The LTAP sets the course for the first 10 years of a 20-year planning horizon.
Megawatt (MW)	One million watts. This term is commonly used to measure both the capacity of generating stations and the rate at which energy can be delivered.
Model Testing	Use of a scale model of a turbine or component in order to verify performance or other characteristics claimed by a manufacturer. The results obtained from a model can be reliably scaled-up to the performance of a full-size unit
Overhaul	Inspection and replacement of worn components.
Penstock	Enclosed intake / pipe system that delivers water to a hydroelectric turbine.
Project	Proposed BC Hydro G.M. Shrum Units 1 to 5 Turbine Replacement Project
Reliability	A measure of the continuity and quality of electric service. Reliability of service to an individual customer depends on the reliability of generation, high-voltage transmission and low-voltage distribution.
Resource Smart	The BC Hydro program involving a strategy of improvements to existing BC Hydro power generation and transmission facilities to increase power output and efficiency.
Revenue Requirements Application (RRA)	BC Hydro filing to the British Columbia Utilities Commission (BCUC) to seek approval for rate changes to support forecast revenue requirements.
Runner	Device for transforming potential energy (water stored in reservoir) into kinetic energy. It is constructed of multiple hydrofoil blades fixed to a supporting structure (crown and band).

Statement of Intent (SOI)	Under the Six-Stage treaty process coordinated by the BC Treaty Commission, A First Nation files with the Treaty Commission a SOI to negotiate a treaty with Canada and BC. The SOI must identify the First Nation's governing body for treaty purposes and the people that body represents and show that the governing body has a mandate from those people to enter the process. The SOI must also describe the geographic area of the First Nation's distinct traditional territory and identify any overlaps with other First Nations.
Turbine	A rotary device caused to turn by the movement of gases, steam or water.
UCA	Utilities Commission Act
Unit	A single power generation system within a multi-unit power generation facility. For example, the BC Hydro GMS Generating Facility contains 10 Units. Each Unit is comprised of several components, including the turbine, generator, transformers, conductors, circuit breakers, and ancillary equipment, all of which are required to create electrical energy and deliver it to the Bulk Transmission System.
Upgrade	Replacement of components
Water License	The authority granted to BC Hydro by the Comptroller of Water Rights of the Province of British Columbia to store and divert water for generating electricity and other purposes.
Water Use Plan (WUP)	A Water Use Plan is a technical document that defines the detailed operating parameters to be used by hydroelectric facility managers in their day-to-day decisions. WUPs are intended to clarify how rights to Provincial water resources should be exercised, and to take account of the multiple uses for those resources. WUPs are reviewed by the Comptroller of Water Rights pursuant to the Water Act.
Wicket Gates	A series of hydrofoil-shaped gates that regulate the flow of water from the penstocks to the runners. The wicket gates for GMS Units 1 to 5 are being proposed for replacement as part of the upgrade project.

Key Assumptions

Factor	Assumption
Nominal Discount Rate	8 per cent
General Inflation	F2009: 0.5 per cent F2010: 2.0 per cent F2011 through F2013: 2.1 per cent F2013+: 2 per cent
Construction Cost Escalation Rates	F2010: 5.0 per cent F2011: 4.0 per cent F2012+: 3.0 per cent
Water Rental Rate – Energy	$6.342/MWh (real)
Reference Value of Energy (to Lower Mainland)	$93. Figure calculated using the cost of marginal energy delivered to the Lower Mainland, identified in the F2006 Call for Tenders at $88 (F2006 Dollars)
Term of Financial Analysis	40 Years (from first unit In-Service)

Gordon M. Shrum Units 1 to 5 Turbine Replacement Project

Appendix

B

BCUC Draft Order

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by British Columbia Hydro and Power Authority (BC Hydro)
Gordon M. Shrum (GMS) Units 1 to 5 Turbine Replacement Project

BEFORE: ________, Commissioner _________________, 2009

O R D E R

WHEREAS:

A. On 5 August, 2009, British Columbia Hydro and Power Authority ("BC Hydro") filed with the Commission an Application for acceptance, pursuant to Section 44.2(1)(b) of the *Utilities Commission Act* (the "Act"), that capital expenditures BC Hydro anticipates making in respect of the GMS Units 1 to 5 Turbine Replacement Project (the "Project") are in the public interest; and

B. The Commission has considered the Application, evidence, and submissions of intervenors and BC Hydro.

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-

NOW THEREFORE the Commission orders, for the Reasons stated in the Decision, that:

1. The expenditures required to complete the Project, as described in the Application, are in the public interest in accordance with Section 44.2(3)(a) of the Act.

2. BC Hydro is directed to file with the Commission bi-annual progress reports on the Project schedule, costs and any variances or difficulties that the Project may be encountering. The form and content of the bi-annual progress reports will be consistent with other BC Hydro capital project progress reports filed with the Commission. The bi-annual progress reports will be filed within 30 days of the end of each reporting period.

BC Hydro is directed to file a final report 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 Project Expected Cost estimate and provide an explanation of all material cost variances.

DATED at the City of Vancouver, in the Province of British Columbia, this day of ________ 2009.

BY ORDER

Gordon M. Shrum Units 1 to 5 Turbine Replacement Project

Appendix

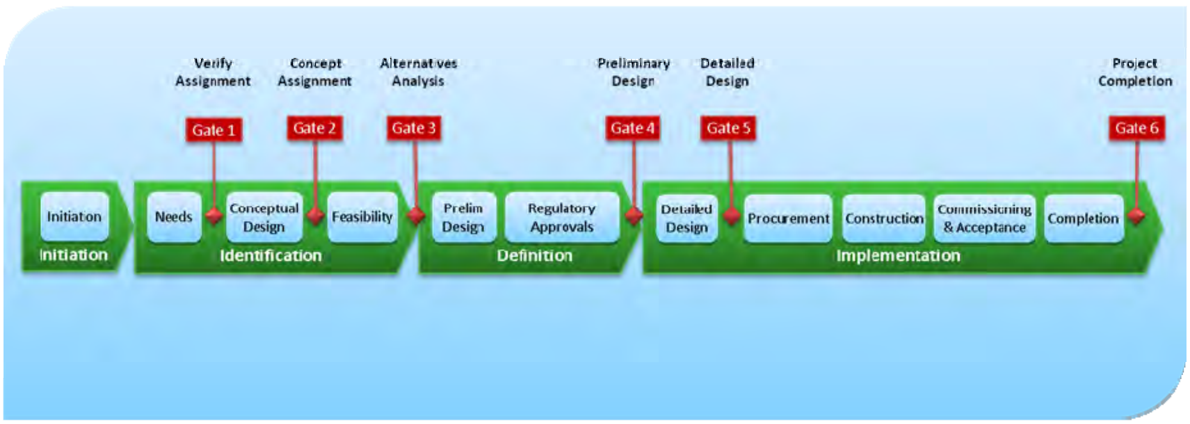
C

Project Lifecycle and Project Cost Estimating

BC Hydro Standard Project Lifecycle

A standard Project Life Cycle is an essential component of good project management practice. BC Hydro's Project Lifecycle is provided as Figure C-1.

Figure C-1 Project Lifecycle Diagram



The Project Life Cycle is composed of phases and stages within those phases. Each phase results in the development of key deliverables that are subject to checking and independent review, functional endorsement and financial due diligence before they receive approval to proceed.

For each of the Project Life Cycle phases, the project initiator and project manager present the recommendations of the key deliverables to a gateway committee for approval to proceed. The gate committee is composed of members of the EARG senior management team. Once the gate committee approves proceeding with the next phase of the project, the recommendation and results of the financial due diligence are presented to Chris O'Riley, the project sponsor, for approval. If the project sponsor does not have the necessary level of delegated financial authority, the decision proceeds to the level required to make the business decision, which for funding requests greater than $20 million, is the BC Hydro Board of Directors.

Initiation Phase

When BC Hydro's EARG generation operations group identifies a problem or opportunity, it is entered into BC Hydro's asset management process. If the project is not included in BC Hydro's current Capital Plan it is reviewed by management prior to formal assignment to the EARG generation project delivery group. If the project is included in the capital plan, the EARG generation project delivery group assigns a qualified project manager to the project. The Initiation phase ends when the EARG finance group approves initial funding for the Identification phase to initiate planning and a project manager to plan and deliver the project has been assigned.

Identification Phase

During the course of the Identification phase conceptual designs are prepared to identify solutions to address the problem or opportunity. Subsequently, feasibility studies are carried out and a preliminary business case is prepared. The Identification phase ends with the selection of a preferred alternative to address the problem or opportunity. At the end of the Identification phase, the gate committee decides whether to fund the Definition phase of the project.

Definition Phase

During the course of Definition phase, field and other studies (preliminary design) are completed to comply with any regulatory obligations, and to finalize the business case. In addition, applicable regulatory authorizations[1] are sought and the project plans and business case are revised to incorporate any conditions imposed by regulatory agencies. The Definition phase ends when the gate committee decides whether to proceed to implement the project.

[1] May include: Water Act, *Canadian Environmental Assessment Act* and BC *Environmental Assessment Act* and the *Utilities Commission Ac*t.

Implementation Phase

During the course of the Implementation phase, detailed design occurs; equipment is procured[2]; the work is manufactured, supplied, installed and constructed; and the testing and commissioning is completed. At this stage, the assets for the project are transferred from the custody of the project team to the staff in the EARG generation operations group that will operate and maintain the asset. The project is complete when the project initiator accepts the project results by signing the project completion report.

Throughout the Project Life Cycle, project monthly reports are issued and reviewed by senior management, and issues are escalated as required to move forward.

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2 Where appropriate, senior management may approve the tendering of equipment in advance of regulatory approvals to reduce project risk. In such cases the contracts awarded will be subject to regulatory approval and contain termination provisions that limit financial exposure.

BC Hydro Project Cost Estimating Practices

BC Hydro's estimating practice for projects expected to cost over $6 million is to establish a range of possible costs based on a probability analysis to determine contingency[1] allowances, and to include specific possible adverse developments outside BC Hydro's control, and potential but uncertain scope expansions. The probability analysis is carried out by breaking the project cost[2] into distinct cost elements, which are internally similar but statistically independent. For each cost element, BC Hydro makes an estimate of the range of possible cost outcomes from low to high, as well as a single best estimate, with the intention that there is only a five per cent probability that the actual outcome will lie outside the low - high range. This range is intended to cover the common reasons for estimate differences, including:

- Difference in site conditions
- Design refinements as engineering continues
- Labour productivity not as assumed
- Quantity variations
- Changes in cost or extra costs

The estimate of the appropriate cost range is determined by experience, professional judgement, or common industry practice, after review of the project Risk Register and discussion with key members of the project team about potential risks and uncertainties in the project. These range estimates are used to create a statistical model of the total project cost; the output of the statistical model is a probability density function indicating the probability of a particular aggregate cost outcome - of particular interest are the P50 and

---

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

P90 values; the cost estimates at which there is a 50 per cent probability that the actual outcome will be less than the estimate, and at which there is a 90 per cent probability that the actual outcome will be less than the estimate. These values are then "loaded" by including them in a monthly cash-flow schedule over the project life. The cash flow schedule allows calculation of IDC to reflect the carrying cost of an asset that has not gone into service, Inflation and Escalation to reflect the nominal dollars to be expended, and an overhead charge to reflect the burden of administrative and financial functions that do not make a direct contribution to the project.

The Loaded P50 value is the Expected Cost of the project, representing BC Hydro's estimate of the likely project cost: by definition there is an equal chance that the actual outcome will be above this value or below this value. The P90 value is a reasonable upper estimate of the cost of the project, except it does not include possible costs outside the control of BC Hydro, including:

- Material changes in exchange rates or general inflation and escalation rates
- Changes in project scope or operating requirements
- Accidents with material cost or schedule implications for the project
- Abnormal weather
- Changes in governmental policy, environmental standards or regulated working conditions

BC Hydro estimates the likelihood of such events and the possible cost impact (on a Loaded basis), and the project initiator and project sponsor jointly determine whether they wish to reflect such costs in the project's Authorized Cost by including them in a Management Reserve. The decision as to what should be included in a Management Reserve is based on professional judgement and experience and will reflect the likelihood and materiality of these

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[2] This analysis includes directs costs and BC Hydro costs, such as Engineering and Project Management, but excludes loadings for overhead or IDC. The range estimates are in constant dollars, which are then increased to reflect anticipated escalation in construction costs.

uncontrollable risks. The project's Authorized Cost is the P90 estimate together with the Management Reserve established by the project initiator and project sponsor.

All projects requiring approval of the BC Hydro Board of Directors (BoD), such as this Project, include a Project Reserve for the Implementation phase. Authority to approve the use of this Project Reserve is delegated to the Chief Executive Officer, unless otherwise determined by the BoD. Any cost overruns that are forecast to exceed the Authorized Cost amount require BoD approval. The project manager is delegated the authority to spend the Expected Cost amount on the project.

Gordon M. Shrum Units 1 to 5 Turbine Replacement Project

Appendix

D

GMS G3 Runner Failure – Technical Analysis and Recommendations Report

GM SHRUM GENERATING STATION
G3 RUNNER FAILURE

TECHNICAL ANALYSIS
AND RECOMMENDATIONS

Prepared for: **EARG Generation Engineering**

BChydro

ENGINEERING

Report No. E653
September 2008

GM SHRUM GENERATING STATION

G3 RUNNER FAILURE

TECHNICAL ANALYSIS AND RECOMMENDATIONS

BC hydro

ENGINEERING

Report No. E653
September 2008
WPR-2633

GM SHRUM GENERATING STATION

G3 RUNNER FAILURE

TECHNICAL ANALYSIS AND RECOMMENDATIONS

PROFESSIONAL
PROVINCE OF
R. F. FINNEGAN
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29/09/08

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ENGINEERING

Report No. E653
September 2008
WPR-2633

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GM SHRUM GENERATING STATION
G3 RUNNER FAILURE

TECHNICAL ANALYSIS AND RECOMMENDATIONS

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DISCLAIMER

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EXECUTIVE SUMMARY

This report analyses the runner failure that occurred on March 02, 2008, in Unit 3 at GMS Generating Station. It examines the possible causes and sequences of the failure, and makes recommendations on how to prevent a similar event from occurring on the other Mitsubishi turbines at GMS.

At 05:28:30, the operator at GMS initiated an emergency shut-down of Unit 3 because of loss of control the unit's power output. An inspection of the turbine revealed significant damage to the wicket gates, runner blades, and bearings.

In addition to inspecting the damaged components extensively, BC Hydro Engineering studied the turbine's historical performance and previous failures, in an effort to determine the probable cause of the failure. Four scenarios were considered:

1. A foreign object entered the turbine by way of the penstock, and caused damage to the wicket gates and runner blades, precipitating the other damage.
2. The new stator, installed in 2007, caused abnormal stresses on the turbine, resulting in failure of the turbine runner, with other damage caused by rapid break-up of the runner.
3. The runner blades failed as a result of metal fatigue, with broken parts of the runner causing damage to the wicket gates and other components.
4. The failure of the shear pin on one of the wicket gates initiated breaking of the shear pins on three adjacent wicket gates, resulting in abnormal water pressure in the turbine distributor and abnormal stresses on the runner. Rapid break-up of the runner caused damage to the wicket gates and other components.

Careful analysis of all available information leads to the conclusion that the failure was caused by the multiple shear pin failure outlined in scenario 4.

This report makes both short-term and long-term recommendations to help prevent a recurrence of this type of failure in the five Mitsubishi turbines at GMS, as well as within

the rest of the BC Hydro turbine fleet. Short term recommendations to prevent a reoccurrence of a similar failure on the GMS 1-5 turbines include:

1. Implement shear pin detection monitoring. The monitoring should be capable of detecting individual shear pin failures.
2. Upgrade the vibration monitoring system on each Unit
3. Immediately shut down the Units when one or more shear pins is broken.
4. Ensure that each shear pin is replaced every two years with a new shear pin.
5. Consider reducing the maximum inspection interval for the turbines from twelve months to six months to ensure that runner cracking can be caught early and continue to be managed.
6. Study the effect of the start/stop and synchronous condense cycles on the runners and other turbine components.
7. Evaluate methods for changing the natural frequencies of the runners to eliminate the coincidence of forcing frequencies and runner natural frequencies. Methods to be considered include adding stiffeners between blades and implementing major modifications to the runner blades. For each proposed method, a complete technical and economic analysis will be required.

Long term recommendations for the GMS 1-5 turbines include:

1. Change the wicket gate linkage design so that the shear pin functions solely as a shear pin.
2. Implement friction-devices on the wicket gate operating mechanism to minimise the likelihood of cascade closure of de-synchronized wicket gates.
3. Consider implementing “automatic wicket gate re-synchronization” in the unit control scheme to re-synchronize the wicket gates and maintain safe unit operation in the period between shear pin failure and replacement.
4. Replace the runners with a modern design.
5. Consider implementing vibration monitoring at the runner band.

Recommendations for preventing a reoccurrence of a similar failure within the BC Hydro turbine fleet include:

1. Initiate a review of the BC Hydro turbine fleet protection, monitoring and shut down schemes. As part of this review, look at:
   a. Technical risks of operating the turbines with desynchronized wicket gates
   b. Opportunities to add instrumentation so that long-term trending of the turbine health can be monitored in OI and Smart Signal. Some examples of monitoring points include servomotor differential pressure, head cover pressure and draft tube pressure
2. Consider Operational Information (OI) training for BC Hydro plant operators so that unusual operational trends can be recognized.

In addition, the following studies and measurements should be considered to gain more insight into the runner failure mode:

1. On-site measurement of the dynamic torque in the main shaft to determine the forces transmitted from the new stator to the runner. Measurements should be performed on two of Units 1 to 5 (one Unit with the new Alstom stator; one Unit with the original General Electric stator).
2. Wicket gate differential pressure tests to characterise the hydraulic tendency of the wicket gates and to quantify the friction forces in the operating mechanism.

1.0 INTRODUCTION

On March 02, 2008, Unit 3 at GMS Generating Station suffered a major runner failure, with significant damage to the wicket gates, runner blades, and bearings. This report analyses the event and the damage to the turbine, examines the possible causes and sequences of the failure, and makes recommendations on how to prevent a similar event from occurring on the other Mitsubishi turbines at GMS.

Note: For an overview of the components and operations of a turbine and generator, refer to Appendix A, The Anatomy of a Turbine.

BC Hydro Engineering considered the following possible contributors to the runner failure: shear pin failure; runner blade failure; ingestion of a foreign object; effects of a newly installed stator; recent changes in operation (synchronous condense and start-stop cycles); instrumentation issues; and turbine design deficiencies (structural dynamics and mechanical design).

BC Hydro Engineering concluded that the most likely failure mode was a cascade closure of four adjacent wicket gates due to shear pin failure, resulting in disruption of the hydraulic flow and forced contact of the runner against the lower seal ring. The resulting complex alternating stresses in the blades and possible excitation of structural natural frequencies led to the blade failures and significant secondary damage.

The repair of this unit will take approximately 13 months.

1.1 BACKGROUND

Generating Units 1 to 5 at GMS were installed in 1968/69, with Mitsubishi turbines and Canadian General Electric generators. The other five units at GMS were installed over the next decade, with turbines and generators from Toshiba and Fuji.

In 1972, four years after initial operation, cracks were found in many of the blades on the Mitsubishi turbines of Units 1 to 5. This problem has recurred regularly over the intervening decades and has been resolved by welding repairs. Because of the efficiency of the turbines, the problem has been considered manageable until replacements could be justified financially.

In 2005, Unit 3 was upgraded to enable it to operate in synchronous condense mode. In this form of operation, the unit functions as an electric motor, absorbing energy from the grid instead of generating energy, as a means of stabilizing the power system. In 2007, the stator on Unit 3 was replaced with an Alstom component as part of a modernization and upgrade process.

1.2 OVERVIEW OF THE UNIT 3 RUNNER FAILURE

On March 02, 2008 at 05:28:30, the operator at GMS Generating Station initiated an emergency shut-down of Unit 3 because of an inability to control the unit's power output. By 05:39:20 the unit had come to a full stop.

Upon visual inspection of the unit, it was discovered that all 24 shear pins on the wicket gates were broken, and the keeper plates on the wicket gate intermediate stem seals had failed. A review of the stored operating data indicated that, from approximately 05:05:00, equipment performance was far from normal. The unit was opened up for inspection, disclosing significant damage to the turbine's runner blades, wicket gates, bearings, seals, and bushings.

2.0 SIGNIFICANT FINDINGS OF THE INVESTIGATION

This section of the report provides an overview of the significant findings of BC Hydro Engineering's investigation into the probable causes of the GMS Unit 3 runner failure.

2.1 STUDY OF OPERATIONAL DATA

Every 6 seconds, sensors within the turbine and generator collect a wide variety of data, which is stored for real-time display and later analysis. The stored data retrieved from Unit 3 indicated that, between 05:05 and 05:28 AM, Unit 3 was behaving very erratically:

- At 05:05, power output suddenly dropped from 254 to 237 MW.
- To correct the power output, the governor began opening the wicket gates, with power rising to 262 MW at 05:10.
- At approximately 05:14, power dropped again to 247 MW, then rose to 252 MW.
- Over the next 10 minutes, output continued to change, dropping as low as 13 MW at 05:22, then rising to 55 MW.

The governor responded to these changes as expected, by opening and closing the wicket gates in an attempt to achieve stable output. Accompanying the erratic power output, were irregular changes in turbine water pressure, turbine vibration frequencies, and bearing temperature.

At 05:28:30, the operator initiated an emergency shutdown, which immediately disconnects the generator from the power grid and closes the intake gate. A maximum speed of 133% is reached as the penstock drains. The unit came to a stop at 05:39:18.

Subsequent analysis of the Operational Information (OI) and Sequence of Events Recorder (SER) data collected during the failure event indicate that the operator responded appropriately to the situation.

Note: For a detailed analysis of the Operational Information data collected during the failure event, refer to Appendix B. For details of the Sequence of Event Recorder Data collected during the failure event, refer to Appendix J.

2.2 INSPECTION OF COMPONENTS

An extensive inspection of the failed turbine's components discovered the following:

- The intake trash rack, the scroll case, the stay vanes, and the scroll case side of all wicket gates showed no signs of damage, and there was no sign of debris in the scroll case.
- The runner side of all wicket gates showed extensive gouging, up to 30mm deep, indicating metal caught in the wicket gate/runner cascade (the space between the wicket gates and runner). The trailing edges of 20 of the 24 wicket gates were bent.
- Three of the runner blades were missing large pieces (about 1.8 m x 1.8m) from their outlet edges, while all blades showed signs of impact and abrasion damage on their inlet edges.
- One of the large blade pieces was found almost intact in the draft tube, along with other metal debris. Smaller pieces of blades were found in the wicket gate/runner cascade and in the draft tube.
- Wicket gate bushings showed significant wear on the inward side of the inner diameter, as well as being out of round. Three wicket gates that were measured in detail proved to be bent.
- All 24 shear pins were broken. One of the shear pins (wicket gate 11) showed clear signs of fatigue cracks, one was inconclusive, and all others were shown to have failed from mechanical (shear) overload alone.
- The shear pin found in wicket gate 11, was stamped with the date January 06 2002. This is the same date stamped on several shear pins found in GMS stores tagged "Do Not Use - Emergency Only".

Note: For a detailed description of the damages discovered during inspections, refer to Appendix C.

2.3 HISTORICAL INVESTIGATION

This section summarizes investigations into the past performance of the Mitsubishi turbines at GMS. For a more detailed discussion and analysis, see Appendix D.

2.3.1 Runner Cracking

As mentioned earlier, the runner blades on the Mitsubishi turbine have been prone to cracking since their installation. Historical studies have indicated that this cracking is due to high dynamic stresses, low fatigue strength, defects in original manufacturing, and defects and stresses introduced by multiple weld-repairs. The units are typically inspected annually for cracks and repaired by welding.

Unit 3 was inspected for runner blade cracking in May 2007. At that time, five blades were found to have cracks, which were not considered at all unusual, and all were repaired in the usual manner. Two blades that had shown significant damage and were repaired in 2006 had no cracks in 2007 and remained intact through the 2008 failure. This indicates that the repair method seems to be satisfactory.

Several past studies by BC Hydro and GE Hydro have shown that there are natural vibration frequencies in the turbine that may contribute to this cracking. In addition, it was found that the metal used to construct the runner is significantly less strong and tough than more modern materials.

2.3.2 Wicket Gate Operating Mechanism

When a wicket gate shear pin is broken, it appears that the wicket gate settles into an almost-closed position. Although this has not been measured directly, analysis of data captured in such events seems to support this conclusion.

When a shear pin breaks and the wicket gate moves to a closed position, that gate's operating lever may come into contact with the lever of the adjacent gate if the adjacent gate is at an angle greater than 20.5°. If the impact is great enough, the force could cause the adjacent shear pin to break.

2.3.3 Shear Pin Failure Analysis

A historical analysis of shear pin failures on Unit 3 shows that by far the majority of failures occur during dynamic events (start-up, shut-down, or transitions between synchronous condense and generating operations). This is consistent with the higher stresses on the wicket gates and operating mechanism components during these operations.

Following the addition of synchronous condense functionality in 2005, Unit 3 has seen a significant increase in the frequency of broken shear pins. However, this analysis also shows that the turbine is able to function with a single broken shear pin for a significant length of time-up to 52 hours in one case. The governor needs to make only a minor adjustment to maintain power output.

In the two cases in which a shear pin broke at high-power output, the wicket gate lever angles were 19.75° and 18.50° -less than the 20.50° at which the levers would make contact. Unit 1, on the other hand, has had three instances in which two adjacent shear pins failed at high-power output. In all three cases, the wicket gate opening angle was greater than 20.50° and there was a significant loss of output power.

2.3.4 Operational Changes

While synchronous condense functionality was added to Unit 3 in 2005, units 1 and 2 have operated as synchronous condensers since commissioning in 1968. Unit 3 operated in synchronous condense mode most recently on March 01, 2008, with no unusual conditions observed.

The only known impact of synchronous condense operations is the greater incidence of broken shear pins, due to the additional stresses of transitioning between power output and synchronous condense modes, as noted earlier.

2.3.5 Effects of the New Stator

In 2007, the General Electric stator on Unit 3 was replaced with an Alstom stator. The new stator has a higher output rating, but this additional capacity has not been used because of limitations in the turbine and other components. Since commissioning in November 2007, there have been no performance or operational issues that can be attributed to the new stator.

3.0 DISCUSSION

BC Hydro Engineering considered a number of hypotheses, in light of the findings, to account for the Unit 3 runner failure. For a detailed discussion, refer to Appendix E.

3.1 INGESTION OF A FOREIGN OBJECT

The lack of damage to the intake trash racks, the scroll case, the stay vanes, or the scroll case side of the wicket gates and the absence of any foreign debris in the turbine make it highly unlikely that an object of sufficient size could have caused the damage.

3.2 EFFECTS OF THE NEW STATOR

No unusual conditions were detected during the four months of new stator operation that would indicate any relationship between the new stator and the runner failure. Additionally, no evidence was found during the onsite investigation linking the new stator with the failed turbine.

3.3 RUNNER BLADE FAILURE DUE TO FATIGUE

In this scenario, one or more blades failed due to fatigue from start/stop operations, with pieces of the blades ejected into the wicket gate/runner cascade, resulting in rapid wicket gate closure and causing the damage observed on the wicket gate skin plates and runner blade inlets. This scenario is considered unlikely because:

- The runner has experienced significantly fewer start/stop operations and operating hours since the most recent overhaul, than is usual between repairs.
- Fracture surfaces on the runner blades are more consistent with brittle fracture (outlet sections from blades 4, 11, 14) and impact (inlet section from blade 3) than with fatigue.

- Shear pin 11 showed clear evidence of fatigue, not shear overload, indicating that it is more likely to have been the initial source of failure.
- The vibration, power output, and servomotor opening data collected early in the failure event is consistent not with a rapid closing of the wicket gates, but with two broken shear pins.

3.4 CASCADING WICKET GATE CLOSURE

In this scenario, the shear pin on wicket gate 11 fails due to fatigue, resulting in the rapid closing of the wicket gate. The lever on wicket gate 11 contacts that of wicket gate 12 with sufficient force to break its shear pin. Both wicket gates 11 and 12 assume an almost closed position. The governor instructs the servomotor to increase wicket gate opening to maintain power output and to respond to an increased demand for power. When it reaches maximum opening, the shear pin on wicket gate 13 fails. Wicket gate 13 closes and its lever contacts that of gate 14, causing its shear pin to break.

With four wicket gates closed, the water flow in the scroll case is unbalanced, and a low pressure zone is created behind those wicket gates. The runner is forced toward the low pressure until contact occurs between the runner band and the lower seal ring. The stresses on the runner caused new cracks and accelerated existing cracks, resulting in blade failure.

As the blades broke apart, one piece was discharged into the draft tube and two were ejected into the wicket gate/runner cascade, slamming the remaining wicket gates closed, breaking the remaining shear pins, and causing further damage to the runner blades and the wicket gates.

This scenario is considered most likely for the following reasons:

- The shear pin on wicket gate 11 showed evidence of torsional fatigue, rather than shear overload. The position of the wicket gates at the time of failure (21.5°) and the closing tendency of wicket gates suggest that following the failure of shear pin 11, wicket gate lever 11 would have contacted gate lever 12.

- The sudden decrease in synchronous vibration at 05:05 is consistent with one or more broken shear pins. The sudden decrease in power is consistent with two adjacent, broken shear pins. The 10% increase in servomotor stroke to maintain power is consistent with two adjacent, broken shear pins.
- The significant increase in turbine synchronous vibration at 05:14 suggests contact between the runner and a stationary component. Carbon steel deposits on the stainless steel lower seal ring, in between wicket gates 11, 12, 13 and 14, indicate contact at this location, suggesting that at this time all four of these gates were closed and that the resulting abnormal large stationary radial load forced the runner band to rub on the lower seal ring. The absence of impact damage on the trailing edge of wicket gates 11 to 14 is consistent with these gates being closed when the two outlet pieces of blade are ejected into the wicket gate/runner cascade.
- The sudden drop in power at 05:22 from 259 to 13 MW (prior to settling at 55MW) and the rise in turbine inlet pressure indicate rapid closure of the wicket gates because of the remaining shear pins breaking. The pattern of impact damage on the trailing edge of wicket gates 1 to 10 and 15 to 24 is consistent with large pieces of metal becoming caught in the wicket gate/runner cascade.
- The serious damage observed on the runner-blade inlets, the wicket gate skin plates and the bottom ring facing plate is consistent with broken runner blade pieces caught in the wicket gate/runner cascade as the unit rotated for 17 minutes until stopping at 05:39.

4.0 CONCLUSION

The most likely cause of the March 02, 2008 runner failure was extended turbine operation with four adjacent wicket gates effectively closed and the runner band in contact with the lower seal ring. Operation in this condition overstressed the runner blades and may have excited one or more natural vibration frequencies in the runner, resulting in rapid failure.

Factors that significantly contributed to the failure include:

- The design of the runner
- The design of the wicket gate operating mechanism
- The absence of protective devices to detect shear pin failure

5.0 RECOMMENDATIONS

Short term recommendations to prevent a reoccurrence of a similar failure on the GMS 1-5 turbines include:

1. Implement shear pin detection monitoring. The monitoring should be capable of detecting individual shear pin failures.
2. Upgrade the vibration monitoring system on each Unit
3. Immediately shut down the Units when one or more shear pins is broken.
4. Ensure that each shear pin is replaced every two years with a new shear pin.
5. Consider reducing the maximum inspection interval for the turbines from twelve months to six months to ensure that runner cracking can be caught early and continue to be managed.
6. Study the effect of the start/stop and synchronous condense cycles on the runners and other turbine components.
7. Evaluate methods for changing the natural frequencies of the runners to eliminate the coincidence of forcing frequencies and runner natural frequencies. Methods to be considered include adding stiffeners between blades and implementing major modifications to the runner blades. For each proposed method, a complete technical and economic analysis will be required.

Long term recommendations for the GMS 1-5 turbines include:

1. Change the wicket gate linkage design so that the shear pin functions solely as a shear pin.
2. Implement friction-devices on the wicket gate operating mechanism to minimise the likelihood of cascade closure of de-synchronized wicket gates.
3. Consider implementing “automatic wicket gate re-synchronization” in the unit control scheme to re-synchronize the wicket gates and maintain safe unit operation in the period between shear pin failure and replacement.
4. Replace the runners with a modern design.
5. Consider implementing vibration monitoring at the runner band.

Recommendations for preventing a reoccurrence of a similar failure within the BC Hydro turbine fleet include:

1. Initiate a review of the BC Hydro turbine fleet protection, monitoring and shut down schemes. As part of this review, look at:
    1. Technical risks of operating the turbines with desynchronized wicket gates
    2. Opportunities to add instrumentation so that long-term trending of the turbine health can be monitored in OI and Smart Signal. Some examples of monitoring points include servomotor differential pressure, head cover pressure and draft tube pressure
2. Consider Operational Information (OI) training for BC Hydro plant operators so that unusual operational trends can be recognized.

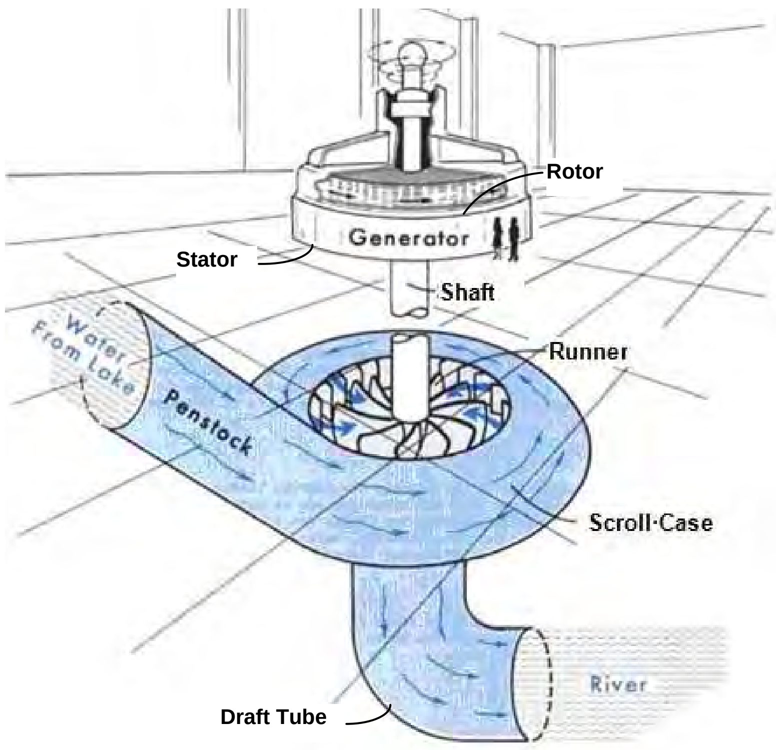
In addition, the following studies and measurements should be considered to gain more insight into the runner failure mode:

1. On-site measurement of the dynamic torque in the main shaft to determine the forces transmitted from the new stator to the runner. Measurements should be performed on two of Units 1 to 5 (one Unit with the new Alstom stator; one Unit with the original General Electric stator).
2. Wicket gate differential pressure tests to characterise the hydraulic tendency of the wicket gates and to quantify the friction forces in the operating mechanism.

APPENDIX A: ANATOMY OF A TURBINE

APPENDIX A: ANATOMY OF A TURBINE

In order to fully comprehend this report, it is necessary to have a basic understanding of the operation and components of the generating unit turbine installed at GMS. Water is conducted from the reservoir through a tube (called the **penstock**) to the turbine, where the water pressure turns a waterwheel (called the **runner**), as shown in the following diagram. The water discharges from the turbine through the **draft tube**.

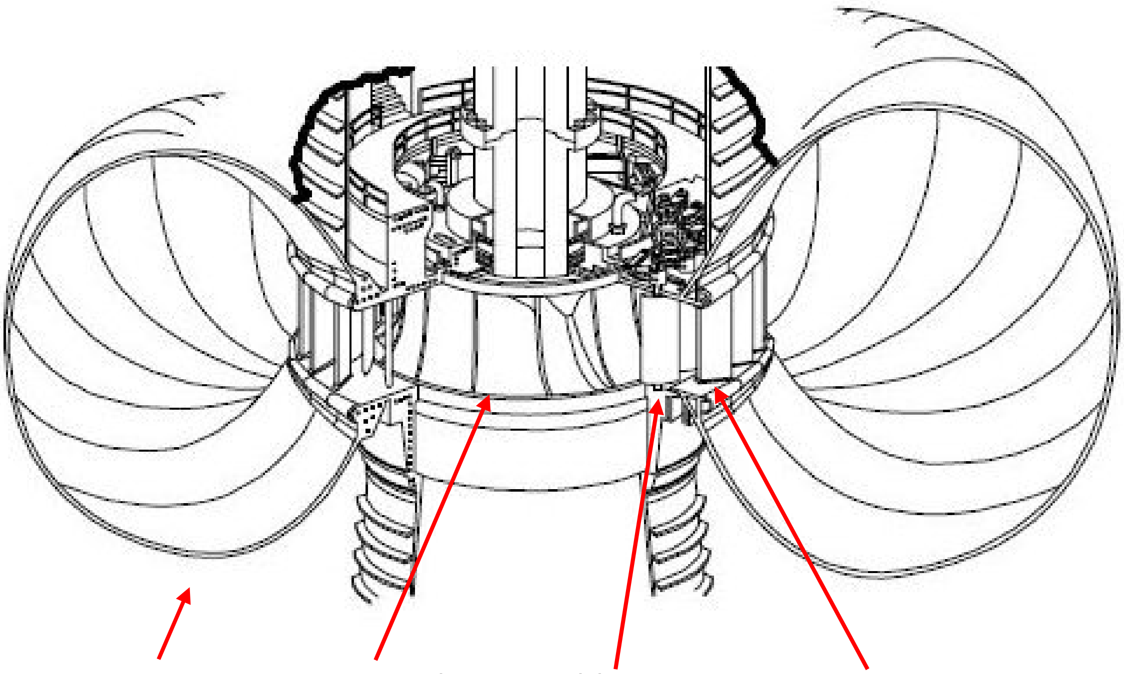


The rotating runner is connected by a **shaft** to the generator, which consists of two major components:

- The **rotor**, a large circular electromagnet connected to the turbine shaft.
- The **stator**, a static coil consisting of electrical conductors tightly wound around a metal core, which encircles the rotor.

When the rotor rotates, driven by the runner in the turbine, electrical energy is induced in the stator windings.

A reaction turbine, such as those at GMS, is a complex mechanism, as shown in the following diagram and discussion:



Water from the penstock enters the **scroll case**, a circular, shell-like tube that wraps around the runner. The inner wall of the scroll case is open to the runner, with a set of stationary **stay vanes** directing the water into and through the runner.

Between the stay vanes and the runner are a set of pivoting **wicket gates**, which are opened and closed hydraulically by the unit's governor to increase or decrease the amount of water admitted to the runner, and thus increase or decrease the amount of power generated by the unit. The **governor** is an electro-hydraulic system that constantly monitors the unit's actual power output, compares it to a power setting, and opens or closes the wicket gates accordingly.

The governor controls a hydraulic servomotor that moves a large ring, which is connected to each wicket gate by a lever. Thus, the wicket gates are normally operated in unison to create an even flow around the circumference of the runner. However, each wicket gate mechanism has a **shear pin**, which is designed to break in the event of a mechanical overload, such as a foreign object blocking the wicket gate's movement. This prevents other parts of the governor/wicket gate system from being damaged.

The runner itself consists of a set of **runner blades** designed to convert the kinetic energy of the moving water into mechanical energy—that is, rotating the shaft—most efficiently.

Every 6 seconds, sensors throughout the turbine and generator collect a wide variety of data, which can be displayed in real time or retrieved later for analysis.

APPENDIX B: DETAILED ANALYSIS OF OPERATIONAL INFORMATION DATA

APPENDIX B: DETAILED ANALYSIS OF OPERATIONAL INFORMATION DATA

Figure 1 shows pertinent data from the failure event of GMS Unit 3 starting at 04:54:37 AM, March 02, 2008 through to 05:39:37 AM, March 02, 2008. The following chronology interprets the data plotted in Figure 1.

Note that the value of turbine synchronous vibration recorded in OI is very low for this class of Unit. Evaluation of the accuracy is beyond the scope of this report, however, the general vibration trend is assumed to be valid.

(1) 05:05:00

- The Unit is in SReg (System Regulate) control mode.
- There is a sudden drop of power output from 254 to 237 MW
- The turbine pressure becomes more erratic
- The turbine synchronous vibration starts reducing from 1.5 mils eventually to 0.24 mils pk-pk
- The turbine bearing temperature starts reducing from 31.8 to 26.3 degrees C
- The servo motors start moving open from 71.3% to 84.3% until the power output reaches 254 MW (05:06:27)
- The Unit control mode is changed from SReg to Jog (05:06:27)
- The servo motors move open from 84.3% to 97.2%

(2) 05:10:54 (approximate)

- The servo motors reach a final opening of 97.2%
- Power output reaches 262 MW
- The Unit control mode is changed from Jog to SReg (05:11:25)
- Turbine bearing temperature starts to increase
- Turbine synchronous vibration starts to increase

(3) 05:14:12 (approximate)

- There is another sudden drop of power from 262 to 247 MW
- Turbine synchronous vibration goes from 0.4 to 2.2 mils pk-pk
- The power settles at 252 MW

(4) 05:19:30

- There is an increase in MW from 252 to 258 MW
- The synchronous vibration goes from 2 to 2.8 mils pk-pk
- The servo motors move closed from 97.2% to 93.0% (05:20:55 to 05:22:12) with no change in Unit power output
- The Unit control mode is changed from SReg to Jog (05:21:22)

(5) 05:22:12 (approximate)

- There is another sudden drop of power from 259 to 13 MW without movement of the servo motors (servo motors remain at 93% open)
- The power settles at 55 MW
- There is a rise in the turbine inlet pressure
- Turbine synchronous vibration goes from 2.2 to 3.5 mils pk-pk
- Turbine bearing temperature starts climbing fast
- The turbine inlet pressure stabilises at a value 3.7% higher than prior to 05:05:00
- The Unit control mode is changed from Jog to SReg (05:24:26), SReg to Base (05:24:58), Base to Local (05:26:14)

(6) 05:27:12

- Servo motor position moves to 45% then back to 97.3%

(7) 05:28:30

- Power goes to 0 MW (unit tripped by GMS operator)
- The Unit control mode is changed from Local to Avail (Available)

(8) 05:29:30

- Unit hits 133.9% speed

(9) 05:31:42

- Turbine bearing temperature hits 129.4 Degrees C

(10) 05:39:18

- Shaft has stopped (0% speed)

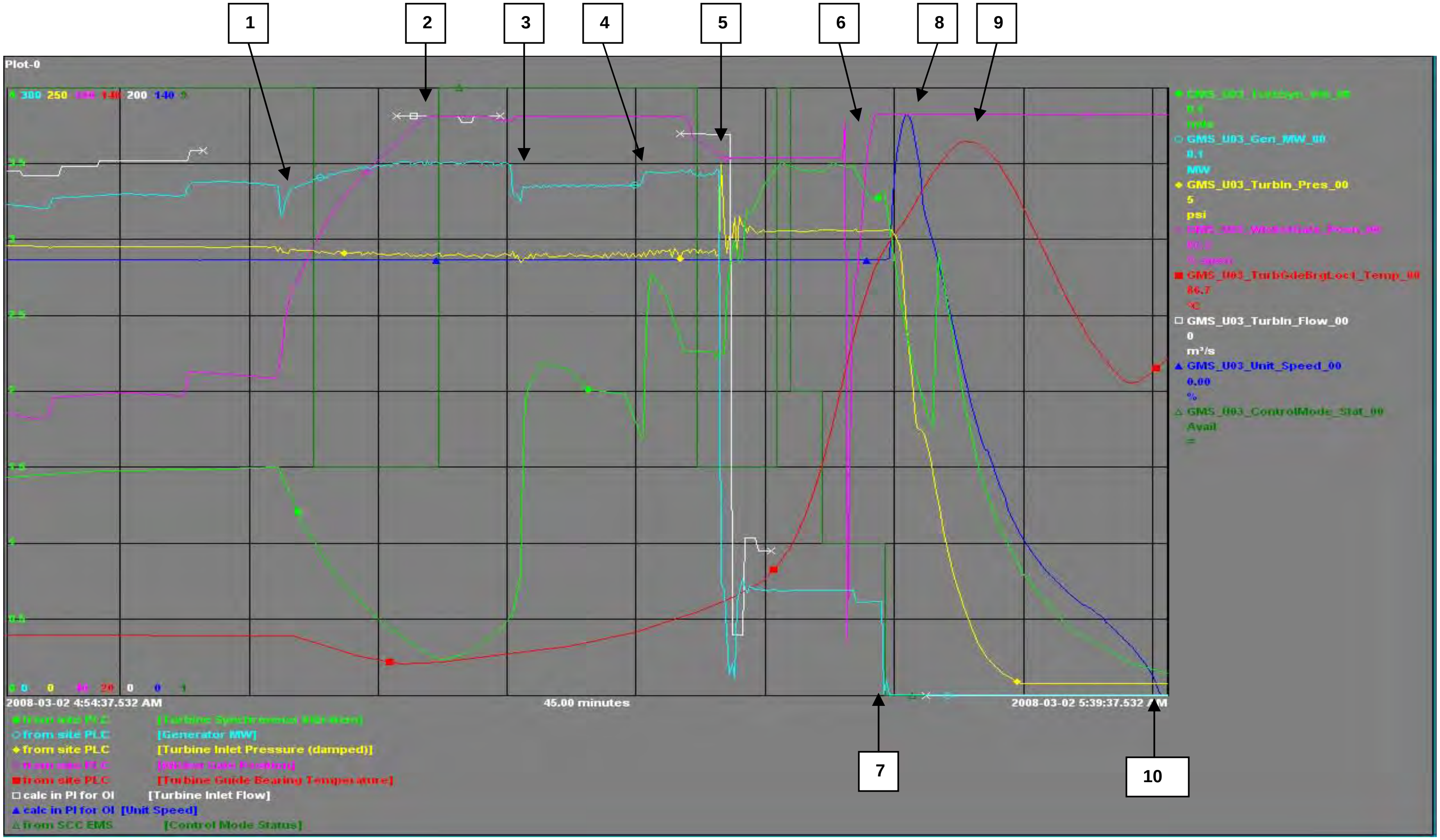


Figure 1: OI Trend during the 03/02/08 U3 Runner Failure

APPENDIX C: SIGNIFICANT FINDINGS FROM SITE INSPECTIONS

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C.1 Initial Inspection (March 07, 2008)

1. The scroll case and stay vanes were in very good condition. There was no indication of material or debris having travelled down the scroll case or passing through the stay vanes. There was no residual debris found in the scroll case.

2. The skin plate on the scroll-case side of all 24 wicket gates was in very good condition.

3. On all 24 wicket gates, the skin plate on the runner-side, downstream of the seal contact line, was in very poor condition. Gouges up to 30mm deep were observed on up to 75% of the metal surface of the damaged skin plates. The shape and pattern of the damages were indicative of pieces of metal becoming caught in the wicket gate/runner cascade while the turbine was still rotating.

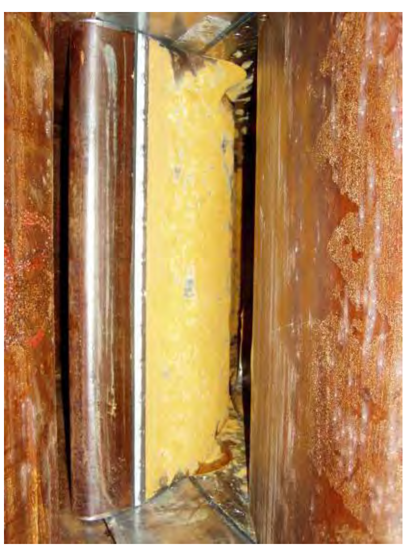


Figure 2: Wicket Gate Skin Plate Damage

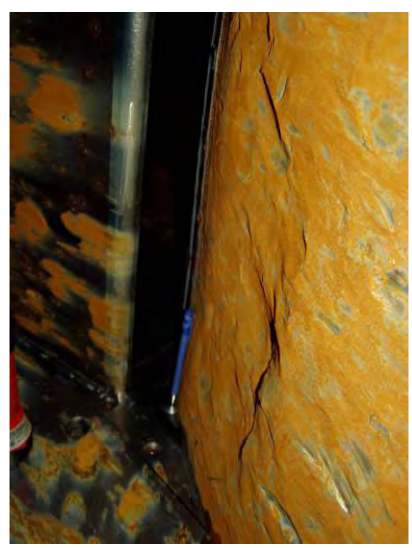


Figure 3: Wicket Gate Skin Plate Damage

4. The trailing edges of wicket gates 1 to 10 and 15 to 24 had been bent due to impact. On all twenty gates, the impact pattern and the location of the damage were the same (~0.30 m above the bottom facing plate).

Figure 4: Wicket Gate Trailing Edge Damage

Figure 5: Wicket Gate Trailing Edge Damage

5. The trailing edges of wicket gates 11 to 14 were in good condition, with none of the localised impact damage on the trailing edge observed on the other gates.

6. Runner blades 4, 11, and 14 were missing significant pieces from the outlet (each approximately 1.8m x 1.8 m). The shapes of these missing pieces were almost identical, and one of the pieces was found fully intact in the draft tube.

Figure 6: Missing Blade Piece

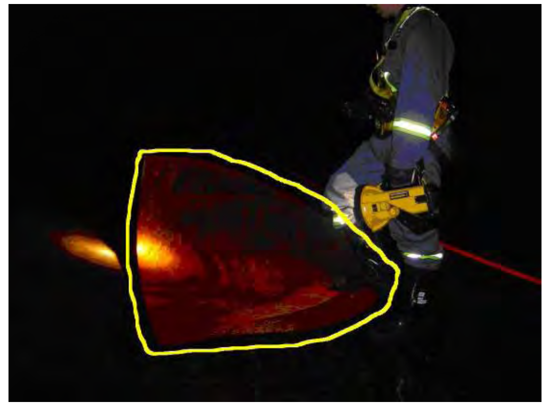


Figure 7: Missing Blade Piece Found in Draft Tube

7. Many smaller runner blade pieces (0.20 m x 0.20 m) were found in the runner/wicket gate cascade, stuck in between adjacent blades, and in the draft tube.

8. Impact and heavy abrasion damage was observed on the inlet-edge of all runner blades (see Figures 8 and 9). On “moderately” damaged inlet-edges, the damage was localised at 0.30 m above the bottom facing plate (the same elevation as the trailing edge damage observed on wicket gates 1-10 and 15-24).

9. Other significant observations from examination of each runner blade are summarised below. Note that the blades are numbered 1 to 17 in the clockwise direction (when viewed from above):

   a. Blade 1 – 1.2 m crack, trailing edge to leading edge (t.e. to l.e.), 8 cm below crown
   b. Blade 2 - 1.5 m crack, t.e. to l.e., 8cm below crown
   c. Blade 3 - through crack from t.e. to l.e.; 0.8 m^2 missing blade piece from the inlet
   d. Blade 4 – 3.0 m^2 missing blade piece from the outlet
   e. Blade 5 – No visible cracks
   f. Blade 6 – No visible cracks

g. Blade 7 - 1.2 m crack, t.e. to l.e., 8cm below crown; 20 cm crack at leading edge at band
h. Blade 8 - 1.5 m crack, t.e. to l.e., 8 cm below crown
i. Blade 9 - 1.2 m crack, t.e. to l.e., 8 cm below crown
j. Blade 10 - 0.6 m crack, t.e. to l.e., 8 cm below crown
k. Blade 11 – 4.0 m^2 missing blade piece from the outlet
l. Blade 12 – No visible cracks
m. Blade 13 – No visible cracks
n. Blade 14 – 3.5 m^2 missing blade piece from the outlet; 10 cm crack at leading edge at band
o. Blade 15 – 20 cm crack at leading edge at band
p. Blade 16 – 2 cm crack at leading edge at band
q. Blade 17 – No visible cracks

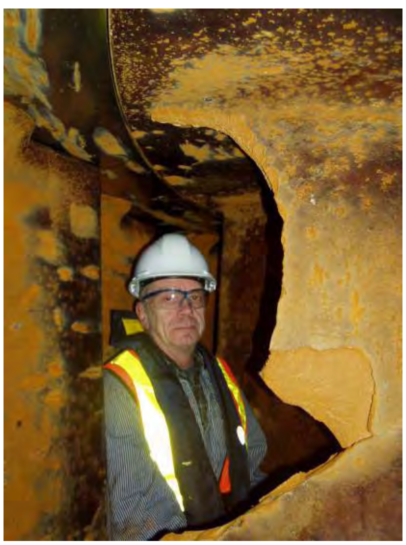


Figure 8: Severely Damaged Inlet Edge

Figure 9: Moderately Damaged Inlet Edge

C.2 Disassembly Inspection

Wicket Gate Intermediate Bushings

All 24 of the wicket gate intermediate journal bushings exhibited wear on a 170° load bearing-zone on the inner diameter (I.D.) of the bushing. This bearing-zone was on the radially-inward side of each bushing, towards the centerline of the unit.

Site measurements of the intermediate bushing inner diameters indicated non-circularity (i.e. out-of-roundness) ranging from 0.5mm (14 out of 24) to 2.0 mm (10 out of 24). On the bushings with non-circularity of 2.0 mm, the grease-distribution slots machined into the I.D. had completely worn away in the most highly loaded bearing-zone. It should be noted that the grease-distribution slots diametrically opposite from the bearing-zone were intact and full of grease. Although the greasing system was functional, it could not supply grease to the bearing zone due to the excessive wear on the distribution slots.

Figure 10: Intermediate Bushing (Typical)

Wicket Gates

Wicket gates 16, 17 and 18, were installed on the lathe at Autinage Utiliser Tracey, Sorel-Tracey, PQ, for journal-concentricity checks. The gates were set-up so that the relative runout between the top and bottom journals, and the intermediate journal could be checked (the top and bottom journals were dialled in on the lathe so that the total runout at these journals was zero). On these three gates, the runout at the intermediate journal was in excess of 2.50 mm.

The sleeves were subsequently removed by zipcutting, and the wall thicknesses were checked by calliper. The wall thicknesses were uniform around the circumference and ranged from 2.75 mm to 3.0 mm. These dimensions were similar to the design dimensions from the 1985 overhaul.

The wicket gates were re-installed on the lathe, with each of the sleeves removed, for runout checks on the bare stems. The gates were aligned so that the runout at the bottom and top journals was zero. The runout at the intermediate journal was similar to that observed previously, indicating that the wicket gate stems were bent.

Lower Seal Ring

In the area between wicket gates 11 to 14 only, there was a significant deposit of carbon steel on the stainless steel lower seal ring, indicating that rubbing had taken place with the runner band.

Figure 11: Carbon Steel Deposited on Lower Seal Ring

Trash Rack

The trash rack was inspected using the submersible remotely operated vehicle (ROV) at GMS. The inspection was performed on the downstream side of the trashrack by lowering the ROV down the intake maintenance gate slot. Complete inspection of the three racks indicated that they were fully intact and in good condition.

Shear Pins

All of the shear pins from Unit 3 were sent to Powertech Labs for detailed inspection. Shear pins 3, 04 (11), 12, 13, 14, 19, and 20 were examined in the scanning electron microscope, with the remaining pins visually examined only. Findings were as follows:

- Pins 3, 12, 14, 19, and 20 showed no evidence of fatigue crack propagation; failure was by shear overload.
- Pin 04, found in wicket gate 11, showed clear evidence of torsional fatigue.

- Pin 13 had a unique fracture surface, indicating impact (high energy and strain rate) and shear overload.
- The remaining pins failed by shear overload. See Appendix F.

Table 1 shows that, with the exception of shear pin 04, from wicket gate 11, the shear pins had been in service for two years or less. This is consistent with the plant's historical practice of replacing each shear pin at least every two years.

Table 1: Summary of G3 Shear Pin In-Service Dates

Wicket Gate No.	Shear Pin ID As Stamped	Date As Stamped	Wicket Gate No.	Shear Pin ID As Stamped	Date As Stamped
1	1	05 2007	13	13	03 2006
2	2	05 2007	14	14	03 2006
3	3	05 2007	15	15	03 2006
4	4	05 2007	16	16	03 2006
5	5	05 2007	17	17	03 2006
6	6	05 2007	18	18	03 2006
7	7	03 2006	19	19	03 2006
8	8	03 2006	20	20	03 2006
9	9	03 2006	21	21	09 2007
10	10	03 2006	22	22	03 2006
11	04	Jan 06 2002	23	23	03 2006
12	12	03 2006	24	24	03 2006

Shear pin 04, found in wicket gate 11, was stamped with the date January 06 2002. This is the same date stamped on several shear pins found in GMS stores tagged "Do Not Use - Emergency Only". It is not clear why these shear pins were tagged with the warning, or why pin 04 was installed in wicket gate 11. Records indicate that shear pins 7 to 24 were replaced with new ones during the 2006 maintenance overhaul. With reference to Table 3, shear pin 04 may have been installed following the October 19, 2006, March 12, 2007 or May 01, 2007 forced outages.

Runner Blade Fracture Surfaces

Visual inspection of the fracture surface on runner blades 3, 4, 11, and 14 was performed at site. No fatigue indications were observed on the fracture surface of the missing inlet section of blade 3 (Figure 8); failure was due to stress overload by impact.

The fracture surface on the missing outlet sections of blades 4 and 11 was entirely brittle fracture, no fatigue indications were observed. The fracture surface on the missing outlet section of blade 14 was entirely brittle fracture, except for a 6.5cm fatigue indication at the trailing edge crown. It is likely that this crack was present prior to the runner failure event.

Further inspection of the fracture surfaces of blades 2, 4, 7, 8 11 and 14 were performed by Powertech Labs under SEM (Appendix F). In addition to supporting the site observations regarding the fracture surfaces on blades 4, 11 and 14, Powertech identified fatigue cracks at the trailing edge crown on samples from blades 2 (8 cm) and 7 (13 cm).

APPENDIX D: RESULTS OF HISTORICAL INVESTIGATIONS

APPENDIX D: RESULTS OF HISTORICAL INVESTIGATIONS

D.1 Runner Considerations

Blade Cracking and Repairs

GMS Units 1-5 turbines have experienced runner-blade cracking since shortly after their original commissioning. Cracking has typically been observed at the blade/band leading edge and the blade/crown trailing edge. Historical studies indicated that cracking at these locations is due to high dynamic stresses, low fatigue strength, defects in original manufacturing, defects introduced by multiple weld-repairs, and residual stresses introduced by multiple weld-repairs.

The Units 1-5 runners are typically inspected for cracks on an annual basis, using visual and dye-penetrant methods. Significant cracks are air-arc gouged to sound metal and ground and rebuilt using a combination of carbon steel and stainless steel electrodes. This approach has been used to manage the cracks for over 35 years.

Prior to the March 02, 2008, failure, the Unit 3 runner was most recently inspected and repaired in May 2007, during the major outage for stator replacement. At that time, cracks were found on five blades: leading edge of blades 1 (0.20 m), 15 (0.10 m), 16 (0.30 m), and trailing edge of blades 7 (0.08 m), 10 (0.30 m). These cracks were not considered large or unusual and were all repaired before the Unit was returned to commercial service in November 2007. It is interesting to note that no cracks were found on the trailing edges of runner blades 1 and 8. In March 2006, 0.60 m x 0.60 m pieces of steel were found missing from the outlet of blades 1 and 8, near the crown.

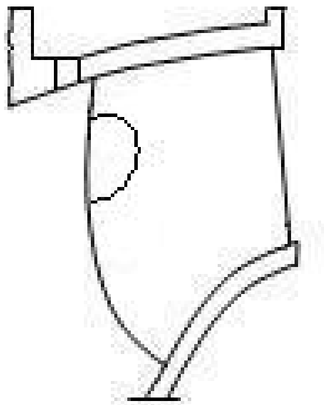


Figure 12: Outline of Missing Piece from Runner Blades #1 and #8, March 2006

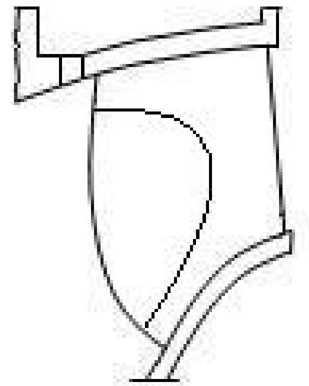


Figure 13: Outline of Missing Piece from Runner Blades #4, #11 and #14, March 2008

In spite of the significant welding done at these locations as part of the repair, the repairs remained perfectly intact throughout the March 02, 2008 failure.

Natural Frequencies

The problem of runner cracking has been studied by experts from BC Hydro and external consultants including GE Hydro.

The significant results of the BC Hydro studies (see BCH Report PSE303) were that:

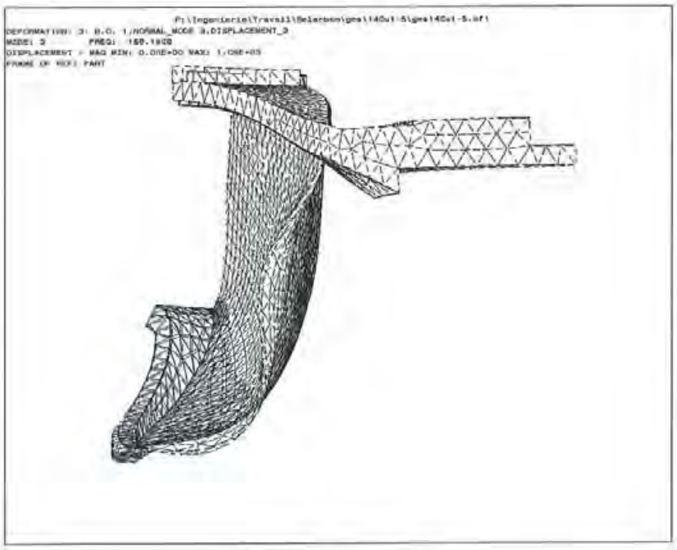
1. Several runner natural frequencies and mode shapes exist that may be excited during normal and abnormal turbine operations.
2. A dominant natural frequency was measured on the prototype runner at 127.5Hz. This frequency is an integer-multiple of a common cyclic disturbance (excitation) during normal turbine operation - the blade passing frequency (17 blades x 2.5Hz synchronous speed = 42.5Hz).

The significant result of the GE Hydro finite element study was that a runner natural frequency exists, in water, somewhere in the range of 56 to 64Hz. This could be excited by wicket gate/runner blade interactions during normal operations; the wicket gate passing frequency is 60Hz (24 wicket gates x 2.5Hz synchronous speed).

The vibration mode of the blade trailing edge (Figure 14) is consistent with increased stress at the junction of the trailing edge and crown, where cracks normally initiate.

Gordon M. Shrum Units 1 to 5 Turbine Replacement Project Appendix D

GE Hydro	RUNNER NATURAL FREQUENCY	CALCULATIONS BOOK
Client: B.C. Hydro	Project: GMS 1-5	Contract:



Blade mode - existing runner

GE Canada Proprietary and Confidential

Prepared by: André Coutu and Stuart Coulson	Date: 2004/12/14	Page 7	Of 13
checked by:	Date: 2004/12/14	parts bill: 140	

Figure 14: Blade Mode Shape Identified by GE Hydro

Runner Materials

Table 2 demonstrates that the strength and toughness of the ASTM A27 65-35 casting used for the Units 1-5 runners is low when compared to modern materials, such as ASTM A743 Grade CA-6NM, ASTM A240 Grades S32205 and 31803, and ASTM A516 Grade 70.

Table 2: Mechanical Properties of Runner Materials

	Min. Tensile Strength (MPa)	Min. Yield Strength (MPa)	Min. Elongation in 50mm (%)	Fracture Toughness K_{IC} (MPa√m)
ASTM A27 65-35	450	241	24	60
ASTM A743 Grade CA-6NM	755	550	15	139
ASTM A240 Grade S32205	665	450	25	220
ASTM A240 Grade 31803	620	450	25	150
ASTM A516 Grade 70	485	260	21	100

D.2 Wicket Gate and Operating Mechanism Considerations

Wicket Gate Closing Tendency

As part of Contract 22 – PMD Turbines, Mitsubishi specified the neutral position of a free wicket gate in the flow to be 4.6°. Confirmation of this was not documented in the original model test or in any CFD analysis. However, practical experience of plant and Engineering staff indicate that when a shear pin is broken, the wicket gate assumes an almost-closed position.

Although the exact gate position has not been measured, this observation is supported by the historical trends captured in OI which indicate a significant reduction in synchronous vibration at the turbine bearing when a shear pin is broken (see Figures 17, 18, 19, 20); the closed wicket gate(s) result in a radially-acting, steady hydraulic unbalance that ”pushes” the shaft-line and runner in the direction of the closed wicket gate(s) and reduces the magnitude of the synchronous vibration. CFD analysis or servomotor differential tests would be required to verify the wicket gate neutral position and the behaviour when desynchronised.

Wicket Gate Lever Geometry

The maximum angular stroke of the wicket gates and gate levers is 29.5°. When a wicket gate is synchronized to the operating mechanism, its stroke is controlled and limited by the servomotors.

When a wicket gate is desynchronised, its stroke is limited by mechanical stops located on the headcover. However, as shown in Figures 15 and 16, the geometry of the gate levers is such that contact occurs between adjacent levers when one lever is fully-closed (0° open) and the other is positioned at openings greater than 20.5°.

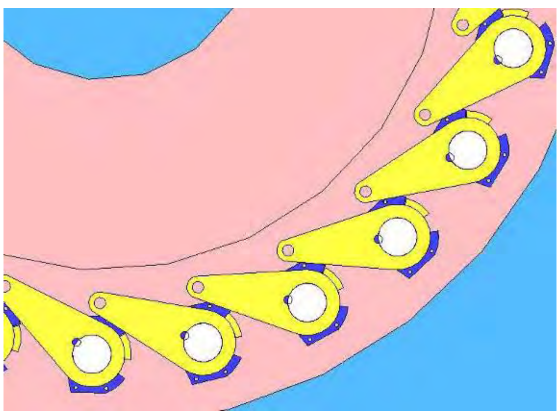


Figure 15: Wicket Gate Levers at 0° Opening

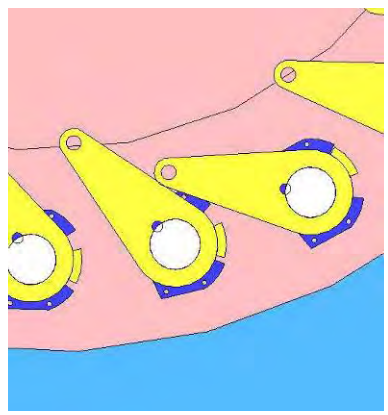


Figure 16: Wicket Gate Levers at 20.5° Opening and One Desynchronized Lever at 0° Opening

Shear Pins

The shear pins in the Mitsubishi design serve two purposes in the operating mechanism: shear pin and link pin. This design results in combined shear, bending and torsional forces being transmitted through the pin. These forces include shear due to the hydraulic forces from the wicket gates, shear and torsion due to the friction load in the wicket gate bushings, bending due to misalignments in the linkage-lever assembly, and bending and torsion due to the opening/closing and ‘squeeze’ cycles on the wicket gates.

The torsional stresses on shear pin 04 that resulted in fatigue failure may have been due to:

- Vertical misalignment between the pin and levers
- Excessive clearances in the eccentric pin bushing or excessive clearance in the wicket gate intermediate bushing resulting in the wicket gate losing its proper adjustment. The excess capacity of the servo motors would concentrate their load on this shear pin during servo motor ‘squeeze’ operations (shut down and synchronous condense)

D.3 Start/Stop Cycles

Unit 3 has experienced a dramatic increase in the number of start/stop and synchronous condense cycles in recent years:

1. Prior to 2004: 50 to 150 cycles per year,
2. 2005 to May 2007: 300 to 400+ cycles per year
3. May to Nov 2007: 0 cycles (outage for stator replacement)
4. Nov 2007 to Mar 2008: approximately 40 cycles

The increased number of start/stop cycles is due to the installation of synchronous condenser capability in 2005 and the recent operational trend of responding to peak domestic loads and energy-export markets.

D.4 Operation with Broken Shear Pins

Unit 3 Shear Pin Failure History

Table 3 summarizes the G3 shear pin failures from 1977 to 31 December 2007 that resulted in forced outages.

Table 3: Summary of G3 Shear Pin Failures

Date	Comments	Approximate Time Spent Running with Broken Shear Pin
Mar-03-1983	OI not online	unknown
Nov-07-1983	OI not online	unknown
Dec-22-1988	OI not online	unknown
Oct-05-1989	OI not online	unknown
Feb-19-1990	OI not online	unknown
May-13-1991	OI not online	unknown
Aug-23-1991	OI not online	unknown
Oct-26-1991	OI not online	unknown
Mar-12-1992	OI not online	unknown
Jul-03-1992	OI not online	unknown
Sep-13-1998	OI not online	unknown
Jan-13-1999	Failed during shut down	3 hrs
Dec-06-1999	Failed at 257MW	3 hrs
Aug-06-2002	Failed during shut down	50 hrs
Nov-15-2004	Failed during shut down	4 hrs
Jun-13-2005	Failed during turbine to synch-condense transition	48 hrs
Aug-09-2005	Failed during synch-condense to turbine transition	4 hrs
Sep-20-2005	Failed at 242MW	0.5 hrs
Sep-27-2005	Failed during start-up	4 hrs
Dec-29-2005	Failed during synch-condense to turbine transition	36 hrs
Oct-19-2006	Failed during synch-condense to turbine transition	14 hrs
Mar-12-2007	Failed during turbine to synch-condense transition	52 hrs
May-01-2007	Failed during start-up	6 hrs

Significant trends realized from Table 3 include:

1. Shear pins typically break during a transition (start-up, shut-down, etc); consistent with the rapid, dynamic loads applied during this event.

2. There has been a dramatic increase in the frequency of broken shear pins since the installation of synchronous condense capability in 2005.

3. On at least two occasions prior to March 02, 2008 (Dec-06-1999 and Sept-20-2005) shear pins have broken with the machine in turbine mode at high power output.

4. The turbine is able to function with a single broken shear pin. During these periods, it can start, stop, synch condense and produce rated power, with a single, de-synchronized wicket gate.

Figure 17 shows three significant operational trends that are evident in the presence of a single broken shear pin:

Point 1 – There is a reduction in synchronous vibration at the turbine bearing. The rationale for this behaviour is discussed in D.2.

Point 2 – There is no substantial decrease in power output immediately following the shear pin breaking.

Point 3 – An approximate 5% increase in servomotor stroke is required to maintain power output after the shear pin has broken.

As Table 3 shows, Unit 3 operated for significant periods of time with a broken shear pin between April 2005 and March 2006. Given the similarity in shape of the missing blade-pieces found on blades 1 and 8 during the March 2006 outage (see Figure 12), and the shape of the missing blade-pieces found on blades 4, 11 and 14 during the March 02, 2008 runner failure (see Figure 13), it should be considered that the March 2006 damage could be related to sustained operation with broken shear pins.

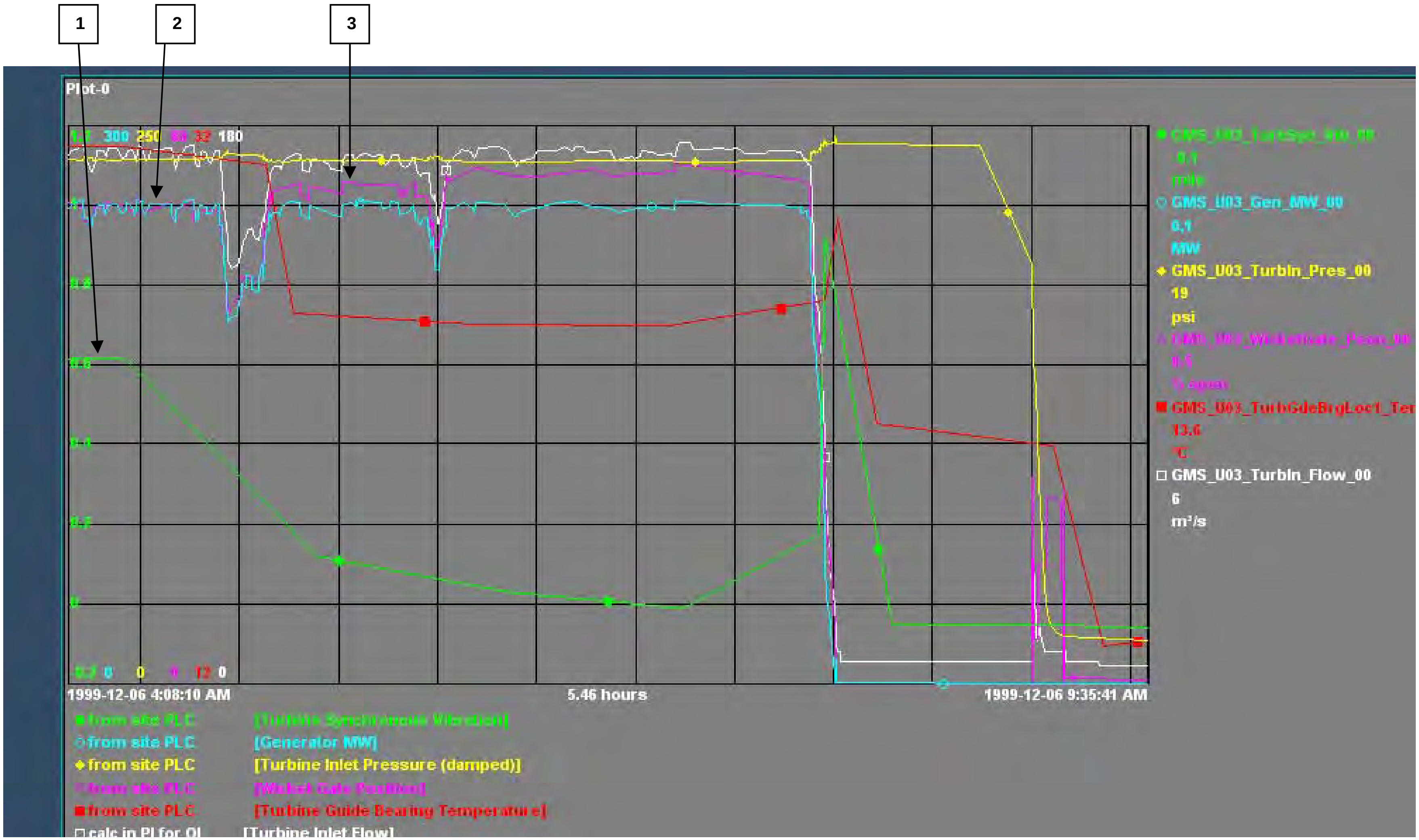


Figure 17: OI Trend during the 12/06/99 Single Shear Pin Failure (U3)

As indicated in Table 3, there have been two occasions in the past where a single shear pin has failed on Unit 3 turbine while the unit was producing power. Table 4 summarizes the relevant operating conditions at the time of those failures.

Table 4: Unit 3 Shear Pin Failures during Normal Operation

Event[1]	Generator Power (MW)[1]	Turbine Power (MW)[2]	NSHE (m^2s^{-2})[1]	Servomotor Opening (%)[1]	Wicket Gate Opening (°)[3]
December 06, 1999	257	261	1610	67	19.75
September 20, 2005	242	246	1590	63	18.50

[1] Data obtained from OI and BC Hydro Forced Outage Statistics

[2] Generator efficiency assumed to be 98.5%

[3] Data obtained from model test report GMS1-5 Baseline Test of Existing Turbine, January 2008

The events described in Table 4 did not result in a cascade failure of the adjacent shear pins. One possible explanation is that the position of the wicket gates and levers at the time of the failure was less than 20.5° and contact between gate levers could not occur.

Unit 1 Dual Shear Pin Failure History

There have been at least three occasions when two adjacent shear pins have failed on Unit 1 turbine while the unit was producing power and the wicket gates were beyond 20.5° open. Table 5 summarizes the relevant operating conditions at the time of those failures, and Figures 18 to 20 show the operational trends plotted from data captured during the events.

Table 5: Unit 1 Dual Shear Pin Failures during Normal Operation

Event[1]	Generator Power (MW)[1]	Turbine Power (MW)[2]	NSHE (m^2s^{-2})[1]	Servomotor Opening (%)[1]	Wicket Gate Opening (°)[3]
December 09, 2001	258	262	1540	73	21.75
December 26, 2001	256	260	1530	73	21.75
December 29, 2001	247	251	1530	70	20.75

[1] Data obtained from OI and BC Hydro Forced Outage Statistics

[2] Generator efficiency assumed to be 98.5%

[3] Data obtained from model test report GMS1-5 Baseline Test of Existing Turbine, January 2008

Figure 18: OI Trend during the 12/09/01 Dual Shear Pin Failure (U1)

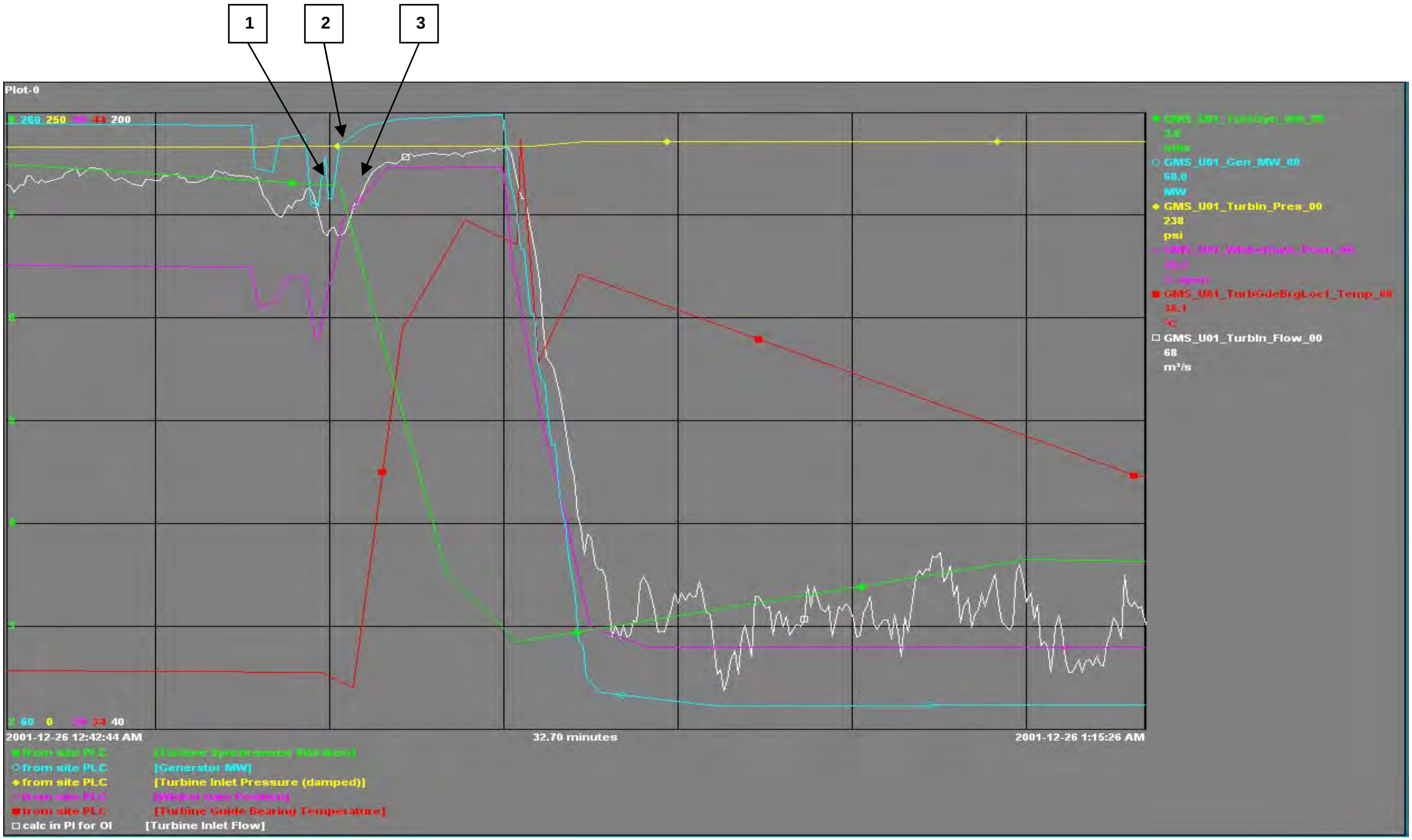


Figure 19: OI Trend during the 12/26/01 Dual Shear Pin Failure (U1)

Figure 20: OI Trend during the 12/29/01 Dual Shear Pin Failure (U1)

Figures 18 to 20, in comparison with Figure 17, demonstrate three significant operational trends that are evident in the presence of two broken shear pins:

Point 1 - There is again a reduction in synchronous vibration at the turbine bearing (as discussed in D.2.).

Point 2 - There is a 13 to 17 MW decrease in power output immediately following two adjacent shear pins breaking due to the drop in discharge and decrease in turbine efficiency.

Point 3 - An approximate 10% increase in servomotor stroke is required to maintain power output after two adjacent shear pins have broken.

The reason for the erratic bearing temperatures following the shear pin failures shown in Figures 18 and 20 is not clear. In both cases, the turbine guide bearing was not repaired or replaced after the shear pin failure event.

D.5 Effect of 1985 Overhaul

In 1985, Unit 3 was completely disassembled for inspection and repair. As part of this Major Overhaul, significant welding was performed on the headcover baffle plates, resulting in severe distortion in the alignment of the wicket gate bores. This misalignment was partially corrected by line boring the top bushings in the headcover concentric with the bottom ring bushings, and replacing the matching journals on the upper wicket gate stems with oversized journals to suit. A detailed description of the process used is included in BCH Report GMS Unit 3 1985 Report on Major Overhaul, Report No. 1500.5.3.

The misalignment described above likely produced the wicket gate intermediate journal wear and wicket gate distortion observed during unit disassembly (refer to Section 3.2). The radial forces on the wicket gate journals due to the bore-misalignment increased the friction-forces between the journals and the wicket gate bushings, aggravating the natural loading and wearing the bushing load-bearing surface. Bending of the wicket gate stem at the intermediate journal was likely a result of the spiral case pressure rise during the runner failure. Misalignment in the wicket gate bores may have contributed to the deformation.

The impact of the misalignment and deformation of the gate stem, in terms of increased friction in the wicket gate bushing, is quantified and analyzed in Appendix H.

D.6 Synchronous Condenser Operation

Units 1 and 2 at GMS have successfully functioned as synchronous condensers since their original commissioning in 1968. Synchronous condense capability was added to Unit 3 in May 2005.

The last time Unit 3 operated in synchronous condense mode prior to the runner failure was on March 01, 2008. No unusual conditions were recorded during this operation:

- The servomotor position was constant at 0% opening
- The synchronous vibration at the turbine bearing was low (0.1 mils pk to pk)
- The unit consumed 7.4 MW of power
- These parameters were consistent with historical trends on Unit 3.

D.7 Stator Upgrade

In 2007, the original General Electric stator on Unit 3 was replaced with the new Alstom stator. Table 6 compares the characteristics of the two stators:

Table 6: Comparison of Unit 3 New and Original Stator

	General Electric (original)	Alstom (new)
Continuous rated output	261 MVA	305 MVA
Maximum continuous rated output (MW)	275 MVA	321 MVA
Power factor	0.95 lagging	0.95 lagging
Voltage	13.8kV	13.8kV
Number of stator bar slots	612	612
Efficiency	98.5%	98.8%

The stator frame, core and winding were replaced as part of the upgrade. The number of stator bar slots was unchanged at 612. No modifications were implemented on the rotor structure, the rotor poles, field winding or excitation system. The brush gear collector rings were replaced with a design without a spiral groove. The conducting surface is flat to improve brush performance and extend brush life.

Stator commissioning included:

- open and short circuit saturation tests
- waveform deviation tests
- load rejections up to 265 MW
- heat run up to 265 MW
- load test up to 300 MW (4 minute duration)
- line charging and zero power factor
- generator efficiency test

No significant performance issues were identified during commissioning, and prior to the runner failure, there had not been any issues with the new stator.

Due to the capacity limitations of the turbine and other generator components, the additional capacity of the stator had not been used since the return-to-commercial-service in November 2007.

APPENDIX E: DETAILED DISCUSSION OF RUNNER FAILURE HYPOTHESES

APPENDIX E: DETAILED DISCUSSION OF RUNNER FAILURE HYPOTHESES

BC Hydro Engineering considered four separate hypotheses to explain the failure of GMS Unit 3 runner. This appendix discusses those hypotheses in detail.

E.1 Foreign Object in the Water Passage

Description

The damage to the runner and wicket gates was caused by a foreign object travelling down the penstock.

Discussion

This scenario is considered unlikely for the reasons below, and is not discussed in any further detail.

1. A foreign object of significant mass and volume would have been required to cause the damage observed. The trash rack was found to be perfectly intact.
2. No damage was observed on the scroll case, the stay vanes, or on the scroll case side of the wicket gate skin plates.
3. No foreign debris was found in the scroll case.
4. Nothing unusual (i.e. loose material or equipment) was found in the intake structure around the Unit 3 gate slots.

E.2 Resonance of the Runner Excited by the New Stator

Description

The runner failed as a result of a torsional resonance excited by the new stator.

Discussion

The number of stator bar slots in the core was unchanged from the original design and no unusual conditions were detected during the four months of new stator operation that would indicate any relationship between the new stator and the runner failure.

Additionally, no evidence was found during the onsite investigation linking the new stator with the failed turbine.

However, it must be noted that during the commissioning of the new stator, no dynamic torque measurements were made on the main shaft. Although it is unlikely that the new stator caused the runner failure, a detailed analysis or site-measurement of the dynamic torque in the main shaft would be required before the effect of the new stator can be completely ruled out.

E.3 Runner Blade Failure due to Fatigue

Description

The trailing edge of blades 4, 11 and 14 failed due to fatigue, as a result of start/stop cycles on the Unit. Two of the broken blade pieces were ejected into the wicket gate cascade, initiating rapid wicket gate closure and causing the damage observed on the wicket gate skin plates and runner blade inlets.

Alternatively, the entrance edge of blade 3 failed due to fatigue, as a result of start/stop cycles on the Unit. The broken blade piece was ejected into the wicket gate cascade, initiating rapid wicket gate closure and causing the damage observed on the wicket gate skin plates and runner blade inlets.

Discussion

This scenario is considered unlikely for the reasons below:

1. The runner had experienced only 40 start/stop cycles since the previous repair period. This is much less than the 300 to 400+ cycles that it had recently been experiencing in between typical repair periods.
2. The runner had experienced only four months of service since the previous repair period; much less than the twelve months of service in between typical repair periods.
3. Shear pin 11 showed clear evidence of torsional fatigue, not shear overload.
4. The fracture surface on the inlet of blade 3 was consistent with impact failure, not fatigue.

5. With reference to Figure 1, at 05:05:00 (Point 1), the trends of synchronous vibration at the turbine bearing, power output, and servomotor stroke are consistent with two adjacent, broken shear pins. Cascade failure of the shear pins (and rapid closure of the wicket gates) did not occur until 05:22:12.

E.4 Cascade Wicket Gate Closure

Description

The shear pin in wicket gate 11 failed first due to fatigue. Wicket gate 11 rapidly closed until lever 11 impacted lever 12, and shear pin 12 broke due to the impact. Wicket gates 11 and 12 were de-synchronised and assumed an almost-closed position. The servomotor stroke increased to maintain power and to respond to an increased demand for power. Shortly after the servomotor stroke reached its maximum opening, it closed slightly and re-opened to maximum, initiating failure of the shear pin in wicket gate 13. Wicket gate 13 rapidly closed until lever 13 impacted lever 14, and shear pin 14 broke due to the impact. Wicket gates 11 to 14 were de-synchronised and in an almost-closed position, as shown in Figure 21.

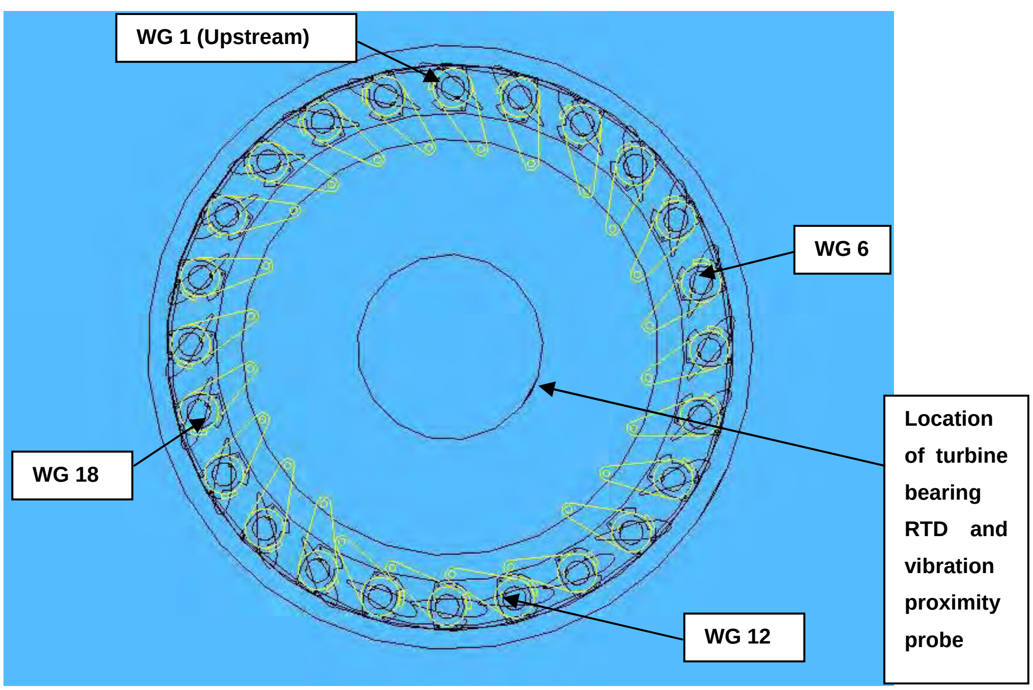


Figure 21: Wicket Gates #1-10 and #15-24 Open, #11-14 Closed

Closure of these wicket gates unbalanced the flow in the distributor, creating a zone of low pressure behind them. The runner was forced towards the low pressure zone until contact occurred between the runner band and the stationary lower seal ring. The runner blades experienced complex dynamic stresses as a result of:

- The disturbed flow pattern and cyclical pressure in the distributor,
- The radial forces from the unbalanced flow,
- The torsional forces from the braking effect of the runner band contacting the lower seal ring
- Possible roundness distortion of the band (cyclical distortion)
- Possible excitation of one or more runner natural frequencies.

The resulting stresses in the runner blades initiated cracks on the runner blades and accelerated propagation of existing cracks, and created the damage observed on the outlet of blades 4, 11 and 14.

As the runner blades broke apart, one "outlet" piece from blades 4, 11 or 14 was discharged into the draft tube. Two "outlet" blade pieces (one each from the other two blades) were ejected into the wicket gate/runner cascade and slammed shut the remaining open wicket gates. The large blade sections remained caught in the cascade. The significant damage to the runner blade inlets and the wicket gate skin plates was created as the "outlet" blade pieces were broken down by impact between the runner blade inlets and the wicket gates.

Discussion

Prior to the failure, the wicket gate angle was 21.5°. (generator power output - 254 MW; turbine power output - 258 MW; gross head - 159.4m; NSHE - 1510 m^2/s^2, servomotor position of 72%).

The closing tendency of the wicket gates, the position of the wicket gates at the time of failure, and the geometry of the gate levers suggest that following the failure of shear pin 11, wicket gate 11 closed and gate lever 11 contacted gate lever 12.

At the same time this contact occurred (5:05:00), the operating mechanism initiated further opening of the wicket gates to maintain demand for power (refer to Figure 1, Point 1). This suggests that shear pin 12 may have failed due to friction or impact between the gate levers. The analysis of these two cases, presented in Appendix B, suggests that impact between gate levers caused the cascade shear pin failure, following the initial failure of shear pin 11.

With reference to Figure 1 and the time sequence presented in Section 2.0, a detailed sequence of events for this above failure hypothesis is presented below. Supporting information, further to what is stated in Section 2.0, is presented below each event. The event numbering is the same as in Section 2.0.

In light of the findings in sections 3 and 4 of this report, the hypothesis of a cascading shear pin failure fully explains the sequence of events described in section 2.0 and illustrated in figure 1 of this report. In the following explanation, the event numbering is the same as that in section 2.0.

(1) 05:05:00 - The shear pin in wicket gate 11 fails first. Wicket gate 11 closes from 21.5° until lever 11 impacts lever 12. Shear pin 12 breaks due to the impact force. Wicket gates 11 and 12 are de-synchronised and assume a closed position.

- The sudden decrease in synchronous vibration at the turbine is consistent with one or more broken shear pins
- The sudden 17 MW decrease in power is consistent with two adjacent broken shear pins
- A 10% increase in servomotor stroke to maintain power is consistent with two adjacent broken shear pins
- The design of the wicket gate levers results in contact between adjacent levers when one wicket gate is at 0° open and the other gate is at openings of 20.5° or greater.
- Calculations suggest that depending on hydraulic torque and friction assumptions, cascade shear pin failure may occur due to impact

between gate levers attached to desynchronised wicket gates. See Appendix G for details.

- The striations observed on the shear surface of shear pin 11 indicated failure due to torsional fatigue. Shear pin 12 showed no fatigue-like striations; failure was due to shear overload, as demonstrated in Appendix F.

(2) 05:10:54 (approximate) – The wicket gates fully open until a generator power output of 262MW is reached. The turbine power output has saturated at 266MW. Wicket gates 11 and 12 remain closed.

- The maximum turbine power output at a NSHE of 1510 m^2/s^2 is approximately 280MW (reference model test report GMS 1-5 Baseline Test of Existing Turbine, January 2008). The reduced maximum power output at this time is attributed to the two wicket gates with broken shear pins.

(3) 05:14:12 (approximate) – After a slight closure and re-opening of the servomotors, shear pin 13 fails. Failure of shear pin 14 occurs due to impact from wicket gate lever 13. Wicket gates 11 to 14 are de-synchronised and assume almost-closed positions. The effective closure of four adjacent wicket gates forces the runner towards the low pressure zone behind the wicket gates until the turbine bearing babitt fails and contact occurs between the runner band and the lower seal ring.

- The fracture surface of shear pin 13 was unique, with initial impressions that failure was in fatigue or bending at a high strain rate, not pure shear overload.
- The significant increase in turbine bearing temperature can be attributed to failure of the babitt.
- The significant increase in turbine synchronous vibration can be attributed to contact between the runner band and the lower seal ring.
- The carbon steel deposits on the stainless steel lower seal ring between wicket gates 11, 12, 13 and 14 indicate contact with the runner band at this location.

- The absence of impact damage on the trailing edge of wicket gates 11 to 14 is consistent with these gates being almost closed when the two outlet pieces of blade are ejected into the wicket gate/runner cascade. See time 05:22:12 (Point 5 on Figure 1)

(4) 05:19:30 – There is a slight change in the position of the de-synchronized wicket gates, increasing the discharge and power output.

- The power output increases from 252 to 258 MW in spite of no change in servo motor position

(5) 05:22:12 (approximate) – The runner breaks apart. One of the “outlet” blade pieces from 4, 11 and 14 is discharged into the draft tube. The two remaining “outlet” blade pieces, are ejected into the wicket gate/runner cascade.

- The dynamic forces acting on the runner due to the cyclic pressure in the distributor, the mechanical contact between the band and the lower seal ring, and possible excitation of natural frequencies, would have resulted in complex stresses that likely exceeded the ultimate strength of the blade material.
- The sudden drop in power from 259 to 13 MW (prior to settling at 55MW) and the rise in turbine inlet pressure indicate rapid closure of the wicket gates. All 24 shear pins are broken.
- Calculations indicate that the outlet pieces could be ejected into the cascade while passing through the area behind four closed wicket gates.
- The pattern of impact damage on the trailing edge of wicket gates 1-10 and 15-24 is consistent with large pieces of metal becoming caught in the wicket gate/runner cascade.
- The damaged observed on the inlet of blade 3 is consistent with impact from one of blades 4, 11 or 14
- One “outlet” blade piece is found intact in the draft tube.

(6) 05:27:12 – The wicket gates are desynchronised from the operating mechanism. Changes in the servomotor position do not affect the Unit power output.

(7) 05:28:30 – The GMS operator initiates an emergency trip.

(8) 05:29:30 – Not significant to the hypotheses.

(9) 05:31:42 – Not significant to the hypotheses.

(10) 05:39:18 – The unit is fully stopped and the penstock is drained.
The serious damage observed on the runner-blade inlets, the wicket gate skin plates and the bottom ring facing plate is consistent with the broken blade pieces caught in the wicket gate/runner cascade as the unit rotated for 17 minutes.

APPENDIX F: POWERTECH LABS REPORT

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Project: 18011-34

September 24, 2008

BC Hydro Engineering, AR and Generation Maintenance
Patterson Building, 7th Floor
4211 Kingsway, Burnaby, BC V5H 1Z6

Attention: Mr. Peter Finnegan, P.Eng

Dear Mr. Finnegan

RE FAILURE INVESTIGATION OF GMS G3 SHEAR PINS AND RUNNER

The turbine runner of generating unit #3 experienced catastrophic failure of several blades as well as the shear pins of the unit. Powertech Labs Inc. was asked to perform a failure investigation of both the runner and the shear pins, in part to determine if several shear pins failed prior to the runner, or as a consequence of the runner failure (secondary damage). To date the investigation has included several site visits, as well as detailed fractographic analyses utilizing optical and scanning electron microscopic examinations.

Shear Pin Examination

All 24 shear pins from unit #3 were sent to Powertech Labs for examination. All the shear pins had fractured in their shear groove. Each individual shear pin fracture surface was examined to determine the failure mode. To facilitate identification of the failure mode, a spare shear pin from the unit having the same material and groove dimensions was fractured by shear overload in the lab.

Shear pins 11 and 13 were flagged during the initial examination as containing unique fracture surface morphology features not consistent with shear overload.

The fracture surface of shear pin 11 contained two distinct areas consistent with fatigue crack propagation. The fracture surface morphology within these areas was flat and smooth, containing beach marks (striations) typical of high amplitude, low cycle fatigue. The two areas were approximately diametrically opposite of one another, characteristic of torsional fatigue (Figure F1).

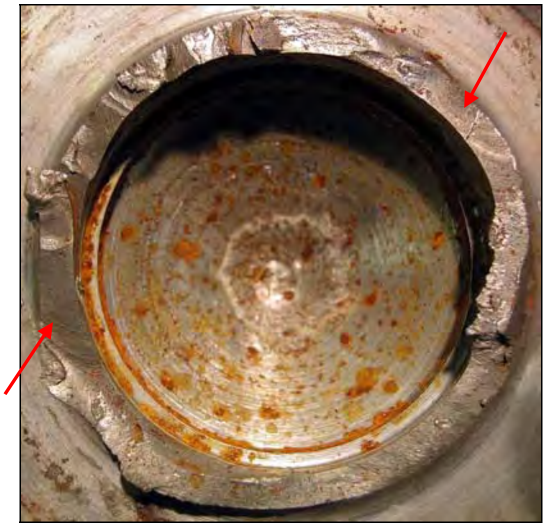

Figure F1: Macro image of fracture surface of shear pin 11. Two distinct areas of fatigue are seen on the fracture surface (indicated with red arrows). Image taken with oblique angle lighting to emphasize fatigue zones.

The fatigue cracks initiated at the outer surface of the shear groove and propagated at a 45-degree angle (Figures F2 and F3). It is well established that torsional fatigue cracks in high strength steels will propagate 45 degrees to the shear axis.

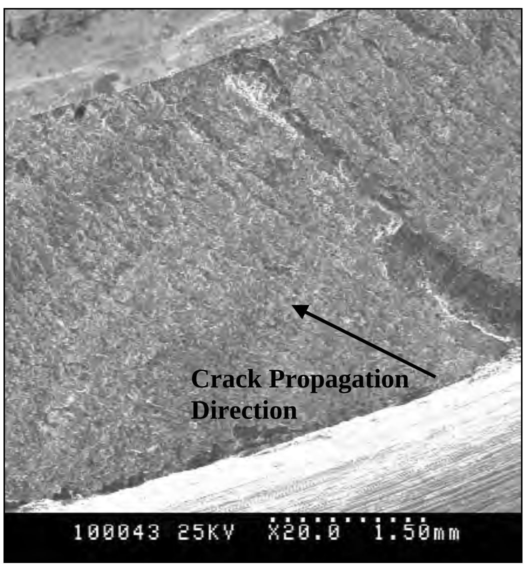

Figure F2: Scanning Electron Microscope (SEM) image of striations seen in fatigue area. Outer surface of shear groove is at bottom of image. Magnification: 20X.

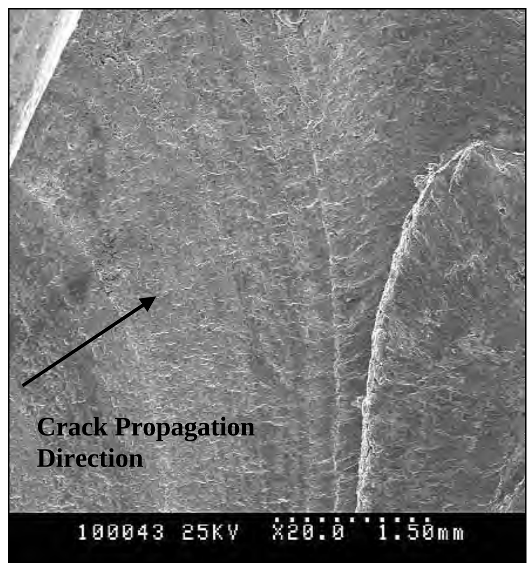

Figure F3: Scanning Electron Microscope (SEM) image of striations seen in fatigue area. Outer surface of shear groove is at top left of image. Magnification: 20X.

The fatigue cracks propagated until the critical crack length was achieved and then the pin failed by shear overload.

The fracture surface of shear pin 13 contained numerous crack initiation sites seen around half of the groove circumference (Figures F4 and F5). The cracks originated at the outer surface of the shear groove and propagated approximately half way through the groove ligament at a shallow angle upwards. Examination in the SEM revealed features consistent with ductile overload (Figure F6). The formation of numerous cracks is indicative of an impact type damage (high energy and high strain rate). The presence of the cracks around half the circumference and their propagation angle indicate that the pin was impacted from one side.

The remaining area of the ligament, as well as the ligament around the other half of the circumference, shows a flat, smeared surface, characteristic of shear overload.

Figure F4: Macro image of fracture surface of shear pin 13.

Figure F5: Macro image of area of fracture surface from shear pin 13 showing numerous crack fronts propagating approximately half way through the groove ligament.

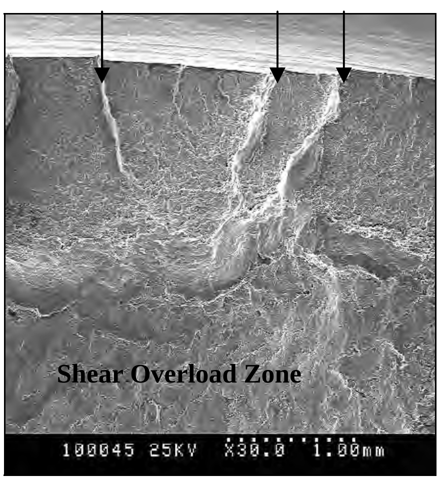

Figure F6: SEM image of area of fracture surface from shear pin 13. Note ductile tear ridges originating from outer surface of groove (indicated by arrows) as well as transition to shear overload. Magnification 30X.

The remaining shear pin fracture surfaces were consistent with shear overload failure.

Turbine Runner Blade Examination

During the second site visit post failure, the fracture surfaces of the blades from which whole sections fractured (blades 4,11 and 14) were cleaned with an acid solution and visually examined. The fracture surface of blade 14 showed features consistent with fatigue crack propagation and was selected for removal. A portion of the fracture surface from blade 4 as well as samples encompassing cracking in blades 2, 7 and 8 were removed and forwarded to Powertech Labs for detailed examination. The samples were removed from the following locations of the turbine runner blades.

Sample from blade 14	Trailing edge of the blade at the crown
Sample from blade 4	Middle section of the trailing edge of blade
Sample from blade 2	Trailing edge of the blade at the crown
Sample from blade 7	Trailing edge of the blade at the crown
Sample from blade 8	Trailing edge of the blade at the crown

The fracture surface of blade 14 showed a distinct zone of fatigue crack propagation (Figure F7). The fracture surface morphology in this areas is flat and smooth, containing beach marks (striations) consistent with high amplitude, low cycle fatigue. The fatigue crack portion of the fracture surface is approximately 6.5 cm in length. Weld defects, consisting of porosity and slag inclusions were noted subsurface of the stainless overlay (Figure F8). Outside the fatigue zone the fracture surface morphology is consistent with a brittle overload fracture.

Figure F7: Macro image of sample removed from blade 14

Figure F8: Macro image of fatigue crack portion of blade 14 fracture surface showing striations and subsurface weld defects (indicated by red arrow).

The fracture surface of blade 2 also contained a distinct zone of fatigue crack propagation (Figure F9), containing beach marks similar to that seen in blade 14. The fatigue crack portion of the fracture surface is approximately 8 cm in length. Sub surface weld defects consisting of slag inclusions were also noted in this sample (Figure F10). Beyond the fatigue zone the fracture surface morphology is consistent with a brittle overload fracture.

Figure F9: Macro image of sample removed from blade 2

Figure F10: Macro image of fatigue crack portion of blade 2 fracture surface showing striations and subsurface weld defects (indicated by red arrow).

The fracture surface morphology features of blade 4 consisted entirely of a brittle overload fracture (Figure F11). Noted on its fracture surface was a large sub surface weld defect (Figure F12).

Figure F11: Macro image of sample removed from blade 4

Figure F12: Macro image of large subsurface weld defect (indicated by red arrow).

Conclusions

The investigation of the fracture surfaces of the shear pins and blade sections suggest the turbine failed due to the following sequence of events.

- Fatigue cracks originated at the outer shear groove surface of shear pin 11 and propagated due to torsional fatigue. The fatigue was high amplitude, low cycle, with initiation and propagation likely due to stop/start cycles of the unit. Once critical crack length was reached the shear pin failed by shear overload.
- An impact type damage with a high energy and a high strain rate bending moment on shear pin 13 resulted in numerous ductile overload cracks around half of the shear pin groove. The cracks moved through half of the groove ligament and led to shear overload failure of the pin.
- Fatigue cracks initiated on the trailing edge of the blades at the transition to the crown in the runner. The fatigue cracks initiated due to stop / start operations of the unit.
- In blade 14, a fatigue crack initiated at the crown trailing edge and propagated approximately 6.5 cm. Subsequently, this section of the blade broke off in a brittle overload fracture due to the change in the dynamic conditions of the turbine runner.
- The entire fracture surface of blades 4 and 8 showed a brittle type of fracture.
- The fracture surface of the remaining blades showed a combination of fatigue cracking followed by brittle fracture.

Prepared by:

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APPENDIX G: ANALYSIS OF CASCADE SHEAR PIN FAILURE

APPENDIX G: ANALYSIS OF CASCADE SHEAR PIN FAILURE

The closing tendency of the wicket gates, the position of the wicket gates at the time of failure, and the geometry of the gate levers suggest that following the failure of shear pin 11, wicket gate 11 closed and gate lever 11 contacted gate lever 12.

With reference to Figure 1, Point 1 (5:05:00), at the same time this contact occurred, the operating mechanism initiated further opening of the wicket gates to maintain demand for power. This suggests that shear pin 12 may have failed due to friction between the gate levers or impact between the gate levers. These two cases are analyzed below to provide insight into the cause of the failure of shear pin 12, as well as why it could have cascaded to 13 and 14, following the initial failure of shear pin 11.

Figure 22 indicates how force is transmitted from the operating mechanism to the shear pin. Figure 23 is the free body diagram of two wicket gate levers in contact; one lever is shown at a gate position of 21.5° (left), the other is shown at 0° (right).

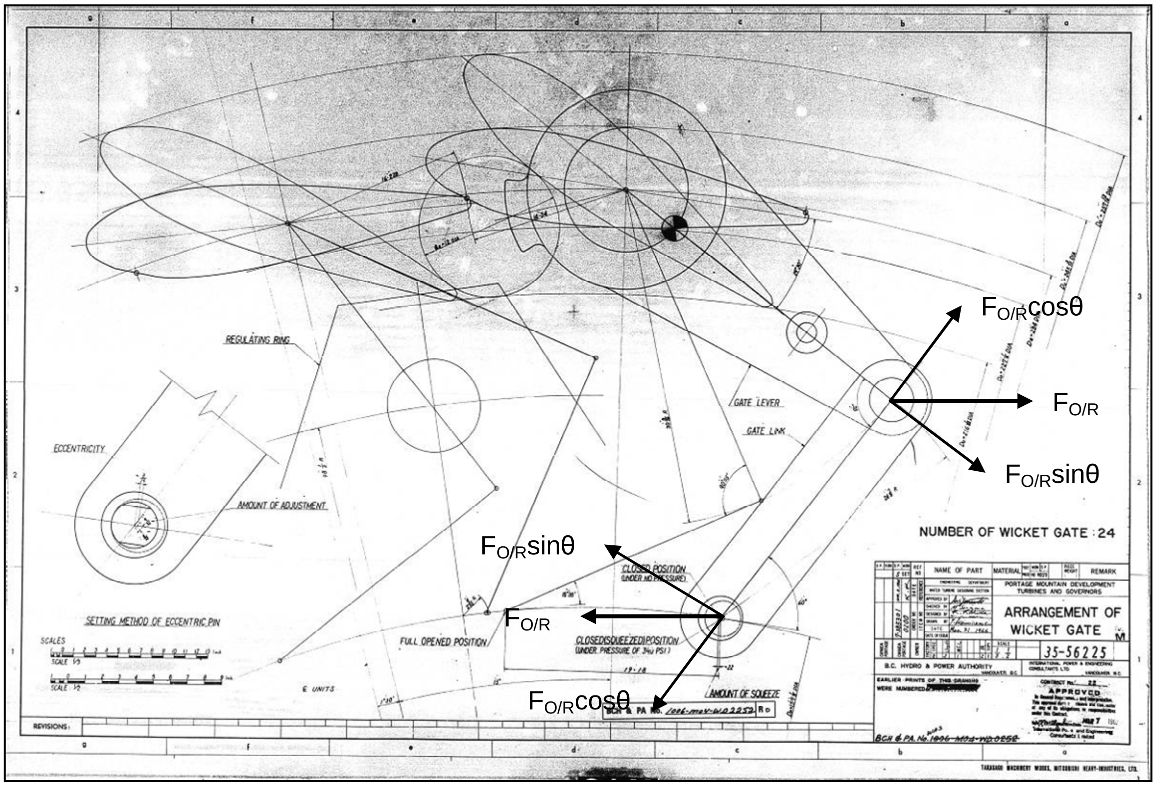


Figure 22: Force Transmitted from Operating Mechanism to Shear Pin

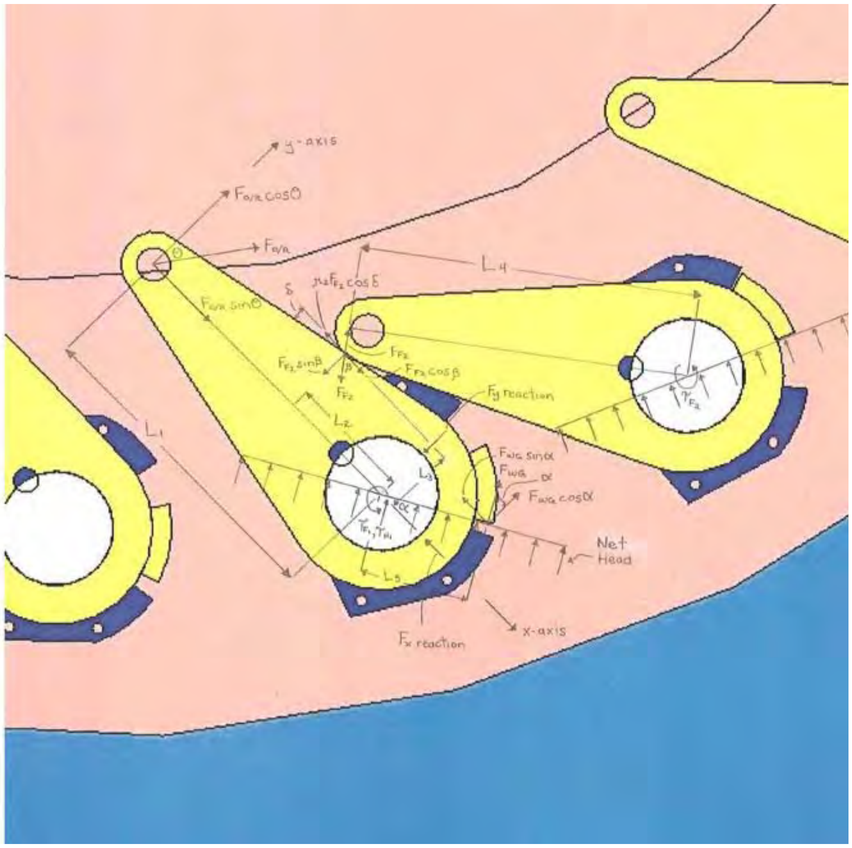


Figure 23: Free Body Diagram of Contacting Gate Levers

The equation relating the forces acting on the gate lever to the force applied to the shear pin from the operating ring ($F_{O/R}$) is derived from Figure 23 and presented below. Full derivation of the equation is presented in Appendix H. See Table 7 for a description of the parameters used in the equation.

$$F_{O/R} = \frac{F_{F2}\left(L_2 \sin\beta + L_2\mu_2 \sin\delta + L_3\mu_2 \cos\delta - L_3 \cos\beta - \mu_1\mu_2 r_1(\cos\delta + \sin\delta)\right) + F_{WG}\mu_1 r_1(\cos\alpha - \sin\alpha) + \tau_{F\_bent\_gate} + \tau_{H1}}{L_1 \cos\theta - \mu_1 r_1(\sin\theta + \cos\theta)}$$

Failure of a shear pin occurs when $F_{O/R}$ exceeds the breaking strength. For a new shear pin, this value is 267,546N.

Table 7: Summary of Parameters Used in Analysis

Parameter	Description	Value
$F_{O/R}$	Force applied to the shear pin from the operating ring	Calculated
F_{F2}	Force transferred from closed wicket gate to adjacent wicket gate	Calculated
τ_{F1}	Friction torque on open wicket gate	Calculated
τ_{H1}	Hydraulic torque on a wicket gate opened to 21.5°	32,000Nm – Estimated from model test report (GE proposed Units 1-5 runner development, Dec. 2004)
F_{WG}	Hydraulic force acting on the wicket gate center of pressure, resulting in hydraulic torque τ_{H1}.	Calculated based upon the assumption that for a symmetric aerofoil, the center of pressure is located at ¼ of the distance between the nose and tail, and the hydraulic torque on a wicket gate opened to 21.5°
τ_{F2}	Friction torque on closed wicket gate	Calculated
L_1	Moment arm	0.77m – Measured from CAD model
L_2	Moment arm	0.29m – Measured from CAD model
L_3	Moment arm	0.17m – Measured from CAD model
L_4	Moment arm	0.81m – Measured from CAD model
L_5	Moment arm	0.24m – Calculated based upon the assumption that for a symmetric aerofoil, the center of pressure is located at ¼ of the distance between the nose and tail
r_1	Radius of intermediate journal sleeve	0.1607m – Taken from Mitsubishi drawing
α	Angle between wicket gate and lever	29.5° - Taken from Mitsubishi drawing
β	Angle	54° - Measured from CAD model
θ	Angle	32° - Calculated from Mitsubishi drawing
P_{net}	Net head at distributor on March 02, 2008	1,506,980Pa – Pressure due to NSHE of 1510m^2/s^2
A_{WG}	Projected area of wicket gate vane	0.953m^2 – Calculated from Mitsubishi drawing
μ_1	Static friction coefficient between bronze and steel	0.2 – Published value
μ_2	Static friction coefficient between steel and steel	1.0 – Published value of 0.8, increased by 25% to account for rough, oxidized surfaces
$F_{X\_reaction}$	Reaction force on wicket gate stem	Calculated
$F_{Y\_reaction}$	Reaction force on wicket gate stem	Calculated

Case One - Cascade Shear Pin Failure due to Friction between Contacting Levers

Assumptions for Analysis

1. F_{F2} is a static force and is from the summation of the following torques acting on the closed wicket gate:
   (a) The friction torque due to the wicket gate being bent, due to the misalignment in the headcover (see Appendix H).
   (b) The friction torque resulting from full hydrostatic pressure acting on the closed gate.

Result

F_{F2} is calculated to be 81,679N and $F_{O/R}$ is calculated to be 128,987N. $F_{O/R}$ in this case is 48% of the breaking strength of a new shear pin.

Conclusions from Case One Analysis

1. Frictional forces between contacting wicket gate levers are likely not enough to break shear pins; gate levers in contact will slide past one another. This is also supported by BC Hydro's operational experiences; normal turbine operation (starts, stops, turbine mode, synchronous condense mode) can be maintained with a single broken shear pin.
2. Cascade failure of shear pins 12, 13 and 14 was likely not a result of excessive friction in the wicket gates and levers.

Case Two – Cascade Shear Pin Failure due to Impact between Contacting Levers

Assumptions for Analysis

1. F_{F2} is calculated from the impact force of the closing gate lever contacting the adjacent gate lever
2. The hydraulic torque acting on the closing wicket gate is the same as τ_{H1} (32,000Nm) due to the same initial positions.
3. The hydraulic torque acting on the closing wicket gate remains constant as the gate closes.
4. The total torque acting on the closing gate is the sum of the following torques:
   (a) The hydraulic torque τ_{H1}.
   (b) The friction torque due to the wicket gate being bent, due to the misalignment in the headcover (see Appendix H).
   (c) The friction torque due to the force that induces the hydraulic torque τ_{H1}.
5. When the gate levers impact, deceleration of the closing gate occurs in 0.04 seconds.
6. Frictional force $\mu_2 F_{F2}$ exists at the moment of impact because the wicket gates were opening at the time of failure.

Results

F_{F2} is calculated to be 298,733N and $F_{O/R}$ is calculated to be 237,633N. $F_{O/R}$ in this case is 89% of the breaking strength of a new shear pin. This is an interesting result, as it is within the normal range of breaking strengths for new and in-service shear pins. Impact between gate levers is a likely shear pin failure mode and could explain the dual shear pin failures experienced on Unit 1 in 2001, and on Unit 3 on March 02, 2008. The result is close enough to the theoretical breaking strength of a shear pin that it could explain why a shear pin may or may not fail due to impact. This may explain why only shear pin 12 broke after shear pin 11 failed - the resulting force from the impact between gate lever 12 and 13 did not exceed the breaking strength of shear pin 13, but likely damaged it. The inconclusive fracture surface observed on shear pin 13 (see Appendix F) was a result of turbine operation between time 05:10:54 and 05:14:12.

This cascading failure shear pin may have stopped at shear pin 15 due to the good condition of this pin.

Conclusions from Case Two Analysis

1. Calculations indicate that the impact force generated by the rapid closure of a desynchronised gate lever is significant and that the resultant force on the adjacent shear pin is within the normal range of breaking strength for the shear pin.

APPENDIX H: WICKET GATE CALCULATIONS

APPENDIX H: WICKET GATE CALCULATIONS

Equation Relating Forces in Contacting Wicket Gate Levers

<u>Force Balance X-Direction (ref. Figure 23)</u>

$$\sum F_x = 0 = F_{O/R}\sin\theta - \mu_2 F_{F2} + F_{F2}\cos\beta - F_{WG}\sin\alpha - F_{Xreaction}$$

$$F_{Xreaction} = F_{O/R}\sin\theta - \mu_2 F_{F2} + F_{F2}\cos\beta - F_{WG}\sin\alpha$$

<u>Force Balance Y-Direction (ref. Figure 23)</u>

$$\sum F_y = 0 = F_{O/R}\cos\theta - F_{F2}\cos\beta + F_{WG}\cos\alpha - F_{Yreaction}$$

$$F_{Yreaction} = F_{O/R}\cos\theta - F_{F2}\cos\beta + F_{WG}\cos\alpha$$

<u>Friction Torque on Open Wicket Gate (ref. Figure 23)</u>

$$\tau_{F1} = \tau_{F\_bent\_gate} + \tau_{FX\_reaction} + \tau_{FY\_reaction}$$

$$\tau_{FX\_reaction} = \mu_1 F_{Xreaction} r_1 = \mu_1 r_1 \left(F_{O/R}\sin\theta - \mu_2 F_{F2} + F_{F2}\cos\beta - F_{WG}\sin\alpha\right)$$

$$\tau_{FY\_reaction} = \mu_1 F_{Yreaction} r_1 = \mu_1 r_1 \left(F_{O/R}\cos\theta - F_{F2}\cos\beta + F_{WG}\cos\alpha\right)$$

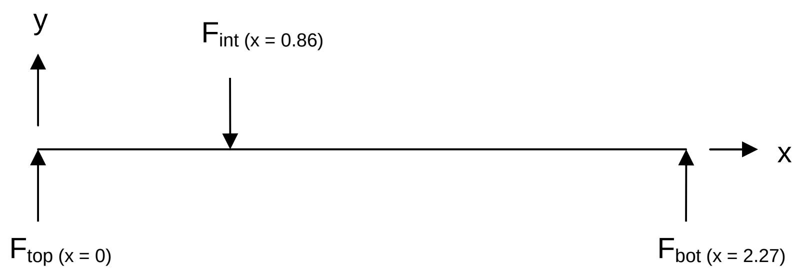
<u>Moment Balance about Wicket Gate Axis (ref. Figure 23)</u>

$$\sum M = 0 = -\left(F_{O/R}\cos\theta\right)L_1 + \left(F_{F2}\sin\beta\right)L_2 + \left(\mu_2 F_{F2} - F_{F2}\cos\beta\right)L_3 - \tau_{F1} + \tau_{H1}$$

$$\sum M = 0 = -\left(F_{O/R}\cos\theta\right)L_1 + \left(F_{F2}\sin\beta\right)L_2 + \left(\mu_2 F_{F2} - F_{F2}\cos\beta\right)L_3$$
$$+ \tau_{F\_bent\_gate} + \tau_{FX\_reaction} + \tau_{FY\_reaction} + \tau_{H1}$$

$$F_{O/R} = \frac{F_{F2}\left(L_2\sin\beta + L_2\mu_2\sin\delta + L_3\mu_2\cos\delta - L_3\cos\beta - \mu_1\mu_2 r_1(\cos\delta + \sin\delta)\right) + F_{WG}\mu_1 r_1(\cos\alpha - \sin\alpha) + \tau_{F\_bent\_gate} + \tau_{H1}}{L_1\cos\theta - \mu_1 r_1(\sin\theta + \cos\theta)}$$

Bending Force in the Wicket Gate



Assumptions

1. Wicket gate can be modelled as a rod with a circular cross-section. The length is equivalent to the distance between the mid-points of the top and bottom journals. The sectional radius is equivalent to the gate stem.
2. F_{int} is the force required to deflect the wicket gate 1.25 mm at the intermediate journal. The magnitude of the deflection is based upon actual measurements taken during the disassembly of Unit 3 turbine. Diametrical measurements of the intermediate bushings indicated out-of-roundness ranging from 0.5mm to 2.0mm. Dial-indicator measurements taken at the intermediate journals on the wicket gates indicated runouts ranging from 1.0 to 3.0 mm.
3. Wicket gate deflection at top and bottom journals is zero.

Sectional Properties

$$I = \frac{\pi}{4} r^4 = \frac{\pi}{4}(0.016)^4 = 5.1472x10^{-4}\, m^4$$

$$E = 207x10^9\, Pa$$

Moment Balances

$$\sum M_{x=2.27} = 0 = -2.27F_{top} + 1.41F_{\text{int}}$$

$$F_{top} = 0.621F_{\text{int}}$$

$$\sum M_{x=0} = 0 = -0.86F_{\text{int}} + 2.27F_{bot}$$

$$F_{bot} = 0.379F_{\text{int}}$$

Deflection Equation

$$V(x) = F_{top}\langle x\rangle^0 - F_{\text{int}}\langle x-0.86\rangle^0 + F_{bot}\langle x-2.27\rangle^0$$

$$EI\frac{d^2y}{dx^2} = M(x) = F_{top}\langle x\rangle^1 - F_{\text{int}}\langle x-0.86\rangle^1 + F_{bot}\langle x-2.27\rangle^1$$

$$EI\frac{dy}{dx} = \frac{F_{top}}{2}\langle x\rangle^2 - \frac{F_{\text{int}}}{2}\langle x-0.86\rangle^2 + \frac{F_{bot}}{2}\langle x-2.27\rangle^2 + C_1$$

$$EIy(x) = \frac{F_{top}}{6}\langle x\rangle^3 - \frac{F_{\text{int}}}{6}\langle x-0.86\rangle^3 + \frac{F_{bot}}{6}\langle x-2.27\rangle^3 + C_1x + C_2$$

Determination of Constants

$$y(0) = 0$$

$$C_2 = 0$$

$$y(2.27) = 0$$

$$C_1 = 0.207F_{\text{int}} - 0.859F_{top}$$

Deflection Equation with Substituted Values

$$y(x) = \frac{1}{EI}\left(\frac{0.621F_{\text{int}}}{6}\langle x\rangle^3 - \frac{F_{\text{int}}}{6}\langle x-0.86\rangle^3 + \frac{0.379F_{\text{int}}}{6}\langle x-2.27\rangle^3 - 0.326F_{\text{int}}x\right)$$

$$y(0.86) = -0.0015$$

$$-0.0015EI = \frac{0.621F_{\text{int}}}{6}(0.86)^3 - 0.326F_{\text{int}}(0.86)$$

$$0.0015EI = 0.214F_{\text{int}}$$

$$F_{\text{int}} = \frac{(0.00125)(5.1472x10^{-4})(207x10^9)}{0.214} = 622{,}354N$$

Friction Torque due to Bent Gate

$$\tau_{F\_bent\_gate} = \mu_1 F_{\text{int}} r_1 = (0.2)(622{,}354)(0.1607) = 20{,}002Nm$$

Calculations Supporting Case One

Friction Torque on Closed Wicket Gate

$$\tau_{F2} = \tau_{F\_pressure} + \tau_{F\_bent\_gate}$$

$$\tau_{F\_pressure} = \mu_1 P_{reservoir} A_{WG} r_1 = 0.2(1{,}506{,}980)(0.953)(0.1607) = 46{,}158Nm$$

$$\tau_{F2} = 20{,}002 + 46{,}158 = 66{,}160Nm$$

Force Transferred to Adjacent Wicket Gate

$$F_{F2} = \frac{\tau_{F2}}{L_4} = \frac{66{,}160}{0.81} = 81{,}679N$$

Force due to Hydraulic Torque on Open Wicket Gate

$$F_{WG} = \frac{\tau_{H1}}{L_5} = \frac{32{,}000Nm}{0.24m} = 133{,}333N$$

Equation with Substituted Values

$$F_{O/R} = \frac{F_{F2}(L_2 \sin\beta + L_2\mu_2 \sin\delta + L_3\mu_2 \cos\delta - L_3 \cos\beta - \mu_1\mu_2 r_1(\cos\delta + \sin\delta)) + F_{WG}\mu_1 r_1(\cos\alpha - \sin\alpha) + \tau_{F\_bent\_gate} + \tau_{H1}}{L_1 \cos\theta - \mu_1 r_1(\sin\theta + \cos\theta)}$$

$$F_{O/R} = 128{,}987N$$

Calculations Supporting Case Two

Wicket Gate Inertia

Assumptions:

1. The stem cross-section is modelled as a cylindrical rod, with a constant radius of 0.16m. The total length is the sum of the top and bottom stems on the real wicket gate.
2. The vane cross-section is modelled as a rectangle. The depth is the same as on the real gate. The width is an 'equivalent', equal to the value required to obtain the same cross-sectional area as the real gate vane. The length is the same as the real wicket gate vane.
3. The gate lever is modelled as a rectangle with equivalent area to the real lever.

$$I_{WG\_total} = 86.38 kgm^2$$

$$m_{WG\_total} = 1852 kg$$

Torques Acting on Closing Wicket Gate

$$\tau_{H1} = 32{,}000 Nm$$

$$\tau_{F\_bent\_gate} = \mu_1 F_{\text{int}} r_1 = (0.2)(622{,}354)(0.1607) = 20{,}002 Nm$$

$$\tau_{F\_hydraulic\_force} = \mu_1 F_{WG} r_1 = (0.2)(145{,}833)(0.1607) = 4697 Nm$$

$$\tau_{H2} = \tau_{H1} - \tau_{F\_bent\_gate} - \tau_{F\_hydraulic\_force} = 7{,}311 Nm$$

Kinematic and Kinetic Equations Describing Impact

The following new parameters are introduced:

$\alpha_{closing}$ - Angular acceleration of wicket gate during closing

$\delta_{closing}$ - Angle swept by gate lever before contacting the adjacent gate lever

$\omega_{closing}$ - Angular velocity of gate lever prior to impact

$\alpha_{deceleration}$ - Angular deceleration of gate lever during impact

$$\alpha_{closing} = \frac{\tau_{H2}}{I_{WG\_total}} = \frac{7,311}{86.38} = 84.5 rads^{-2}$$

$$\delta_{closing} = 21° = 0.366 rad$$

$$\omega_{closing} = \sqrt{2\alpha_{closing}\delta_{closing}}$$

$$\alpha_{deceleration} = \frac{\omega_{closing}}{t_{deceleration}} = 199.1 rads^{-1}$$

Force Transferred to Adjacent Wicket Gate

$$F_{F2} = m_{WG\_total}\alpha_{deceleration}L_4 = 298,733N$$

Equation with Substituted Values

$$F_{O/R} = \frac{F_{F2}\left(L_2 \sin\beta + L_2\mu_2 \sin\delta + L_3\mu_2 \cos\delta - L_3 \cos\beta - \mu_1\mu_2 r_1(\cos\delta + \sin\delta)\right) + F_{WG}\mu_1 r_1(\cos\alpha - \sin\alpha) + \tau_{F\_bent\_gate} + \tau_{H1}}{L_1 \cos\theta - \mu_1 r_1(\sin\theta + \cos\theta)}$$

$$F_{O/R} = 237,633N$$

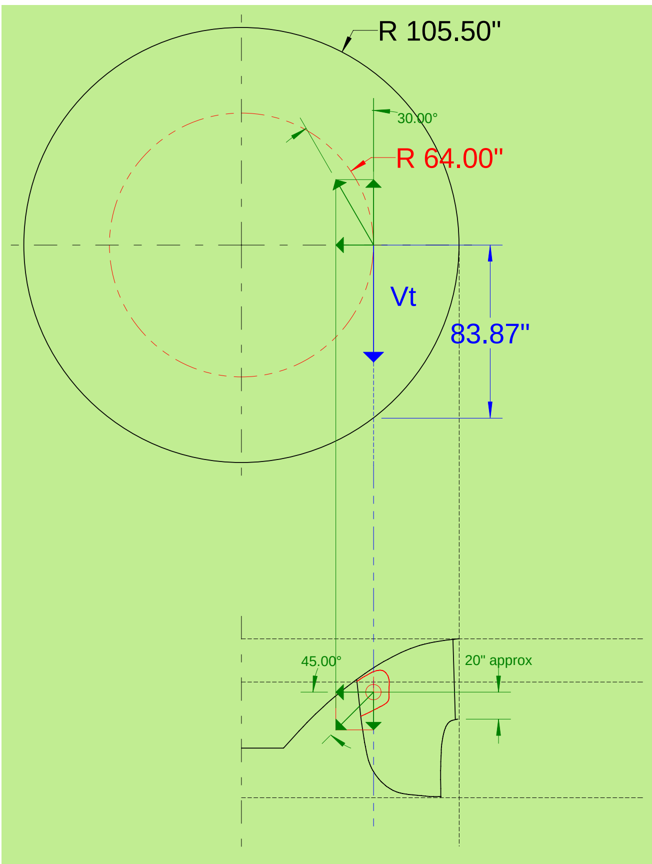
APPENDIX I: OTHER CALCULATIONS

GMS - G3 Failure - Behavior of a free blade section detached from the trailing edge

$n := 150 \cdot \frac{1}{min}$ Nominal rotational speed

$\omega := \frac{2 \cdot \pi \cdot n}{60 \frac{s}{min}}$ $\omega = 15.708 \cdot \frac{rad}{s}$ Nominal Angular speed

$r := 64 \cdot in$ Radius of the mass center of the broken blade section



Tangential speed of the broken section of blade right after rupture:

$Vt := \omega \cdot r$ $Vt = 25.535 \frac{m}{s}$

$Vt = 91.926 \cdot \frac{km}{hr}$

$di := 90 \cdot in$ Distance to travel for the blade section before impact in the WG (evaluated from CAD dwg)

$di = 2.286\,m$

Time required to travel "di" at a speed of "Vt":

$t := \frac{di}{Vt}$ $t = 0.08952\,s$

Effect of gravity on the blade section (vertical loss of "altitude" during the time "t"):

$g = 9.807\,\frac{m}{s^2}$ Earth gravitational acceleration

$Ev := \frac{1}{2}\cdot g\cdot t^2$ $Ev = 0.039\,m$ Much smaller than the initial 0.510 m approx above the bottom ring at the separation moment.

Note that the calculation above consider no effect of the Turbine water flow (event assumed to be happening right behind the 4 closed WG # 11 to 14.

Clearly, the blade section lands in the WG area with it initial speed of 25 m/s approx (neglecting the friction effect of air and of the little water that may be circulating behind the closed WG .

The next set of calculations below, look at the water flow effect, should the blade section get detached in an area where the WG are opened.

The flow in the Turbine was estimated from the 97.2% gate opening and the information obtained from the model test in January 2008 (NSHE = 1510 m2/s2).

$Q := 188\cdot\frac{m^3}{s}$ estimated flow around 97% gate opening

Assumption: The flow above is the one existing right before the major failure; this number is used for the calculation to come. As 4 WG were assumed closed at the time right before the failure, this very flow translates in higher flow velocity proportionally to 4 gates closed over 24 gates total.

Estimated "outlet" opening at the radius where the blade section failed:

$th := 0.05\cdot m$ Thickness of the blade in the failure area

$oph := \left(\frac{\pi\cdot 2\cdot r}{17}\right) - th$ $oph = 0.551\,m$

Estimated transverse opening between blades:

$opv := 0.60\cdot m$

Section of the inter blade channel:

$A := oph\cdot opv$ $A = 0.33\,m^2$

Estimated average speed in the interblade channel (with 4 gates closed):

$$V := \frac{Q}{(A \cdot 17) \cdot \frac{20}{24}} \qquad V = 40.154 \frac{m}{s}$$

Module of the vector force and resulting acceleration/deceleraton of the free blade section:

left column = if the blade section travel with is smallest section against the flow (the more likely case).

right column = if the blade section travel with is largest section against the flow (unlikely case).

$$S1 := 1.8 \cdot m \cdot th \qquad S1 = 0.09\,m^2$$

$$S2 := 1.8m \cdot 1.8 \cdot m \qquad S2 = 3.24\,m^2$$

$\rho := 1000 \frac{kg}{m^3}$ Water density

$k1 := 0.15$ Hydrodynamic coef.

$k2 := 1$

Relative *simplified* speed of the blade section in the water:

$$VT := Vt + V \qquad VT = 65.689 \frac{m}{s}$$

Drag force on the blade section:

$$F1 := \frac{1}{2} k1 \cdot \rho \cdot S1 \cdot VT^2$$

$$F1 = 2.913 \times 10^4\,N$$

Drag force on the blade section:

$$F2 := \frac{1}{2} k2 \cdot \rho \cdot S2 \cdot VT^2$$

$$F2 = 6.99 \times 10^6\,N$$

Estimated mass of the blade section:

$$M := (1.8m)^2 \cdot th \cdot 7860 \cdot \frac{kg}{m^3} \qquad M = 1.273 \times 10^3\,kg$$

Corresponding deceleration:

$$\gamma1 := \frac{-F1}{M} \qquad \gamma1 = -22.874 \frac{m}{s^2}$$

Corresponding deceleration:

$$\gamma2 := \frac{-F2}{M} \qquad \gamma2 = -5489.9 \frac{m}{s^2}$$

Duration before to reach speed = 0

$$T1 := \frac{-Vt}{\gamma 1} \qquad T1 = 1.116\,s$$

Distance covered during "T1":

$$E1 := \frac{1}{2}\cdot\gamma 1\cdot T1^2 + Vt\cdot T1$$

$$E1 = 14.252\,m$$

Can reach the WG easily

Actual duration to cover the 2.286 m:

$$Tx := 0.09345\cdot s$$

$$E := \frac{1}{2}\cdot\gamma 1\cdot Tx^2 + Vt\cdot Tx$$

$$E = 2.286\,m$$

Duration before to reach speed = 0

$$T2 := \frac{-Vt}{\gamma 2} \qquad T2 = 0.0047\,s$$

Distance covered during "T2":

$$E2 := \frac{1}{2}\cdot\gamma 2\cdot T2^2 + Vt\cdot T2$$

$$E2 = 0.059\,m$$

Does not reach the WG

DAB4

20080824

APPENDIX J: SEQUENCE OF EVENTS RECORDER DATA

APPENDIX J: SEQUENCE OF EVENTS RECORDER DATA

The alarm data archived by the GMS Sequence of Events Recorder is presented in Table 8. Note the following with regards to the times listed in Table 8.

- The SER Time and OI Time (Figure 1) are out-of-synch by 3:00 minutes. 05:02:00 SER Time corresponds to 5:05:00 OI Time.
- SER time 05:03:03 was selected as the zero-time event because it was the first alarm recorded by the SER and corresponds well with the change in operating parameters described in Figure 1, Point 1.
- There is very good correspondence between the timing of significant events recorded in OI and significant events recorded by the SER (i.e. initiation of the runner failure event, 86N shut down, and emergency shut down)

Significant information gathered from Table 8 includes:

- Between 05:02:00 and 05:19:00 SER time (05:05:00 and 05:22:00 OI time), the only alarms indicating potential turbine problems were high oil levels (generator and turbine) and high bearing temperature (turbine). These alarms were intermittent; the multiple ALARM/CLEAR sequences may have been attributed to 'chatter' from the sensing element. Further to this, no vibration alarms registered. During this time period, it would not have been obvious to the GMS Operator that there was a significant problem with the turbine.
- Following 05:19:00 SER time (05:22:00 OI time), when rapid closure of the wicket gates occurred, several alarms registered that, in addition to the previous alarms, would have suggested that there indeed was a problem with the turbine. The changes in AGC modes (Figure 1 Point 5) immediately following this event indicate that the operator recognized that a problem had occurred and attempted to regain control over the Unit.
- At 05:24:15 SER time (05:27:15 OI time), an 86N shut down was initiated by the turbine bearing high temperature alarm (See Figure 1, Point 6). The closure of the wicket gates to the speed-no-load position was incomplete because all of the shear pins had been broken during the rapid closure of the wicket gates and the gates were desynchronised from the operating mechanism.

- At 05:25:30 SER time (05:28:30 OI time), the operator correctly initiated an emergency shutdown of the Unit.

Table 8: SER Data Collected During the Unit 3 Runner Failure

Date yyyy-mm-dd	SER Time hh.mm.ss.sss	Incremental Time From Zero Time Event: days hh:mm:secs	Point	Code	Message
2008-03-02	05:44:12.577	+ 0 00:42:08.663	156	A	GEN 3 BEARING OIL LEVEL HIGH-LOW
2008-03-02	05:26:11.349	+ 0 00:24:07.435	1419	N	U3 INTAKE GATE TROUBLE NORMAL
2008-03-02	05:26:08.537	+ 0 00:24:04.623	177	A	U3 GOVERNOR NON-URGENT ALARM
2008-03-02	05:25:33.564	+ 0 00:23:29.650	136	N	U3 REGULATOR/BUS VOLT CLEARED
2008-03-02	05:25:31.811	+ 0 00:23:27.897	1419	A	U3 INTAKE GATE TROUBLE FAILURE
2008-03-02	05:25:30.321	+ 0 00:23:26.407	136	A	U3 REGULATOR/BUS VOLT FAILURE
2008-03-02	05:25:29.964	+ 0 00:23:26.050	755	N	FAULT RECORDER RESET
2008-03-02	05:25:29.823	+ 0 00:23:25.909	842	A	13CB3 TRIPPED
2008-03-02	05:25:29.515	+ 0 00:23:25.601	755	A	FAULT RECORDER OPERATED
2008-03-02	05:25:29.495	+ 0 00:23:25.581	132	A	U3 PY EMERG LOCKOUT SHDN OPERATED
2008-03-02	05:24:56.738	+ 0 00:22:52.824	173	N	GOV 3 OIL SYST LAG PUMP STOPPED
2008-03-02	05:24:23.059	+ 0 00:22:19.145	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:24:22.802	+ 0 00:22:18.888	167	A	U3 ACC TANK OIL LEVEL HIGH-LOW
2008-03-02	05:24:22.307	+ 0 00:22:18.393	173	A	GOV 3 OIL SYST LAG PUMP RUNNING
2008-03-02	05:24:15.625	+ 0 00:22:11.711	131	A	U3 NORMAL LOCKOUT SHDN OPERATED
2008-03-02	05:20:46.136	+ 0 00:18:42.222	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:20:01.172	+ 0 00:17:57.258	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:20:01.142	+ 0 00:17:57.228	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:20:01.074	+ 0 00:17:57.160	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:20:01.061	+ 0 00:17:57.147	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:20:00.924	+ 0 00:17:57.010	156	N	GEN 3 BEARING OIL LEVEL RESTORED
2008-03-02	05:19:20.200	+ 0 00:17:16.286	153	A	U3 TUR PIT WATER LEVEL HIGH-LOW
2008-03-02	05:19:13.287	+ 0 00:17:09.373	190	N	U3 OVEREXCITATION LIMIT RESET
2008-03-02	05:19:10.779	+ 0 00:17:06.865	154	A	U3 DELUGE/DELUGE TROUBLE OPERATED
2008-03-02	05:19:10.246	+ 0 00:17:06.332	755	N	FAULT RECORDER RESET
2008-03-02	05:19:09.797	+ 0 00:17:05.883	755	A	FAULT RECORDER OPERATED
2008-03-02	05:19:09.766	+ 0 00:17:05.852	192	N	U3 MIN. EXCITATION LIMIT RESET
2008-03-02	05:19:09.689	+ 0 00:17:05.775	192	A	U3 MIN. EXCITATION LIMIT APPLIED
2008-03-02	05:19:09.561	+ 0 00:17:05.647	755	N	FAULT RECORDER RESET
2008-03-02	05:19:09.455	+ 0 00:17:05.541	192	N	U3 MIN. EXCITATION LIMIT RESET
2008-03-02	05:19:09.127	+ 0 00:17:05.213	190	A	U3 OVEREXCITATION LIMIT APPLIED
2008-03-02	05:19:09.112	+ 0 00:17:05.198	755	A	FAULT RECORDER OPERATED
2008-03-02	05:19:08.900	+ 0 00:17:04.986	192	A	U3 MIN. EXCITATION LIMIT APPLIED
2008-03-02	05:19:08.766	+ 0 00:17:04.852	192	N	U3 MIN. EXCITATION LIMIT RESET
2008-03-02	05:19:08.516	+ 0 00:17:04.602	1245	A	G1-5 LFC GATE LIMITED ALARM
2008-03-02	05:19:08.516	+ 0 00:17:04.602	172	A	GOV 3 URGENT ALARM
2008-03-02	05:19:08.182	+ 0 00:17:04.268	192	A	U3 MIN. EXCITATION LIMIT APPLIED
2008-03-02	05:17:18.347	+ 0 00:15:14.433	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:17:18.334	+ 0 00:15:14.420	157	N	TUR 3 BRG OIL LEVEL RESTORED

Date yyyy-mm-dd	SER Time hh.mm.ss.sss	Incremental Time From Zero Time Event: days hh:mm:secs	Point	Code	Message
2008-03-02	05:17:18.292	+ 0 00:15:14.378	156	A	GEN 3 BEARING OIL LEVEL HIGH-LOW
2008-03-02	05:17:18.178	+ 0 00:15:14.264	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:17:18.148	+ 0 00:15:14.234	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:17:18.082	+ 0 00:15:14.168	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:17:18.052	+ 0 00:15:14.138	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:17:17.986	+ 0 00:15:14.072	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:17:17.973	+ 0 00:15:14.059	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:17:17.906	+ 0 00:15:13.992	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:17:17.894	+ 0 00:15:13.980	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:17:17.735	+ 0 00:15:13.821	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:17:17.705	+ 0 00:15:13.791	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:17:17.668	+ 0 00:15:13.754	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:17:17.655	+ 0 00:15:13.741	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:17:17.582	+ 0 00:15:13.668	156	N	GEN 3 BEARING OIL LEVEL RESTORED
2008-03-02	05:15:41.285	+ 0 00:13:37.371	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:15:41.238	+ 0 00:13:37.324	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:15:36.831	+ 0 00:13:32.917	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:15:36.790	+ 0 00:13:32.876	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:15:20.024	+ 0 00:13:16.110	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:15:19.993	+ 0 00:13:16.079	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:14:46.149	+ 0 00:12:42.235	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:46.127	+ 0 00:12:42.213	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:46.057	+ 0 00:12:42.143	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:14:46.019	+ 0 00:12:42.105	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:14:44.988	+ 0 00:12:41.074	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:44.977	+ 0 00:12:41.063	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:44.895	+ 0 00:12:40.981	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:44.884	+ 0 00:12:40.970	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:44.864	+ 0 00:12:40.950	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:44.852	+ 0 00:12:40.938	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:44.734	+ 0 00:12:40.820	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:44.723	+ 0 00:12:40.809	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:44.353	+ 0 00:12:40.439	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:44.340	+ 0 00:12:40.426	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:44.204	+ 0 00:12:40.290	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:44.182	+ 0 00:12:40.268	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:43.768	+ 0 00:12:39.854	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:43.757	+ 0 00:12:39.843	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:43.731	+ 0 00:12:39.817	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:43.719	+ 0 00:12:39.805	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:43.667	+ 0 00:12:39.753	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:43.653	+ 0 00:12:39.739	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:43.627	+ 0 00:12:39.713	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:43.616	+ 0 00:12:39.702	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:43.436	+ 0 00:12:39.522	162	A	TUR 3 GUIDE BEARING TEMP HIGH

Date yyyy-mm-dd	SER Time hh.mm.ss.sss	Incremental Time From Zero Time Event: days hh:mm:secs	Point	Code	Message
2008-03-02	05:14:43.424	+ 0 00:12:39.510	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:43.413	+ 0 00:12:39.499	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:43.402	+ 0 00:12:39.488	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:43.391	+ 0 00:12:39.477	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:43.367	+ 0 00:12:39.453	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:43.279	+ 0 00:12:39.365	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:43.245	+ 0 00:12:39.331	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:43.225	+ 0 00:12:39.311	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:43.213	+ 0 00:12:39.299	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:43.157	+ 0 00:12:39.243	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:43.145	+ 0 00:12:39.231	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:43.097	+ 0 00:12:39.183	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:43.049	+ 0 00:12:39.135	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.969	+ 0 00:12:39.055	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.955	+ 0 00:12:39.041	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.916	+ 0 00:12:39.002	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.905	+ 0 00:12:38.991	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.893	+ 0 00:12:38.979	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.882	+ 0 00:12:38.968	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.868	+ 0 00:12:38.954	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.854	+ 0 00:12:38.940	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.842	+ 0 00:12:38.928	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.793	+ 0 00:12:38.879	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.731	+ 0 00:12:38.817	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.706	+ 0 00:12:38.792	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.683	+ 0 00:12:38.769	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.650	+ 0 00:12:38.736	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.639	+ 0 00:12:38.725	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.625	+ 0 00:12:38.711	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.610	+ 0 00:12:38.696	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.571	+ 0 00:12:38.657	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.560	+ 0 00:12:38.646	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.509	+ 0 00:12:38.595	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.496	+ 0 00:12:38.582	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.481	+ 0 00:12:38.567	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.470	+ 0 00:12:38.556	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.453	+ 0 00:12:38.539	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.441	+ 0 00:12:38.527	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.430	+ 0 00:12:38.516	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.407	+ 0 00:12:38.493	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.370	+ 0 00:12:38.456	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.347	+ 0 00:12:38.433	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.279	+ 0 00:12:38.365	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.261	+ 0 00:12:38.347	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.248	+ 0 00:12:38.334	162	N	TUR 3 GUIDE BEARING TEMP NORMAL

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2008-03-02	05:14:42.237	+ 0 00:12:38.323	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.183	+ 0 00:12:38.269	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.149	+ 0 00:12:38.235	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.121	+ 0 00:12:38.207	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.109	+ 0 00:12:38.195	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.098	+ 0 00:12:38.184	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:42.074	+ 0 00:12:38.160	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:42.013	+ 0 00:12:38.099	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.957	+ 0 00:12:38.043	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.945	+ 0 00:12:38.031	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.934	+ 0 00:12:38.020	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.921	+ 0 00:12:38.007	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.899	+ 0 00:12:37.985	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.886	+ 0 00:12:37.972	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.875	+ 0 00:12:37.961	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.841	+ 0 00:12:37.927	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.829	+ 0 00:12:37.915	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.788	+ 0 00:12:37.874	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.774	+ 0 00:12:37.860	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.692	+ 0 00:12:37.778	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.677	+ 0 00:12:37.763	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.652	+ 0 00:12:37.738	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.629	+ 0 00:12:37.715	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.615	+ 0 00:12:37.701	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.603	+ 0 00:12:37.689	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.588	+ 0 00:12:37.674	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.542	+ 0 00:12:37.628	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.508	+ 0 00:12:37.594	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.441	+ 0 00:12:37.527	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.379	+ 0 00:12:37.465	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.353	+ 0 00:12:37.439	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.281	+ 0 00:12:37.367	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.270	+ 0 00:12:37.356	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.257	+ 0 00:12:37.343	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.246	+ 0 00:12:37.332	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.234	+ 0 00:12:37.320	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.220	+ 0 00:12:37.306	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.203	+ 0 00:12:37.289	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.180	+ 0 00:12:37.266	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.143	+ 0 00:12:37.229	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.131	+ 0 00:12:37.217	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.101	+ 0 00:12:37.187	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.090	+ 0 00:12:37.176	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.077	+ 0 00:12:37.163	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.066	+ 0 00:12:37.152	162	A	TUR 3 GUIDE BEARING TEMP HIGH

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2008-03-02	05:14:41.052	+ 0 00:12:37.138	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:41.040	+ 0 00:12:37.126	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:41.002	+ 0 00:12:37.088	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:40.991	+ 0 00:12:37.077	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:40.978	+ 0 00:12:37.064	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:40.967	+ 0 00:12:37.053	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:40.932	+ 0 00:12:37.018	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:40.908	+ 0 00:12:36.994	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:40.893	+ 0 00:12:36.979	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:40.859	+ 0 00:12:36.945	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:40.834	+ 0 00:12:36.920	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:40.823	+ 0 00:12:36.909	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:40.793	+ 0 00:12:36.879	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:40.782	+ 0 00:12:36.868	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:40.771	+ 0 00:12:36.857	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:40.760	+ 0 00:12:36.846	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:40.748	+ 0 00:12:36.834	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:40.737	+ 0 00:12:36.823	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:40.724	+ 0 00:12:36.810	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:40.713	+ 0 00:12:36.799	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:40.524	+ 0 00:12:36.610	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:40.469	+ 0 00:12:36.555	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:40.366	+ 0 00:12:36.452	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:40.354	+ 0 00:12:36.440	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:40.282	+ 0 00:12:36.368	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:40.270	+ 0 00:12:36.356	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:40.192	+ 0 00:12:36.278	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:40.169	+ 0 00:12:36.255	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:39.945	+ 0 00:12:36.031	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:39.933	+ 0 00:12:36.019	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:39.893	+ 0 00:12:35.979	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:39.882	+ 0 00:12:35.968	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:39.792	+ 0 00:12:35.878	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:39.769	+ 0 00:12:35.855	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:39.676	+ 0 00:12:35.762	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:39.665	+ 0 00:12:35.751	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:39.557	+ 0 00:12:35.643	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:39.546	+ 0 00:12:35.632	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:39.441	+ 0 00:12:35.527	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:39.419	+ 0 00:12:35.505	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:39.408	+ 0 00:12:35.494	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:39.397	+ 0 00:12:35.483	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:39.265	+ 0 00:12:35.351	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:39.242	+ 0 00:12:35.328	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:38.914	+ 0 00:12:35.000	162	N	TUR 3 GUIDE BEARING TEMP NORMAL

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2008-03-02	05:14:38.902	+ 0 00:12:34.988	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:38.877	+ 0 00:12:34.963	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:38.866	+ 0 00:12:34.952	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:38.621	+ 0 00:12:34.707	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:38.610	+ 0 00:12:34.696	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:38.510	+ 0 00:12:34.596	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:38.498	+ 0 00:12:34.584	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:38.430	+ 0 00:12:34.516	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:38.419	+ 0 00:12:34.505	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:38.367	+ 0 00:12:34.453	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:38.355	+ 0 00:12:34.441	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:38.331	+ 0 00:12:34.417	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:38.320	+ 0 00:12:34.406	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:38.258	+ 0 00:12:34.344	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:38.234	+ 0 00:12:34.320	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:38.139	+ 0 00:12:34.225	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:38.128	+ 0 00:12:34.214	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:38.068	+ 0 00:12:34.154	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:38.056	+ 0 00:12:34.142	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:37.944	+ 0 00:12:34.030	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:37.931	+ 0 00:12:34.017	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:37.888	+ 0 00:12:33.974	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:37.876	+ 0 00:12:33.962	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:37.808	+ 0 00:12:33.894	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:37.797	+ 0 00:12:33.883	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:37.782	+ 0 00:12:33.868	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:37.771	+ 0 00:12:33.857	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:37.715	+ 0 00:12:33.801	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:37.704	+ 0 00:12:33.790	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:37.623	+ 0 00:12:33.709	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:37.601	+ 0 00:12:33.687	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:37.556	+ 0 00:12:33.642	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:37.534	+ 0 00:12:33.620	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:37.495	+ 0 00:12:33.581	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:37.484	+ 0 00:12:33.570	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:37.432	+ 0 00:12:33.518	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:37.418	+ 0 00:12:33.504	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:37.404	+ 0 00:12:33.490	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:37.392	+ 0 00:12:33.478	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:37.030	+ 0 00:12:33.116	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:37.019	+ 0 00:12:33.105	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:35.982	+ 0 00:12:32.068	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:35.970	+ 0 00:12:32.056	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:35.955	+ 0 00:12:32.041	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:35.944	+ 0 00:12:32.030	162	A	TUR 3 GUIDE BEARING TEMP HIGH

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2008-03-02	05:14:35.831	+ 0 00:12:31.917	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:35.820	+ 0 00:12:31.906	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:35.808	+ 0 00:12:31.894	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:35.797	+ 0 00:12:31.883	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:35.774	+ 0 00:12:31.860	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:35.762	+ 0 00:12:31.848	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:35.521	+ 0 00:12:31.607	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:35.509	+ 0 00:12:31.595	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:35.497	+ 0 00:12:31.583	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:35.486	+ 0 00:12:31.572	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:33.162	+ 0 00:12:29.248	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:33.149	+ 0 00:12:29.235	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:32.148	+ 0 00:12:28.234	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:32.136	+ 0 00:12:28.222	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:14:31.930	+ 0 00:12:28.016	162	N	TUR 3 GUIDE BEARING TEMP NORMAL
2008-03-02	05:14:31.918	+ 0 00:12:28.004	162	A	TUR 3 GUIDE BEARING TEMP HIGH
2008-03-02	05:13:14.077	+ 0 00:11:10.163	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:13:14.031	+ 0 00:11:10.117	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:12:39.404	+ 0 00:10:35.490	156	A	GEN 3 BEARING OIL LEVEL HIGH-LOW
2008-03-02	05:12:39.333	+ 0 00:10:35.419	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:12:39.320	+ 0 00:10:35.406	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:12:39.224	+ 0 00:10:35.310	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:12:39.193	+ 0 00:10:35.279	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:12:39.193	+ 0 00:10:35.279	156	N	GEN 3 BEARING OIL LEVEL RESTORED
2008-03-02	05:12:39.128	+ 0 00:10:35.214	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:12:39.098	+ 0 00:10:35.184	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:12:39.022	+ 0 00:10:35.108	156	A	GEN 3 BEARING OIL LEVEL HIGH-LOW
2008-03-02	05:12:38.881	+ 0 00:10:34.967	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:12:38.868	+ 0 00:10:34.954	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:12:38.772	+ 0 00:10:34.858	156	N	GEN 3 BEARING OIL LEVEL RESTORED
2008-03-02	05:12:33.576	+ 0 00:10:29.662	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:12:33.534	+ 0 00:10:29.620	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:12:06.850	+ 0 00:10:02.936	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:12:06.806	+ 0 00:10:02.892	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:11:47.667	+ 0 00:09:43.753	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:11:47.632	+ 0 00:09:43.718	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:11:32.793	+ 0 00:09:28.879	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:11:32.744	+ 0 00:09:28.830	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:11:31.249	+ 0 00:09:27.335	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:11:31.201	+ 0 00:09:27.287	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:11:30.469	+ 0 00:09:26.555	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:11:30.425	+ 0 00:09:26.511	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:11:30.161	+ 0 00:09:26.247	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:11:30.125	+ 0 00:09:26.211	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:11:21.053	+ 0 00:09:17.139	180	N	U3 13PT1 OR 13PT2 CLEARED

Date yyyy-mm-dd	SER Time hh.mm.ss.sss	Incremental Time From Zero Time Event: days hh:mm:secs	Point	Code	Message
2008-03-02	05:11:21.008	+ 0 00:09:17.094	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:11:16.464	+ 0 00:09:12.550	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:11:16.423	+ 0 00:09:12.509	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:11:12.277	+ 0 00:09:08.363	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:11:12.255	+ 0 00:09:08.341	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:10:14.662	+ 0 00:08:10.748	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:10:14.624	+ 0 00:08:10.710	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:10:02.745	+ 0 00:07:58.831	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:10:02.704	+ 0 00:07:58.790	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:09:54.923	+ 0 00:07:51.009	156	A	GEN 3 BEARING OIL LEVEL HIGH-LOW
2008-03-02	05:09:51.467	+ 0 00:07:47.553	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:09:51.432	+ 0 00:07:47.518	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:09:51.270	+ 0 00:07:47.356	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:09:51.258	+ 0 00:07:47.344	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:09:51.191	+ 0 00:07:47.277	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:09:51.179	+ 0 00:07:47.265	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:09:51.143	+ 0 00:07:47.229	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:09:51.114	+ 0 00:07:47.200	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:09:51.047	+ 0 00:07:47.133	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:09:51.035	+ 0 00:07:47.121	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:09:51.010	+ 0 00:07:47.096	156	N	GEN 3 BEARING OIL LEVEL RESTORED
2008-03-02	05:09:44.291	+ 0 00:07:40.377	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:09:44.255	+ 0 00:07:40.341	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:09:37.897	+ 0 00:07:33.983	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:09:37.850	+ 0 00:07:33.936	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:08:38.743	+ 0 00:06:34.829	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:08:38.718	+ 0 00:06:34.804	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:08:12.285	+ 0 00:06:08.371	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:08:12.246	+ 0 00:06:08.332	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:08:00.166	+ 0 00:05:56.252	156	A	GEN 3 BEARING OIL LEVEL HIGH-LOW
2008-03-02	05:07:58.203	+ 0 00:05:54.289	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:07:58.151	+ 0 00:05:54.237	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:07:56.294	+ 0 00:05:52.380	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:07:56.244	+ 0 00:05:52.330	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:07:53.444	+ 0 00:05:49.530	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:07:53.432	+ 0 00:05:49.518	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:07:53.401	+ 0 00:05:49.487	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:07:53.242	+ 0 00:05:49.328	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:07:52.930	+ 0 00:05:49.016	156	N	GEN 3 BEARING OIL LEVEL RESTORED
2008-03-02	05:07:38.523	+ 0 00:05:34.609	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:07:38.484	+ 0 00:05:34.570	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:07:26.773	+ 0 00:05:22.859	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:07:26.757	+ 0 00:05:22.843	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:07:25.271	+ 0 00:05:21.357	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:07:25.242	+ 0 00:05:21.328	180	A	U3 13PT1 OR 13PT2 FAILURE

Date yyyy-mm-dd	SER Time hh.mm.ss.sss	Incremental Time From Zero Time Event: days hh:mm:secs	Point	Code	Message
2008-03-02	05:07:20.381	+ 0 00:05:16.467	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:07:20.335	+ 0 00:05:16.421	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:07:15.666	+ 0 00:05:11.752	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:07:15.626	+ 0 00:05:11.712	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:07:11.945	+ 0 00:05:08.031	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:07:11.930	+ 0 00:05:08.016	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:07:11.175	+ 0 00:05:07.261	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:07:11.131	+ 0 00:05:07.217	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:07:10.130	+ 0 00:05:06.216	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:07:10.112	+ 0 00:05:06.198	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:07:08.697	+ 0 00:05:04.783	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:07:08.649	+ 0 00:05:04.735	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:07:04.656	+ 0 00:05:00.742	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:07:04.613	+ 0 00:05:00.699	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:07:00.899	+ 0 00:04:56.985	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:07:00.862	+ 0 00:04:56.948	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:06:59.166	+ 0 00:04:55.252	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:06:59.119	+ 0 00:04:55.205	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:06:46.616	+ 0 00:04:42.702	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:06:46.578	+ 0 00:04:42.664	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:06:44.712	+ 0 00:04:40.798	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:06:36.207	+ 0 00:04:32.293	156	A	GEN 3 BEARING OIL LEVEL HIGH-LOW
2008-03-02	05:06:34.178	+ 0 00:04:30.264	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:06:33.661	+ 0 00:04:29.747	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:06:33.614	+ 0 00:04:29.700	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:06:32.480	+ 0 00:04:28.566	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:06:32.434	+ 0 00:04:28.520	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:06:26.744	+ 0 00:04:22.830	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:06:24.150	+ 0 00:04:20.236	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:06:23.555	+ 0 00:04:19.641	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:06:23.518	+ 0 00:04:19.604	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:06:20.688	+ 0 00:04:16.774	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:06:20.641	+ 0 00:04:16.727	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:06:19.635	+ 0 00:04:15.721	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:06:19.588	+ 0 00:04:15.674	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:06:18.574	+ 0 00:04:14.660	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:06:18.454	+ 0 00:04:14.540	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:06:18.408	+ 0 00:04:14.494	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:06:16.622	+ 0 00:04:12.708	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:06:16.574	+ 0 00:04:12.660	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:06:16.525	+ 0 00:04:12.611	156	N	GEN 3 BEARING OIL LEVEL RESTORED
2008-03-02	05:06:12.059	+ 0 00:04:08.145	156	A	GEN 3 BEARING OIL LEVEL HIGH-LOW
2008-03-02	05:06:10.985	+ 0 00:04:07.071	157	N	TUR 3 BRG OIL LEVEL RESTORED
2008-03-02	05:06:10.979	+ 0 00:04:07.065	156	N	GEN 3 BEARING OIL LEVEL RESTORED
2008-03-02	05:06:06.672	+ 0 00:04:02.758	180	N	U3 13PT1 OR 13PT2 CLEARED

Date yyyy-mm-dd	SER Time hh.mm.ss.sss	Incremental Time From Zero Time Event: days hh:mm:secs	Point	Code	Message
2008-03-02	05:06:06.650	+ 0 00:04:02.736	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:06:03.747	+ 0 00:03:59.833	157	A	TUR 3 BRG OIL LEVEL HIGH-LOW
2008-03-02	05:05:58.601	+ 0 00:03:54.687	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:05:58.566	+ 0 00:03:54.652	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:05:47.419	+ 0 00:03:43.505	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:05:47.375	+ 0 00:03:43.461	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:05:39.957	+ 0 00:03:36.043	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:05:39.909	+ 0 00:03:35.995	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:05:37.112	+ 0 00:03:33.198	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:05:37.063	+ 0 00:03:33.149	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:05:21.871	+ 0 00:03:17.957	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:05:21.827	+ 0 00:03:17.913	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:05:15.141	+ 0 00:03:11.227	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:05:15.094	+ 0 00:03:11.180	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:05:08.272	+ 0 00:03:04.358	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:05:08.226	+ 0 00:03:04.312	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:05:07.331	+ 0 00:03:03.417	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:05:07.297	+ 0 00:03:03.383	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:04:57.745	+ 0 00:02:53.831	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:04:57.706	+ 0 00:02:53.792	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:04:55.165	+ 0 00:02:51.251	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:04:55.120	+ 0 00:02:51.206	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:04:52.393	+ 0 00:02:48.479	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:04:52.344	+ 0 00:02:48.430	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:04:31.799	+ 0 00:02:27.885	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:04:31.755	+ 0 00:02:27.841	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:04:27.655	+ 0 00:02:23.741	156	A	GEN 3 BEARING OIL LEVEL HIGH-LOW
2008-03-02	05:04:26.723	+ 0 00:02:22.809	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:04:26.674	+ 0 00:02:22.760	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:04:15.825	+ 0 00:02:11.911	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:04:15.804	+ 0 00:02:11.890	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:03:20.698	+ 0 00:01:16.784	180	N	U3 13PT1 OR 13PT2 CLEARED
2008-03-02	05:03:20.659	+ 0 00:01:16.745	180	A	U3 13PT1 OR 13PT2 FAILURE
2008-03-02	05:02:22.725	+ 0 00:00:18.811	156	N	GEN 3 BEARING OIL LEVEL RESTORED
2008-03-02	05:02:03.914	Zero Time Event	156	A	GEN 3 BEARING OIL LEVEL HIGH-LOW

Gordon M. Shrum Units 1 to 5 Turbine Replacement Project

BC hydro

Appendix

E

Equipment Health Rating Technical Prescription Reports

EQUIPMENT HEALTH RATING
Technical Prescription Report

Equipment Information

Facility: **GMS**	Unit: **UNIT01**	Division:	System: **N/A**	Equip Type: **TURB**	Equip No: **SYSTEM**
Major Asset: **TURB**	UTC: **753461**	Category:		Comp Type:	Comp No:

Health Assessment Summary

Letter Grade: **Unsatisfactory**
Assessed By: **M. SMITH, P. FIN-NEGAN**
Assessment Date: **2009-06-12**

HAS ID: **1880**
Status: **Active**

Based on the available inspection records, operational information, known problems and comparison to equipment of similar design, this turbine is assessed to be in "Unsatisfactory" health. The main concerns with this equipment are the design flaws as outlined in the GMS G3 Failure report. (E653)

Construction of the WAC Bennett dam began in November 1961 and reservoir filling began in December 1967. The first three units at GM Shrum generating station were in service on September 22, 1968 and all 10 units in service by February 12, 1980.

Technical Prescription

TP ID: **3068** Status: **Accepted** Reviewed By: **CMESSER** Reviewed Date: **2009-06-26**

Intervention Information

Intervention: **Turbine Upgrade**

Intervention Type: **Significant**

Intervention Year:
Earliest: **2009** Latest: **2017**

Description/Explanation:

Major rehabilitation of the turbine is required including replacement of the runner, wicket gates and operating mechanism, head cover, and associated components.
The earliest supply date would be 2012 if action is initiated now for this project. It is highly recommended that this project is initiated as soon as possible given the timelines associated with a project of this magnitude and ongoing risk and cost to keep units operational.

Work Scope:

Headcover

Replace the headcover with a modern design. Replacement is required in order to:
1. Eliminate the deficiencies with the existing design.
2. Eliminate the risk of adverse interaction in between the existing headcover and new runner.
3. Eliminate the risks (technical, schedule and cost) associated with refurbishment.

Shaft Seal

Replace the shaft seal with a modern design in order to eliminate the historical issues inherent to the existing design.

Main Shaft

Perform geometry-verification and complete non-destructive examination of the main shaft. If required, correct the geometry to re-establish tolerances and to accommodate the new runner.

Turbine Bearing

Perform geometry-verification and complete non-destructive examination of the turbine bearing and bearing support ring. If required, re-babbitt and correct the geometry to re-establish tolerances. (Since new headcover design segmented bearing design instead of split shell)

Operating Mechanism

Replace the operating mechanism with a modern design in order to eliminate the deficiencies with the existing design (see Engineering

EQUIPMENT HEALTH RATING
Technical Prescription Report

Report E653).

Wicket Gates

Replace the wicket gates with a modern design. Replacement is required in order to:
1. Eliminate the risk of adverse interaction in between the existing wicket gate design and new runner.
2. Eliminate the risks (technical, schedule and cost) associated with refurbishment.
3. Achieve the potential efficiency gains associated with a more modern design.
4. Increase the sizing of bushings to reduce the currently high pressures placed on them.

Runner

Replace the runner with a modern design in order to eliminate the deficiencies with the existing design. (see PSE303).

Spiral Case

Perform a non-destructive examination of the critical welds in the spiral case, including "sounding" for voids behind the steel liner. Weld repair and inject grout where required. Paint the spiral case.

Stay Ring

Perform geometry-verification and complete non-destructive examination of the stay ring and stay vanes. Correct the geometry of the stay ring if required to re-establish alignment tolerances. Consider modification of the stay vane profile if it is determined that this work would benefit the performance of the turbine. Paint the stay vanes.

Discharge Ring

Replace the lower seal ring to renew its service life, re-establish alignment tolerances and to accommodate the new runner. Replace the facing plates to renew their service life, re-establish alignment tolerances and to accommodate the new wicket gates. Replace the wicket gate bushings and seals to renew their service life.

Draft Tube

Visually inspect the channels, pier nose and steel liner. Perform a non-destructive examination of the welds on the steel liner, including "sounding" for voids behind the liner. Weld repair and inject grout where required.

Time and Cost Estimates

Time in Months			Cost in Thousands of Dollars		
Engineering:	24		Engineering:	3,000	
Supply:	16		Supply:	22,000	
Install:	8		Install:	5,000	
Intervention Duration:	**48**	Months	Intervention Cost $:	**30,000**	k
(Project Initiation to In-Service)			(Cost of Intervention)		
Outage Duration:	**8**	Months			

Technical Benefit Statement	Possible Consequences (of Not Doing it or Delaying it)	Estimate Basis
Turbine replacement will improve reliability, availability, efficiency and improve machine safety.	No turbine replacement will risk another major failure resulting in an extended outage and ongoing higher maintenance costs resulting from equipment with significant problems.	This is a preliminary estimate of direct work only. The estimate is based on current project work in 2009 dollars, assuming that all 5 units will be done as one project and significant project costs will be incurred during design and installation of the first unit. The first unit upgrade will take approximately 4 years (as shown in the time estimate) with outages for the additional units occurring every year.

EHR

EQUIPMENT HEALTH RATING
Technical Prescription Report

Equipment Information

Facility: **GMS**	Unit: **UNIT02**	Division:	System: **N/A**	Equip Type: **TURB**	Equip No: **SYSTEM**
Major Asset: **TURB**	UTC: **753462**	Category:		Comp Type:	Comp No:

Health Assessment Summary

Letter Grade: **Unsatisfactory**
Assessed By: **M. SMITH, P. FINNEGAN**
Assessment Date: **2009-06-12**

HAS ID: **1881**
Status: **Active**

Based on the available inspection records, operational information, known problems and comparison to equipment of similar design, this turbine is assessed to be in "Unsatisfactory" health. The main concerns with this equipment are the design flaws as outlined in the GMS G3 Failure report. (E653)

Construction of the WAC Bennett dam began in November 1961 and reservoir filling began in December 1967. The first three units at GM Shrum generating station were in service on September 22, 1968 and all 10 units in service by February 12, 1980.

Technical Prescription

TP ID: **3069** Status: **Accepted** Reviewed By: **CMESSER** Reviewed Date: **2009-06-26**

Intervention Information

Intervention: **Turbine Upgrade**

Intervention Type: **Significant**

Intervention Year:
Earliest: **2009** Latest: **2017**

Description/Explanation:

Major rehabilitation of the turbine is required including replacement of the runner, wicket gates and operating mechanism, head cover, and associated components.
The earliest supply date would be 2012 if action is initiated now for this project. It is highly recommended that this project is initiated as soon as possible given the timelines associated with a project of this magnitude and ongoing risk and cost to keep units operational.

Work Scope:

Headcover

Replace the headcover with a modern design. Replacement is required in order to:
1. Eliminate the deficiencies with the existing design.
2. Eliminate the risk of adverse interaction in between the existing headcover and new runner.
3. Eliminate the risks (technical, schedule and cost) associated with refurbishment.

Shaft Seal

Replace the shaft seal with a modern design in order to eliminate the historical issues inherent to the existing design.

Main Shaft

Perform geometry-verification and complete non-destructive examination of the main shaft. If required, correct the geometry to re-establish tolerances and to accommodate the new runner.

Turbine Bearing

Perform geometry-verification and complete non-destructive examination of the turbine bearing and bearing support ring. If required, re-babbitt and correct the geometry to re-establish tolerances. (Since new headcover design segmented bearing design instead of split shell)

Operating Mechanism

Replace the operating mechanism with a modern design in order to eliminate the deficiencies with the existing design (see Engineering

EHR

EQUIPMENT HEALTH RATING
Technical Prescription Report

Report E653).

Wicket Gates

Replace the wicket gates with a modern design. Replacement is required in order to:
1. Eliminate the risk of adverse interaction in between the existing wicket gate design and new runner.
2. Eliminate the risks (technical, schedule and cost) associated with refurbishment.
3. Achieve the potential efficiency gains associated with a more modern design.
4. Increase the sizing of bushings to reduce the currently high pressures placed on them.

Runner

Replace the runner with a modern design in order to eliminate the deficiencies with the existing design. (see PSE303).

Spiral Case

Perform a non-destructive examination of the critical welds in the spiral case, including "sounding" for voids behind the steel liner. Weld repair and inject grout where required. Paint the spiral case.

Stay Ring

Perform geometry-verification and complete non-destructive examination of the stay ring and stay vanes. Correct the geometry of the stay ring if required to re-establish alignment tolerances. Consider modification of the stay vane profile if it is determined that this work would benefit the performance of the turbine. Paint the stay vanes.

Discharge Ring

Replace the lower seal ring to renew its service life, re-establish alignment tolerances and to accommodate the new runner. Replace the facing plates to renew their service life, re-establish alignment tolerances and to accommodate the new wicket gates. Replace the wicket gate bushings and seals to renew their service life.

Draft Tube

Visually inspect the channels, pier nose and steel liner. Perform a non-destructive examination of the welds on the steel liner, including "sounding" for voids behind the liner. Weld repair and inject grout where required.

Time and Cost Estimates

Time in Months			Cost in Thousands of Dollars		
Engineering:	24		Engineering:	3,000	
Supply:	16		Supply:	22,000	
Install:	8		Install:	5,000	
Intervention Duration:	**48**	Months	Intervention Cost $:	**30,000**	k
(Project Initiation to In-Service)			(Cost of Intervention)		
Outage Duration:	**8**	Months			

Technical Benefit Statement	Possible Consequences (of Not Doing it or Delaying it)	Estimate Basis
Turbine replacement will improve reliability, availability, efficiency and improve machine safety.	No turbine replacement will risk another major failure resulting in an extended outage and ongoing higher maintenance costs resulting from equipment with significant problems.	This is a preliminary estimate of direct work only. The estimate is based on current project work in 2009 dollars, assuming that all 5 units will be done as one project and significant project costs will be incurred during design and installation of the first unit. The first unit upgrade will take approximately 4 years (as shown in the time estimate) with outages for the additional units occurring every year.

EHR

EQUIPMENT HEALTH RATING
Technical Prescription Report

Equipment Information

Facility: **GMS**	Unit: **UNIT03**	Division:	System: **N/A**	Equip Type: **TURB**	Equip No: **SYSTEM**
Major Asset: **TURB**	UTC: **753463**	Category:		Comp Type:	Comp No:

Health Assessment Summary

Letter Grade: **Draft-Fair**
Assessed By: **M. SMITH, P. FINNEGAN**
Assessment Date: **2009-06-12**
HAS ID: **1879**
Status: **Active**

Repairs were completed on G3 in 2008/2009 but were not completed to the full scope of the recommendation in this technical prescription (TP ID #3067). The time constraints on the G3 emergency repair prevented important work to be completed: headcover was not replaced and is experiencing cracking problems, the wicket gates were not replaced, only temporary repairs were made. The repairs made to G3 were designed around a ten year life. More operating time and inspections are required to determine whether the "draft" rating can be removed.

Construction of the WAC Bennett dam began in November 1961 and reservoir filling began in December 1967. The first three units at GM Shrum generating station were in service on September 22, 1968 and all 10 units in service by February 12, 1980.

Technical Prescription

TP ID: **3067**	Status: **Accepted**	Reviewed By: **CMESSER**	Reviewed Date: **2009-06-26**

Intervention Information

Intervention: **Turbine Upgrade**

Intervention Type: **Significant**

Intervention Year:
Earliest: **2009** Latest: **2017**

Description/Explanation:

Major rehabilitation of the turbine is required including replacement of the runner, wicket gates and operating mechanism, head cover, and associated components.
Unit 3 should be scheduled to be the last unit upgraded as long as the temporary repairs perform well. It is highly recommended that this project is initiated as soon as possible given the timelines and magnitude associated with this project.

Repairs were completed on G3 in 2008/2009 but were not completed to the full scope of the recommendation in this technical prescription. The time constraints on the G3 overhaul prevented important work to be completed: headcover was not replaced and is experiencing cracking problems, the wicket gates were not replaced, only temporary repairs were made. The repairs made to G3 were designed around a ten year life. More operating time and inspections are required to determine whether the "draft" rating can be removed.

Work Scope:

Headcover

Replace the headcover with a modern design. Replacement is required in order to:
1. Eliminate the deficiencies with the existing design.
2. Eliminate the risk of adverse interaction in between the existing headcover and new runner.
3. Eliminate the risks (technical, schedule and cost) associated with refurbishment.

Shaft Seal

Replace the shaft seal with a modern design in order to eliminate the historical issues inherent to the existing design.

Main Shaft

Perform geometry-verification and complete non-destructive examination of the main shaft. If required, correct the geometry to re-establish tolerances and to accommodate the new runner.

EHR

EQUIPMENT HEALTH RATING
Technical Prescription Report

Turbine Bearing

Perform geometry-verification and complete non-destructive examination of the turbine bearing and bearing support ring. If required, re-babbitt and correct the geometry to re-establish tolerances. (Since new headcover design segmented bearing design instead of split shell)

Operating Mechanism

Replace the operating mechanism with a modern design in order to eliminate the deficiencies with the existing design (see Engineering Report E653).

Wicket Gates

Replace the wicket gates with a modern design. Replacement is required in order to:
1. Eliminate the risk of adverse interaction in between the existing wicket gate design and new runner.
2. Eliminate the risks (technical, schedule and cost) associated with refurbishment.
3. Achieve the potential efficiency gains associated with a more modern design.
4. Increase the sizing of bushings to reduce the currently high pressures placed on them.

Runner

Replace the runner with a modern design in order to eliminate the deficiencies with the existing design. (see PSE303).

Spiral Case

Perform a non-destructive examination of the critical welds in the spiral case, including "sounding" for voids behind the steel liner. Weld repair and inject grout where required. Paint the spiral case.

Stay Ring

Perform geometry-verification and complete non-destructive examination of the stay ring and stay vanes. Correct the geometry of the stay ring if required to re-establish alignment tolerances. Consider modification of the stay vane profile if it is determined that this work would benefit the performance of the turbine. Paint the stay vanes.

Discharge Ring

Replace the lower seal ring to renew its service life, re-establish alignment tolerances and to accommodate the new runner. Replace the facing plates to renew their service life, re-establish alignment tolerances and to accommodate the new wicket gates. Replace the wicket gate bushings and seals to renew their service life.

Draft Tube

Visually inspect the channels, pier nose and steel liner. Perform a non-destructive examination of the welds on the steel liner, including "sounding" for voids behind the liner. Weld repair and inject grout where required.

Time and Cost Estimates

Time in Months			Cost in Thousands of Dollars		
Engineering:	24		Engineering:	3,000	
Supply:	16		Supply:	22,000	
Install:	8		Install:	5,000	
Intervention Duration:	**48**	Months	Intervention Cost $:	**30,000**	k
(Project Initiation to In-Service)			(Cost of Intervention)		
Outage Duration:	**8**	Months			

EHR

EQUIPMENT HEALTH RATING
Technical Prescription Report

Technical Benefit Statement	Possible Consequences (of Not Doing it or Delaying it)	Estimate Basis
Turbine replacement will improve reliability, availability, efficiency and improve machine safety.	No turbine replacement will risk another major failure resulting in an extended outage and ongoing higher maintenance costs resulting from equipment with significant problems.	This is a preliminary estimate of direct work only. The estimate is based on current project work in 2009 dollars, assuming that all 5 units will be done as one project and significant project costs will be incurred during design and installation of the first unit. The first unit upgrade will take approximately 4 years (as shown in the time estimate) with outages for the additional units occurring every year.

EHR

EQUIPMENT HEALTH RATING
Technical Prescription Report

Equipment Information

Facility: **GMS**	Unit: **UNIT04**	Division:	System: **N/A**	Equip Type: **TURB**	Equip No: **SYSTEM**
Major Asset: **TURB**	UTC: **753464**	Category:		Comp Type:	Comp No:

Health Assessment Summary

Letter Grade: **Unsatisfactory**
Assessed By: **M. SMITH, P. FIN-NEGAN**
Assessment Date: **2009-06-12**

HAS ID: **1882**
Status: **Active**

Based on the available inspection records, operational information, known problems and comparison to equipment of similar design, this turbine is assessed to be in "Unsatisfactory" health. The main concerns with this equipment are the design flaws as outlined in the GMS G3 Failure report. (E653)

Construction of the WAC Bennett dam began in November 1961 and reservoir filling began in December 1967. The first three units at GM Shrum generating station were in service on September 22, 1968 and all 10 units in service by February 12, 1980.

Technical Prescription

TP ID: **3070**	Status: **Accepted**	Reviewed By: **CMESSER**	Reviewed Date: **2009-06-26**

Intervention Information

Intervention: **Turbine Upgrade**

Intervention Type: **Significant**

Intervention Year:
Earliest: **2009** Latest: **2017**

Description/Explanation:

Major rehabilitation of the turbine is required including replacement of the runner, wicket gates and operating mechanism, head cover, and associated components.
The earliest supply date would be 2012 if action is initiated now for this project. It is highly recommended that this project is initiated as soon as possible given the timelines associated with a project of this magnitude and ongoing risk and cost to keep units operational.

Work Scope:

Headcover

Replace the headcover with a modern design. Replacement is required in order to:
1. Eliminate the deficiencies with the existing design.
2. Eliminate the risk of adverse interaction in between the existing headcover and new runner.
3. Eliminate the risks (technical, schedule and cost) associated with refurbishment.

Shaft Seal

Replace the shaft seal with a modern design in order to eliminate the historical issues inherent to the existing design.

Main Shaft

Perform geometry-verification and complete non-destructive examination of the main shaft. If required, correct the geometry to re-establish tolerances and to accommodate the new runner.

Turbine Bearing

Perform geometry-verification and complete non-destructive examination of the turbine bearing and bearing support ring. If required, re-babbitt and correct the geometry to re-establish tolerances. (Since new headcover design segmented bearing design instead of split shell)

Operating Mechanism

Replace the operating mechanism with a modern design in order to eliminate the deficiencies with the existing design (see Engineering

EHR

EQUIPMENT HEALTH RATING
Technical Prescription Report

Report E653).

Wicket Gates

Replace the wicket gates with a modern design. Replacement is required in order to:
1. Eliminate the risk of adverse interaction in between the existing wicket gate design and new runner.
2. Eliminate the risks (technical, schedule and cost) associated with refurbishment.
3. Achieve the potential efficiency gains associated with a more modern design.
4. Increase the sizing of bushings to reduce the currently high pressures placed on them.

Runner

Replace the runner with a modern design in order to eliminate the deficiencies with the existing design. (see PSE303).

Spiral Case

Perform a non-destructive examination of the critical welds in the spiral case, including "sounding" for voids behind the steel liner. Weld repair and inject grout where required. Paint the spiral case.

Stay Ring

Perform geometry-verification and complete non-destructive examination of the stay ring and stay vanes. Correct the geometry of the stay ring if required to re-establish alignment tolerances. Consider modification of the stay vane profile if it is determined that this work would benefit the performance of the turbine. Paint the stay vanes.

Discharge Ring

Replace the lower seal ring to renew its service life, re-establish alignment tolerances and to accommodate the new runner. Replace the facing plates to renew their service life, re-establish alignment tolerances and to accommodate the new wicket gates. Replace the wicket gate bushings and seals to renew their service life.

Draft Tube

Visually inspect the channels, pier nose and steel liner. Perform a non-destructive examination of the welds on the steel liner, including "sounding" for voids behind the liner. Weld repair and inject grout where required.

Time and Cost Estimates

Time in Months			Cost in Thousands of Dollars		
Engineering:	24		Engineering:	3,000	
Supply:	16		Supply:	22,000	
Install:	8		Install:	5,000	
Intervention Duration:	**48**	Months	Intervention Cost $:	**30,000**	k
(Project Initiation to In-Service)			(Cost of Intervention)		
Outage Duration:	**8**	Months			

Technical Benefit Statement	Possible Consequences (of Not Doing it or Delaying it)	Estimate Basis
Turbine replacement will improve reliability, availability, efficiency and improve machine safety.	No turbine replacement will risk another major failure resulting in an extended outage and ongoing higher maintenance costs resulting from equipment with significant problems.	This is a preliminary estimate of direct work only. The estimate is based on current project work in 2009 dollars, assuming that all 5 units will be done as one project and significant project costs will be incurred during design and installation of the first unit. The first unit upgrade will take approximately 4 years (as shown in the time estimate) with outages for the additional units occurring every year.

EQUIPMENT HEALTH RATING
Technical Prescription Report

Equipment Information

Facility: **GMS**	Unit: **UNIT05**	Division:	System: **N/A**	Equip Type: **TURB**	Equip No: **SYSTEM**
Major Asset: **TURB**	UTC: **753465**	Category:		Comp Type:	Comp No:

Health Assessment Summary

Letter Grade: **Unsatisfactory**
Assessed By: **M. SMITH, P. FIN-NEGAN**
Assessment Date: **2009-06-12**

HAS ID: **1883**
Status: **Active**

Based on the available inspection records, operational information, known problems and comparison to equipment of similar design, this turbine is assessed to be in "Unsatisfactory" health. The main concerns with this equipment are the design flaws as outlined in the GMS G3 Failure report. (E653)

Construction of the WAC Bennett dam began in November 1961 and reservoir filling began in December 1967. The first three units at GM Shrum generating station were in service on September 22, 1968 and all 10 units in service by February 12, 1980.

Technical Prescription

TP ID: **3071** Status: **Accepted** Reviewed By: **CMESSER** Reviewed Date: **2009-06-26**

Intervention Information

Intervention: **Turbine Upgrade**

Intervention Type: **Significant**

Intervention Year:
Earliest: **2009** Latest: **2017**

Description/Explanation:

Major rehabilitation of the turbine is required including replacement of the runner, wicket gates and operating mechanism, head cover, and associated components.
The earliest supply date would be 2012 if action is initiated now for this project. It is highly recommended that this project is initiated as soon as possible given the timelines associated with a project of this magnitude and ongoing risk and cost to keep units operational.

Work Scope:

Headcover

Replace the headcover with a modern design. Replacement is required in order to:
1. Eliminate the deficiencies with the existing design.
2. Eliminate the risk of adverse interaction in between the existing headcover and new runner.
3. Eliminate the risks (technical, schedule and cost) associated with refurbishment.

Shaft Seal

Replace the shaft seal with a modern design in order to eliminate the historical issues inherent to the existing design.

Main Shaft

Perform geometry-verification and complete non-destructive examination of the main shaft. If required, correct the geometry to re-establish tolerances and to accommodate the new runner.

Turbine Bearing

Perform geometry-verification and complete non-destructive examination of the turbine bearing and bearing support ring. If required, re-babbitt and correct the geometry to re-establish tolerances. (Since new headcover design segmented bearing design instead of split shell)

Operating Mechanism

Replace the operating mechanism with a modern design in order to eliminate the deficiencies with the existing design (see Engineering

EHR

EQUIPMENT HEALTH RATING
Technical Prescription Report

Report E653).

Wicket Gates

Replace the wicket gates with a modern design. Replacement is required in order to:
1. Eliminate the risk of adverse interaction in between the existing wicket gate design and new runner.
2. Eliminate the risks (technical, schedule and cost) associated with refurbishment.
3. Achieve the potential efficiency gains associated with a more modern design.
4. Increase the sizing of bushings to reduce the currently high pressures placed on them.

Runner

Replace the runner with a modern design in order to eliminate the deficiencies with the existing design. (see PSE303).

Spiral Case

Perform a non-destructive examination of the critical welds in the spiral case, including "sounding" for voids behind the steel liner. Weld repair and inject grout where required. Paint the spiral case.

Stay Ring

Perform geometry-verification and complete non-destructive examination of the stay ring and stay vanes. Correct the geometry of the stay ring if required to re-establish alignment tolerances. Consider modification of the stay vane profile if it is determined that this work would benefit the performance of the turbine. Paint the stay vanes.

Discharge Ring

Replace the lower seal ring to renew its service life, re-establish alignment tolerances and to accommodate the new runner. Replace the facing plates to renew their service life, re-establish alignment tolerances and to accommodate the new wicket gates. Replace the wicket gate bushings and seals to renew their service life.

Draft Tube

Visually inspect the channels, pier nose and steel liner. Perform a non-destructive examination of the welds on the steel liner, including "sounding" for voids behind the liner. Weld repair and inject grout where required.

Time and Cost Estimates

Time in Months			Cost in Thousands of Dollars		
Engineering:	24		Engineering:	3,000	
Supply:	16		Supply:	22,000	
Install:	8		Install:	5,000	
Intervention Duration:	**48**	Months	Intervention Cost $:	**30,000**	k
(Project Initiation to In-Service)			(Cost of Intervention)		
Outage Duration:	**8**	Months			

Technical Benefit Statement	Possible Consequences (of Not Doing it or Delaying it)	Estimate Basis
Turbine replacement will improve reliability, availability, efficiency and improve machine safety.	No turbine replacement will risk another major failure resulting in an extended outage and ongoing higher maintenance costs resulting from equipment with significant problems.	This is a preliminary estimate of direct work only. The estimate is based on current project work in 2009 dollars, assuming that all 5 units will be done as one project and significant project costs will be incurred during design and installation of the first unit. The first unit upgrade will take approximately 4 years (as shown in the time estimate) with outages for the additional units occurring every year.

Gordon M. Shrum Units 1 to 5 Turbine Replacement Project

BC hydro

Appendix

F

GMS Water Licence

Province of British Columbia
Water Act

FINAL WATER LICENCE

British Columbia Hydro and Power Authority is hereby authorised to store water as follows:

a) The stream on which the rights are granted is the Peace River and the reservoir is Williston Lake.

b) The site of the dam which creates Williston Lake reservoir is PD36606, located, as shown on the attached plans.

c) The date from which this licence shall have precedence is February 14, 1962.

d) The purpose for which this licence is issued is storage. The storage purpose supports the power purpose at the GM Shrum Generating Station authorised under Final Water Licences 123018, 123019 and 123020.

e) Water may be stored as described below:

   i) The water may be stored in the reservoir between elevations of 642.04 metres (2106.43 feet), the minimum operating level, and 672.08 metres (2205 feet), the full supply level, measured at the dam using the Geodetic Survey of Canada (GSC) datum.

   ii) The volume of water authorised to be stored between the minimum operating level and the full supply level under this licence is estimated to be 39,471.648 million cubic metres (32 million acre-feet).

   iii) Surcharging the reservoir above full supply level, drafting the reservoir to full supply level and drafting the reservoir below the minimum operating level shall be done in accordance with the Operation, Maintenance and Surveillance Manual.

f) Water may be collected into storage, held in storage, and used throughout the whole year.

g) This licence is appurtenant to the undertaking of the British Columbia Hydro and Power Authority to generate and supply power from the GM Shrum Generating Station situated on District Lot 2991, Peace River District.

h) The works authorised are the WAC Bennett Dam, spillway and low level outlets at PD36606 located as shown on the attached plan 1 of 2, the Williston Lake reservoir located as shown on attached plan 2 of 2, and ancillary works associated with the operation of the dam.

i) The licensee shall clear the reservoir in the manner and to the extent as may be directed by the Comptroller of Water Rights after consultation with the provincial forests ministry.

j) The licensee shall provide public access to the reservoir area as may be directed by the Comptroller of Water Rights.

k) Remedial measures for the protection of fisheries and wildlife habitat shall be carried out as directed by the Comptroller of Water Rights after consultation with the licensee and the provincial fisheries and wildlife agencies.

l) The licensee shall construct and operate such components of a hydrometeorological network for Williston Lake reservoir as may be directed by the Comptroller and shall make the information obtained available to and as directed by the Comptroller.

m) The licensee shall make such minimum releases from the reservoir as directed by the Comptroller, and in addition shall make such further releases as may be directed by the Comptroller from time to time in the public interest.

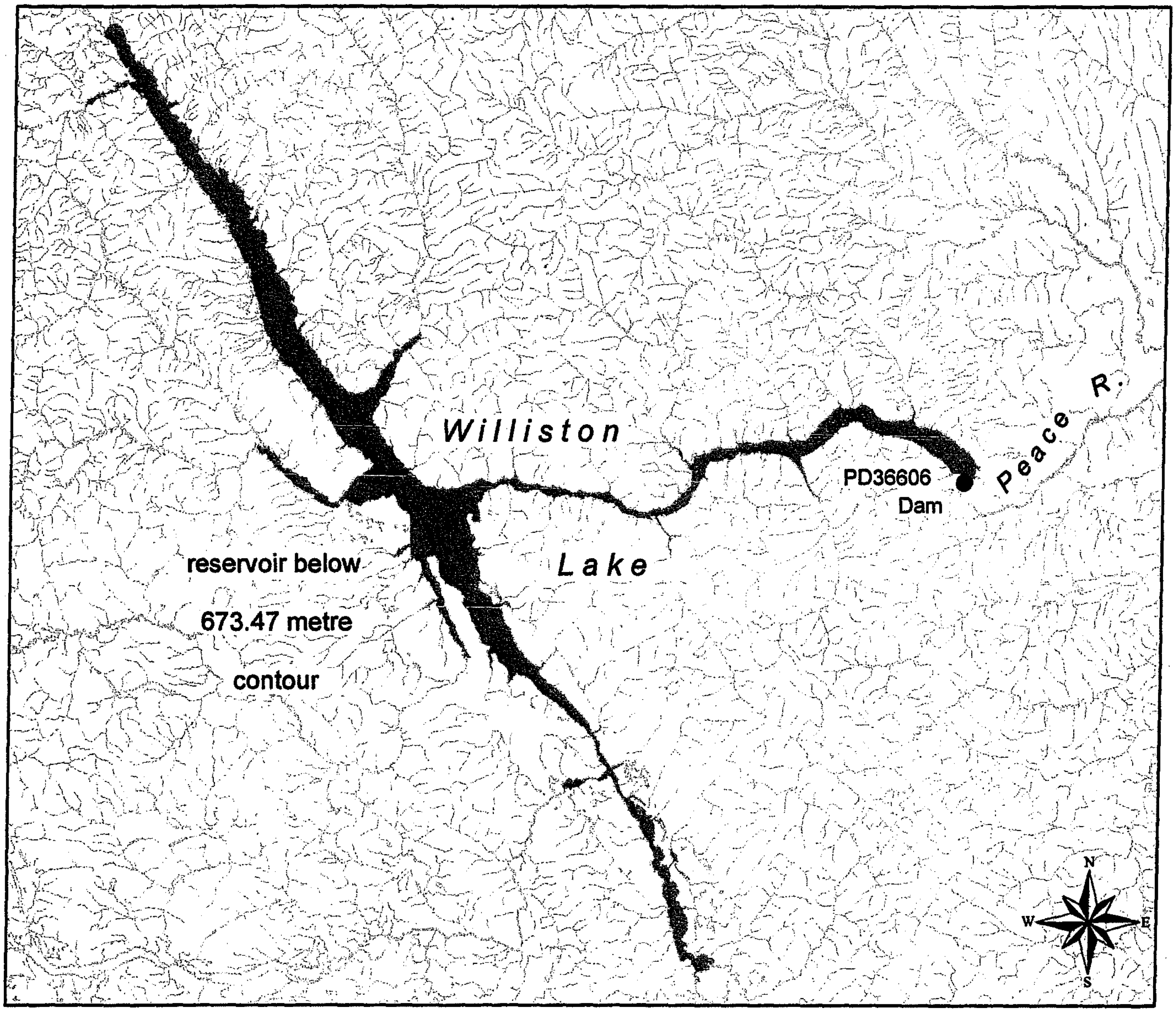
n) The licensee's rights issued under this licence shall be deemed to be subsequent to any rights granted under any licence or licences which may be issued at any time for the consumptive use of water.

o) This licence is issued in substitution of CWL 27722.

Glen Davidson, P. Eng.
Deputy Comptroller of Water Rights

File: 0242651 Date Issued: April 4, 2008 Final Licence 123021

BRITISH COLUMBIA



WATER DISTRICT: PRINCE GEORGE
PRECINCT: PARSNIP
LAND DISTRICT: PEACE RIVER

Signature:

Date: April 4, 2008

LEGEND

Scale:	1 : 1,200,000
Dam:	●
Map Number:	WR 94B.010
Permit over Crown Land:	

F.L. 123021 for C.L. 27722
File 0242651
P.C.L. 25875

Plan 2 of 2

Province of British Columbia
Water Act

FINAL WATER LICENCE

British Columbia Hydro and Power Authority is hereby authorised to divert and use water as follows:

a) The stream on which the rights are granted is the Peace River.

b) The point of diversion is PD36606, located as shown on the attached plan.

c) The date from which this licence shall have precedence is February 14, 1962.

d) The purpose for which this licence is issued is power which is to be generated at GM Shrum Generating Station.

e) The maximum rate at which water may be diverted and used under this licence is 1650.87 cubic metres per second (58,300 cubic feet per second).

f) Water may be diverted and used throughout the whole year.

g) This licence is appurtenant to the undertaking of the British Columbia Hydro and Power Authority to generate and supply power from the GM Shrum Generating Station situated on District Lot 2991, Peace River District.

h) The authorised works are the WAC Bennett Dam, intakes, penstocks, power house, spillway and low level outlets, tailrace and substation located as shown on the attached plan and ancillary works associated with the operation of the dam and powerhouse.

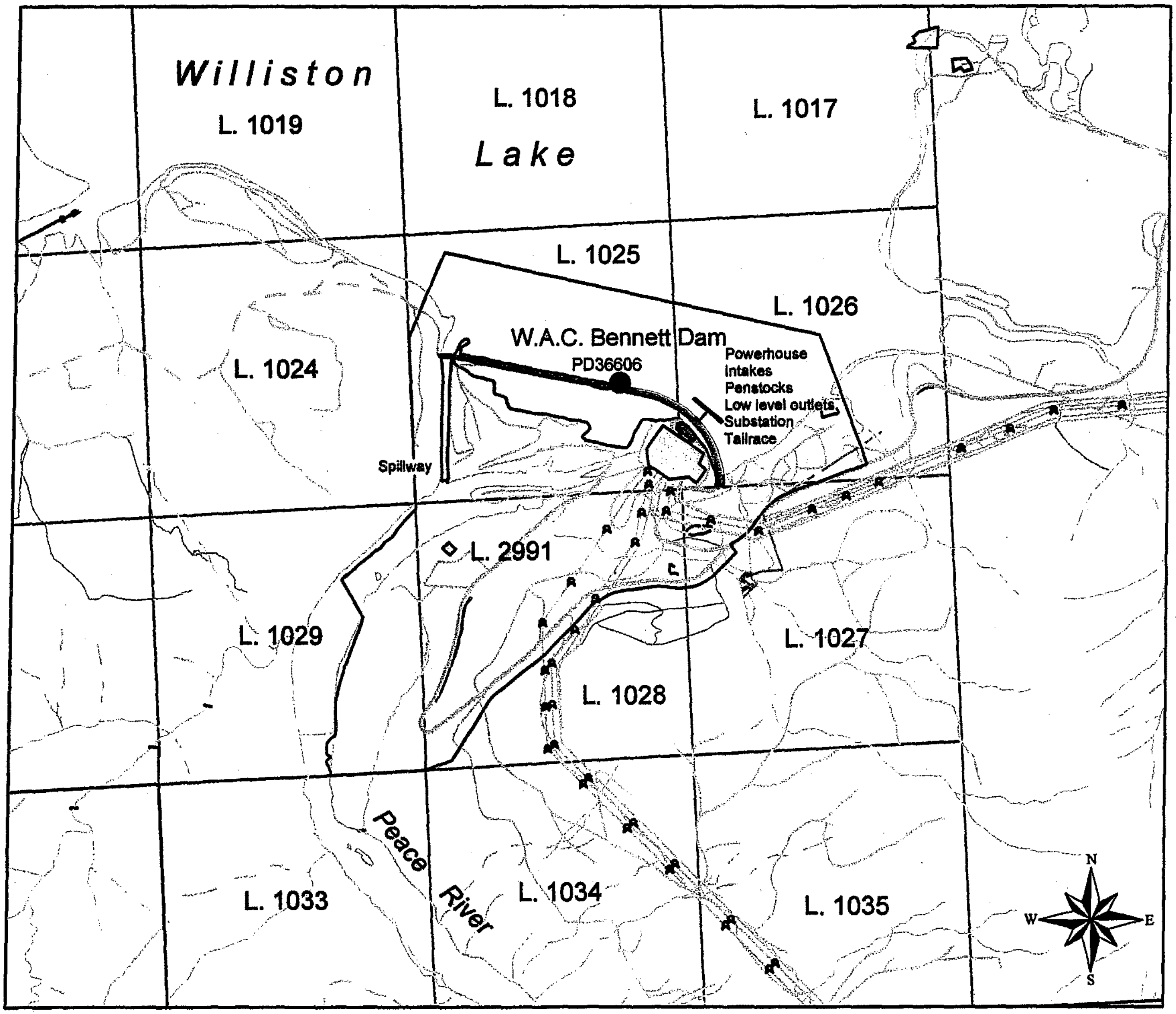
i) The rights granted under this licence shall be deemed to be subsequent to any rights granted under any licence or licences which may be issued at any time for the consumptive use of water.

j) This licence is issued in substitution of CWL 27721.

Glen Davidson, P. Eng.
Deputy Comptroller of Water Rights

File: 0242651 Date Issued: April 4, 2008 Final Licence 123018

BRITISH COLUMBIA



WATER DISTRICT: PRINCE GEORGE
PRECINCT: PARSNIP
LAND DISTRICT: PEACE RIVER

Signature: [signature]

Date: April 4, 2008

LEGEND

Scale:	1 : 36,000
Point of Diversion:	●
Map Number:	WR 94B.010

F.L. 123018 for C.L. 27721
File 0242651

Province of British Columbia
Water Act

FINAL WATER LICENCE

British Columbia Hydro and Power Authority is hereby authorised to divert and use water as follows:

a) The stream on which the rights are granted is the Peace River.

b) The point of diversion is PD36606 located as shown on the attached plan.

c) The date from which this licence shall have precedence is September 30, 1974.

d) The purpose for which this licence is issued is power which is to be generated at the GM Shrum Generating Station.

e) The maximum rate at which water may be diverted and used under this licence is 206.15 cubic metres per second (7,280 cubic feet per second).

f) Water may be diverted and used throughout the whole year.

g) This licence is appurtenant to the undertaking of the British Columbia Hydro and Power Authority to generate and supply power from the GM Shrum Generating Station situated on District Lot 2991, Peace River District.

h) The authorised works are the WAC Bennett Dam, intakes, penstocks, power house, spillway and low level outlets, tailrace and substation located as shown on the attached plan and ancillary works associated with the operation of the dam and powerhouse.

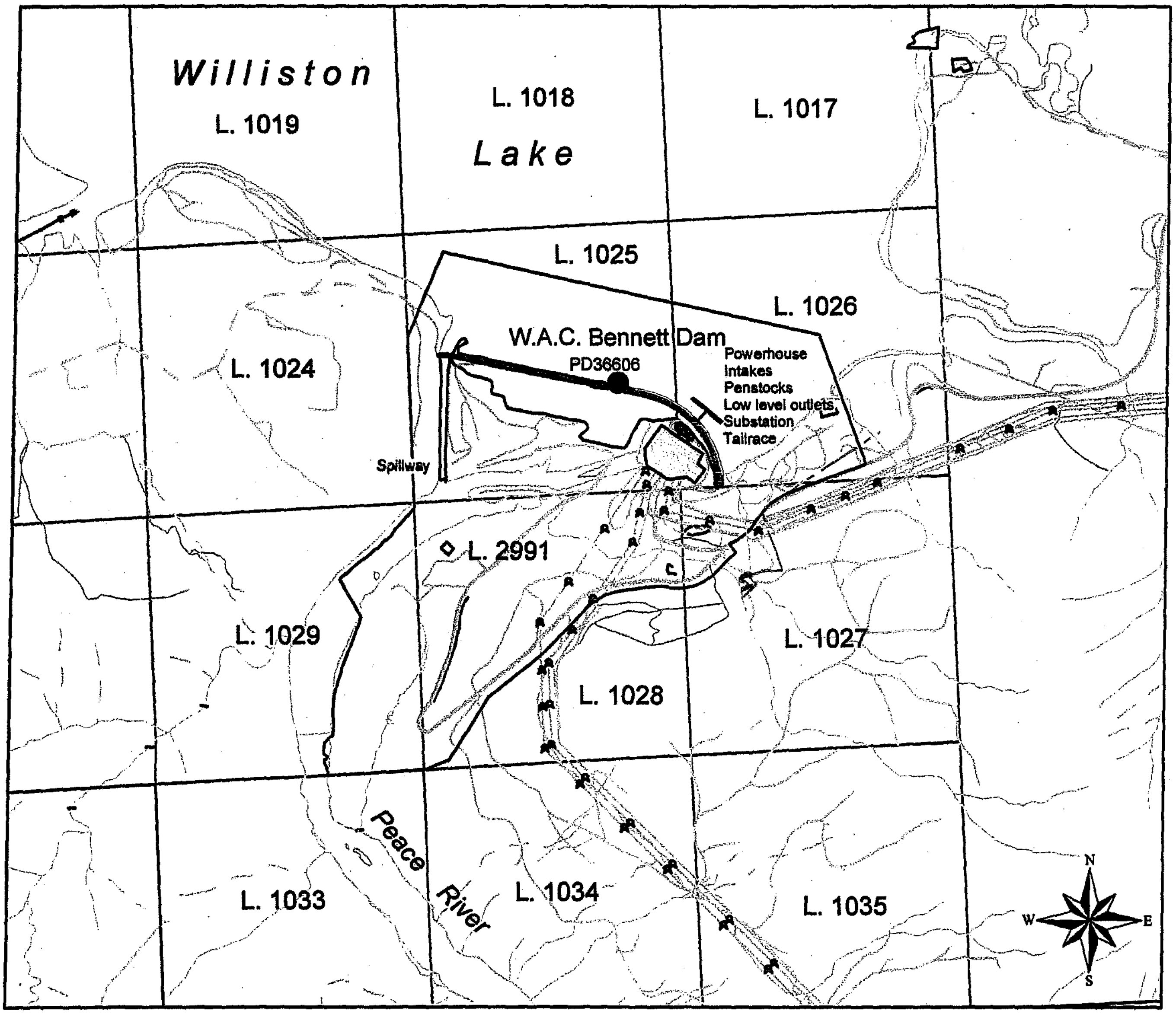
i) The rights granted under this licence shall be deemed to be subsequent to any rights granted under any licence or licences which may be issued at any time for the consumptive use of water.

j) This licence is issued in substitution of CWL 43431.

Glen Davidson, P. Eng.
Deputy Comptroller of Water Rights

File: 0323949 Date Issued: Final Licence 123019

BRITISH COLUMBIA



WATER DISTRICT: PRINCE GEORGE
PRECINCT: PARSNIP
LAND DISTRICT: PEACE RIVER

Signature:

Date: April 4, 2008

LEGEND

Scale:	1 : 36,000
Point of Diversion:	●
Map Number:	WR 94B.010

F.L. 123019 for C.L. 43431
File 0323949

Province of British Columbia
Water Act

FINAL WATER LICENCE

British Columbia Hydro and Power Authority is hereby authorised to divert and use water as follows:

a) The stream on which the rights are granted is the Peace River.

b) The point of diversion is PD36606 located as shown on the attached plan.

c) The date from which this licence shall have precedence is May 12, 1977.

d) The purpose for which this licence is issued is power which is to be generated at the GM Shrum Generating Station.

e) The maximum rate at which water may be diverted and used under this licence is 111.00 cubic metres per second (3,920 cubic feet per second).

f) Water may be diverted and used throughout the whole year.

g) This licence is appurtenant to the undertaking of the British Columbia Hydro and Power Authority to generate and supply power from the GM Shrum Generating Station situated on District Lot 2991, Peace River District.

h) The authorised works are the WAC Bennett Dam, intakes, penstocks, power house, spillway and low level outlets, tailrace and substation located as shown on the attached plan and ancillary works associated with the operation of the dam and powerhouse.

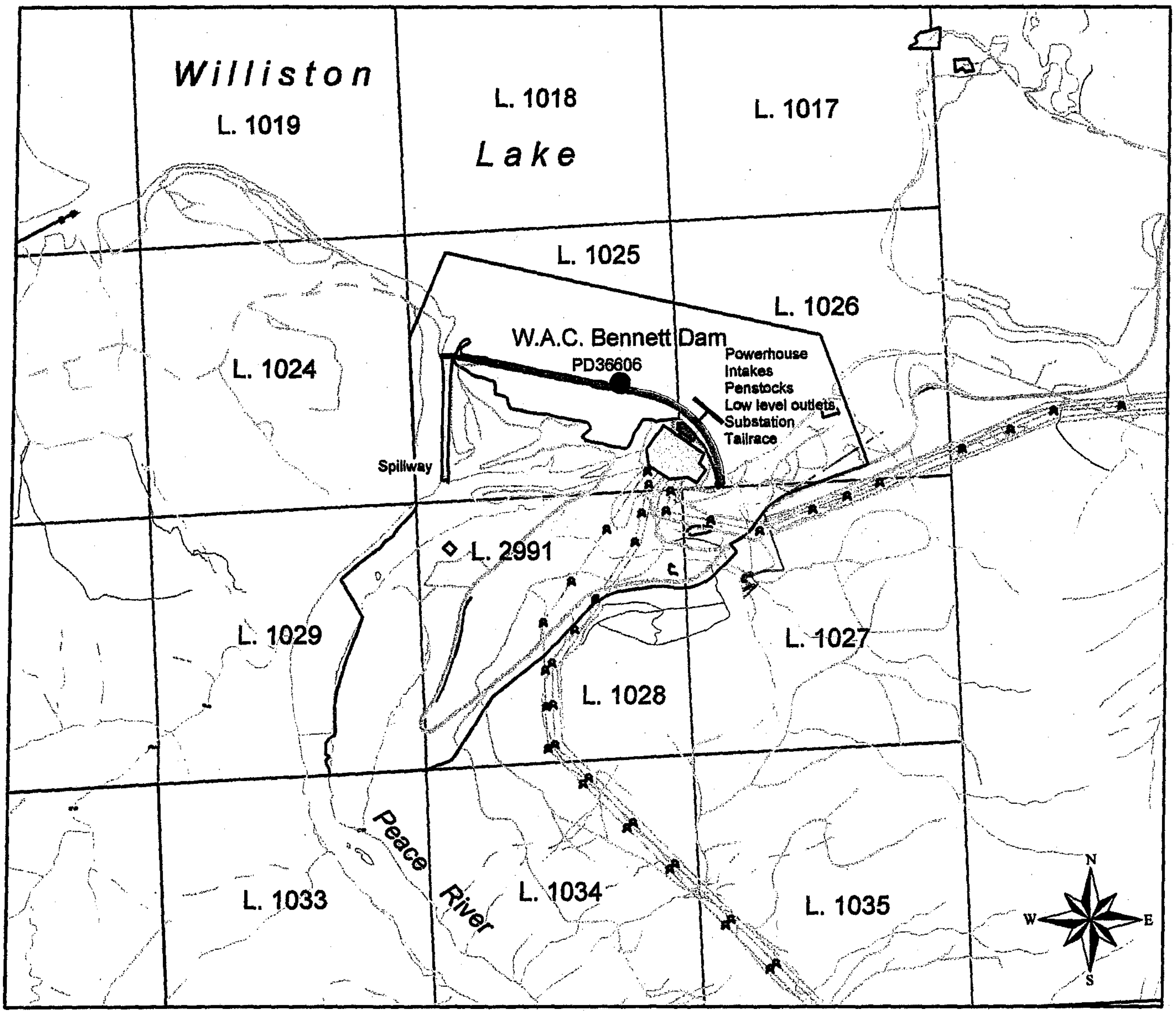
i) The rights granted under this licence shall be deemed to be subsequent to any rights granted under any licence or licences which may be issued at any time for the consumptive use of water.

j) This licence is issued in substitution of CWL 49679.

Glen Davidson, P. Eng.
Deputy Comptroller of Water Rights

File: 0341266 Date Issued: April 4, 2008 Final Licence 123020

BRITISH COLUMBIA



WATER DISTRICT: PRINCE GEORGE
PRECINCT: PARSNIP
LAND DISTRICT: PEACE RIVER

Signature: ____________

Date: April 4, 2008

LEGEND

Scale:	1 : 36,000
Point of Diversion:	●
Map Number:	WR 94B.010

F.L. 123020 for C.L. 49679
File 0341266

Province of British Columbia
Water Act

PERMIT AUTHORIZING THE OCCUPATION OF CROWN LAND SECTION 26

The Holder of Final Water Licence 123021 which authorizes the storage of water from Peace River in the reservoir of Williston Lake is hereby authorized to occupy Crown Land by flooding and by the works authorized in the above licence.

(a) The Crown Land which is authorized to be occupied under this permit is described as the Crown land below the 673.46 metre contour (2,209.5 feet) being Williston Lake reservoir, the location of which is shown approximately on the plan attached. The storage of water in the reservoir will be as set out in Final Water Licence 123021, or as otherwise approved in writing by the Comptroller of Water Rights. Flooding of Crown land above the full supply level set out in Final Water Licence 123021 must be in accordance with the Operation, Maintenance and Surveillance Manual referred to in the above licence.

(b) The approximate area of Crown Land authorized to be occupied under this permit is 172,669 hectares for a reservoir.

(c) Prior to the cutting, destruction or flooding of any timber, the permittee shall apply for and obtain all applicable licences to cut timber from the District Forest Manager. The amount of stumpage, royalty and (or) compensation payable to the Crown in respect of trees, including merchantable or young growth, cut, removed, damaged, or destroyed by the permittee, shall be the sum or sums fixed by the Forest Service of the Province of British Columbia.

(d) This permit is appurtenant to the undertaking to which the aforesaid water licence is appurtenant.

(e) This permit shall become void if the water licence with respect to which the permit is issued should terminate, be abandoned or cancelled, or amended so as to render this permit unnecessary.

(f) This permit is issued and accepted on the understanding that the permittee shall indemnify and save harmless the Government of the Province of British Columbia for all loss, damage to works, cost or expense suffered by the permittee by reason of the Crown Land or any portion thereof being submerged or damaged by erosion or otherwise affected by flooding.

(g) The holder of this permit shall not be entitled to compensation if the Crown grants permits to other persons to occupy the land affected by this permit.

(h) In the event of a dispute at any time with respect to the area or boundaries of the land affected by this permit, the holder shall, at his own expense, have the said land surveyed by a duly qualified surveyor.

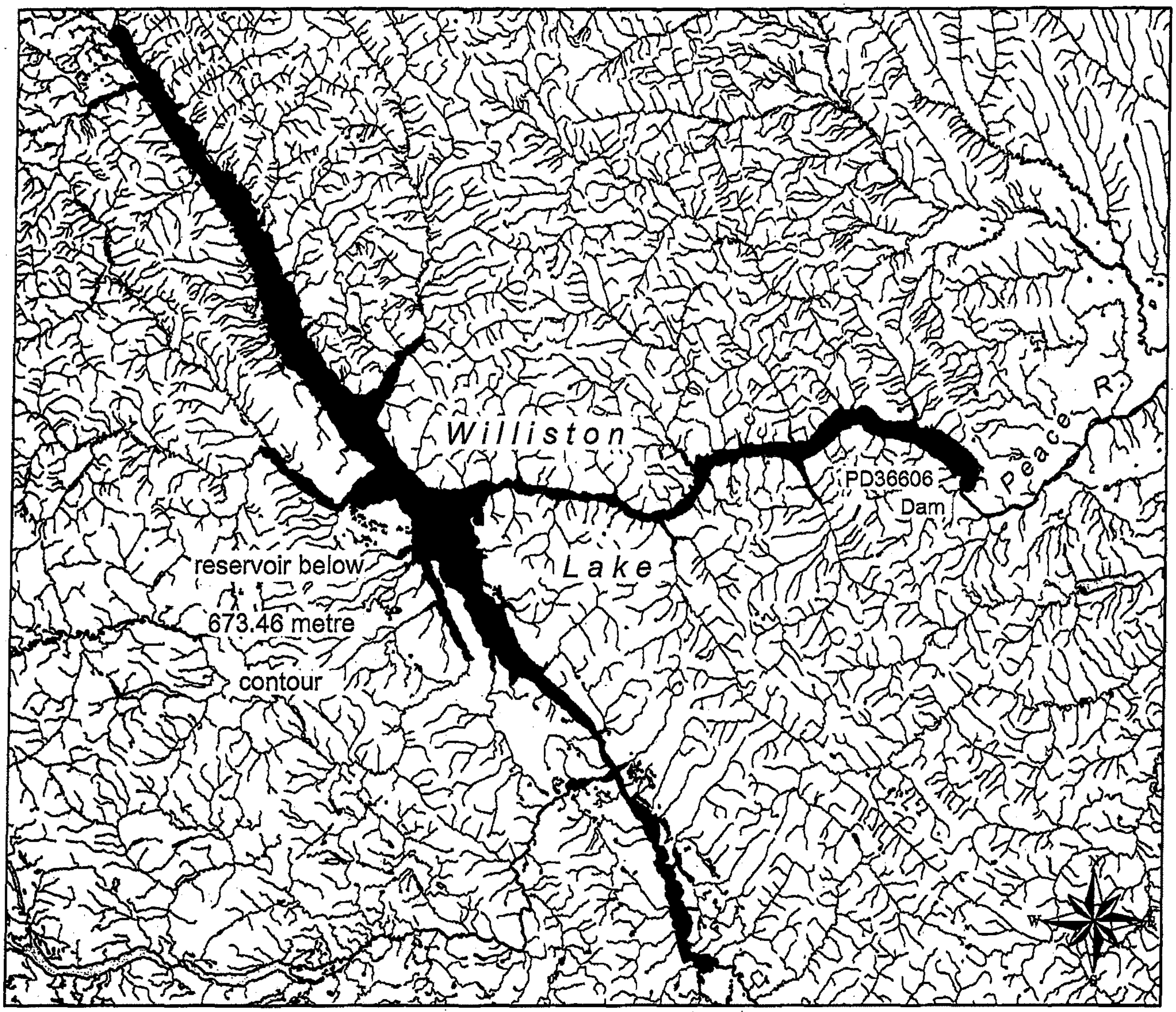
(i) This permit is issued in substitution of Permit # 25875.

P Bekker

Pieter Bekker
Deputy Comptroller of Water Rights

File No.: 0242651 Date Issued: May 8, 2008 PERMIT NO: 26011

BRITISH COLUMBIA



WATER DISTRICT: PRINCE GEORGE
PRECINCT: PARSNIP
LAND DISTRICT: PEACE RIVER

Signature: [signature]

Date: May 8, 2003

LEGEND

Scale:	1 : 1,200,000
Dam:	●
Map Number:	WR 94B.010
Permit over Crown Land:	

File 0242651
P.C.L. 26011

Province of British Columbia
Water Act

CONDITIONAL WATER LICENCE

British Columbia Hydro and Power Authority is hereby authorised to store, divert and use water as follows:

a) The stream on which the rights are granted is the Peace River and the reservoir is Dinosaur Lake.

b) The point of diversion and the site of the dam which creates Dinosaur Lake reservoir is PD36223 located as shown on the attached plans 1 and 2.

c) The date from which this licence shall have precedence is January 18, 1974.

d) The purposes for which this licence is issued are power, which is to be generated at the Peace Canyon Generating Station, and storage. The storage purpose supports the power purpose at the Peace Canyon Generating Station.

e) The maximum rate at which water may be diverted and used under this licence is 1982.18 cubic metres per second (70,000 cubic feet per second).

f) Conditions for the storage of water in Dinosaur Lake reservoir are as follows:

   i) The water may be stored in the reservoir between elevations of 497.00 metres, the minimum operating level and 502.92 metres, the full supply level, measured at the dam using the Geodetic Survey of Canada (GSC) datum.

   ii) The volume of water authorised to be stored between the minimum operating level and the full supply level under this licence is estimated to be 49.03 million cubic metres.

   iii) Surcharging the reservoir above the full supply level, drafting the reservoir to full supply level and drafting the reservoir below the minimum operating level shall be done in accordance with the Operations Maintenance and Surveillance Manual.

g) Water may be collected into storage, held in storage, and used throughout the whole year.

h) This licence is appurtenant to the undertaking of the British Columbia Hydro and Power Authority to generate and supply power from the Peace Canyon Generating Station situated on District Lot 3937, Peace River District.

i) The authorised works are Peace Canyon Dam, intakes, penstocks, power house, spillway, tailrace and substation located as shown on the attached plan 1 of 2, the Dinosaur Lake reservoir located as shown on attached plan 2 of 2, and ancillary works associated with the operation of the dam and powerhouse.

j) The rights granted under this licence shall be deemed to be subsequent to any rights granted under any licence or licences which may be issued at any time for the consumptive use of water.

k) The flooded area shall be cleared to such extent and in such manner as shall be directed by the Comptroller of Water Rights.

l) Programmes for the protection or enhancement of fisheries and wildlife habitat shall be carried out as directed by the Comptroller of Water Rights after consultation with the licensee and the provincial fisheries and wildlife agencies.

m) Public access to the reservoir and related recreational facilities shall be provided and maintained as directed by the Comptroller of Water Rights after consultation with the licensee and the provincial parks department.

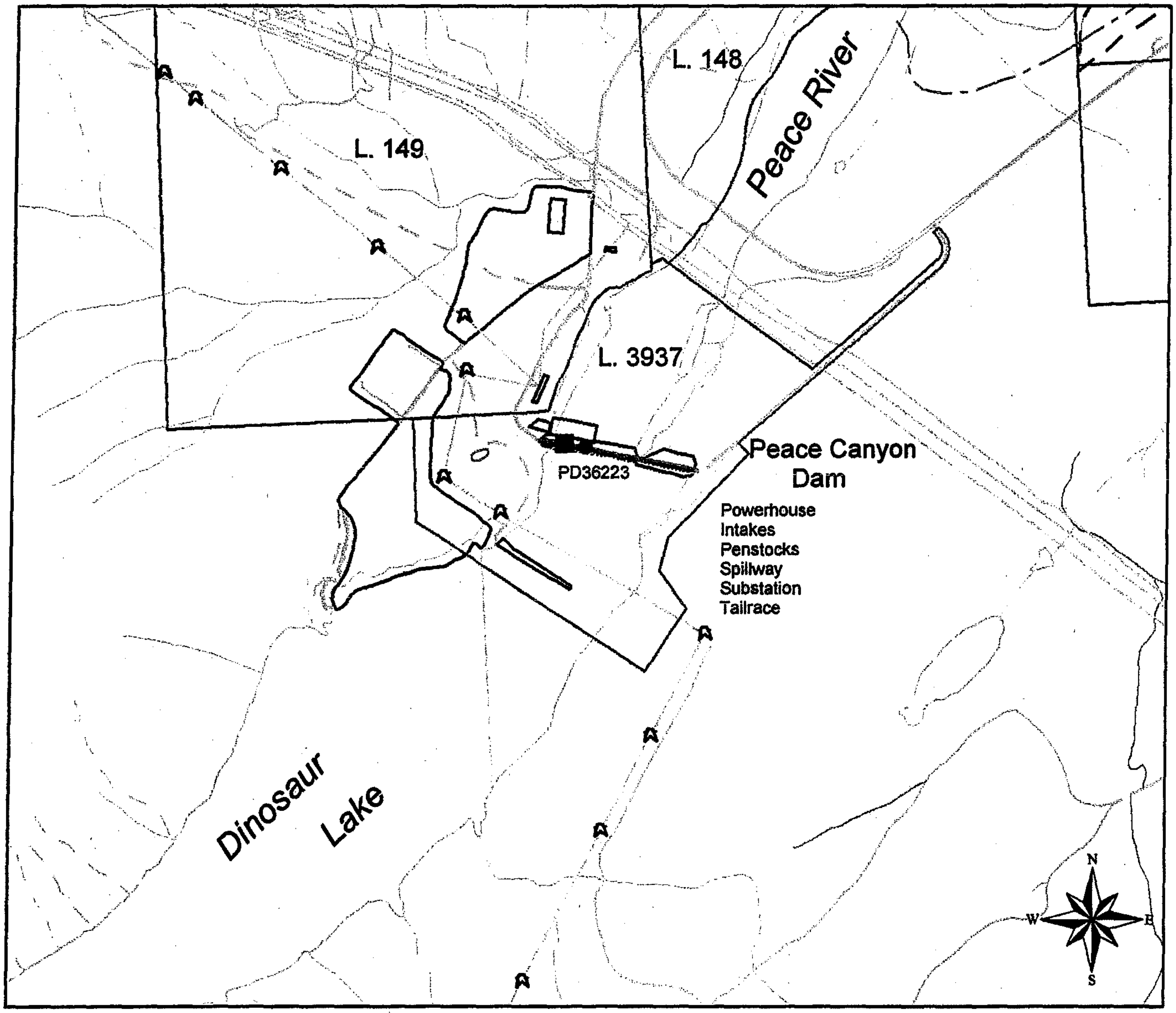
n) A review conducted to the satisfaction of the Comptroller of Water Rights, of the effects of drafting the reservoir below the temporary minimum operating level of 500.00 metres, will be submitted for decision by the Comptroller before any such drawdown is carried out.

o) This licence is issued in substitution of CWL 42203.

Glen Davidson, P. Eng.
Deputy Comptroller of Water Rights

File: 0322380 Date Issued: April 4, 2008 Conditional Licence 123025

BRITISH COLUMBIA



WATER DISTRICT: PRINCE GEORGE
PRECINCT: PARSNIP
LAND DISTRICT: PEACE RIVER

Signature: [signature]

Date: April 4, 2008

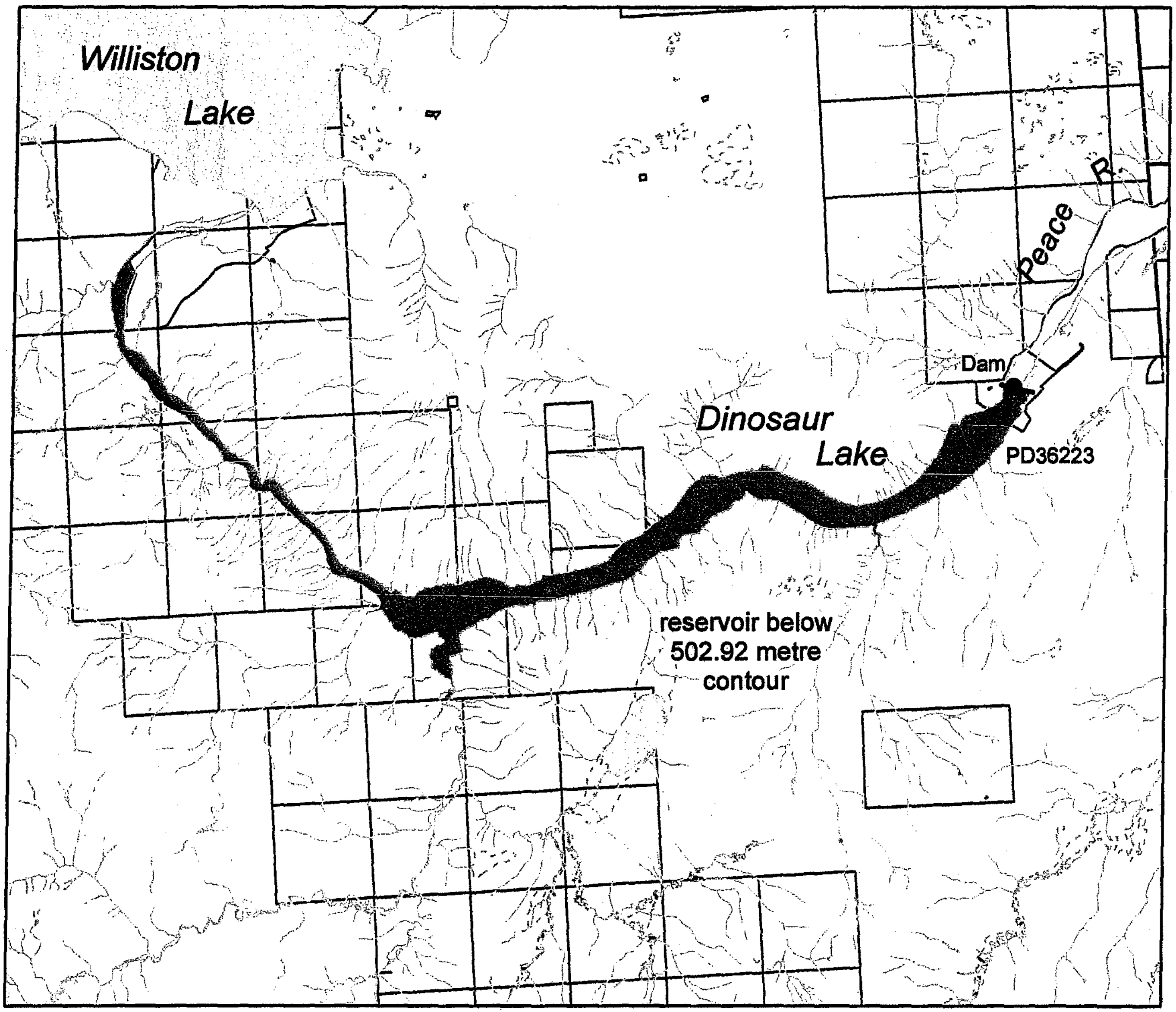
LEGEND

Scale: 1 : 20,000
Point of Diversion: ●
Map Number: WR 93P.091

C.L. 123025 for C.L. 42203
File 0322380

Plan 1 of 2

BRITISH COLUMBIA



WATER DISTRICT: PRINCE GEORGE
PRECINCT: PARSNIP
LAND DISTRICT: PEACE RIVER

Signature:

Date: April 4, 2008

LEGEND

Scale: 1 : 100,000
Dam: ●
Map Number: WR 93P.091
Permit over Crown Land:

C.L. 123025 for C.L. 42203
File 0322380
P.C.L. 25876

Plan 2 of 2

Province of British Columbia
Water Act

PERMIT AUTHORIZING THE OCCUPATION OF CROWN LAND SECTION 26

The Holder of Conditional Water Licence 123025 which authorizes the storage of water from Peace River in the reservoir of Dinosaur Lake is hereby authorized to occupy Crown Land by the works authorized under the said licence.

(a) The Crown Land which is authorized to be occupied under this permit is described as the Crown land below the 502.92 metre contour (1,650 feet) being Dinosaur Lake reservoir, the location of which is shown approximately as coloured red on Plan 2 of 2 attached to the said water licence. The storage of water in the reservoir will be as set out in Conditional Water Licence 123025, or as otherwise approved in writing by the Comptroller of Water Rights.

(b) The approximate area of Crown Land authorized to be occupied under this permit is 860 hectares for a reservoir.

(c) Prior to the cutting, destruction or flooding of any timber, the permittee shall apply for and obtain all applicable licences to cut timber from the District Forest Manager. The amount of stumpage, royalty and (or) compensation payable to the Crown in respect of trees, including merchantable or young growth, cut, removed, damaged, or destroyed by the permittee, shall be the sum or sums fixed by the Forest Service of the Province of British Columbia.

(d) This permit is appurtenant to the undertaking to which the aforesaid water licence is appurtenant.

(e) This permit shall become void if the water licence with respect to which the permit is issued should terminate, be abandoned or cancelled, or amended so as to render this permit unnecessary.

(f) This permit is issued and accepted on the understanding that the permittee shall indemnify and save harmless the Government of the Province of British Columbia for all loss, damage to works, cost or expense suffered by the permittee by reason of the Crown Land or any portion thereof being submerged or damaged by erosion or otherwise affected by flooding.

(g) The holder of this permit shall not be entitled to compensation if the Crown grants permits to other persons to occupy the land affected by this permit.

(h) In the event of a dispute at any time with respect to the area or boundaries of the land affected by this permit, the holder shall, at his own expense, have the said land surveyed by a duly qualified surveyor.

(i) This permit is issued in substitution of Permit # 18365.

Glen Davidson, P.Eng.
Deputy Comptroller of Water Rights

File No.: 0322380 Date Issued: April 4, 2008 PERMIT NO: 25876

Gordon M. Shrum Units 1 to 5 Turbine Replacement Project

BC hydro

Appendix

G

First Nations and Public Consultation Materials

The following letters of correspondence between BC Hydro and First Nations regarding the GMS Units 1 to 5 Turbine Replacement Proejct are included in Appendix G1:

Halfway River First Nation
- Correspondence from BC Hydro to Chief Ed Whitford dated January 12, 2009;
- Correspondence from BC Hydro to Chief Ed Whitford dated May 14, 2009;
- Correspondence from BC Hydro to Chief Ed Whitford dated July 16, 2009;

Kwadacha First Nation
- Correspondence from BC Hydro to Chief Donny Van Somer dated January 12, 2009;
- Correspondence from Chief Donny Van Somer to BC Hydro dated February 4, 2009;
- Correspondence from BC Hydro to Chief Donny Van Somer dated May 14, 2009;
- Correspondence from BC Hydro to Chief Donny Van Somer dated July 16, 2009;

McLeod Lake First Nation
- Correspondence from BC Hydro to Chief Derek Orr dated January 12, 2009;
- Correspondence from BC Hydro to Chief Derek Orr dated May 14, 2009;
- Correspondence from BC Hydro to Chief Derek Orr dated July 16, 2009;

Tsay Keh Dene First Nation
- Correspondence from BC Hydro to Chief Ella Pierre dated January 12, 2009;
- Correspondence from BC Hydro to Chief Ella Pierre dated May 14, 2009;
- Correspondence from BC Hydro to Chief Ella Pierre dated July 16, 2009;

West Moberly
- Correspondence from BC Hydro to Chief Roland Wilson dated January 12, 2009;
- Correspondence from BC Hydro to Chief Roland Wilson dated May 14, 2009;
- Correspondence from BC Hydro to Chief Roland Wilson dated July 16, 2009;

BC hydro
FOR GENERATIONS

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

January 12, 2009

Chief Ed Whitford
Halfway River First Nation
PO Box 59
Wonowon, BC V0C 2N0

BY FACSIMILE (250) 772-5200 *(original to follow by mail)*

Dear Chief Whitford:

Re: GMS Units 1 to 5 Turbine Rehabilitation

I am writing to notify you of BC Hydro's proposed Units 1 to 5 Turbine Rehabilitation Project at the Gordon M. Shrum (GMS) Generating Station. Located next to the W.A.C. Bennett Dam on the Peace River near Hudson's Hope the GMS power plant houses 10 generating units with a total generation capacity of 2,730 megawatts (MW). The facility is capable of generating an average of 13,225 gigawatt hours per year (GWhr/yr) of energy, roughly 30% of BC Hydro's generated energy.

GMS generating units 1 to 5 utilize late 1960's vintage Mitsubishi Francis turbines. A recent assessment of equipment health indicated that the turbines no longer meet reliability standards and must be replaced to protect against failures and costly forced outages. The health and reliability of these generating units is important to the security of the province's electricity supply.

The turbine rehabilitation program proposes to replace one turbine per year, including the runners and wicket gates, with the first unit forecast to come into service in 2012. The work will be confined to the plant. Once complete, each rehabilitated turbine unit will have a maximum capacity of 305 MW; however the upgraded units will continue to be operated at the existing 261 MW maximum capacity as they are limited by other equipment in the unit. The new turbines are expected to achieve an incremental 2% efficiency gain (118 GWhr/yr), which can be attributed to the improved efficiency of a modern turbine design. Existing water licence conditions will continue to be adhered to,

BC hydro
FOR GENERATIONS

with no change to water flows or reservoir levels anticipated as a result of the upgrades. Water licence amendments may be sought in future to take advantage of the full capacity of the upgraded units.

Owing to its cost, the Units 1 to 5 Turbine Rehabilitation Project requires the approval of the British Columbia Utilities Commission (BCUC), the province's regulator of electric utilities. It is anticipated that an Application will be submitted to the BCUC in September 2009, with a decision expected in January 2010. For more information about the BCUC process, please visit their website at www.bcuc.com.

For additional information on the GMS Units 1 to 5 Turbine Rehabilitation Project, please find enclosed a Fact Sheet which provides an overview of the Project. Should you require further information, or should you have any concerns that the proposed Project may affect the Halfway River First Nation's rights or interests, please do not hesitate to contact me at 604-528-8331 or stewart.dill@bchydro.com. For your information, I have also enclosed a second Fact Sheet which describes other work being undertaken at GMS.

Please note that I am copying this letter to the Treaty 8 Tribal Association, such that if the Tribal Association wishes to receive further information about the Project, or has any questions or concerns, they may contact me.

Sincerely,

S A Dill

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

cc: Shona Nelson, Treaty and Aboriginal Rights Research Director, Treaty 8 Tribal Association

Enclosures (2)

BC hydro FOR GENERATIONS

FACT SHEET

GMS Turbine 1-5 Project Update

BC Hydro – Meeting Demand For Generations

Clean, abundant electricity has been, and will continue to be, a key to British Columbia's economic prosperity and quality of life. BC Hydro provides energy solutions to its customers in an environmentally and socially responsible way by balancing British Columbians' energy needs with concern for the environment.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30% over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

Gordon M. Shrum Generation Station – An Historic Asset

The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's generation system. It is also an important part of BC Hydro's heritage. GMS is located next to the W.A.C. Bennett Dam on the Peace River, near Hudson's Hope and about 90 kilometres west of Fort St. John. The GMS power plant houses 10 generating units with a generation capacity of 2,730 megawatts (MW) roughly one quarter of BC Hydro's generating capacity. GMS is capable of generating an average of 13,225 gigawatt hours/per year of energy, roughly 30% of BC Hydro's generated energy.

The first generating units were installed in 1968, with all 10 in service by 1980. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. It must be either replaced or refurbished. Various projects are being undertaken at GMS to address these issues. A short description of one such project is provided below. A description of the other projects is provided in an associated Fact Sheet.

Project: Unit 1 to 5 Turbine Rehabilitation

GMS generating units 1 to 5 represent 12% of BC Hydro's electricity producing capacity, which means that their reliability has an impact on the security of the province's electricity supply.

A hydro electric turbine is a simple rotating mechanical device with few parts that uses flowing water to produce electrical energy. Water from the Williston Reservoir flows by gravity in a large pipe (called a penstock) across turbine blades mounted on a shaft that causes the shaft to turn. The mechanical energy produced from the shaft rotation is converted into electrical energy in a generator through the use of a magnetic field.

The need for renewal

The turbines in Units 1 to 5 were built in the 1960s. Equipment Health Ratings (EHRs) done by BC Hydro found the turbines in GMS Units 1 to 5 no longer meet BC Hydro's equipment health criteria and must be replaced. The GMS Units 1 to 5 Rehabilitation Project is being undertaken to protect against failures and costly forced outages. An ancillary benefit of the project will be an improvement in turbine efficiency as the new turbines will incorporate the technological advances of the last forty years.

The current maximum capacity per machine is 261 MW. The new turbines will be limited to the current capacity because of other existing equipment capacity constraints and the existing water licence limitations. The new turbine design will ultimately allow the generating units to one day operate at a capacity of 305 MW after the necessary water licence revisions are approved some time in the future and additional equipment upgrades are completed.

What's involved?

There are a limited number of world manufacturers capable of supplying the large turbines such as those used at GMS and those manufacturers are seeing a significant number of orders at this time. The result is

that the overall upgrade project will take a number of years. The first stage will focus on the design and modelling of the turbine to demonstrate the robustness and efficiency guarantees. The second stage will consist of shop fabrication of the turbine followed by site construction, installation, and start-up of the turbines. The first unit is forecast to come into service in 2012, and one unit per year thereafter. The fifth and final unit is expected to be in service by the beginning of 2017.

An Application for a BCUC Determination will be filed in 2009 because the cost of implementing the project is more than $50M.

This update was provided to keep residents of the Peace region informed on the Turbine Units 1 to 5 Project. For information on other asset refurbishment being made to the Gordon M. Shrum Generating Station please see the associated Fact Sheet. For more information please contact BC Hydro's Community Relations Manager, Bob Gammer at 250 561-4858, or bob.gammer@bchydro.com or Stewart Dill, Aboriginal Relations Coordinator at 604 528-8331, or stewart.dill@bchydro.com.

BC hydro FOR GENERATIONS

FACT SHEET

GMS Projects Update

BC Hydro – Meeting Demand For Generations

Clean, abundant electricity has been, and will continue to be, a key to British Columbia's economic prosperity and quality of life. BC Hydro provides energy solutions to its customers in an environmentally and socially responsible way by balancing British Columbians' energy needs with concern for the environment.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30% over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

Gordon M. Shrum Generation Station – An Historic Asset

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The first generating units were installed in 1968, with all 10 in service by 1980. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. It must be either replaced or refurbished. Various projects are being undertaken at GMS to address these issues and a short description of each is included below. A description of one additional project, the Unit 1 to 5 Turbine Rehabilitation project, is provided in an associated Fact Sheet.

Project: Units 1 to 4 Generator Stators Replacement

The generator stators (the stationary part of the generating unit that converts the mechanical energy of the rotor into electrical energy) in Units 1 to 4 were built in the 1960s. Their Equipment Health Ratings (EHRs) no longer meet BC Hydro's equipment health criteria and replacement began in 2006 (two units are now complete) and is forecast to be completed by the beginning of 2010.

The new stator design will ultimately allow the units to one day operate at a capacity of 305 MW, but are now limited to the current 261 MW capacity because of other existing equipment capacity constraints and the existing water licence requirements.

Project: Units 6 & 7 Rotor Pole Replacement

Rotor poles (the rotating part of the generator connected to the turbine) on GMS Units 6 and 7 were also determined to no longer meet BC Hydro's equipment health criteria and also needed to be redesigned and replaced to accommodate the increased generating capacity on Units 6 to 7 (see 6 to 8 capacity increase below). The first installation was completed in November 2007. Replacement of the second unit will be completed in November 2010.

Project: Transformer Replacement

GMS has thirty unit transformers (the device that increases the voltage to allow transmission over distance). Ten of these transformers will be replaced to ensure the reliability of the plant. Installation of the new transformers started in October 2008 and will be completed in 2011.

Project: Units 6 to 8 Capacity Increase

GMS Units 6 to 8 will be refurbished to increase the capacity of GMS by 90 MW by replacing the generator circuit breakers (special switches to shut off and turn on power from the generator system) and iso-phase

BC hydro FOR GENERATIONS

FACT SHEET

GMS Projects Update

bus (special electrical conductors that carry the power from the underground powerhouse to the substation on the surface). The increase in capacity is allowable within the current water licence. The B.C. Environmental Assessment Office (BCEAO) reviewed the proposed upgrade and confirmed the project would not require an Environmental Assessment Certificate and may proceed because it will not have significant adverse environmental, economic, social, heritage, or health affects. The BCEAO made this conclusion after extensive consultation with and feedback from, appropriate government agencies, local governments and First Nations. Work will commence in April 2009 and the total project is expected to be completed by June 2011.

Project: Station Service Replacement

Various equipment and emergency supply systems at GMS will also be replaced. The station service system provides the power for the plant controls, battery systems, fire systems and all the auxiliary systems necessary to run the plant's generators. The general contract has been awarded and the replacement work is scheduled to start in May 2009 and completion is expected by 2011.

This update was provided to keep residents of the Peace region informed on asset refurbishments being made to the Gordon M. Shrum Generating Station. For information about the Turbine Units 1 to 5 Project please see the associated Fact Sheet. Please contact BC Hydro's Community Relations Manager, Bob Gammer at 250 561-4858, or bob.gammer@bchydro.com or Stewart Dill, Aboriginal Relations Coordinator at 604 528-8331, or stewart.dill@bchydro.com for more information on any of the above projects.

BC hydro

FAX COVER SHEET

Aboriginal Relations and Negotiations

6911 Southpoint Drive (E16), Burnaby, B.C. V3N 4X8
www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

***TO:* Chief Ed Whitford**
Halfway River First Nation

DATE: January 12, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-772-5200

No. of pages (including cover sheet): **7**

MESSAGE

Please see enclosed letter.

 P. 1

* * * Communication Result Report (Jan. 13. 2009 12:46PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: Jan. 13. 2009 12:43PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
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Reason for error
E. 1) Hang up or line fail
E. 2) Busy
E. 3) No answer
E. 4) No facsimile connection
E. 5) Exceeded max. E-mail size

BChydro

FAX COVER SHEET

Aboriginal Relations and Negotiations

6911 Southpoint Drive (E16), Burnaby, B.C. V3N 4X8
www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: Chief Ed Whitford
Halfway River First Nation

DATE: January 12, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-772-6200

No. of pages (including cover sheet): 7

MESSAGE

Please see enclosed letter.

BC hydro
FOR GENERATIONS

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

May 14, 2009

Chief Ed Whitford
Halfway River First Nation
PO Box 59
Wonowon, BC V0C 2N0

BY FACSIMILE (250) 772-5200 *(original to follow by mail)*

Dear Chief Whitford:

Re: GMS Units 1 to 5 Turbine Rehabilitation

I am writing further to my letter of January 12, 2009 to provide you with an update on BC Hydro's proposed Units 1 to 5 Turbine Rehabilitation Project at the Gordon M. Shrum (GMS) Generating Station. In that letter I notified you of BC Hydro's plans to replace the turbines in five of the generating units at GMS in order to maintain the health and reliability of the units. The work will be confined to the plant and no change to water flows or reservoir levels are anticipated as a result of the upgrades.

The design and modelling of turbine options is ongoing. It is expected that a final design will be selected in summer 2010, which will be followed by fabrication of the turbines, site construction, installation and start-up. The first unit is forecast to come into service in 2012, with all five units in service by early 2017.

BC Hydro continues to anticipate submitting an Application in respect of the Units 1 to 5 Turbine Rehabilitation Project to the British Columbia Utilities Commission (BCUC) in September 2009, which will be preceded by an intervenor workshop in summer 2009.

For additional information on the GMS Units 1 to 5 Turbine Rehabilitation Project, please find enclosed a fact sheet which provides an updated overview of the Project. As before, should you require further information, or should you have any concerns that the proposed Project may affect the Halfway River First Nation's rights or interests, please do not hesitate to contact me at 604-528-8331 or stewart.dill@bchydro.com.

BC hydro
FOR GENERATIONS

For your information, the enclosed fact sheet also provides an update on other work being undertaken at GMS.

Sincerely,

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

cc: Shona Nelson, Treaty and Aboriginal Rights Research Director, Treaty 8 Tribal Association

Enclosure

BC HYDRO
MEETING DEMAND FOR GENERATIONS
UPDATE MAY 2009

GORDON M. SHRUM GENERATION STATION —AN HISTORIC ASSET

The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's generation system. GMS is located next to the W.A.C. Bennett Dam on the Peace River, near Hudson's Hope. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. Various projects are being undertaken at GMS to address these issues and a short description and status update of each is included below:

Project: Units 1 to 5 Turbine Rehabilitation

GMS generating Units 1 to 5 represent 12 per cent of BC Hydro's electricity producing capacity, which means that their reliability has an impact on the security of the province's electricity supply.

The need for renewal

Equipment Health Rating (EHRs) assessments undertaken by BC Hydro found that the 1960s era turbines in GMS Units 1 to 5 must be replaced. The project is being undertaken to ensure ongoing reliability, availability and operational flexibility of these units. A secondary benefit of the project will be an improvement in turbine efficiency.

The current maximum capacity per machine is 261 MW. The new turbines will be limited to the current capacity because of other existing equipment capacity constraints and the existing water licence limitations. The new turbines will ultimately allow the generating units to one day operate at a capacity of 305 MW. However, this capacity increase will require additional equipment upgrades and BC Hydro must also apply for a water licence revision and receive approval from the Ministry of Environment.

What's involved?

There are a limited number of manufacturers capable of supplying the large turbines used at GMS and those manufacturers are seeing a significant number of orders at this time – meaning this upgrade project will take several years. The first stage of project implementation consists of the design and modelling of a turbine to demonstrate the robustness and efficiency guarantees of the final product. To optimise the design and efficiency improvements and still maintain commercial competitiveness, the design and modelling work was awarded to two manufacturers, Voith Siemens Hydro Power Generation Inc. and Andritz Hydro Power Canada Inc, that will compete to provide the best possible solution for this project. Final award to a single manufacturer is anticipated for the summer of 2010 at which time the selected firm will proceed to the implementation of the second stage of the project. The second stage includes shop fabrication of the turbine followed by site construction, installation and start-up of the turbines. The first unit is forecast to come into service in 2012, and one unit per year thereafter. The final unit is expected to be in service in early 2017.

The cost of implementing the project is more than $50M and therefore an application will be made to the British Columbia Utilities Commission (BCUC) seeking a determination that the project is in the public interest. This application will be filed in the summer of 2009. Prior to filing the application, BC Hydro will hold a workshop on this application. It is expected that the BCUC will hold a hearing on the application during the fall of 2009.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on annual net power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30 per cent over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

BChydro
FOR GENERATIONS

Project: Units 1 to 4 Generator Stators Replacement

The generator stators (the stationary part of the generating unit that converts the mechanical energy of the rotor into electrical energy) in Units 1 to 4 were also built in the 1960s and are due for replacement. A contract was awarded to Alstom Canada Inc. for the replacement of the stators. Two units are now complete and the other two are forecast to be completed by the end of 2010.

Project: Units 6 & 7 Rotor Pole Replacement

Rotor poles (the rotating part of the generator connected to the turbine) on GMS Units 6 and 7 were also determined to no longer meet BC Hydro's EHR criteria and required a redesign and replacement to accommodate the increased generating capacity on Units 6 and 7 (see 6 to 8 Project below). The first installation is complete and the second unit will be completed in late 2010.

Project: Transformer Replacement

GMS has thirty unit transformers (the device that increases the voltage to allow transmission over distance). Ten of these transformers will be replaced to ensure the reliability of the plant. Installation of the new transformers started in October 2008 and will be completed in 2011. Five new transformers will arrive at GMS in late spring and installation activities will last into fall 2009.

Project: Units 6 to 8 Capacity Increase

GMS Units 6 to 8 will be refurbished to increase the capacity of GMS by 90 MW by replacing the generator circuit breakers and iso-phase bus. The increase in capacity is allowable within the current water licence. The B.C. Environmental Assessment Office (BCEAO) reviewed the proposed upgrade and confirmed the project would not require an Environmental Assessment Certificate and may proceed because it will not have significant adverse environmental, economic, social, heritage, or health affects. The BCEAO made this conclusion after extensive consultation with and feedback from, appropriate government agencies, local governments and First Nations. The contract was awarded to Alstom Canada Inc. Work will start this summer and is expected to be completed by summer 2011.

Project: Station Service Replacement

The station service system provides the power for the plant controls, battery systems, fire systems and all the auxiliary systems necessary to run the plant's generators. The general contract has been awarded to ABB Inc. and completion is expected by 2011.

This update is provided to keep residents of the Peace region informed on asset refurbishments being made to the G. M. Shrum Generating Station.

Please contact BC Hydro Community Relations at 250 561 4858, or bob.gammer@bchydro.com or BC Hydro Aboriginal Relations at 604 528 8331, or stewart.dill@bchydro.com for more information on any of the above projects.

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GD509-149

BC hydro

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Aboriginal Relations and Negotiations

6911 Southpoint Drive (E16), Burnaby, B.C. V3N 4X8
www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Chief Ed Whitford**
Halfway River River First Nation

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-772-5200

No. of pages (including cover sheet): **5**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (May. 14. 2009 5:16PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: May. 14. 2009 5:15PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
1414	Memory TX	912507725200	P. 5	OK	

Reason for error
E. 1) Hang up or line fail
E. 2) Busy
E. 3) No answer
E. 4) No facsimile connection
E. 5) Exceeded max. E-mail size

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Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: Chief Ed Whitford
Halfway River River First Nation

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-772-5200

No. of pages (including cover sheet): 5

MESSAGE

Please see enclosed letter.

BC hydro
FOR GENERATIONS

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

July 16, 2009

Chief Ed Whitford
Halfway River First Nation
PO Box 59
Wonowon, BC V0C 2N0

BY FACSIMILE (250) 772-5200 *(original to follow by mail)*

Dear Chief Whitford:

Re: GMS Units 1 to 5 Turbine Replacement

I am writing further to my letters of January 12, 2009 and May 14, 2009 to provide you with an update on BC Hydro's plans to submit an application to the British Columbia Utilities Commission (BCUC) in respect of the Units 1 to 5 Turbine Replacement Project at the Gordon M. Shrum (GMS) Generating Station.

BC Hydro intends to file its application with the BCUC around the end of July 2009. Once the application is filed, it becomes a public document and the BCUC will start a public hearing process that is expected to include a workshop. Further information on the public hearing process can be found at the BCUC website: www.bcuc.com/Hearing.aspx.

As before, should you require further information, or should you have any concerns that the proposed GMS Units 1 to 5 Turbine Replacement Project may affect the Halfway River First Nation's rights or interests, please do not hesitate to contact me at 604-528-8331 or stewart.dill@bchydro.com.

Sincerely,

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

cc: Shona Nelson, Treaty and Aboriginal Rights Research Director, Treaty 8 Tribal Association

BC hydro

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Aboriginal Relations and Negotiations

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www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

***TO:* Chief Ed Whitford**
Halfway River River First Nation

DATE: July 16, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-772-5200

No. of pages (including cover sheet): **3**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (Jul. 16. 2009 3:39PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: Jul. 16. 2009 3:32PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
2460	Memory TX	912507725200	P. 3	OK	

Reason for error
E. 1) Hang up or line fail
E. 2) Busy
E. 3) No answer
E. 4) No facsimile connection
E. 5) Exceeded max. E-mail size

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www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: Chief Ed Whitford
Halfway River River First Nation

DATE: July 16, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-772-5200

No. of pages (including cover sheet): 3

MESSAGE

Please see enclosed letter.

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

January 12, 2009

Chief Donny Van Somer
Kwadacha First Nation
P.O. Box 86
Fort Ware, BC V0J 3B0

BY FACSIMILE (250) 471-2701 *(original to follow by mail)*

Dear Chief Van Somer:

Re: <u>GMS Units 1 to 5 Turbine Rehabilitation</u>

Pursuant to Section 9.8 (a) of the Kwadacha First Nation Final Agreement, I am writing to notify you of anticipated future regulatory proceedings relating to BC Hydro's proposed Units 1 to 5 Turbine Rehabilitation Project at the Gordon M. Shrum (GMS) Generating Station.

Located next to the W.A.C. Bennett Dam on the Peace River near Hudson's Hope the GMS power plant houses 10 generating units with a total generation capacity of 2,730 megawatts (MW). The facility is capable of generating an average of 13,225 gigawatt hours per year (GWhr/yr) of energy, roughly 30% of BC Hydro's generated energy.

GMS generating units 1 to 5 utilize late 1960's vintage Mitsubishi Francis turbines. A recent assessment of equipment health indicated that the turbines no longer meet reliability standards and must be replaced to protect against failures and costly forced outages. The health and reliability of these generating units is important to the security of the province's electricity supply.

The turbine rehabilitation program proposes to replace one turbine per year, including the runners and wicket gates, with the first unit forecast to come into service in 2012. The work will be confined to the plant. Once complete, each rehabilitated turbine unit will have a maximum capacity of 305 MW; however the upgraded units will continue to be operated at the existing 261 MW maximum capacity as they are limited by other

BC hydro
FOR GENERATIONS

equipment in the unit. The new turbines are expected to achieve an incremental 2% efficiency gain (118 GWhr/yr), which can be attributed to the improved efficiency of a modern turbine design. Existing water licence conditions will continue to be adhered to, with no change to water flows or reservoir levels anticipated as a result of the upgrades. Water licence amendments may be sought in future to take advantage of the full capacity of the upgraded units.

Owing to its cost, the Units 1 to 5 Turbine Rehabilitation Project requires the approval of the British Columbia Utilities Commission (BCUC), the province's regulator of electric utilities. It is anticipated that an Application will be submitted to the BCUC in September 2009, with a decision expected in January 2010. For more information about the BCUC process, please visit their website at www.bcuc.com.

For additional information on the GMS Units 1 to 5 Turbine Rehabilitation Project, please find enclosed a Fact Sheet which provides an overview of the Project. Should you require further information, or should you have any questions or concerns, please do not hesitate to contact me at 604-528-8331 or stewart.dill@bchydro.com. For your information, I have also enclosed a second Fact Sheet which describes other work being undertaken at GMS.

Sincerely,

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

cc: P. John Landry, Davis LLP
Rod Hill, Aboriginal Relations Coordinator, BC Hydro

Enclosures (2)

BC hydro FOR GENERATIONS

FACT SHEET

GMS Turbine 1-5
Project Update

BC Hydro – Meeting Demand For Generations

Clean, abundant electricity has been, and will continue to be, a key to British Columbia's economic prosperity and quality of life. BC Hydro provides energy solutions to its customers in an environmentally and socially responsible way by balancing British Columbians' energy needs with concern for the environment.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30% over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

Gordon M. Shrum Generation Station – An Historic Asset

The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's generation system. It is also an important part of BC Hydro's heritage. GMS is located next to the W.A.C. Bennett Dam on the Peace River, near Hudson's Hope and about 90 kilometres west of Fort St. John. The GMS power plant houses 10 generating units with a generation capacity of 2,730 megawatts (MW) roughly one quarter of BC Hydro's generating capacity. GMS is capable of generating an average of 13,225 gigawatt hours/per year of energy, roughly 30% of BC Hydro's generated energy.

The first generating units were installed in 1968, with all 10 in service by 1980. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. It must be either replaced or refurbished. Various projects are being undertaken at GMS to address these issues. A short description of one such project is provided below. A description of the other projects is provided in an associated Fact Sheet.

Project: Unit 1 to 5 Turbine Rehabilitation

GMS generating units 1 to 5 represent 12% of BC Hydro's electricity producing capacity, which means that their reliability has an impact on the security of the province's electricity supply.

A hydro electric turbine is a simple rotating mechanical device with few parts that uses flowing water to produce electrical energy. Water from the Williston Reservoir flows by gravity in a large pipe (called a penstock) across turbine blades mounted on a shaft that causes the shaft to turn. The mechanical energy produced from the shaft rotation is converted into electrical energy in a generator through the use of a magnetic field.

The need for renewal

The turbines in Units 1 to 5 were built in the 1960s. Equipment Health Ratings (EHRs) done by BC Hydro found the turbines in GMS Units 1 to 5 no longer meet BC Hydro's equipment health criteria and must be replaced. The GMS Units 1 to 5 Rehabilitation Project is being undertaken to protect against failures and costly forced outages. An ancillary benefit of the project will be an improvement in turbine efficiency as the new turbines will incorporate the technological advances of the last forty years.

The current maximum capacity per machine is 261 MW. The new turbines will be limited to the current capacity because of other existing equipment capacity constraints and the existing water licence limitations. The new turbine design will ultimately allow the generating units to one day operate at a capacity of 305 MW after the necessary water licence revisions are approved some time in the future and additional equipment upgrades are completed.

What's involved?

There are a limited number of world manufacturers capable of supplying the large turbines such as those used at GMS and those manufacturers are seeing a significant number of orders at this time. The result is

that the overall upgrade project will take a number of years. The first stage will focus on the design and modelling of the turbine to demonstrate the robustness and efficiency guarantees. The second stage will consist of shop fabrication of the turbine followed by site construction, installation, and start-up of the turbines. The first unit is forecast to come into service in 2012, and one unit per year thereafter. The fifth and final unit is expected to be in service by the beginning of 2017.

An Application for a BCUC Determination will be filed in 2009 because the cost of implementing the project is more than $50M.

This update was provided to keep residents of the Peace region informed on the Turbine Units 1 to 5 Project. For information on other asset refurbishment being made to the Gordon M. Shrum Generating Station please see the associated Fact Sheet. For more information please contact BC Hydro's Community Relations Manager, Bob Gammer at 250 561-4858, or bob.gammer@bchydro.com or Stewart Dill, Aboriginal Relations Coordinator at 604 528-8331, or stewart.dill@bchydro.com.

BC hydro
FOR GENERATIONS

FACT SHEET

GMS Projects Update

BC Hydro – Meeting Demand For Generations

Clean, abundant electricity has been, and will continue to be, a key to British Columbia's economic prosperity and quality of life. BC Hydro provides energy solutions to its customers in an environmentally and socially responsible way by balancing British Columbians' energy needs with concern for the environment.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30% over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

Gordon M. Shrum Generation Station – An Historic Asset

The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's generation system. It is also an important part of BC Hydro's heritage. GMS is located next to the W.A.C. Bennett Dam on the Peace River, near Hudson's Hope and about 90 kilometres west of Fort St. John. The GMS power plant houses 10 generating units with a generation capacity of 2,730 megawatts (MW), roughly one quarter of BC Hydro's generating capacity. GMS is capable of generating an average of 13,225 gigawatt hours/per year of energy, roughly 30% of BC Hydro's generated energy.

The first generating units were installed in 1968, with all 10 in service by 1980. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. It must be either replaced or refurbished. Various projects are being undertaken at GMS to address these issues and a short description of each is included below. A description of one additional project, the Unit 1 to 5 Turbine Rehabilitation project, is provided in an associated Fact Sheet.

Project: Units 1 to 4 Generator Stators Replacement

The generator stators (the stationary part of the generating unit that converts the mechanical energy of the rotor into electrical energy) in Units 1 to 4 were built in the 1960s. Their Equipment Health Ratings (EHRs) no longer meet BC Hydro's equipment health criteria and replacement began in 2006 (two units are now complete) and is forecast to be completed by the beginning of 2010.

The new stator design will ultimately allow the units to one day operate at a capacity of 305 MW, but are now limited to the current 261 MW capacity because of other existing equipment capacity constraints and the existing water licence requirements.

Project: Units 6 & 7 Rotor Pole Replacement

Rotor poles (the rotating part of the generator connected to the turbine) on GMS Units 6 and 7 were also determined to no longer meet BC Hydro's equipment health criteria and also needed to be redesigned and replaced to accommodate the increased generating capacity on Units 6 to 7 (see 6 to 8 capacity increase below). The first installation was completed in November 2007. Replacement of the second unit will be completed in November 2010.

Project: Transformer Replacement

GMS has thirty unit transformers (the device that increases the voltage to allow transmission over distance). Ten of these transformers will be replaced to ensure the reliability of the plant. Installation of the new transformers started in October 2008 and will be completed in 2011.

Project: Units 6 to 8 Capacity Increase

GMS Units 6 to 8 will be refurbished to increase the capacity of GMS by 90 MW by replacing the generator circuit breakers (special switches to shut off and turn on power from the generator system) and iso-phase

bus (special electrical conductors that carry the power from the underground powerhouse to the substation on the surface). The increase in capacity is allowable within the current water licence. The B.C. Environmental Assessment Office (BCEAO) reviewed the proposed upgrade and confirmed the project would not require an Environmental Assessment Certificate and may proceed because it will not have significant adverse environmental, economic, social, heritage, or health affects. The BCEAO made this conclusion after extensive consultation with and feedback from, appropriate government agencies, local governments and First Nations. Work will commence in April 2009 and the total project is expected to be completed by June 2011.

Project: Station Service Replacement

Various equipment and emergency supply systems at GMS will also be replaced. The station service system provides the power for the plant controls, battery systems, fire systems and all the auxiliary systems necessary to run the plant's generators. The general contract has been awarded and the replacement work is scheduled to start in May 2009 and completion is expected by 2011.

This update was provided to keep residents of the Peace region informed on asset refurbishments being made to the Gordon M. Shrum Generating Station. For information about the Turbine Units 1 to 5 Project please see the associated Fact Sheet. Please contact BC Hydro's Community Relations Manager, Bob Gammer at 250 561-4858, or bob.gammer@bchydro.com or Stewart Dill, Aboriginal Relations Coordinator at 604 528-8331, or stewart.dill@bchydro.com for more information on any of the above projects.

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6911 Southpoint Drive (E16), Burnaby, B.C. V3N 4X8
www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Chief Donny Van Somer**
Kwadacha First Nation

DATE: January 12, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-471-2701

No. of pages (including cover sheet): **7**

MESSAGE

Please see enclosed letter.

P. 1

* * * Communication Result Report (Jan. 13. 2009 12:30PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: Jan. 13. 2009 12:24PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
0384	Memory TX	912504712701	P. 7	OK	

Reason for error
E. 1) Hang up or line fail
E. 3) No answer
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www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: Chief Donny Van Somer
Kwadacha First Nation

DATE: January 12, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-471-2701

No. of pages (including cover sheet): 7

MESSAGE

Please see enclosed letter.

BC hydro

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www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **John Landry**
Davis, LLP

DATE: January 12, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 604-605-3588

No. of pages (including cover sheet): **7**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (Jan. 13. 2009 12:33PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: Jan. 13. 2009 12:25PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
0385	Memory TX	96046053588	P. 7	OK	

Reason for error
E. 1) Hang up or line fail
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TO: John Landry
Davis, LLP

DATE: January 12, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 604-605-3588

No. of pages (including cover sheet): 7

MESSAGE

Please see enclosed letter.

February 4, 2009

Stewart Dill
BC Hydro aboriginal Relations and Negotiations
6911 Southpoint Drive
Burnaby, British Columbia, V3N 4X8

Dear Mr. Dill:

Re: GMS Units 1 to 5 Turbine Rehabilitation

Thank you for your letter of notification dated January 12, 2009.

We understand from your letter that the project is intended only to replace existing turbines, and that Williston Reservoir water levels and flows will not be affected. On that basis, Kwadacha has no objection to the planned rehabilitation.

Thank you for keeping us informed.

Sincerely,

Donny Van Somer

Chief Donny Van Somer

ADMINISTRATION OFFICE #207 - 513 AHBAU STREET PRINCE GEORGE BC V2M 3R8 (250) 563-4161 FAX (250) 563-2668
FORT WARE OFFICE PO BOX 86 FORT WARE BC V0J 3B0 (250) 471-2302 FAX (250) 471-2701

BC hydro
FOR GENERATIONS

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

May 14, 2009

Chief Donny Van Somer
Kwadacha First Nation
P.O. Box 86
Fort Ware, BC V0J 3B0

BY FACSIMILE (250) 471-2701 *(original to follow by mail)*

Dear Chief Van Somer:

Re: GMS Units 1 to 5 Turbine Rehabilitation

I am writing further to my letter of January 12, 2009, to provide you with an update on BC Hydro's proposed Units 1 to 5 Turbine Rehabilitation Project at the Gordon M. Shrum (GMS) Generating Station, and to thank you for your letter of February 4, 2009 in which you indicate that the Kwadacha First Nation has no objection to the proposed Project.

In my January 12, 2009 letter I notified you of anticipated future regulatory proceedings relating to BC Hydro's plans to replace the turbines in five of the generating units at GMS. The work is being undertaken in order to maintain the health and reliability of the units and will be confined to the plant. No change to water flows or reservoir levels are anticipated as a result of the upgrades.

The design and modelling of turbine options is ongoing. It is expected that a final design will be selected in summer 2010, which will be followed by fabrication of the turbines, site construction, installation and start-up. The first unit is forecast to come into service in 2012, with all five units in service by early 2017.

BC Hydro continues to anticipate submitting an Application in respect of the Units 1 to 5 Turbine Rehabilitation Project to the British Columbia Utilities Commission (BCUC) in September 2009, which will be preceded by an intervenor workshop in summer 2009.

BC hydro

FOR GENERATIONS

For additional information on the GMS Units 1 to 5 Turbine Rehabilitation Project, please find enclosed a fact sheet which provides an updated overview of the Project. As before, should you require further information, or should you have any questions or concerns, please do not hesitate to contact me at 604-528-8331 or stewart.dill@bchydro.com. For your information, the enclosed fact sheet also provides an update on other work being undertaken at GMS.

Sincerely,

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

cc: P. John Landry, Davis LLP
Rod Hill, Aboriginal Relations Coordinator, BC Hydro

Enclosure

BC HYDRO MEETING DEMAND FOR GENERATIONS UPDATE MAY 2009

GORDON M. SHRUM GENERATION STATION —AN HISTORIC ASSET

The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's generation system. GMS is located next to the W.A.C. Bennett Dam on the Peace River, near Hudson's Hope. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. Various projects are being undertaken at GMS to address these issues and a short description and status update of each is included below:

Project: Units 1 to 5 Turbine Rehabilitation

GMS generating Units 1 to 5 represent 12 per cent of BC Hydro's electricity producing capacity, which means that their reliability has an impact on the security of the province's electricity supply.

The need for renewal

Equipment Health Rating (EHRs) assessments undertaken by BC Hydro found that the 1960s era turbines in GMS Units 1 to 5 must be replaced. The project is being undertaken to ensure ongoing reliability, availability and operational flexibility of these units. A secondary benefit of the project will be an improvement in turbine efficiency.

The current maximum capacity per machine is 261 MW. The new turbines will be limited to the current capacity because of other existing equipment capacity constraints and the existing water licence limitations. The new turbines will ultimately allow the generating units to one day operate at a capacity of 305 MW. However, this capacity increase will require additional equipment upgrades and BC Hydro must also apply for a water licence revision and receive approval from the Ministry of Environment.

What's involved?

There are a limited number of manufacturers capable of supplying the large turbines used at GMS and those manufacturers are seeing a significant number of orders at this time – meaning this upgrade project will take several years. The first stage of project implementation consists of the design and modelling of a turbine to demonstrate the robustness and efficiency guarantees of the final product. To optimise the design and efficiency improvements and still maintain commercial competitiveness, the design and modelling work was awarded to two manufacturers, Voith Siemens Hydro Power Generation Inc. and Andritz Hydro Power Canada Inc, that will compete to provide the best possible solution for this project. Final award to a single manufacturer is anticipated for the summer of 2010 at which time the selected firm will proceed to the implementation of the second stage of the project. The second stage includes shop fabrication of the turbine followed by site construction, installation and start-up of the turbines. The first unit is forecast to come into service in 2012, and one unit per year thereafter. The final unit is expected to be in service in early 2017.

The cost of implementing the project is more than $50M and therefore an application will be made to the British Columbia Utilities Commission (BCUC) seeking a determination that the project is in the public interest. This application will be filed in the summer of 2009. Prior to filing the application, BC Hydro will hold a workshop on this application. It is expected that the BCUC will hold a hearing on the application during the fall of 2009.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on annual net power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30 per cent over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

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FOR GENERATIONS

Project: Units 1 to 4 Generator Stators Replacement

The generator stators (the stationary part of the generating unit that converts the mechanical energy of the rotor into electrical energy) in Units 1 to 4 were also built in the 1960s and are due for replacement. A contract was awarded to Alstom Canada Inc. for the replacement of the stators. Two units are now complete and the other two are forecast to be completed by the end of 2010.

Project: Units 6 & 7 Rotor Pole Replacement

Rotor poles (the rotating part of the generator connected to the turbine) on GMS Units 6 and 7 were also determined to no longer meet BC Hydro's EHR criteria and required a redesign and replacement to accommodate the increased generating capacity on Units 6 and 7 (see 6 to 8 Project below). The first installation is complete and the second unit will be completed in late 2010.

Project: Transformer Replacement

GMS has thirty unit transformers (the device that increases the voltage to allow transmission over distance). Ten of these transformers will be replaced to ensure the reliability of the plant. Installation of the new transformers started in October 2008 and will be completed in 2011. Five new transformers will arrive at GMS in late spring and installation activities will last into fall 2009.

Project: Units 6 to 8 Capacity Increase

GMS Units 6 to 8 will be refurbished to increase the capacity of GMS by 90 MW by replacing the generator circuit breakers and iso-phase bus. The increase in capacity is allowable within the current water licence. The B.C. Environmental Assessment Office (BCEAO) reviewed the proposed upgrade and confirmed the project would not require an Environmental Assessment Certificate and may proceed because it will not have significant adverse environmental, economic, social, heritage, or health affects. The BCEAO made this conclusion after extensive consultation with and feedback from, appropriate government agencies, local governments and First Nations. The contract was awarded to Alstom Canada Inc. Work will start this summer and is expected to be completed by summer 2011.

Project: Station Service Replacement

The station service system provides the power for the plant controls, battery systems, fire systems and all the auxiliary systems necessary to run the plant's generators. The general contract has been awarded to ABB Inc. and completion is expected by 2011.

This update is provided to keep residents of the Peace region informed on asset refurbishments being made to the G. M. Shrum Generating Station.

Please contact BC Hydro Community Relations at 250 561 4858, or bob.gammer@bchydro.com or BC Hydro Aboriginal Relations at 604 528 8331, or stewart.dill@bchydro.com for more information on any of the above projects.

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FOR GENERATIONS

GDS09-149

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www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Chief Donny Van Somer**
Kwadacha First Nation

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-471-2701

No. of pages (including cover sheet): **5**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (May. 14. 2009 5:25PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: May. 14. 2009 5:21PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
1420	Memory TX	912504712701	P. 5	OK	

Reason for error
E. 1) Hang up or line fail
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6011 Southpoint Drive (E16), Burnaby, B.C. V3N 4X8
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TO: **Chief Donny Van Somer**
Kwadacha First Nation

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-471-2701

No. of pages (including cover sheet): 5

MESSAGE

Please see enclosed letter.

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Aboriginal Relations and Negotiations

6911 Southpoint Drive (E16), Burnaby, B.C. V3N 4X8
www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **John Landry**
Davis, LLP

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 604-605-3588

No. of pages (including cover sheet): **5**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (May. 14. 2009 5:27PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: May. 14. 2009 5:22PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
1421	Memory TX	96046053588	P. 5	OK	

Reason for error
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E. 2) Busy
E. 3) No answer
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TO: John Landry
Davis, LLP

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 604-605-3588

No. of pages (including cover sheet): 5

MESSAGE

Please see enclosed letter.

BC hydro
FOR GENERATIONS

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

July 16, 2009

Chief Donny Van Somer
Kwadacha First Nation
P.O. Box 86
Fort Ware, BC V0J 3B0

BY FACSIMILE (250) 471-2701 *(original to follow by mail)*

Dear Chief Van Somer:

Re: GMS Units 1 to 5 Turbine Replacement

I am writing further to my letters of January 12, 2009 and May 14, 2009 to provide you with an update on BC Hydro's plans to submit an application to the British Columbia Utilities Commission (BCUC) in respect of the Units 1 to 5 Turbine Replacement Project at the Gordon M. Shrum (GMS) Generating Station.

BC Hydro intends to file its application with the BCUC around the end of July 2009. Once the application is filed, it becomes a public document and the BCUC will start a public hearing process that is expected to include a workshop. Further information on the public hearing process can be found at the BCUC website: www.bcuc.com/Hearing.aspx.

As before, should you require further information, or should you have any questions or concerns about the proposed GMS Units 1 to 5 Turbine Replacement Project, please do not hesitate to contact me at 604-528-8331 or stewart.dill@bchydro.com.

Sincerely,

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

cc: P. John Landry, Davis LLP
Rod Hill, Aboriginal Relations Coordinator, BC Hydro

BC hydro

FAX COVER SHEET

Aboriginal Relations and Negotiations

6911 Southpoint Drive (E16), Burnaby, B.C. V3N 4X8
www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Chief Donny Van Somer**
Kwadacha First Nation

DATE: July 16, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-471-2701

No. of pages (including cover sheet): **3**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (Jul. 16. 2009 3:44PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: Jul. 16. 2009 3:37PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
2467	Memory TX	912504712701	P. 3	OK	

Reason for error
E. 1) Hang up or line fail
E. 2) Busy
E. 3) No answer
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Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: Chief Donny Van Somer
Kwadacha First Nation

DATE: July 16, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-471-2701

No. of pages (including cover sheet): 3

MESSAGE

Please see enclosed letter.

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www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **John Landry**
Davis, LLP

DATE: July 16, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 604-605-3588

No. of pages (including cover sheet): **3**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (Jul. 16. 2009 3:40PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: Jul. 16. 2009 3:38PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
2468	Memory TX	96046053588	P. 3	OK	

Reason for error
E. 1) Hang up or line fail
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E. 4) No facsimile connection
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Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: John Landry
Davis, LLP

DATE: July 16, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 604-605-3588

No. of pages (including cover sheet): 3

MESSAGE

Please see enclosed letter.

BC hydro
FOR GENERATIONS

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

January 12, 2009

Chief Derek Orr
McLeod Lake Indian Band
General Delivery
McLeod Lake, BC V0J 2G0

BY FACSIMILE (250) 750-4420 *(original to follow by mail)*

Dear Chief Orr:

Re: GMS Units 1 to 5 Turbine Rehabilitation

I am writing to notify you of BC Hydro's proposed Units 1 to 5 Turbine Rehabilitation Project at the Gordon M. Shrum (GMS) Generating Station. Located next to the W.A.C. Bennett Dam on the Peace River near Hudson's Hope the GMS power plant houses 10 generating units with a total generation capacity of 2,730 megawatts (MW). The facility is capable of generating an average of 13,225 gigawatt hours per year (GWhr/yr) of energy, roughly 30% of BC Hydro's generated energy.

GMS generating units 1 to 5 utilize late 1960's vintage Mitsubishi Francis turbines. A recent assessment of equipment health indicated that the turbines no longer meet reliability standards and must be replaced to protect against failures and costly forced outages. The health and reliability of these generating units is important to the security of the province's electricity supply.

The turbine rehabilitation program proposes to replace one turbine per year, including the runners and wicket gates, with the first unit forecast to come into service in 2012. The work will be confined to the plant. Once complete, each rehabilitated turbine unit will have a maximum capacity of 305 MW; however the upgraded units will continue to be operated at the existing 261 MW maximum capacity as they are limited by other equipment in the unit. The new turbines are expected to achieve an incremental 2% efficiency gain (118 GWhr/yr), which can be attributed to the improved efficiency of a modern turbine design. Existing water licence conditions will continue to be adhered to,

BC hydro
FOR GENERATIONS

with no change to water flows or reservoir levels anticipated as a result of the upgrades. Water licence amendments may be sought in future to take advantage of the full capacity of the upgraded units.

Owing to its cost, the Units 1 to 5 Turbine Rehabilitation Project requires the approval of the British Columbia Utilities Commission (BCUC), the province's regulator of electric utilities. It is anticipated that an Application will be submitted to the BCUC in September 2009, with a decision expected in January 2010. For more information about the BCUC process, please visit their website at www.bcuc.com.

For additional information on the GMS Units 1 to 5 Turbine Rehabilitation Project, please find enclosed a Fact Sheet which provides an overview of the Project. Should you require further information, or should you have any concerns that the proposed Project may affect the McLeod Lake Indian Band's rights or interests, please do not hesitate to contact me at 604-528-8331 or stewart.dill@bchydro.com. For your information, I have also enclosed a second Fact Sheet which describes other work being undertaken at GMS.

Sincerely,

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

Enclosures (2)

BC hydro
FOR GENERATIONS

FACT SHEET

GMS Turbine 1-5
Project Update

BC Hydro – Meeting Demand For Generations

Clean, abundant electricity has been, and will continue to be, a key to British Columbia's economic prosperity and quality of life. BC Hydro provides energy solutions to its customers in an environmentally and socially responsible way by balancing British Columbians' energy needs with concern for the environment.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30% over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

Gordon M. Shrum Generation Station – An Historic Asset

The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's generation system. It is also an important part of BC Hydro's heritage. GMS is located next to the W.A.C. Bennett Dam on the Peace River, near Hudson's Hope and about 90 kilometres west of Fort St. John. The GMS power plant houses 10 generating units with a generation capacity of 2,730 megawatts (MW) roughly one quarter of BC Hydro's generating capacity. GMS is capable of generating an average of 13,225 gigawatt hours/per year of energy, roughly 30% of BC Hydro's generated energy.

The first generating units were installed in 1968, with all 10 in service by 1980. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. It must be either replaced or refurbished. Various projects are being undertaken at GMS to address these issues. A short description of one such project is provided below. A description of the other projects is provided in an associated Fact Sheet.

Project: Unit 1 to 5 Turbine Rehabilitation

GMS generating units 1 to 5 represent 12% of BC Hydro's electricity producing capacity, which means that their reliability has an impact on the security of the province's electricity supply.

A hydro electric turbine is a simple rotating mechanical device with few parts that uses flowing water to produce electrical energy. Water from the Williston Reservoir flows by gravity in a large pipe (called a penstock) across turbine blades mounted on a shaft that causes the shaft to turn. The mechanical energy produced from the shaft rotation is converted into electrical energy in a generator through the use of a magnetic field.

The need for renewal

The turbines in Units 1 to 5 were built in the 1960s. Equipment Health Ratings (EHRs) done by BC Hydro found the turbines in GMS Units 1 to 5 no longer meet BC Hydro's equipment health criteria and must be replaced. The GMS Units 1 to 5 Rehabilitation Project is being undertaken to protect against failures and costly forced outages. An ancillary benefit of the project will be an improvement in turbine efficiency as the new turbines will incorporate the technological advances of the last forty years.

The current maximum capacity per machine is 261 MW. The new turbines will be limited to the current capacity because of other existing equipment capacity constraints and the existing water licence limitations. The new turbine design will ultimately allow the generating units to one day operate at a capacity of 305 MW after the necessary water licence revisions are approved some time in the future and additional equipment upgrades are completed.

What's involved?

There are a limited number of world manufacturers capable of supplying the large turbines such as those used at GMS and those manufacturers are seeing a significant number of orders at this time. The result is

that the overall upgrade project will take a number of years. The first stage will focus on the design and modelling of the turbine to demonstrate the robustness and efficiency guarantees. The second stage will consist of shop fabrication of the turbine followed by site construction, installation, and start-up of the turbines. The first unit is forecast to come into service in 2012, and one unit per year thereafter. The fifth and final unit is expected to be in service by the beginning of 2017.

An Application for a BCUC Determination will be filed in 2009 because the cost of implementing the project is more than $50M.

This update was provided to keep residents of the Peace region informed on the Turbine Units 1 to 5 Project. For information on other asset refurbishment being made to the Gordon M. Shrum Generating Station please see the associated Fact Sheet. For more information please contact BC Hydro's Community Relations Manager, Bob Gammer at 250 561-4858, or bob.gammer@bchydro.com or Stewart Dill, Aboriginal Relations Coordinator at 604 528-8331, or stewart.dill@bchydro.com.

BC hydro FOR GENERATIONS

FACT SHEET

GMS Projects Update

BC Hydro – Meeting Demand For Generations

Clean, abundant electricity has been, and will continue to be, a key to British Columbia's economic prosperity and quality of life. BC Hydro provides energy solutions to its customers in an environmentally and socially responsible way by balancing British Columbians' energy needs with concern for the environment.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30% over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

Gordon M. Shrum Generation Station – An Historic Asset

The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's generation system. It is also an important part of BC Hydro's heritage. GMS is located next to the W.A.C. Bennett Dam on the Peace River, near Hudson's Hope and about 90 kilometres west of Fort St. John. The GMS power plant houses 10 generating units with a generation capacity of 2,730 megawatts (MW), roughly one quarter of BC Hydro's generating capacity. GMS is capable of generating an average of 13,225 gigawatt hours/per year of energy, roughly 30% of BC Hydro's generated energy.

The first generating units were installed in 1968, with all 10 in service by 1980. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. It must be either replaced or refurbished. Various projects are being undertaken at GMS to address these issues and a short description of each is included below. A description of one additional project, the Unit 1 to 5 Turbine Rehabilitation project, is provided in an associated Fact Sheet.

Project: Units 1 to 4 Generator Stators Replacement

The generator stators (the stationary part of the generating unit that converts the mechanical energy of the rotor into electrical energy) in Units 1 to 4 were built in the 1960s. Their Equipment Health Ratings (EHRs) no longer meet BC Hydro's equipment health criteria and replacement began in 2006 (two units are now complete) and is forecast to be completed by the beginning of 2010.

The new stator design will ultimately allow the units to one day operate at a capacity of 305 MW, but are now limited to the current 261 MW capacity because of other existing equipment capacity constraints and the existing water licence requirements.

Project: Units 6 & 7 Rotor Pole Replacement

Rotor poles (the rotating part of the generator connected to the turbine) on GMS Units 6 and 7 were also determined to no longer meet BC Hydro's equipment health criteria and also needed to be redesigned and replaced to accommodate the increased generating capacity on Units 6 to 7 (see 6 to 8 capacity increase below). The first installation was completed in November 2007. Replacement of the second unit will be completed in November 2010.

Project: Transformer Replacement

GMS has thirty unit transformers (the device that increases the voltage to allow transmission over distance). Ten of these transformers will be replaced to ensure the reliability of the plant. Installation of the new transformers started in October 2008 and will be completed in 2011.

Project: Units 6 to 8 Capacity Increase

GMS Units 6 to 8 will be refurbished to increase the capacity of GMS by 90 MW by replacing the generator circuit breakers (special switches to shut off and turn on power from the generator system) and iso-phase

bus (special electrical conductors that carry the power from the underground powerhouse to the substation on the surface). The increase in capacity is allowable within the current water licence. The B.C. Environmental Assessment Office (BCEAO) reviewed the proposed upgrade and confirmed the project would not require an Environmental Assessment Certificate and may proceed because it will not have significant adverse environmental, economic, social, heritage, or health affects. The BCEAO made this conclusion after extensive consultation with and feedback from, appropriate government agencies, local governments and First Nations. Work will commence in April 2009 and the total project is expected to be completed by June 2011.

Project: Station Service Replacement

Various equipment and emergency supply systems at GMS will also be replaced. The station service system provides the power for the plant controls, battery systems, fire systems and all the auxiliary systems necessary to run the plant's generators. The general contract has been awarded and the replacement work is scheduled to start in May 2009 and completion is expected by 2011.

This update was provided to keep residents of the Peace region informed on asset refurbishments being made to the Gordon M. Shrum Generating Station. For information about the Turbine Units 1 to 5 Project please see the associated Fact Sheet. Please contact BC Hydro's Community Relations Manager, Bob Gammer at 250 561-4858, or bob.gammer@bchydro.com or Stewart Dill, Aboriginal Relations Coordinator at 604 528-8331, or stewart.dill@bchydro.com for more information on any of the above projects.

BC hydro

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www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Chief Derek Orr**
McLeod Lake First Nation

DATE: January 12, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-750-4420

No. of pages (including cover sheet): **7**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (Jan. 13. 2009 12:36PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: Jan. 13. 2009 12:27PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
0388	Memory TX	912507504420	P. 7	OK	

Reason for error
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TO: Chief Derek Orr
McLeod Lake First Nation

DATE: January 12, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-750-4420

No. of pages (including cover sheet): 7

MESSAGE

Please see enclosed letter.

BC hydro
FOR GENERATIONS

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

May 14, 2009

Chief Derek Orr
McLeod Lake Indian Band
General Delivery
McLeod Lake, BC V0J 2G0

BY FACSIMILE (250) 750-4420 *(original to follow by mail)*

Dear Chief Orr:

Re: GMS Units 1 to 5 Turbine Rehabilitation

I am writing further to my letter of January 12, 2009 to provide you with an update on BC Hydro's proposed Units 1 to 5 Turbine Rehabilitation Project at the Gordon M. Shrum (GMS) Generating Station. In that letter I notified you of BC Hydro's plans to replace the turbines in five of the generating units at GMS in order to maintain the health and reliability of the units. The work will be confined to the plant and no change to water flows or reservoir levels are anticipated as a result of the upgrades.

The design and modelling of turbine options is ongoing. It is expected that a final design will be selected in summer 2010, which will be followed by fabrication of the turbines, site construction, installation and start-up. The first unit is forecast to come into service in 2012, with all five units in service by early 2017.

BC Hydro continues to anticipate submitting an Application in respect of the Units 1 to 5 Turbine Rehabilitation Project to the British Columbia Utilities Commission (BCUC) in September 2009, which will be preceded by an intervenor workshop in summer 2009.

For additional information on the GMS Units 1 to 5 Turbine Rehabilitation Project, please find enclosed a fact sheet which provides an updated overview of the Project. As before, should you require further information, or should you have any concerns that the proposed Project may affect the McLeod Lake Indian Band's rights or interests, please do not hesitate to contact me at 604-528-8331 or stewart.dill@bchydro.com.

BC hydro
FOR GENERATIONS

For your information, the enclosed fact sheet also provides an update on other work being undertaken at GMS.

Sincerely,

Stewart Dill

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

Enclosure

vancouver 2010 vancouver 2010 PARALYMPIC GAMES JEUX PARALYMPIQUES BC hydro FOR GENERATIONS OFFICIAL SUPPORTER

GORDON M. SHRUM GENERATION STATION —AN HISTORIC ASSET

The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's generation system. GMS is located next to the W.A.C. Bennett Dam on the Peace River, near Hudson's Hope. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. Various projects are being undertaken at GMS to address these issues and a short description and status update of each is included below:

Project: Units 1 to 5 Turbine Rehabilitation

GMS generating Units 1 to 5 represent 12 per cent of BC Hydro's electricity producing capacity, which means that their reliability has an impact on the security of the province's electricity supply.

The need for renewal

Equipment Health Rating (EHRs) assessments undertaken by BC Hydro found that the 1960s era turbines in GMS Units 1 to 5 must be replaced. The project is being undertaken to ensure ongoing reliability, availability and operational flexibility of these units. A secondary benefit of the project will be an improvement in turbine efficiency.

The current maximum capacity per machine is 261 MW. The new turbines will be limited to the current capacity because of other existing equipment capacity constraints and the existing water licence limitations. The new turbines will ultimately allow the generating units to one day operate at a capacity of 305 MW. However, this capacity increase will require additional equipment upgrades and BC Hydro must also apply for a water licence revision and receive approval from the Ministry of Environment.

What's involved?

There are a limited number of manufacturers capable of supplying the large turbines used at GMS and those manufacturers are seeing a significant number of orders at this time – meaning this upgrade project will take several years. The first stage of project implementation consists of the design and modelling of a turbine to demonstrate the robustness and efficiency guarantees of the final product. To optimise the design and efficiency improvements and still maintain commercial competitiveness, the design and modelling work was awarded to two manufacturers, Voith Siemens Hydro Power Generation Inc. and Andritz Hydro Power Canada Inc, that will compete to provide the best possible solution for this project. Final award to a single manufacturer is anticipated for the summer of 2010 at which time the selected firm will proceed to the implementation of the second stage of the project. The second stage includes shop fabrication of the turbine followed by site construction, installation and start-up of the turbines. The first unit is forecast to come into service in 2012, and one unit per year thereafter. The final unit is expected to be in service in early 2017.

The cost of implementing the project is more than $50M and therefore an application will be made to the British Columbia Utilities Commission (BCUC) seeking a determination that the project is in the public interest. This application will be filed in the summer of 2009. Prior to filing the application, BC Hydro will hold a workshop on this application. It is expected that the BCUC will hold a hearing on the application during the fall of 2009.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on annual net power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30 per cent over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

FOR GENERATIONS

Project: Units 1 to 4 Generator Stators Replacement

The generator stators (the stationary part of the generating unit that converts the mechanical energy of the rotor into electrical energy) in Units 1 to 4 were also built in the 1960s and are due for replacement. A contract was awarded to Alstom Canada Inc. for the replacement of the stators. Two units are now complete and the other two are forecast to be completed by the end of 2010.

Project: Units 6 & 7 Rotor Pole Replacement

Rotor poles (the rotating part of the generator connected to the turbine) on GMS Units 6 and 7 were also determined to no longer meet BC Hydro's EHR criteria and required a redesign and replacement to accommodate the increased generating capacity on Units 6 and 7 (see 6 to 8 Project below). The first installation is complete and the second unit will be completed in late 2010.

Project: Transformer Replacement

GMS has thirty unit transformers (the device that increases the voltage to allow transmission over distance). Ten of these transformers will be replaced to ensure the reliability of the plant. Installation of the new transformers started in October 2008 and will be completed in 2011. Five new transformers will arrive at GMS in late spring and installation activities will last into fall 2009.

Project: Units 6 to 8 Capacity Increase

GMS Units 6 to 8 will be refurbished to increase the capacity of GMS by 90 MW by replacing the generator circuit breakers and iso-phase bus. The increase in capacity is allowable within the current water licence. The B.C. Environmental Assessment Office (BCEAO) reviewed the proposed upgrade and confirmed the project would not require an Environmental Assessment Certificate and may proceed because it will not have significant adverse environmental, economic, social, heritage, or health affects. The BCEAO made this conclusion after extensive consultation with and feedback from, appropriate government agencies, local governments and First Nations. The contract was awarded to Alstom Canada Inc. Work will start this summer and is expected to be completed by summer 2011.

Project: Station Service Replacement

The station service system provides the power for the plant controls, battery systems, fire systems and all the auxiliary systems necessary to run the plant's generators. The general contract has been awarded to ABB Inc. and completion is expected by 2011.

This update is provided to keep residents of the Peace region informed on asset refurbishments being made to the G. M. Shrum Generating Station.

Please contact BC Hydro Community Relations at 250 561 4858, or bob.gammer@bchydro.com or BC Hydro Aboriginal Relations at 604 528 8331, or stewart.dill@bchydro.com for more information on any of the above projects.

BC hydro

FOR GENERATIONS

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BC hydro

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www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Chief Derek Orr**
McLeod Lake First Nation

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-750-4420

No. of pages (including cover sheet): **5**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (May. 14. 2009 5:21PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: May. 14. 2009 5:18PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
1417	Memory TX	912507504420	P. 5	OK	

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TO: Chief Derek Orr
McLeod Lake First Nation

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-750-4420

No. of pages (including cover sheet): 5

MESSAGE

Please see enclosed letter.

BC hydro
FOR GENERATIONS

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

July 16, 2009

Chief Derek Orr
McLeod Lake Indian Band
General Delivery
McLeod Lake, BC V0J 2G0

BY FACSIMILE (250) 750-4420 *(original to follow by mail)*

Dear Chief Orr:

Re: GMS Units 1 to 5 Turbine Replacement

I am writing further to my letters of January 12, 2009 and May 14, 2009 to provide you with an update on BC Hydro's plans to submit an application to the British Columbia Utilities Commission (BCUC) in respect of the Units 1 to 5 Turbine Replacement Project at the Gordon M. Shrum (GMS) Generating Station.

BC Hydro intends to file its application with the BCUC around the end of July 2009. Once the application is filed, it becomes a public document and the BCUC will start a public hearing process that is expected to include a workshop. Further information on the public hearing process can be found at the BCUC website: www.bcuc.com/Hearing.aspx.

As before, should you require further information, or should you have any concerns that the proposed GMS Units 1 to 5 Turbine Replacement Project may affect the McLeod Lake Indian Band's rights or interests, please do not hesitate to contact me at 604-528-8331 or stewart.dill@bchydro.com.

Sincerely,

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

BC hydro

FAX COVER SHEET

Aboriginal Relations and Negotiations

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www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Chief Derek Orr**
McLeod Lake First Nation

DATE: July 16, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-750-4420

No. of pages (including cover sheet): **3**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (Jul. 16. 2009 3:35PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: Jul. 16. 2009 3:35PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
2464	Memory TX	912507504420	P. 3	OK	

Reason for error
E. 1) Hang up or line fail
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E. 3) No answer
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TO: Chief Derek Orr
McLeod Lake First Nation

DATE: July 16, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-750-4420

No. of pages (including cover sheet): 3

MESSAGE

Please see enclosed letter.

BC hydro
FOR GENERATIONS

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

January 12, 2009

Chief Ella Pierre
Tsay Keh Dene First Nation
#11 – 1839 First Avenue
Prince George, BC V2L 2Y8

BY FACSIMILE (250) 562-8899 *(original to follow by mail)*

Dear Chief Pierre:

Re: <u>GMS Units 1 to 5 Turbine Rehabilitation</u>

Pursuant to Section 5.7 (a) of the Tsay Keh Dene First Nation Interim Agreement, I am writing to notify you of anticipated future regulatory proceedings relating to BC Hydro's proposed Units 1 to 5 Turbine Rehabilitation Project at the Gordon M. Shrum (GMS) Generating Station.

Located next to the W.A.C. Bennett Dam on the Peace River near Hudson's Hope the GMS power plant houses 10 generating units with a total generation capacity of 2,730 megawatts (MW). The facility is capable of generating an average of 13,225 gigawatt hours per year (GWhr/yr) of energy, roughly 30% of BC Hydro's generated energy.

GMS generating units 1 to 5 utilize late 1960's vintage Mitsubishi Francis turbines. A recent assessment of equipment health indicated that the turbines no longer meet reliability standards and must be replaced to protect against failures and costly forced outages. The health and reliability of these generating units is important to the security of the province's electricity supply.

The turbine rehabilitation program proposes to replace one turbine per year, including the runners and wicket gates, with the first unit forecast to come into service in 2012. The work will be confined to the plant. Once complete, each rehabilitated turbine unit will have a maximum capacity of 305 MW; however the upgraded units will continue to be operated at the existing 261 MW maximum capacity as they are limited by other

BC hydro
FOR GENERATIONS

equipment in the unit. The new turbines are expected to achieve an incremental 2% efficiency gain (118 GWhr/yr), which can be attributed to the improved efficiency of a modern turbine design. Existing water licence conditions will continue to be adhered to, with no change to water flows or reservoir levels anticipated as a result of the upgrades. Water licence amendments may be sought in future to take advantage of the full capacity of the upgraded units.

Owing to its cost, the Units 1 to 5 Turbine Rehabilitation Project requires the approval of the British Columbia Utilities Commission (BCUC), the province's regulator of electric utilities. It is anticipated that an Application will be submitted to the BCUC in September 2009, with a decision expected in January 2010. For more information about the BCUC process, please visit their website at www.bcuc.com.

For additional information on the GMS Units 1 to 5 Turbine Rehabilitation Project, please find enclosed a Fact Sheet which provides an overview of the Project. Should you require further information, or should you have any questions or concerns, please do not hesitate to contact me at 604-528-8331 or stewart.dill@bchydro.com. For your information, I have also enclosed a second Fact Sheet which describes other work being undertaken at GMS.

Sincerely,

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

cc: Eric Woodhouse, Cook Roberts LLP
Rod Hill, Aboriginal Relations Coordinator, BC Hydro

Enclosures (2)

BC hydro
FOR GENERATIONS

FACT SHEET

GMS Turbine 1-5
Project Update

BC Hydro – Meeting Demand For Generations

Clean, abundant electricity has been, and will continue to be, a key to British Columbia's economic prosperity and quality of life. BC Hydro provides energy solutions to its customers in an environmentally and socially responsible way by balancing British Columbians' energy needs with concern for the environment.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30% over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

Gordon M. Shrum Generation Station – An Historic Asset

The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's generation system. It is also an important part of BC Hydro's heritage. GMS is located next to the W.A.C. Bennett Dam on the Peace River, near Hudson's Hope and about 90 kilometres west of Fort St. John. The GMS power plant houses 10 generating units with a generation capacity of 2,730 megawatts (MW) roughly one quarter of BC Hydro's generating capacity. GMS is capable of generating an average of 13,225 gigawatt hours/per year of energy, roughly 30% of BC Hydro's generated energy.

The first generating units were installed in 1968, with all 10 in service by 1980. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. It must be either replaced or refurbished. Various projects are being undertaken at GMS to address these issues. A short description of one such project is provided below. A description of the other projects is provided in an associated Fact Sheet.

Project: Unit 1 to 5 Turbine Rehabilitation

GMS generating units 1 to 5 represent 12% of BC Hydro's electricity producing capacity, which means that their reliability has an impact on the security of the province's electricity supply.

A hydro electric turbine is a simple rotating mechanical device with few parts that uses flowing water to produce electrical energy. Water from the Williston Reservoir flows by gravity in a large pipe (called a penstock) across turbine blades mounted on a shaft that causes the shaft to turn. The mechanical energy produced from the shaft rotation is converted into electrical energy in a generator through the use of a magnetic field.

The need for renewal

The turbines in Units 1 to 5 were built in the 1960s. Equipment Health Ratings (EHRs) done by BC Hydro found the turbines in GMS Units 1 to 5 no longer meet BC Hydro's equipment health criteria and must be replaced. The GMS Units 1 to 5 Rehabilitation Project is being undertaken to protect against failures and costly forced outages. An ancillary benefit of the project will be an improvement in turbine efficiency as the new turbines will incorporate the technological advances of the last forty years.

The current maximum capacity per machine is 261 MW. The new turbines will be limited to the current capacity because of other existing equipment capacity constraints and the existing water licence limitations. The new turbine design will ultimately allow the generating units to one day operate at a capacity of 305 MW after the necessary water licence revisions are approved some time in the future and additional equipment upgrades are completed.

What's involved?

There are a limited number of world manufacturers capable of supplying the large turbines such as those used at GMS and those manufacturers are seeing a significant number of orders at this time. The result is

that the overall upgrade project will take a number of years. The first stage will focus on the design and modelling of the turbine to demonstrate the robustness and efficiency guarantees. The second stage will consist of shop fabrication of the turbine followed by site construction, installation, and start-up of the turbines. The first unit is forecast to come into service in 2012, and one unit per year thereafter. The fifth and final unit is expected to be in service by the beginning of 2017.

An Application for a BCUC Determination will be filed in 2009 because the cost of implementing the project is more than $50M.

This update was provided to keep residents of the Peace region informed on the Turbine Units 1 to 5 Project. For information on other asset refurbishment being made to the Gordon M. Shrum Generating Station please see the associated Fact Sheet. For more information please contact BC Hydro's Community Relations Manager, Bob Gammer at 250 561-4858, or bob.gammer@bchydro.com or Stewart Dill, Aboriginal Relations Coordinator at 604 528-8331, or stewart.dill@bchydro.com.

BC hydro FOR GENERATIONS

FACT SHEET

GMS Projects Update

BC Hydro – Meeting Demand For Generations

Clean, abundant electricity has been, and will continue to be, a key to British Columbia's economic prosperity and quality of life. BC Hydro provides energy solutions to its customers in an environmentally and socially responsible way by balancing British Columbians' energy needs with concern for the environment.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30% over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

Gordon M. Shrum Generation Station – An Historic Asset

The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's generation system. It is also an important part of BC Hydro's heritage. GMS is located next to the W.A.C. Bennett Dam on the Peace River, near Hudson's Hope and about 90 kilometres west of Fort St. John. The GMS power plant houses 10 generating units with a generation capacity of 2,730 megawatts (MW), roughly one quarter of BC Hydro's generating capacity. GMS is capable of generating an average of 13,225 gigawatt hours/per year of energy, roughly 30% of BC Hydro's generated energy.

The first generating units were installed in 1968, with all 10 in service by 1980. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. It must be either replaced or refurbished. Various projects are being undertaken at GMS to address these issues and a short description of each is included below. A description of one additional project, the Unit 1 to 5 Turbine Rehabilitation project, is provided in an associated Fact Sheet.

Project: Units 1 to 4 Generator Stators Replacement

The generator stators (the stationary part of the generating unit that converts the mechanical energy of the rotor into electrical energy) in Units 1 to 4 were built in the 1960s. Their Equipment Health Ratings (EHRs) no longer meet BC Hydro's equipment health criteria and replacement began in 2006 (two units are now complete) and is forecast to be completed by the beginning of 2010.

The new stator design will ultimately allow the units to one day operate at a capacity of 305 MW, but are now limited to the current 261 MW capacity because of other existing equipment capacity constraints and the existing water licence requirements.

Project: Units 6 & 7 Rotor Pole Replacement

Rotor poles (the rotating part of the generator connected to the turbine) on GMS Units 6 and 7 were also determined to no longer meet BC Hydro's equipment health criteria and also needed to be redesigned and replaced to accommodate the increased generating capacity on Units 6 to 7 (see 6 to 8 capacity increase below). The first installation was completed in November 2007. Replacement of the second unit will be completed in November 2010.

Project: Transformer Replacement

GMS has thirty unit transformers (the device that increases the voltage to allow transmission over distance). Ten of these transformers will be replaced to ensure the reliability of the plant. Installation of the new transformers started in October 2008 and will be completed in 2011.

Project: Units 6 to 8 Capacity Increase

GMS Units 6 to 8 will be refurbished to increase the capacity of GMS by 90 MW by replacing the generator circuit breakers (special switches to shut off and turn on power from the generator system) and iso-phase

BC hydro FOR GENERATIONS

FACT SHEET

GMS Projects Update

bus (special electrical conductors that carry the power from the underground powerhouse to the substation on the surface). The increase in capacity is allowable within the current water licence. The B.C. Environmental Assessment Office (BCEAO) reviewed the proposed upgrade and confirmed the project would not require an Environmental Assessment Certificate and may proceed because it will not have significant adverse environmental, economic, social, heritage, or health affects. The BCEAO made this conclusion after extensive consultation with and feedback from, appropriate government agencies, local governments and First Nations. Work will commence in April 2009 and the total project is expected to be completed by June 2011.

Project: Station Service Replacement

Various equipment and emergency supply systems at GMS will also be replaced. The station service system provides the power for the plant controls, battery systems, fire systems and all the auxiliary systems necessary to run the plant's generators. The general contract has been awarded and the replacement work is scheduled to start in May 2009 and completion is expected by 2011.

This update was provided to keep residents of the Peace region informed on asset refurbishments being made to the Gordon M. Shrum Generating Station. For information about the Turbine Units 1 to 5 Project please see the associated Fact Sheet. Please contact BC Hydro's Community Relations Manager, Bob Gammer at 250 561-4858, or bob.gammer@bchydro.com or Stewart Dill, Aboriginal Relations Coordinator at 604 528-8331, or stewart.dill@bchydro.com for more information on any of the above projects.

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Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Chief Ella Pierre**
Tsay Keh Dene First Nation

DATE: January 12, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-562-8899

No. of pages (including cover sheet): **7**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (Jan. 13. 2009 12:35PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: Jan. 13. 2009 12:25PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
0386	Memory TX	912505628899	P. 7	OK	

Reason for error
E. 1) Hang up or line fail
E. 2) Busy
E. 3) No answer
E. 4) No facsimile connection
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Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Chief Ella Pierre**
Tsay Keh Dene First Nation

DATE: January 12, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-562-8899

No. of pages (including cover sheet): **7**

MESSAGE

Please see enclosed letter.

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Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Eric Woodhouse**
Cook Roberts, LLP

DATE: January 12, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-413-3300

No. of pages (including cover sheet): **7**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (Jan. 13. 2009 12:27PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: Jan. 13. 2009 12:26PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
0387	Memory TX	912504133300	P. 7	OK	

Reason for error
E. 1) Hang up or line fail
E. 2) Busy
E. 3) No answer
E. 4) No facsimile connection
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Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: Eric Woodhouse
Cook Roberts, LLP

DATE: January 12, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-413-3300

No. of pages (including cover sheet): 7

MESSAGE

Please see enclosed letter.

BC hydro
FOR GENERATIONS

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

May 14, 2009

Chief Ella Pierre
Tsay Keh Dene First Nation
#11 – 1839 First Avenue
Prince George, BC V2L 2Y8

BY FACSIMILE (250) 562-8899 *(original to follow by mail)*

Dear Chief Pierre:

Re: <u>GMS Units 1 to 5 Turbine Rehabilitation</u>

I am writing further to my letter of January 12, 2009 to provide you with an update on BC Hydro's proposed Units 1 to 5 Turbine Rehabilitation Project at the Gordon M. Shrum (GMS) Generating Station. In that letter I notified you of anticipated future regulatory proceedings relating to BC Hydro's plans to replace the turbines in five of the generating units at GMS. The work is being undertaken in order to maintain the health and reliability of the units and will be confined to the plant. No change to water flows or reservoir levels are anticipated as a result of the upgrades.

The design and modelling of turbine options is ongoing. It is expected that a final design will be selected in summer 2010, which will be followed by fabrication of the turbines, site construction, installation and start-up. The first unit is forecast to come into service in 2012, with all five units in service by early 2017.

BC Hydro continues to anticipate submitting an Application in respect of the Units 1 to 5 Turbine Rehabilitation Project to the British Columbia Utilities Commission (BCUC) in September 2009, which will be preceded by an intervenor workshop in summer 2009.

For additional information on the GMS Units 1 to 5 Turbine Rehabilitation Project, please find enclosed a fact sheet which provides an updated overview of the Project. As before, should you require further information, or should you have any questions or concerns, please do not hesitate to contact me at 604-528-8331 or

BC hydro
FOR GENERATIONS

stewart.dill@bchydro.com. For your information, the enclosed fact sheet also provides an update on other work being undertaken at GMS.

Sincerely,

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

cc: Eric Woodhouse, Cook Roberts LLP
Rod Hill, Aboriginal Relations Coordinator, BC Hydro

Enclosure

BC HYDRO
MEETING DEMAND FOR GENERATIONS
UPDATE MAY 2009

GORDON M. SHRUM GENERATION STATION —AN HISTORIC ASSET

The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's generation system. GMS is located next to the W.A.C. Bennett Dam on the Peace River, near Hudson's Hope. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. Various projects are being undertaken at GMS to address these issues and a short description and status update of each is included below:

Project: Units 1 to 5 Turbine Rehabilitation

GMS generating Units 1 to 5 represent 12 per cent of BC Hydro's electricity producing capacity, which means that their reliability has an impact on the security of the province's electricity supply.

The need for renewal

Equipment Health Rating (EHRs) assessments undertaken by BC Hydro found that the 1960s era turbines in GMS Units 1 to 5 must be replaced. The project is being undertaken to ensure ongoing reliability, availability and operational flexibility of these units. A secondary benefit of the project will be an improvement in turbine efficiency.

The current maximum capacity per machine is 261 MW. The new turbines will be limited to the current capacity because of other existing equipment capacity constraints and the existing water licence limitations. The new turbines will ultimately allow the generating units to one day operate at a capacity of 305 MW. However, this capacity increase will require additional equipment upgrades and BC Hydro must also apply for a water licence revision and receive approval from the Ministry of Environment.

What's involved?

There are a limited number of manufacturers capable of supplying the large turbines used at GMS and those manufacturers are seeing a significant number of orders at this time – meaning this upgrade project will take several years. The first stage of project implementation consists of the design and modelling of a turbine to demonstrate the robustness and efficiency guarantees of the final product. To optimise the design and efficiency improvements and still maintain commercial competitiveness, the design and modelling work was awarded to two manufacturers, Voith Siemens Hydro Power Generation Inc. and Andritz Hydro Power Canada Inc, that will compete to provide the best possible solution for this project. Final award to a single manufacturer is anticipated for the summer of 2010 at which time the selected firm will proceed to the implementation of the second stage of the project. The second stage includes shop fabrication of the turbine followed by site construction, installation and start-up of the turbines. The first unit is forecast to come into service in 2012, and one unit per year thereafter. The final unit is expected to be in service in early 2017.

The cost of implementing the project is more than $50M and therefore an application will be made to the British Columbia Utilities Commission (BCUC) seeking a determination that the project is in the public interest. This application will be filed in the summer of 2009. Prior to filing the application, BC Hydro will hold a workshop on this application. It is expected that the BCUC will hold a hearing on the application during the fall of 2009.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on annual net power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30 per cent over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

BC hydro
FOR GENERATIONS

Project: Units 1 to 4 Generator Stators Replacement

The generator stators (the stationary part of the generating unit that converts the mechanical energy of the rotor into electrical energy) in Units 1 to 4 were also built in the 1960s and are due for replacement. A contract was awarded to Alstom Canada Inc. for the replacement of the stators. Two units are now complete and the other two are forecast to be completed by the end of 2010.

Project: Units 6 & 7 Rotor Pole Replacement

Rotor poles (the rotating part of the generator connected to the turbine) on GMS Units 6 and 7 were also determined to no longer meet BC Hydro's EHR criteria and required a redesign and replacement to accommodate the increased generating capacity on Units 6 and 7 (see 6 to 8 Project below). The first installation is complete and the second unit will be completed in late 2010.

Project: Transformer Replacement

GMS has thirty unit transformers (the device that increases the voltage to allow transmission over distance). Ten of these transformers will be replaced to ensure the reliability of the plant. Installation of the new transformers started in October 2008 and will be completed in 2011. Five new transformers will arrive at GMS in late spring and installation activities will last into fall 2009.

Project: Units 6 to 8 Capacity Increase

GMS Units 6 to 8 will be refurbished to increase the capacity of GMS by 90 MW by replacing the generator circuit breakers and iso-phase bus. The increase in capacity is allowable within the current water licence. The B.C. Environmental Assessment Office (BCEAO) reviewed the proposed upgrade and confirmed the project would not require an Environmental Assessment Certificate and may proceed because it will not have significant adverse environmental, economic, social, heritage, or health affects. The BCEAO made this conclusion after extensive consultation with and feedback from, appropriate government agencies, local governments and First Nations. The contract was awarded to Alstom Canada Inc. Work will start this summer and is expected to be completed by summer 2011.

Project: Station Service Replacement

The station service system provides the power for the plant controls, battery systems, fire systems and all the auxiliary systems necessary to run the plant's generators. The general contract has been awarded to ABB Inc. and completion is expected by 2011.

This update is provided to keep residents of the Peace region informed on asset refurbishments being made to the G. M. Shrum Generating Station.

Please contact BC Hydro Community Relations at 250 561 4858, or bob.gammer@bchydro.com or BC Hydro Aboriginal Relations at 604 528 8331, or stewart.dill@bchydro.com for more information on any of the above projects.

BC hydro

FOR GENERATIONS

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Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Chief Ella Pierre**
Tsay Ke Dene First Nation

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-562-8899

No. of pages (including cover sheet): **5**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (May. 14. 2009 5:22PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: May. 14. 2009 5:19PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
1418	Memory TX	912505628899	P. 5	OK	

Reason for error
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Telephone: (604) 528-6231 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: Chief Ella Pierre
Tsay Ke Dene First Nation

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-562-8899

No. of pages (including cover sheet): 5

MESSAGE

Please see enclosed letter.

BC hydro

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6911 Southpoint Drive (E16), Burnaby, B.C. V3N 4X8
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Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Eric Woodhouse**
Cook Roberts, LLP

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-413-3300

No. of pages (including cover sheet): **5**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (May. 14. 2009 5:32PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: May. 14. 2009 5:31PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
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Reason for error
E. 1) Hang up or line fail
E. 2) Busy
E. 3) No answer
E. 4) No facsimile connection
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www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: Eric Woodhouse
Cook Roberts, LLP

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-413-3300

No. of pages (including cover sheet): 6

MESSAGE

Please see enclosed letter.

BC hydro
FOR GENERATIONS

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

July 16, 2009

Chief Ella Pierre
Tsay Keh Dene First Nation
#11 – 1839 First Avenue
Prince George, BC V2L 2Y8

BY FACSIMILE (250) 562-8899 *(original to follow by mail)*

Dear Chief Pierre:

Re: GMS Units 1 to 5 Turbine Replacement

I am writing further to my letters of January 12, 2009 and May 14, 2009 to provide you with an update on BC Hydro's plans to submit an application to the British Columbia Utilities Commission (BCUC) in respect of the Units 1 to 5 Turbine Replacement Project at the Gordon M. Shrum (GMS) Generating Station.

BC Hydro intends to file its application with the BCUC around the end of July 2009. Once the application is filed, it becomes a public document and the BCUC will start a public hearing process that is expected to include a workshop. Further information on the public hearing process can be found at the BCUC website: www.bcuc.com/Hearing.aspx.

As before, should you require further information, or should you have any questions or concerns about the proposed GMS Units 1 to 5 Turbine Replacement Project, please do not hesitate to contact me at 604-528-8331 or stewart.dill@bchydro.com.

Sincerely,

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

cc: Eric Woodhouse, Cook Roberts LLP
Rod Hill, Aboriginal Relations Coordinator, BC Hydro

BC hydro

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Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Chief Ella Pierre**
Tsay Ke Dene First Nation

DATE: July 16, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-562-8899

No. of pages (including cover sheet): **3**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (Jul. 16. 2009 3:36PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: Jul. 16. 2009 3:35PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
2465	Memory TX	912505628899	P. 3	OK	

Reason for error
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E. 2) Busy
E. 3) No answer
E. 4) No facsimile connection
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Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: Chief Ella Pierre
Tsay Ke Dene First Nation

DATE: July 16, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-562-8899

No. of pages (including cover sheet): 3

MESSAGE

Please see enclosed letter.

BC hydro

FAX COVER SHEET

Aboriginal Relations and Negotiations

6911 Southpoint Drive (E16), Burnaby, B.C. V3N 4X8
www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Eric Woodhouse**
Cook Roberts, LLP

DATE: July 16, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-413-3300

No. of pages (including cover sheet): **3**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (Jul. 16. 2009 3:37PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: Jul. 16. 2009 3:36PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
2466	Memory TX	912504133300	P. 3	OK	

Reason for error
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E. 2) Busy
E. 3) No answer
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TO: Eric Woodhouse
Cook Roberts, LLP

DATE: July 16, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-413-3300

No. of pages (including cover sheet): 3

MESSAGE

Please see enclosed letter.

BC hydro
FOR GENERATIONS

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

January 12, 2009

Chief Roland Willson
West Moberly First Nations
PO Box 90
Moberly Lake, BC V0C 1X0

BY FACSIMILE (250) 788-9792 *(original to follow by mail)*

Dear Chief Willson:

Re: GMS Units 1 to 5 Turbine Rehabilitation

I am writing to notify you of BC Hydro's proposed Units 1 to 5 Turbine Rehabilitation Project at the Gordon M. Shrum (GMS) Generating Station. Located next to the W.A.C. Bennett Dam on the Peace River near Hudson's Hope the GMS power plant houses 10 generating units with a total generation capacity of 2,730 megawatts (MW). The facility is capable of generating an average of 13,225 gigawatt hours per year (GWhr/yr) of energy, roughly 30% of BC Hydro's generated energy.

GMS generating units 1 to 5 utilize late 1960's vintage Mitsubishi Francis turbines. A recent assessment of equipment health indicated that the turbines no longer meet reliability standards and must be replaced to protect against failures and costly forced outages. The health and reliability of these generating units is important to the security of the province's electricity supply.

The turbine rehabilitation program proposes to replace one turbine per year, including the runners and wicket gates, with the first unit forecast to come into service in 2012. The work will be confined to the plant. Once complete, each rehabilitated turbine unit will have a maximum capacity of 305 MW; however the upgraded units will continue to be operated at the existing 261 MW maximum capacity as they are limited by other equipment in the unit. The new turbines are expected to achieve an incremental 2% efficiency gain (118 GWhr/yr), which can be attributed to the improved efficiency of a modern turbine design. Existing water licence conditions will continue to be adhered to,

BC hydro
FOR GENERATIONS

with no change to water flows or reservoir levels anticipated as a result of the upgrades. Water licence amendments may be sought in future to take advantage of the full capacity of the upgraded units.

Owing to its cost, the Units 1 to 5 Turbine Rehabilitation Project requires the approval of the British Columbia Utilities Commission (BCUC), the province's regulator of electric utilities. It is anticipated that an Application will be submitted to the BCUC in September 2009, with a decision expected in January 2010. For more information about the BCUC process, please visit their website at www.bcuc.com.

For additional information on the GMS Units 1 to 5 Turbine Rehabilitation Project, please find enclosed a Fact Sheet which provides an overview of the Project. Should you require further information, or should you have any concerns that the proposed Project may affect the West Moberly First Nations' rights or interests, please do not hesitate to contact me at 604-528-8331 or stewart.dill@bchydro.com. For your information, I have also enclosed a second Fact Sheet which describes other work being undertaken at GMS.

Please note that I am copying this letter to the Treaty 8 Tribal Association, such that if the Tribal Association wishes to receive further information about the Project, or has any questions or concerns, they may contact me.

Sincerely,

S A Dill

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

cc: Shona Nelson, Treaty and Aboriginal Rights Research Director, Treaty 8 Tribal Association

Enclosures (2)

BC hydro FOR GENERATIONS

FACT SHEET

GMS Turbine 1-5
Project Update

BC Hydro – Meeting Demand For Generations

Clean, abundant electricity has been, and will continue to be, a key to British Columbia's economic prosperity and quality of life. BC Hydro provides energy solutions to its customers in an environmentally and socially responsible way by balancing British Columbians' energy needs with concern for the environment.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30% over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

Gordon M. Shrum Generation Station – An Historic Asset

The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's generation system. It is also an important part of BC Hydro's heritage. GMS is located next to the W.A.C. Bennett Dam on the Peace River, near Hudson's Hope and about 90 kilometres west of Fort St. John. The GMS power plant houses 10 generating units with a generation capacity of 2,730 megawatts (MW) roughly one quarter of BC Hydro's generating capacity. GMS is capable of generating an average of 13,225 gigawatt hours/per year of energy, roughly 30% of BC Hydro's generated energy.

The first generating units were installed in 1968, with all 10 in service by 1980. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. It must be either replaced or refurbished. Various projects are being undertaken at GMS to address these issues. A short description of one such project is provided below. A description of the other projects is provided in an associated Fact Sheet.

Project: Unit 1 to 5 Turbine Rehabilitation

GMS generating units 1 to 5 represent 12% of BC Hydro's electricity producing capacity, which means that their reliability has an impact on the security of the province's electricity supply.

A hydro electric turbine is a simple rotating mechanical device with few parts that uses flowing water to produce electrical energy. Water from the Williston Reservoir flows by gravity in a large pipe (called a penstock) across turbine blades mounted on a shaft that causes the shaft to turn. The mechanical energy produced from the shaft rotation is converted into electrical energy in a generator through the use of a magnetic field.

The need for renewal

The turbines in Units 1 to 5 were built in the 1960s. Equipment Health Ratings (EHRs) done by BC Hydro found the turbines in GMS Units 1 to 5 no longer meet BC Hydro's equipment health criteria and must be replaced. The GMS Units 1 to 5 Rehabilitation Project is being undertaken to protect against failures and costly forced outages. An ancillary benefit of the project will be an improvement in turbine efficiency as the new turbines will incorporate the technological advances of the last forty years.

The current maximum capacity per machine is 261 MW. The new turbines will be limited to the current capacity because of other existing equipment capacity constraints and the existing water licence limitations. The new turbine design will ultimately allow the generating units to one day operate at a capacity of 305 MW after the necessary water licence revisions are approved some time in the future and additional equipment upgrades are completed.

What's involved?

There are a limited number of world manufacturers capable of supplying the large turbines such as those used at GMS and those manufacturers are seeing a significant number of orders at this time. The result is

that the overall upgrade project will take a number of years. The first stage will focus on the design and modelling of the turbine to demonstrate the robustness and efficiency guarantees. The second stage will consist of shop fabrication of the turbine followed by site construction, installation, and start-up of the turbines. The first unit is forecast to come into service in 2012, and one unit per year thereafter. The fifth and final unit is expected to be in service by the beginning of 2017.

An Application for a BCUC Determination will be filed in 2009 because the cost of implementing the project is more than $50M.

This update was provided to keep residents of the Peace region informed on the Turbine Units 1 to 5 Project. For information on other asset refurbishment being made to the Gordon M. Shrum Generating Station please see the associated Fact Sheet. For more information please contact BC Hydro's Community Relations Manager, Bob Gammer at 250 561-4858, or bob.gammer@bchydro.com or Stewart Dill, Aboriginal Relations Coordinator at 604 528-8331, or stewart.dill@bchydro.com.

BC hydro FOR GENERATIONS

FACT SHEET

GMS Projects Update

BC Hydro – Meeting Demand For Generations

Clean, abundant electricity has been, and will continue to be, a key to British Columbia's economic prosperity and quality of life. BC Hydro provides energy solutions to its customers in an environmentally and socially responsible way by balancing British Columbians' energy needs with concern for the environment.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30% over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

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The first generating units were installed in 1968, with all 10 in service by 1980. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. It must be either replaced or refurbished. Various projects are being undertaken at GMS to address these issues and a short description of each is included below. A description of one additional project, the Unit 1 to 5 Turbine Rehabilitation project, is provided in an associated Fact Sheet.

Project: Units 1 to 4 Generator Stators Replacement

The generator stators (the stationary part of the generating unit that converts the mechanical energy of the rotor into electrical energy) in Units 1 to 4 were built in the 1960s. Their Equipment Health Ratings (EHRs) no longer meet BC Hydro's equipment health criteria and replacement began in 2006 (two units are now complete) and is forecast to be completed by the beginning of 2010.

The new stator design will ultimately allow the units to one day operate at a capacity of 305 MW, but are now limited to the current 261 MW capacity because of other existing equipment capacity constraints and the existing water licence requirements.

Project: Units 6 & 7 Rotor Pole Replacement

Rotor poles (the rotating part of the generator connected to the turbine) on GMS Units 6 and 7 were also determined to no longer meet BC Hydro's equipment health criteria and also needed to be redesigned and replaced to accommodate the increased generating capacity on Units 6 to 7 (see 6 to 8 capacity increase below). The first installation was completed in November 2007. Replacement of the second unit will be completed in November 2010.

Project: Transformer Replacement

GMS has thirty unit transformers (the device that increases the voltage to allow transmission over distance). Ten of these transformers will be replaced to ensure the reliability of the plant. Installation of the new transformers started in October 2008 and will be completed in 2011.

Project: Units 6 to 8 Capacity Increase

GMS Units 6 to 8 will be refurbished to increase the capacity of GMS by 90 MW by replacing the generator circuit breakers (special switches to shut off and turn on power from the generator system) and iso-phase

bus (special electrical conductors that carry the power from the underground powerhouse to the substation on the surface). The increase in capacity is allowable within the current water licence. The B.C. Environmental Assessment Office (BCEAO) reviewed the proposed upgrade and confirmed the project would not require an Environmental Assessment Certificate and may proceed because it will not have significant adverse environmental, economic, social, heritage, or health affects. The BCEAO made this conclusion after extensive consultation with and feedback from, appropriate government agencies, local governments and First Nations. Work will commence in April 2009 and the total project is expected to be completed by June 2011.

Project: Station Service Replacement

Various equipment and emergency supply systems at GMS will also be replaced. The station service system provides the power for the plant controls, battery systems, fire systems and all the auxiliary systems necessary to run the plant's generators. The general contract has been awarded and the replacement work is scheduled to start in May 2009 and completion is expected by 2011.

This update was provided to keep residents of the Peace region informed on asset refurbishments being made to the Gordon M. Shrum Generating Station. For information about the Turbine Units 1 to 5 Project please see the associated Fact Sheet. Please contact BC Hydro's Community Relations Manager, Bob Gammer at 250 561-4858, or bob.gammer@bchydro.com or Stewart Dill, Aboriginal Relations Coordinator at 604 528-8331, or stewart.dill@bchydro.com for more information on any of the above projects.

BC hydro

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Aboriginal Relations and Negotiations

6911 Southpoint Drive (E16), Burnaby, B.C. V3N 4X8
www.bchydro.com

Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: **Chief Roland Willson**
West Moberly First Nations

DATE: January 12, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-788-9792

No. of pages (including cover sheet): **7**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (Jan. 13. 2009 12:23PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: Jan. 13. 2009 12:22PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
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Reason for error
E. 1) Hang up or line fail
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E. 3) No answer
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TO: **Chief Roland Willson**
West Moberly First Nations

DATE: January 12, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-788-9792

No. of pages (including cover sheet): 7

MESSAGE

Please see enclosed letter.

BC hydro
FOR GENERATIONS

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

May 14, 2009

Chief Roland Willson
West Moberly First Nations
PO Box 90
Moberly Lake, BC V0C 1X0

BY FACSIMILE (250) 788-9792 *(original to follow by mail)*

Dear Chief Willson:

Re: <u>GMS Units 1 to 5 Turbine Rehabilitation</u>

I am writing further to my letter of January 12, 2009 to provide you with an update on BC Hydro's proposed Units 1 to 5 Turbine Rehabilitation Project at the Gordon M. Shrum (GMS) Generating Station. In that letter I notified you of BC Hydro's plans to replace the turbines in five of the generating units at GMS in order to maintain the health and reliability of the units. The work will be confined to the plant and no change to water flows or reservoir levels are anticipated as a result of the upgrades.

The design and modelling of turbine options is ongoing. It is expected that a final design will be selected in summer 2010, which will be followed by fabrication of the turbines, site construction, installation and start-up. The first unit is forecast to come into service in 2012, with all five units in service by early 2017.

BC Hydro continues to anticipate submitting an Application in respect of the Units 1 to 5 Turbine Rehabilitation Project to the British Columbia Utilities Commission (BCUC) in September 2009, which will be preceded by an intervenor workshop in summer 2009.

For additional information on the GMS Units 1 to 5 Turbine Rehabilitation Project, please find enclosed a fact sheet which provides an updated overview of the Project. As before, should you require further information, or should you have any concerns that the proposed Project may affect the West Moberly First Nations' rights or interests, please do not hesitate to contact me at 604-528-8331 or stewart.dill@bchydro.com.

BC hydro
FOR GENERATIONS

For your information, the enclosed fact sheet also provides an update on other work being undertaken at GMS.

Sincerely,

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

cc: Shona Nelson, Treaty and Aboriginal Rights Research Director, Treaty 8 Tribal Association

Enclosure

BC HYDRO
MEETING DEMAND FOR GENERATIONS
UPDATE MAY 2009

GORDON M. SHRUM GENERATION STATION —AN HISTORIC ASSET

The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's generation system. GMS is located next to the W.A.C. Bennett Dam on the Peace River, near Hudson's Hope. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. Various projects are being undertaken at GMS to address these issues and a short description and status update of each is included below:

Project: Units 1 to 5 Turbine Rehabilitation

GMS generating Units 1 to 5 represent 12 per cent of BC Hydro's electricity producing capacity, which means that their reliability has an impact on the security of the province's electricity supply.

The need for renewal

Equipment Health Rating (EHRs) assessments undertaken by BC Hydro found that the 1960s era turbines in GMS Units 1 to 5 must be replaced. The project is being undertaken to ensure ongoing reliability, availability and operational flexibility of these units. A secondary benefit of the project will be an improvement in turbine efficiency.

The current maximum capacity per machine is 261 MW. The new turbines will be limited to the current capacity because of other existing equipment capacity constraints and the existing water licence limitations. The new turbines will ultimately allow the generating units to one day operate at a capacity of 305 MW. However, this capacity increase will require additional equipment upgrades and BC Hydro must also apply for a water licence revision and receive approval from the Ministry of Environment.

What's involved?

There are a limited number of manufacturers capable of supplying the large turbines used at GMS and those manufacturers are seeing a significant number of orders at this time – meaning this upgrade project will take several years. The first stage of project implementation consists of the design and modelling of a turbine to demonstrate the robustness and efficiency guarantees of the final product. To optimise the design and efficiency improvements and still maintain commercial competitiveness, the design and modelling work was awarded to two manufacturers, Voith Siemens Hydro Power Generation Inc. and Andritz Hydro Power Canada Inc, that will compete to provide the best possible solution for this project. Final award to a single manufacturer is anticipated for the summer of 2010 at which time the selected firm will proceed to the implementation of the second stage of the project. The second stage includes shop fabrication of the turbine followed by site construction, installation and start-up of the turbines. The first unit is forecast to come into service in 2012, and one unit per year thereafter. The final unit is expected to be in service in early 2017.

The cost of implementing the project is more than $50M and therefore an application will be made to the British Columbia Utilities Commission (BCUC) seeking a determination that the project is in the public interest. This application will be filed in the summer of 2009. Prior to filing the application, BC Hydro will hold a workshop on this application. It is expected that the BCUC will hold a hearing on the application during the fall of 2009.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on annual net power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30 per cent over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

BC hydro
FOR GENERATIONS

Project: Units 1 to 4 Generator Stators Replacement

The generator stators (the stationary part of the generating unit that converts the mechanical energy of the rotor into electrical energy) in Units 1 to 4 were also built in the 1960s and are due for replacement. A contract was awarded to Alstom Canada Inc. for the replacement of the stators. Two units are now complete and the other two are forecast to be completed by the end of 2010.

Project: Units 6 & 7 Rotor Pole Replacement

Rotor poles (the rotating part of the generator connected to the turbine) on GMS Units 6 and 7 were also determined to no longer meet BC Hydro's EHR criteria and required a redesign and replacement to accommodate the increased generating capacity on Units 6 and 7 (see 6 to 8 Project below). The first installation is complete and the second unit will be completed in late 2010.

Project: Transformer Replacement

GMS has thirty unit transformers (the device that increases the voltage to allow transmission over distance). Ten of these transformers will be replaced to ensure the reliability of the plant. Installation of the new transformers started in October 2008 and will be completed in 2011. Five new transformers will arrive at GMS in late spring and installation activities will last into fall 2009.

Project: Units 6 to 8 Capacity Increase

GMS Units 6 to 8 will be refurbished to increase the capacity of GMS by 90 MW by replacing the generator circuit breakers and iso-phase bus. The increase in capacity is allowable within the current water licence. The B.C. Environmental Assessment Office (BCEAO) reviewed the proposed upgrade and confirmed the project would not require an Environmental Assessment Certificate and may proceed because it will not have significant adverse environmental, economic, social, heritage, or health affects. The BCEAO made this conclusion after extensive consultation with and feedback from, appropriate government agencies, local governments and First Nations. The contract was awarded to Alstom Canada Inc. Work will start this summer and is expected to be completed by summer 2011.

Project: Station Service Replacement

The station service system provides the power for the plant controls, battery systems, fire systems and all the auxiliary systems necessary to run the plant's generators. The general contract has been awarded to ABB Inc. and completion is expected by 2011.

This update is provided to keep residents of the Peace region informed on asset refurbishments being made to the G. M. Shrum Generating Station.

Please contact BC Hydro Community Relations at 250 561 4858, or bob.gammer@bchydro.com or BC Hydro Aboriginal Relations at 604 528 8331, or stewart.dill@bchydro.com for more information on any of the above projects.

BC hydro
FOR GENERATIONS

GDS09-149

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Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

***TO:* Chief Roland Willson**
West Moberly First Nation

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-788-9792

No. of pages (including cover sheet): **5**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (May. 14. 2009 5:17PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: May. 14. 2009 5:16PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
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Reason for error
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E. 3) No answer
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Telephone: (604) 528-8331 E-mail: stewart.dill@bchydro.com Fax: (604) 528-2822

TO: Chief Roland Willson
West Moberly First Nation

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-788-9792

No. of pages (including cover sheet): 5

MESSAGE

Please see enclosed letter.

BC hydro
FOR GENERATIONS

Stewart Dill
BC Hydro Aboriginal Relations & Negotiations
6911 Southpoint Drive
Burnaby, BC V3N 4X8

July 16, 2009

Chief Roland Willson
West Moberly First Nations
PO Box 90
Moberly Lake, BC V0C 1X0

BY FACSIMILE (250) 788-9792 *(original to follow by mail)*

Dear Chief Willson:

Re: GMS Units 1 to 5 Turbine Replacement

I am writing further to my letters of January 12, 2009 and May 14, 2009 to provide you with an update on BC Hydro's plans to submit an application to the British Columbia Utilities Commission (BCUC) in respect of the Units 1 to 5 Turbine Replacement Project at the Gordon M. Shrum (GMS) Generating Station.

BC Hydro intends to file its application with the BCUC around the end of July 2009. Once the application is filed, it becomes a public document and the BCUC will start a public hearing process that is expected to include a workshop. Further information on the public hearing process can be found at the BCUC website: www.bcuc.com/Hearing.aspx.

As before, should you require further information, or should you have any concerns that the proposed GMS Units 1 to 5 Turbine Replacement Project may affect the West Moberly First Nations' rights or interests, please do not hesitate to contact me at 604-528-8331 or stewart.dill@bchydro.com.

Sincerely,

Stewart Dill
Senior Aboriginal Relations Coordinator
Aboriginal Relations and Negotiations

cc: Shona Nelson, Treaty and Aboriginal Rights Research Director, Treaty 8 Tribal Association

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TO: **Chief Roland Willson**
West Moberly First Nation

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-788-9792

No. of pages (including cover sheet): **3**

MESSAGE

Please see enclosed letter.

* * * Communication Result Report (Jul. 16. 2009 3:32PM) * * *

1) BC HYDRO ABORIGINAL RELATIONS
2)

Date/Time: Jul. 16. 2009 3:31PM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
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Reason for error
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West Moberly First Nation

DATE: May 14, 2009

FROM: Stewart Dill
Sr. Aboriginal Relations Coordinator

FAX NO: 250-788-9792

No. of pages (including cover sheet): 3

MESSAGE

Please see enclosed letter.

During BC Hydro's public consultation for the Project, information on the GMS Units 1 to 5 Turbine Replacement Project was sent to the following members of the public.

Chamber of Commerce
Chetwynd
Dawson Creek & District
Fort Nelson
Fort St. John
Mackenzie
Tumbler Ridge

Mayor & Council
Fort Nelson
Fort St. John
Chetwynd
Taylor
Hudson's Hope
Fort Nelson
Pouce Coupe
Dawson Creek
Mackenzie

Peace Williston Advisory Committee
Don Hicks – Chetwynd
Chief Donny Van Somer- Kwadacha Band
Chief Ella Pierre – Tsay Keh Dene Band
Gwen Johansson – Hudson's Hope
Jack Weisgerber - Chair
Kevin Neary – Mackenzie
Leigh Summer – Hudson's Hope
Lori Ackerman – Fort St. John
Rick Hopkins – Fort St. John
Ron Terlesky – Quesnel
Terry Johnson – Taylor
Wayne Dahlen – Dawson Creek

Stakeholders
South Peace Economic Development Commission
North Peace Economic Development Commission
Blair Lekstrom, MLA
Karen Goodings, Chair Regional District of Peace River
Pat Bell, MLA
Pat Pimm, MLA
Portage Mountain Yacht Club

A copy of the correspondence forwarded to the above noted parties is attached.

BC hydro FOR GENERATIONS

FACT SHEET

GMS Project Update

BC Hydro – Meeting Demand For Generations

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The first generating units were installed in 1968, with all 10 in service by 1980. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. It must be either replaced or refurbished. Various projects are being undertaken at GMS to address these issues and a short description of each is included below:

Project: Unit 1 to 5 Turbine Rehabilitation

GMS generating units 1 to 5 represent 12% of BC Hydro's electricity producing capacity, which means that their reliability has an impact on the security of the province's electricity supply.

A hydro electric turbine is a simple rotating mechanical device with few parts that uses flowing water to produce electrical energy. Water from the Williston Reservoir flows by gravity in a large pipe (called a penstock) across turbine blades mounted on a shaft that causes the shaft to turn. The mechanical energy produced from the shaft rotation is converted into electrical energy in a generator through the use of a magnetic field.

The need for renewal

The turbines in Units 1 to 5 were built in the 1960s. Equipment Health Ratings (EHRs) done by BC Hydro found the turbines in GMS Units 1 to 5 no longer meet BC Hydro's equipment health criteria and must be replaced. The GMS Units 1 to 5 Rehabilitation Project is being undertaken to protect against failures and costly forced outages. An ancillary benefit of the project will be an improvement in turbine efficiency as the new turbines will incorporate the technological advances of the last forty years.

The current maximum capacity per machine is 261 MW. The new turbines will be limited to the current capacity because of other existing equipment capacity constraints and the existing water licence limitations. The new turbine design will ultimately allow the generating units to one day operate at a capacity of 305 MW after the necessary water licence revisions are approved some time in the future and additional equipment upgrades are completed.

What's involved?

There are a limited number of world manufacturers capable of supplying the large turbines such as those used at GMS and those manufacturers are seeing a significant number of orders at this time. The result is that the overall upgrade project will take a number of years. The first stage will focus on the design and modelling of the turbine to demonstrate the robustness and efficiency guarantees. The second stage will consist of shop fabrication of the turbine followed by site construction, installation, and start-up of the turbines. The first unit is forecast to come into service in 2012, and one unit per year thereafter. The fifth and final unit is expected to be in service by the beginning of 2017.

An Application for a BCUC Determination will be filed in 2009 because the cost of implementing the project is more than $50M.

Project: Units 1 to 4 Generator Stators Replacement

The generator stators (the stationary part of the generating unit that converts the mechanical energy of the rotor into electrical energy) in Units 1 to 4 were also built in the 1960s. Their Equipment Health Ratings (EHRs) also no longer meet BC Hydro's equipment health criteria and replacement began in 2006 (two units are now complete) and is forecast to be completed by the beginning of 2010.

As in the new turbine design, the new stator design will ultimately allow the units to one day operate at a capacity of 305 MW, but are now limited to the current capacity because of other existing equipment capacity constraints and the existing water licence requirements.

Project: Units 6 & 7 Rotor Pole Replacement

Rotor poles (the rotating part of the generator connected to the turbine) on GMS Units 6 and 7 were also determined to no longer meet BC Hydro's equipment health criteria and also needed to be redesigned and replaced to accommodate the increased generating capacity on Units 6 to 7 (see 6 to 8 capacity increase below). The first installation was completed in November 2007. Replacement of the second unit will be completed in November 2010.

Project: Transformer Replacement

GMS has thirty unit transformers (the device that increases the voltage to allow transmission over distance). Ten of these transformers will be replaced to ensure the reliability of the plant. Installation of the new transformers started in October 2008 and will be completed in 2011.

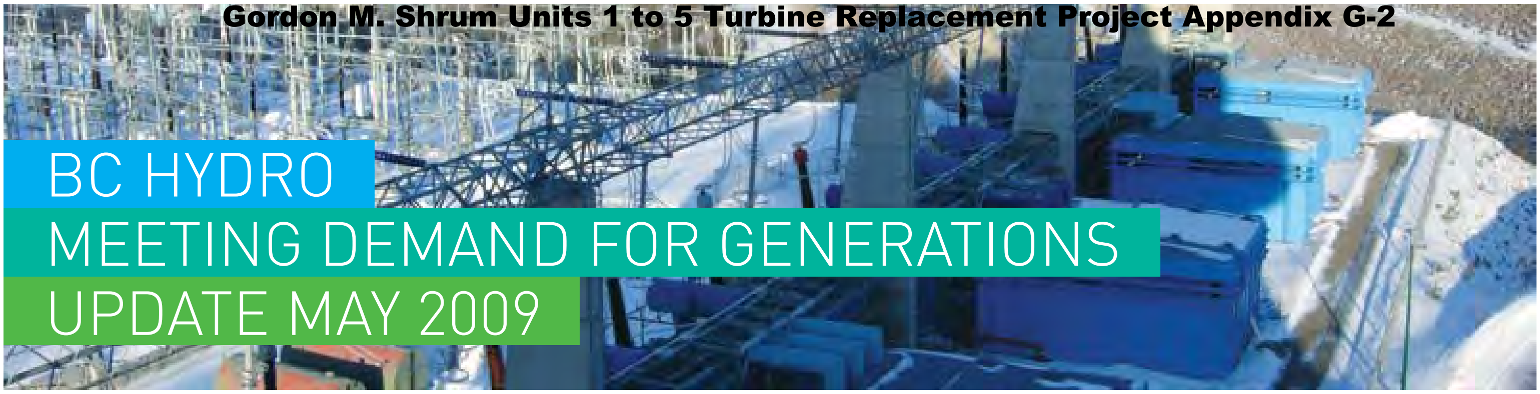
Project: Units 6 to 8 Capacity Increase

GMS Units 6 to 8 will be refurbished to increase the capacity of GMS by 90 MW by replacing the generator circuit breakers (special switches to shut off and turn on power from the generator system) and iso-phase bus (special electrical conductors that carry the power from the underground powerhouse to the substation on the surface). The increase in capacity is allowable within the current water licence. The B.C. Environmental Assessment Office (BCEAO) reviewed the proposed upgrade and confirmed the project would not require an Environmental Assessment Certificate and may proceed because it will not have significant adverse environmental, economic, social, heritage, or health affects. The BCEAO made this conclusion after extensive consultation with and feedback from, appropriate government agencies, local governments and First Nations. Work will commence in April 2009 and the total project is expected to be completed by June 2011.

Project: Station Service Replacement

Various equipment and emergency supply systems at GMS will also be replaced. The station service system provides the power for the plant controls, battery systems, fire systems and all the auxiliary systems necessary to run the plant's generators. The general contract has been awarded and the replacement work is scheduled to start in May 2009 and completion is expected by 2011.

This update was provided to keep residents of the Peace region informed on asset refurbishments being made to the Gordon M. Shrum Generating Station. Please contact BC Hydro's Community Relations Manager, Bob Gammer at 250 561-4858, or bob.gammer@bchydro.com or Stewart Dill, Aboriginal Relations Coordinator at 604 528-8331, or stewart.dill@bchydro.com for more information on any of the above projects.



BC HYDRO
MEETING DEMAND FOR GENERATIONS
UPDATE MAY 2009

GORDON M. SHRUM GENERATION STATION —AN HISTORIC ASSET

The Gordon M. Shrum (GMS) Generating Station is a cornerstone of BC Hydro's generation system. GMS is located next to the W.A.C. Bennett Dam on the Peace River, near Hudson's Hope. BC Hydro has determined that some of the key equipment in the power plant is in poor health and represents a risk to reliability. Various projects are being undertaken at GMS to address these issues and a short description and status update of each is included below:

Project: Units 1 to 5 Turbine Rehabilitation

GMS generating Units 1 to 5 represent 12 per cent of BC Hydro's electricity producing capacity, which means that their reliability has an impact on the security of the province's electricity supply.

The need for renewal

Equipment Health Rating (EHRs) assessments undertaken by BC Hydro found that the 1960s era turbines in GMS Units 1 to 5 must be replaced. The project is being undertaken to ensure ongoing reliability, availability and operational flexibility of these units. A secondary benefit of the project will be an improvement in turbine efficiency.

The current maximum capacity per machine is 261 MW. The new turbines will be limited to the current capacity because of other existing equipment capacity constraints and the existing water licence limitations. The new turbines will ultimately allow the generating units to one day operate at a capacity of 305 MW. However, this capacity increase will require additional equipment upgrades and BC Hydro must also apply for a water licence revision and receive approval from the Ministry of Environment.

What's involved?

There are a limited number of manufacturers capable of supplying the large turbines used at GMS and those manufacturers are seeing a significant number of orders at this time – meaning this upgrade project will take several years. The first stage of project implementation consists of the design and modelling of a turbine to demonstrate the robustness and efficiency guarantees of the final product. To optimise the design and efficiency improvements and still maintain commercial competitiveness, the design and modelling work was awarded to two manufacturers, Voith Siemens Hydro Power Generation Inc. and Andritz Hydro Power Canada Inc, that will compete to provide the best possible solution for this project. Final award to a single manufacturer is anticipated for the summer of 2010 at which time the selected firm will proceed to the implementation of the second stage of the project. The second stage includes shop fabrication of the turbine followed by site construction, installation and start-up of the turbines. The first unit is forecast to come into service in 2012, and one unit per year thereafter. The final unit is expected to be in service in early 2017.

The cost of implementing the project is more than $50M and therefore an application will be made to the British Columbia Utilities Commission (BCUC) seeking a determination that the project is in the public interest. This application will be filed in the summer of 2009. Prior to filing the application, BC Hydro will hold a workshop on this application. It is expected that the BCUC will hold a hearing on the application during the fall of 2009.

BC Hydro's efficient, reliable system delivers some of the lowest electricity rates in North America. While B.C. was once self-sufficient, we have been relying on annual net power imports to meet up to 15% of the province's electricity needs in seven of the past ten years.

To continue to meet B.C.'s current and growing demand for electricity, projected to rise by 25 to 30 per cent over the next two decades, it is critical that BC Hydro undertakes capital work to renew and upgrade hydroelectric infrastructure at several facilities.

Project: Units 1 to 4 Generator Stators Replacement

The generator stators (the stationary part of the generating unit that converts the mechanical energy of the rotor into electrical energy) in Units 1 to 4 were also built in the 1960s and are due for replacement. A contract was awarded to Alstom Canada Inc. for the replacement of the stators. Two units are now complete and the other two are forecast to be completed by the end of 2010.

Project: Units 6 & 7 Rotor Pole Replacement

Rotor poles (the rotating part of the generator connected to the turbine) on GMS Units 6 and 7 were also determined to no longer meet BC Hydro's EHR criteria and required a redesign and replacement to accommodate the increased generating capacity on Units 6 and 7 (see 6 to 8 Project below). The first installation is complete and the second unit will be completed in late 2010.

Project: Transformer Replacement

GMS has thirty unit transformers (the device that increases the voltage to allow transmission over distance). Ten of these transformers will be replaced to ensure the reliability of the plant. Installation of the new transformers started in October 2008 and will be completed in 2011. Five new transformers will arrive at GMS in late spring and installation activities will last into fall 2009.

Project: Units 6 to 8 Capacity Increase

GMS Units 6 to 8 will be refurbished to increase the capacity of GMS by 90 MW by replacing the generator circuit breakers and iso-phase bus. The increase in capacity is allowable within the current water licence. The B.C. Environmental Assessment Office (BCEAO) reviewed the proposed upgrade and confirmed the project would not require an Environmental Assessment Certificate and may proceed because it will not have significant adverse environmental, economic, social, heritage, or health affects. The BCEAO made this conclusion after extensive consultation with and feedback from, appropriate government agencies, local governments and First Nations. The contract was awarded to Alstom Canada Inc. Work will start this summer and is expected to be completed by summer 2011.

Project: Station Service Replacement

The station service system provides the power for the plant controls, battery systems, fire systems and all the auxiliary systems necessary to run the plant's generators. The general contract has been awarded to ABB Inc. and completion is expected by 2011.

This update is provided to keep residents of the Peace region informed on asset refurbishments being made to the G. M. Shrum Generating Station.

Please contact BC Hydro Community Relations at 250 561 4858, or bob.gammer@bchydro.com or BC Hydro Aboriginal Relations at 604 528 8331, or stewart.dill@bchydro.com for more information on any of the above projects.

BC hydro
FOR GENERATIONS

GDS09-149

BC hydro
FOR GENERATIONS

Bob Gammer
Community Relations Coordinator
Northern Region
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July 16, 2009

Dear Chamber,

Subject: G.M. Shrum Generating Station Unit 1 to Unit 5 Turbine Replacement Project Update

I am writing to provide you with an update on one of our projects proposed for the Peace region. As you are aware from project update newsletters issued in January and May 2009, BC Hydro is preparing to replace the turbine runners on generating units 1 to 5 at the W.A.C Bennett dam's G.M. Shrum Generating Station (GMS) near Hudson's Hope in the coming years. This work is being undertaken in order to maintain the health and reliability of the units. All work will be confined to the plant. The project will cost more than $50 million; therefore review of the project by the B.C. Utilities Commission (BCUC) is required.

BC Hydro intends to file its application for the GMS Units 1 to 5 upgrade project with the BCUC around the end of July 2009. Once the application is filed, it becomes a public document and the BCUC will start a public hearing process that is expected to include a workshop. BC Hydro would make the slide presentation from the workshop available on its website.

Further information on the public hearing process can be found at the BCUC website: www.bcuc.com/Hearing.aspx. BC Hydro will continue to provide regular project updates at key project milestones.

To date we have not received any issues or concerns raised as a result of the newsletters to local stakeholders or media coverage. BC Hydro welcomes your input in this process; please contact us at:

BC Hydro
Attn: Northern Community Relations
PO Box 6500
Prince George, BC V2N 2K4

You may also contact us at:
Phone: 250 561-4858, or 604 528-8331
Email: bob.gammer@bchydro.com, or
stewart.dill@bchydro.com

Yours truly,

Bob Gammer

c: Dave Conway, BC Hydro Community Relations Manager

BC hydro
FOR GENERATIONS

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Northern Region
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Fax: 250 561-4990
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July 16, 2009

Dear Mayor and Council,

Subject: G.M. Shrum Generating Station Unit 1 to Unit 5 Turbine Replacement Project Update

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Yours truly,

Bob Gammer

c: Dave Conway, BC Hydro Community Relations Manager

British Columbia Hydro and Power Authority
PO Box 6500, 3333 22nd Avenue, Prince George, BC V2N 2K4
bchydro.com

vancouver 2010 vancouver 2010 PARALYMPIC GAMES JEUX PARALYMPIQUES
BC hydro OFFICIAL SUPPORTER

BC hydro
FOR GENERATIONS

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Community Relations Coordinator
Northern Region
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Fax: 250 561-4990
Email: bob.gammer@bchydro.com

July 16, 2009

Dear PWAC Member,

Subject: G.M. Shrum Generating Station Unit 1 to Unit 5 Turbine Replacement Project Update

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Yours truly,

Bob Gammer

c: Dave Conway, BC Hydro Community Relations Manager

Bob Gammer
Community Relations Coordinator
Northern Region
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Cell: 250 961-0676
Fax: 250 561-4990
Email: bob.gammer@bchydro.com

July 16, 2009

Dear Stakeholder,

Subject: G.M. Shrum Generating Station Unit 1 to Unit 5 Turbine Replacement Project Update

I am writing to provide you with an update on one of our projects proposed for the Peace region. As you are aware from project update newsletters issued in January and May 2009, BC Hydro is preparing to replace the turbine runners on generating units 1 to 5 at the W.A.C Bennett dam's G.M. Shrum Generating Station (GMS) near Hudson's Hope in the coming years. This work is being undertaken in order to maintain the health and reliability of the units. All work will be confined to the plant. The project will cost more than $50 million; therefore review of the project by the B.C. Utilities Commission (BCUC) is required.

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Email: bob.gammer@bchydro.com, or stewart.dill@bchydro.com

Yours truly,

Bob Gammer

c: Dave Conway, BC Hydro Community Relations Manager

Gordon M. Shrum Units 1 to 5 Turbine Replacement Project

Appendix

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Project Expenditures

GMS Turbine Replacement Project Expenditures - $ Million
Fiscal Years

	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	Total Expected	Total Authorized
Costs to Stage 1													
Direct	0.4	1.3	0.9	5.7	2.9							11.2	11.2
Overhead	0.0	0.2	0.1	0.8	0.4							1.4	1.4
IDC	0.0	0.1	0.2	0.4	1.0	1.1	0.8					3.5	3.5
Total	0.4	1.6	1.1	6.8	4.2	1.1	0.8					16.1	16.1
Stage 2 Costs													
Direct - Expected Costs					5.3	26.0	31.8	29.8	28.5	25.0	11.9	158.2	158.2
Management & Engineering					0.4	1.3	1.9	2.1	1.8	1.4	0.7	9.5	9.5
Project Allowance						1.4	1.8	1.8	1.8	1.2		8.0	8.0
					5.7	28.7	35.4	33.8	32.1	27.6	12.6	175.8	175.8
Project Contingency - Expected Costs					0.8	2.2	3.4	4.6	3.9	2.5	1.2	18.7	18.7
Project Contingency - Increse to Authorized Costs					1.2	3.3	5.1	7.0	5.8	3.8	3.8		30.1
Dismantling and Removal						0.0	0.1	0.2	0.3	0.5	0.3	1.4	1.4
												195.9	226.0
Overhead - Expected					0.9	4.1	5.2	5.1	4.8	4.0	1.8	25.9	25.9
IDC - Expected					0.2	1.5	3.6	4.4	5.3	5.6	3.6	24.1	24.1
Overhead - Increase to Authorized					0.2	0.4	0.7	0.9	0.8	0.5	0.5		4.0
IDC - Increase to Authorized					0.0	0.2	0.5	1.1	1.6	2.1	1.6		7.2
					8.9	40.4	54.0	57.0	54.7	46.7	25.5	245.9	287.2
Project Costs before Management Reserve	0.4	1.6	1.1	6.8	13.1	41.5	54.8	57.0	54.7	46.7	25.5	262.0	303.3
Management Reserve (Loaded)							2.7	2.9	3.1	3.3	3.5		15.4
Project Costs	0.4	1.6	1.1	6.8	13.1	41.5	57.5	59.9	57.7	49.9	29.0	262.0	318.7

Gordon M. Shrum Units 1 to 5 Turbine Replacement Project

BC hydro

Appendix

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Net Present Value Analysis

Nominal Discount Rate	8.0%	
Incremental Energy (plant gate)		
Restricted	(164.0)	GWh/Yr
Overhaul	0.0	
Replacement	177.0	
Energy Value	93.39	2009$ converted from 2006
less Water Rental	(6.22)	2009$ converted from 2010
Plant Gate Value	*87.17*	
Net of Transmission Value	78.03	NB - Water rental paid on Plant Gate generation, Market Value is net of Transmission Losses
Avoidable outages	6	unit-weeks/year
Value of Outage	250	$K/Unit-Week
Peplacement Avoidable Repairs	250	$K/Yr
OH Avoidable Repairs	125	$K/Yr
Cost Of Install Outage	4,300	$K
Transmission Losses (Peace River Region to Lower Mainland)	9.79%	

			Calendar Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Long-Term Inflation Forecast				2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
By Fiscal Year				**F2010**	**F2011**	**F2012**	**F2013**	**F2014**	**F2015**	**F2016**	**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**	**F2035**	**F2036**	**F2037**	**F2038**	**F2039**
				2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
General Inflation - Cumulative Index			1.00	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52	1.55	1.58	1.61	1.64	1.67	1.71	1.74	1.78	1.81
Real Discount Rate				5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%
Cumulative Real Discount Factor			1.00	0.94	0.89	0.84	0.80	0.75	0.71	0.67	0.63	0.60	0.56	0.53	0.50	0.48	0.45	0.42	0.40	0.38	0.36	0.34	0.32	0.30	0.28	0.27	0.25	0.24	0.23	0.21	0.20	0.19	0.18
Capital Inflation - Annual						3%	3%	3%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%												
Capital Inflation - Cumulative Index					1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.22	1.24	1.27	1.29	1.32	1.34	1.37	1.40	1.43	1.46												
Capital - Direct, Unloaded - Implementation Phase																																	
	PV	Total		F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
Nominal $000s	@F2010																																
Overhaul - Expected Costs (Stage 2 Implementation)	110,092.2	162,748.2		0.0	5,192.6	22,618.0	31,365.3	34,309.9	31,044.4	24,735.1	13,482.9	0.0	0.0	0.0																			
Overhaul - Deferred Replacement of Turbines	77,588.2	245,701.2	1.510	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,372.8	39,552.1	49,279.0	48,404.9	45,156.7	37,704.6	17,231.1												
Overhaul - Authorized	143,750.1	213,025.5		0.0	7,195.0	28,155.2	39,943.1	45,953.2	40,795.7	31,092.0	19,891.3	0.0	0.0	0.0																			
Subsequent Replacement	89,289.6	283,361.2	1.330	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,921.7	43,793.8	55,786.0	57,151.4	52,410.7	42,387.7	21,910.0												
Management Reserve	10,906.2	16,162.0																															
Replacement Capital Costs - Expected	132,452.3	194,496.4		0.0	6,478.1	30,885.8	38,814.2	38,399.4	36,005.5	30,124.8	13,788.6																						
Replacement Dismantling Costs	857.7	1,420.1		0.0	0.0	15.9	64.5	164.1	322.9	505.8	346.9																						
Replacement Capital Costs - Authorized	152,597.5	224,589.3		0.0	7,676.5	34,199.8	43,947.9	45,367.6	41,841.3	33,929.3	17,626.9																						
Replacement Dismantling Costs	857.7	1,420.1		0.0	0.0	15.9	64.5	164.1	322.9	505.8	346.9																						
Management Reserve	10,445.9	15,374.0																															
Incremental Energy	*units in service -->*			*0*	*0*	*0*	*1*	*2*	*3*	*4*	*5*																						
GWh annually (Plant Gate)	@F2010	Total		F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
Overhaul																																	
Avoided Loss	941	4,578		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.1	58.1	99.1	140.1	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
Efficiency Gain	982	4,853		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.8	50.2	85.6	121.0	156.4	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0
	1,923	9,431		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.8	108.2	184.6	261.0	320.4	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0
Replacement																																	
Avoided Loss	1,851	6,218		0.0	0.0	0.0	17.1	58.1	99.1	140.1	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
Efficiency Gain	1,937	6,623		0.0	0.0	0.0	14.8	50.2	85.6	121.0	156.4	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0
	3,789	12,841		0.0	0.0	0.0	31.8	108.2	184.6	261.0	320.4	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0
Value of Incremental Energy																																	
Nominal $000s (net of Transmission Losses)	@F2010	Total		F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
Overhaul	161,996	1,446,638		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,538.5	12,271.6	21,352.6	30,791.9	38,544.8	41,850.0	42,687.0	43,540.7	44,411.6	45,299.8	46,205.8	47,129.9	48,072.5	49,034.0	50,014.6	51,014.9	52,035.2
Replacement	319,157	1,803,426		0.0	0.0	0.0	2,902.8	10,067.0	17,516.6	25,260.1	31,620.2	34,331.6	35,018.2	35,718.6	36,432.9	37,161.6	37,904.8	38,662.9	39,436.2	40,224.9	41,029.4	41,850.0	42,687.0	43,540.7	44,411.6	45,299.8	46,205.8	47,129.9	48,072.5	49,034.0	50,014.6	51,014.9	52,035.2
Cost of Energy (Water Rental)																																	
Unit Cost	$/MWh		6.34	6.90	7.53	8.00	8.49	9.02	9.76	10.56	11.11	11.46	11.70	11.94	12.19	12.45	12.71	12.98	13.25	13.53	13.81	14.10	14.40	14.70	15.01	15.33	15.65	15.98	16.31	16.65	17.00	17.36	17.73
Expected Annual Rate of Increase (2008 LTAP)				8.7%	9.2%	6.2%	6.2%	6.2%	8.2%	8.2%	5.2%	3.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
	PV @F2010	Total																															
Overhaul	18,748	168,241		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	404.7	1,404.7	2,446.6	3,531.6	4,425.2	4,809.4	4,910.4	5,013.5	5,118.8	5,226.2	5,336.0	5,448.1	5,562.5	5,679.3	5,798.5	5,920.3	6,044.6
Replacement	36,299	208,369		0.0	0.0	0.0	270.4	976.3	1,802.4	2,757.8	3,559.2	3,906.9	3,988.9	4,072.7	4,158.2	4,245.5	4,334.7	4,425.7	4,518.7	4,613.6	4,710.4	4,809.4	4,910.4	5,013.5	5,118.8	5,226.2	5,336.0	5,448.1	5,562.5	5,679.3	5,798.5	5,920.3	6,044.6
Effect of other Factors	PV @F2010	Total																															
Replacement - Avoided Future Outage Opportunity Cost	17,573	95,586		0	0	0	406	828	1,267	1,723	1,757	1,793	1,828	1,865	1,902	1,940	1,979	2,019	2,059	2,100	2,142	2,185	2,229	2,273	2,319	2,365	2,413	2,461	2,510	2,560	2,612	2,664	2,717
Overhaul - Avoided Future Outage Opportunity Cost	9,628	79,267		0	0	0	0	0	0	0	0	0	0	0	0	485	990	1,514	2,059	2,100	2,142	2,185	2,229	2,273	2,319	2,365	2,413	2,461	2,510	2,560	2,612	2,664	2,717
Replacement - Maintenance and Inspection Savings	2,840	15,790		0	0	0	54	110	169	230	293	299	305	311	317	323	330	336	343	350	357	364	371	379	386	394	402	410	418	427	435	444	453
Overhaul - Avoided Future Maintenance Cost	1,420	7,895		0	0	0	27	55	84	115	146	149	152	155	159	162	165	168	172	175	179	182	186	189	193	197	201	205	209	213	218	222	226
Overhaul - Avoided Future Maintenance Cost after Replacement	723	6,353		0	0	0	0	0	0	0	0	0	0	0	0	0	33	67	103	140	179	182	186	189	193	197	201	205	209	213	218	222	226
Capital Costs (to end of Stage 1 Implementation)	10,809	11,673		11,673	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Installation Outages - Opportunity Costs																																	
Replacement	15,308	24,222		0	0	0	4,654	4,748	4,842	4,939	5,038	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Overhaul	24,460	53,170		0	0	0	4,654	4,748	4,842	4,939	5,038	0	0	0	0	5,563	5,674	5,787	5,903	6,021	0	0	0	0	0	0	0	0	0	0	0	0	0

Nominal Discount Rate
Incremental Energy (plant gate)
Restricted
Overhaul
Replacement
Energy Value
less Water Rental
Plant Gate Value
Net of Transmission Value

Avoidable outages
Value of Outage
Peplacement Avoidable Repairs
OH Avoidable Repairs
Cost Of Install Outage

Transmission Losses (Peace River Region to Lower Mainland)

	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Long-Term Inflation Forecast	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
By Fiscal Year	**F2040**	**F2041**	**F2042**	**F2043**	**F2044**	**F2045**	**F2046**	**F2047**	**F2048**	**F2049**	**F2050**	**F2051**	**F2052**
	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	1.5%
General Inflation - Cumulative Index	1.85	1.88	1.92	1.96	2.00	2.04	2.08	2.12	2.16	2.21	2.25	2.30	2.33
Real Discount Rate	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%	5.88%
Cumulative Real Discount Factor	0.17	0.16	0.15	0.14	0.14	0.13	0.12	0.11	0.11	0.10	0.10	0.09	0.09
Capital Inflation - Annual													
Capital Inflation - Cumulative Index													
Capital - Direct, Unloaded - Implementation Phase													
	F2040	F2041	F2042	F2043	F2044	F2045	F2046	F2047	F2048	F2049	F2050	F2051	F2052
Nominal $000s													
Overhaul - Expected Costs (Stage 2 Implementation)													
Overhaul - Deferred Replacement of Turbines													
Overhaul - Authorized													
Subsequent Replacement													
Management Reserve													
Replacement Capital Costs - Expected													
Replacement Dismantling Costs													
Replacement Capital Costs - Authorized													
Replacement Dismantling Costs													
Management Reserve													
Incremental Energy													
GWh annually (Plant Gate)	F2040	F2041	F2042	F2043	F2044	F2045	F2046	F2047	F2048	F2049	F2050	F2051	F2052
Overhaul													
Avoided Loss	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
Efficiency Gain	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0
	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0
Replacement													
Avoided Loss	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
Efficiency Gain	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0
	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0
Value of Incremental Energy													
Nominal $000s (net of Transmission Losses)	F2040	F2041	F2042	F2043	F2044	F2045	F2046	F2047	F2048	F2049	F2050	F2051	F2052
Overhaul	53,075.9	54,137.4	55,220.2	56,324.6	57,451.1	58,600.1	59,772.1	60,967.6	62,186.9	63,430.6	64,699.3	65,993.2	66,983.1
Replacement	53,075.9	54,137.4	55,220.2	56,324.6	57,451.1	58,600.1	59,772.1	60,967.6	62,186.9	63,430.6	64,699.3	65,993.2	66,983.1
Cost of Energy (Water Rental)													
Unit Cost	18.10	18.48	18.87	19.26	19.67	20.08	20.50	20.93	21.37	21.82	22.28	22.75	23.22
Expected Annual Rate of Increase (2008 LTAP)	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
Overhaul	6,171.6	6,301.2	6,433.5	6,568.6	6,706.5	6,847.4	6,991.2	7,138.0	7,287.9	7,440.9	7,597.2	7,756.7	7,919.6
Replacement	6,171.6	6,301.2	6,433.5	6,568.6	6,706.5	6,847.4	6,991.2	7,138.0	7,287.9	7,440.9	7,597.2	7,756.7	7,919.6
Effect of other Factors													
Replacement - Avoided Future Outage Opportunity Cost	2,771	2,827	2,883	2,941	3,000	3,060	3,121	3,183	3,247	3,312	3,378	3,446	3,498
Overhaul - Avoided Future Outage Opportunity Cost	2,771	2,827	2,883	2,941	3,000	3,060	3,121	3,183	3,247	3,312	3,378	3,446	3,498
Replacement - Maintenance and Inspection Savings	462	471	481	490	500	510	520	531	541	552	563	574	583
Overhaul - Avoided Future Maintenance Cost	231	236	240	245	250	255	260	265	271	276	282	287	291
Overhaul - Avoided Future Maintenance Cost after Replacement	231	236	240	245	250	255	260	265	271	276	282	287	291
Capital Costs (to end of Stage 1 Implementation)	0	0	0	0	0	0	0	0	0	0	0	0	0
Installation Outages - Opportunity Costs													
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0
Overhaul	0	0	0	0	0	0	0	0	0	0	0	0	0

Project Capacity and Energy					
				Per Unit	**Total**
Rated Capacity (No Change)	MW			261	1,305
Average Annual Energy (Constrained Dispatch)	GWh/Year			1,287	6,436
Incremental Energy by Removing Constraints	GWh/Year			33	164
Expected Incremental Energy	GWh/Year			35	177
Total Expected Energy after Replacement	GWh/Year			1,355	6,777
Project NPV and Cost of Energy		**Overhaul**		**Replacement**	
		Expected	Authorized	Expected	Authorized
Capital Costs (Stage 2 Implementation)	PV $M	110	155	133	164
Capital Costs (to end of Stage 1 Implementation)	PV $M	11	11	11	11
Deferred Replacement of Turbines	PV $M	78	89		
Installation Outage Opportunity Costs	PV $M	24	24	15	15
Cost of Energy (Water Rental)	PV $M	19	19	36	36
Avoided Future Outage Opportunity Cost	PV $M	(10)	(10)	(18)	(18)
Avoided Future Maintenance Cost	PV $M	(2)	(2)	(3)	(3)
Net Cost	PV $M	230	286	175	206
Value of Energy (Net of Transmission Losses)	PV $M	162	162	319	319
Project NPV	**NPV $M**	(68)	(124)	144	113
Energy Benefits	PV GWh	1,735	1,735	3,418	3,418
Levelized Cost of Energy (Net Cost/Energy Benefits)	$ / MWh	132.5	165.0	51.3	60.2