newfoundland labrador
hydro
a nalcor energy company

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August 5, 2013

BY HAND

Board of Commissioners
of Public Utilities
P.O. Box 21040
St. John's, NF
A1A 5B2

Attention: Cheryl Blundon – Director of Corporate Services and Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro – 2014 Capital Budget Application

Please find enclosed ten copies of Hydro's 2014 Capital Budget Application, in two volumes, filed in accordance with the Provisional Capital Budget Application Guidelines issued by the board in October of 2007 and in accordance with the guidelines and conditions for capital budget proposals as outlined by the Board in Order No. P.U. 7 (2002-2003).

Under this Application, Hydro is seeking approval of $98.7 million in capital expenditures. Also, Hydro is seeking approval of its 2012 rate base in the amount of $1,526,051,000.

We trust that you will find the enclosed to be in order and satisfactory. Should you have any questions or comments about any of the enclosed please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young,
Senior Legal Counsel

Encl.

cc: Mr. Peter Alteen, Newfoundland Power
Mr. Tom Johnson, Consumer Advocate O'Dea, Earle
Mr. Dean Porter Poole Althouse
Mr. Paul Coxworthy Stewart McKelvey Stirling Scales

An Application to the
Board of Commissioners of Public Utilities

2014 Capital Budget Application

Volume I

August 2013

newfoundland labrador hydro
a nalcor energy company

Table of Contents
Volume I

Table of Contents
Volume I
(cont'd.)

Table of Contents
Volume II
(cont'd.)

IN THE MATTER OF the *Public Utilities Act*, (the "Act"); and

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for an Order approving: (1) its 2014 capital budget pursuant to s.41(1) of the Act; (2) its 2014 capital purchases, and construction projects in excess of $50,000 pursuant to s.41 (3) (a) of the Act; (3) its leases in excess of $5,000 pursuant to s. 41 (3) (b) of the Act; and (4) its estimated contributions in aid of construction for 2014 pursuant to s.41 (5) of the Act and for an Order pursuant to s. 78 of the Act fixing and determining its average rate base for 2012.

TO: The Board of Commissioners of Public Utilities ("the Board")

THE APPLICATION of Newfoundland and Labrador Hydro ("Hydro") ("the Applicant") states that:

1. Hydro is a corporation continued and existing under the Hydro *Corporation Act, 2007,* is a public utility within the meaning of the Act and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. Section A to this Application is Hydro's proposed 2014 Capital Budget in the amount of approximately $98.7 million prepared in accordance with the guidelines and conditions outlined in Order No. P.U. 7 (2002-2003) and the Capital Budget Application Guidelines issued October 29, 2007.

3. Section B to this Application is Hydro's proposed 2014 Capital Budget with multi-year projects listed separately and prepared in accordance with the guidelines and conditions outlined in Order No. P.U. 7 (2002-2003) and the Capital Budget Application Guidelines issued October 29, 2007.

4. Section C to this Application is a list of the proposed 2014 Construction Projects and Capital Purchases for $500,000 and over, prepared in accordance with Order No. P.U. 7 (2002-2003) and the Capital Budget Application Guidelines.

5. Section D to this Application is a list of the proposed 2014 Construction Projects and Capital Purchases for $200,000 and over, but less than $500,000, prepared in accordance with Order No. P.U. 7 (2002-2003) and the Capital Budget Application Guidelines.

6. Section E to this Application is a list of the proposed 2014 Construction Projects and Capital Purchases in excess of $50,000 but less than $200,000 prepared in accordance with Order No. P.U. 7 (2002-2003) and the Capital Budget Application Guidelines.

7. Section F to this Application summarizes Hydro's proposed 2014 capital projects by definitions, by classification and by materiality as required by the Capital Budget Application Guidelines.

8. Section G contains no new leases proposed for 2014 in excess of $5,000 per year.

9. Section H to this Application is a Schedule of Hydro's Capital Expenditures for the period 2009 to 2018.

10. Section I to this Application is a report on the status of the 2013 capital expenditures including those approved by Orders No. P.U. 2 (2013) and P.U. 4 (2013), projects under $50,000 not included in these Orders, and the 2012 capital expenditures carried forward to 2013.

11. Section J to this Application is a report on the ten year Plan of Maintenance Expenditures for the Holyrood Generating Station required to be filed by Order No. P.U. 14 (2004).

12. Section K to this Application shows Hydro's actual average rate base for 2012 of $1,526,051,000.

13. Volume I and Volume II to this Application contain the supplementary reports referred to in various capital budget proposals.

14. The proposed capital expenditures for 2014 as set out in this Application are required to allow Hydro to continue to provide to its customers service and facilities which are reasonably safe, adequate and reliable as required by Section 37 of the Act.

15. The Applicant has estimated the total of contributions in aid of construction for 2014 to be approximately $300,000. The information contained in the 2013 Capital Budget (Section A) takes into account this estimate of the contributions in aid of construction to be received from customers. All contributions to be recovered from customers shall be calculated in accordance with the relevant policies as approved by the Board.

16. Communications with respect to this Application should be forwarded to Geoffrey P. Young, Senior Legal Counsel, P.O. Box 12400, St. John's, Newfoundland and Labrador, A1B 4K7, Telephone: (709) 737-1277, Fax: (709) 737-1782.

18. The Applicant requests that the Board make an Order as follows:

(1) Approving Hydro's 2014 Capital Budget as set out in Section A hereto, pursuant to section 41 (1) of the Act;

(2) Approving 2014 Capital Purchases and Construction Projects in excess of $50,000 as set out in Sections C, D, and E hereto, and its leases as set in Section F, pursuant to section 41 (3) of the Act;

(3) Approving the proposed estimated contributions in aid of construction as set out in paragraph 12 hereof for 2014 as required by section 41 (5) of the Act, with all such contributions to be calculated in accordance with the policies approved by the Board; and

(4) Fixing and determining Hydro's average rate base for 2012 in the amount of $1,526,051,000 pursuant to section 78 of the Act.

DATED at St. John's, Newfoundland, this 5th day of August, 2013.

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young,
Senior Legal Counsel

Newfoundland and Labrador Hydro,
500 Columbus Drive, P.O. Box 12400
St. John's, Newfoundland, A1B 4K7
Telephone: (709) 737-1715
Facsimile: (709) 737-1782

IN THE MATTER OF the *Public Utilities Act*, (the "Act"); and

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for an Order approving: (1) its 2014 capital budget pursuant to s.41(1) of the Act; (2) its 2014 capital purchases, and construction projects in excess of $50,000 pursuant to s.41 (3) (a) of the Act; (3) its leases in excess of $5,000 pursuant to s. 41 (3) (b) of the Act; and (4) its estimated contributions in aid of construction for 2014 pursuant to s.41 (5) of the Act and for an Order pursuant to s. 78 of the Act fixing and determining its average rate base for 2012.

AFFIDAVIT

I, Robert J. Henderson, Professional Engineer, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am Vice-President, Newfoundland and Labrador Hydro, the Applicant named in the attached Application.
2. I have read and understand the foregoing Application.
3. I have personal knowledge of the facts contained therein, except where otherwise indicated, and they are true to the best of my knowledge, information and belief.

SWORN at St. John's in the)
Province of Newfoundland and)
Labrador)
this 5th day of August 2013,)
before me:)

Barrister – Newfoundland and Labrador

Robert J. Henderson

A Report to the

Board of Commissioners of Public Utilities

2014 Capital Projects Overview

newfoundland labrador hydro

a nalcor energy company

INTRODUCTION

Hydro is required to provide reliable service to its customers, through the provisions of the Hydro Corporation Act, 2007, the Electrical Power Control Act, 1994, and the Public Utilities Act. The provision of a safe, reliable, least cost supply of electricity requires that Hydro continuously maintain, refurbish, renew, and expand its generation, transmission and distribution assets, and the assets that support those systems. Hydro must also address changing environmental and other regulatory requirements, challenges which often require the acquisition of new assets or improvement to existing assets. Hydro's long term planning initiatives are framed in the context of the following key drivers: the shift in load centers caused by such events as the closure of two paper mills, the expected startup of a nickel processing facility, and continued load growth on the Avalon Peninsula. This Overview will discuss the projects proposed for 2014. Discussion of the five year plan is contained in the section entitled "2014 Capital Plan".

2014 PLAN CONSIDERATIONS

Maintaining Hydro's systems in reliable operating condition is accomplished through a combination of planned maintenance, rehabilitation of existing assets, and replacement of assets which have reached the end of their useful lives. Assets may also be replaced by ones which will result in lower life cycle costs or improved operational characteristics or as required for load growth or criteria violations.

The majority of Hydro's installed assets are more than forty years old. This is true of Hydro's largest hydroelectric installation at Bay d'Espoir, the Holyrood Thermal Generating Station, and much of Hydro's transmission and distribution systems. In addition, many other generation assets, such as the Stephenville Gas Turbine, the Hardwoods Gas Turbine and the Hinds Lake Generating Station are more than thirty years old.

The sustaining capital proposals contained in this and previous capital budget applications appropriately consider both the age and condition of Hydro's existing assets in determining whether to renew or replace them. The number of these sustaining capital proposals can be expected to increase as the assets age and their condition continues to be assessed. In other cases, the introduction of newer, more efficient technologies justifies the replacement of equipment.

The age of Hydro's assets also has implications for efficient operating methods and safety. Some of Hydro's generating plants were constructed at a time when most systems and auxiliary equipment were manually operated. Today, most equipment is automated or remotely controlled which permits the operators to spend more time focused on maximizing efficiency and equipment monitoring. This Application contains proposals to improve the safety of Hydro's workplaces and to implement automation or improvements in the control of equipment that enable the safe and efficient operation of assets.

Consideration in the development of a capital proposal is given to:

- System performance and reliability criteria;
- Long term asset management strategy;
- Load growth and system planning criteria;
- Maintenance history;
- Condition assessment;
- Performance assessment;
- Legislative requirements;
- Cost efficiencies;
- Operating experience;
- Changing operating conditions;
- Familiarity with equipment;
- Operating and Maintenance cost; and
- Professional judgment.

There are three broad categories of replacement criteria:

- Time and condition based, such as diesel generators (100,000 hours of operation) and vehicles (combination of years and operating hours for some classes);
- Condition based, such as transmission line wood poles and turbine bushings and seals, transformer gas analysis; and
- Technical assessment based, where an evaluation of reliability, performance, condition, costs and other factors results in a capital proposal.

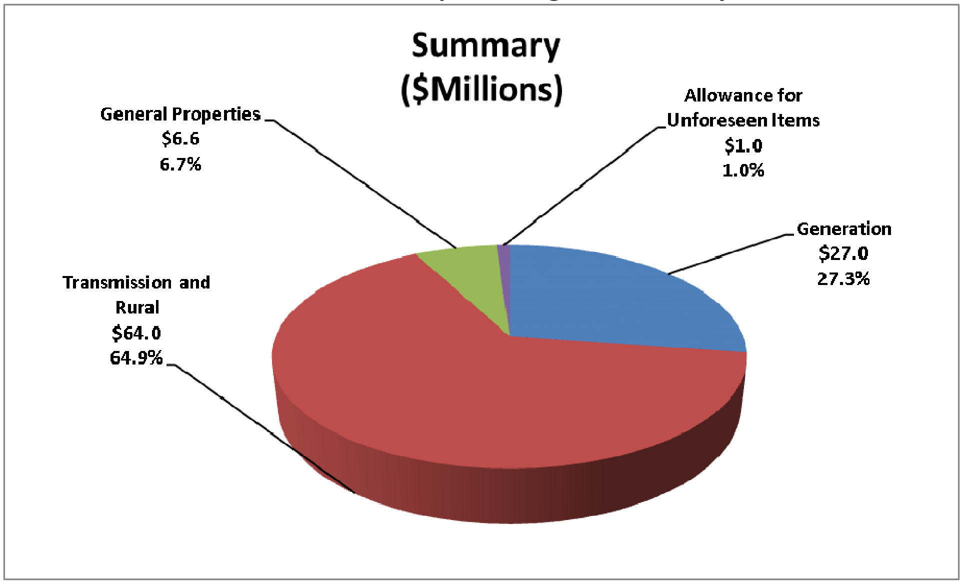
2014 CAPITAL BUDGET

This Application contains a capital plan in which the overriding consideration is least cost and reliable generation, transmission and distribution of electricity while maintaining and enhancing safety and environmental performance.

Hydro's 2014 capital budget contains 96 projects requiring expenditures totaling $98,668,500, addressing both the need to sustain the existing asset base and to grow the asset base in response to growing customer demand.

Chart 1 shows the 2014 Capital Budget by major classification. The classifications, other than the Allowance for Unforeseen Items, which represents 1 percent of the 2014 budget, are then discussed further.

Chart 1: 2014 Capital Budget – Summary



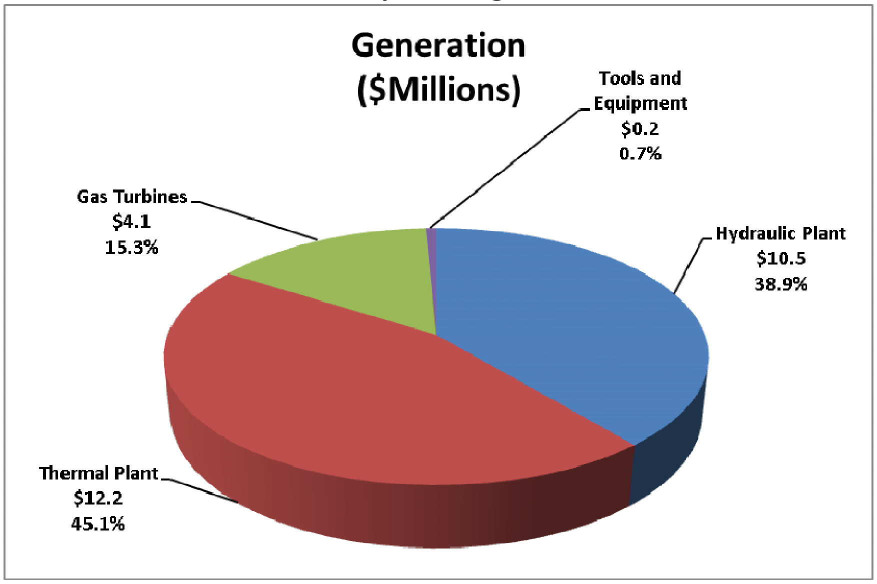
GENERATION

On the Island Interconnected System, power and energy are provided by Hydro through a mix of hydroelectric and fossil-fired generation, supplemented by power purchases. This production, along with the transmission system, is managed by the Energy Control Centre to ensure economic and reliable dispatch of available resources. At the end of 2012, Hydro's Island Interconnected production facilities consisted of 14 generating stations varying in size from 360 kW to 592 MW, with a total 1,507 MW of net capacity.

The Generation classification expenditures account for 27.3 percent of overall expenditures for 2014 and totals $27.0 million.

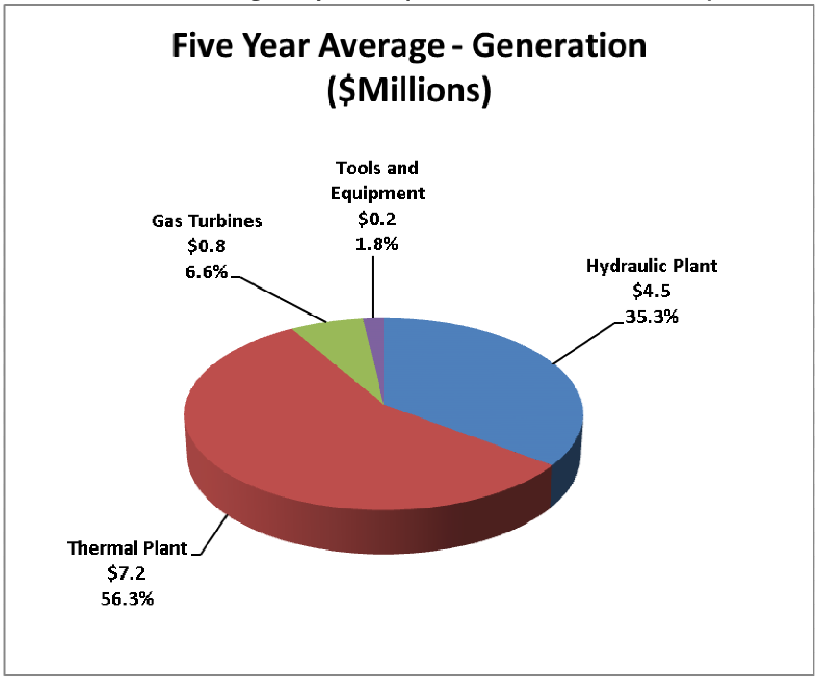
The division of the 2014 Capital Budget for Generation among Hydraulic Plant, Thermal Plant, Gas Turbines and Tools and Equipment expenditures is shown in Chart 2.

Chart 2: 2014 Capital Budget – Generation



The five-year (2008 to 2012) average capital expenditures are shown in Chart 3. For 2014, Thermal Plant represents 45.1 percent of the Island Interconnected generation capital budget, compared with an average of 56.3 percent over the past five years. Thermal plant continues to require major capital expenditures as the majority of the equipment and systems have reached the final phase of their life cycle and have undergone life extension in some cases. Significant expenditures are required to ensure that these important generating assets can continue to operate reliably until retired and replaced. Hydraulic Plant represents 38.9 percent of the 2014 capital budget for generation, compared with an average of 35.3% over the past five years. Expenditures for Gas Turbines and Tools and Equipment represent 15.3 and 0.7 percent of the total budgeted generation expenditures for 2014, compared with five year average expenditures of 6.6 percent and 1.8 percent respectively. The increase in gas turbine expenditures is primarily a result of the need to refurbish aging assets.

Chart 3: Five-Year Average Capital Expenditures - Generation (2008 - 2012)



Hydraulic Plant

Hydro's major hydraulic generating plants range from ten to 46 years of age. Capital expenditures are required to ensure reliability and to maximize the useful operating lives of these assets, many of the components of which have reached or are nearing the end of their expected service lives. This Application includes proposals for the rewind of the stator on Unit 3 and the refurbishment of Surge Tank 3 at Bay d'Espoir. Additional proposals are included for the upgrade of hydraulic structures, overhaul of generating units at Bay d'Espoir and Hind's Lake, and upgrade of plant auxiliary systems.

Thermal Plant

The three units of the Holyrood Thermal Generating Station have now reached or exceeded their generally expected service life of 30 years. Continued condition assessment and selective life extension will permit them to operate reliably until the 2020 -2021 timeframe. Holyrood remains critical to the reliable supply of power to the Island Interconnected System, as it serves the base load of the system and will be required to do so in the short to medium term. The long term operational plan for this facility has been developed in the context of the development of Muskrat Falls with a high voltage direct current transmission link to the Island. Holyrood will remain a critically important facility during construction and commissioning. Following completion of Muskrat Falls and the Labrador Island Transmission Link, the Holyrood plant will continue to be an essential component of the Provincial electrical grid. Initially, the plant will function as a fully capable standby facility during the early years of operation of the Muskrat Falls Generating Plant and the HVdc link between Labrador and Newfoundland, until the 2020-2021 timeframe. After this period thermal assets will be decommissioned and the facility will be partially converted to a synchronous condensing configuration.

The challenges faced by Hydro are complex because circumstances require that Holyrood must operate in a manner quite different than the norm for thermal plants. Conventional practice is that a thermal plant is base loaded throughout its life until it reaches maturity and is then operated as a peaking or standby facility in its final years, operating at a very low capacity factor, often less than 10 percent. The Holyrood thermal plant has passed the age at which other utilities have performed condition assessment and life extension studies, similar to Hydro's approach, and have either retired their facilities or have initiated major life extension projects. However, until the Muskrat Falls Generating Plant is completed and power is brought to the Island Interconnected System via an HVdc link, the Holyrood plant must continue to operate at or near its historical levels with annual capacity factor in the range of 35 to 45 percent and at higher levels through the winter period when availability is critical to meet peak demand. When the nickel processing plant being constructed at Long Harbour begins operation, demand on Holyrood will increase. This is in addition to general growth due to the favourable economy of the province which drives growth in the residential and commercial sectors. The Holyrood capital projects contained in this application are necessary to refurbish and renew assets which are at the end of their useful lives, and which must be replaced to maintain reliability through to the completion of the Muskrat Falls development. Additionally, proposals are included for continued plant component condition assessment, upgrade of plant auxiliary systems, overhaul of major equipment, and upgrade of plant monitoring and fire protection systems.

Also see the Holyrood Overview section for further discussion pertaining to the 2014 Holyrood projects.

Gas Turbines

Hydro's gas turbine plants at Stephenville and Hardwoods are more than thirty years old. The generally accepted life expectancy for gas turbine plants is between twenty-five and thirty years. A complicating factor in Hydro's case is that the manufacturer of the power turbines, one of the key components at the Stephenville and Hardwoods plants, is no longer in business, eliminating the availability of factory technical support and spare parts. Also, the gas generators (jet engines) utilized at the Stephenville and Hardwoods plants are no longer manufactured and the supply of spare parts and availability of technical support and repair facilities continues to diminish.

During 2007, Hydro engaged a consultant to perform a condition assessment of the Hardwoods and Stephenville gas turbines. Their findings and recommendations were used to prepare plans for refurbishment of these facilities to ensure that they continue to operate reliably and that their useful service lives can be extended as long as can be financially justified. The refurbishment of the Hardwoods Gas Turbine is now substantially complete and the refurbishment of the Stephenville Gas Turbine is planned, beginning in 2014. Hydro’s gas turbine facilities will continue to play an important role within Hydro’s integrated generation plan until their expected retirement in 2025 and 2028 for Hardwoods and Stephenville, respectively.

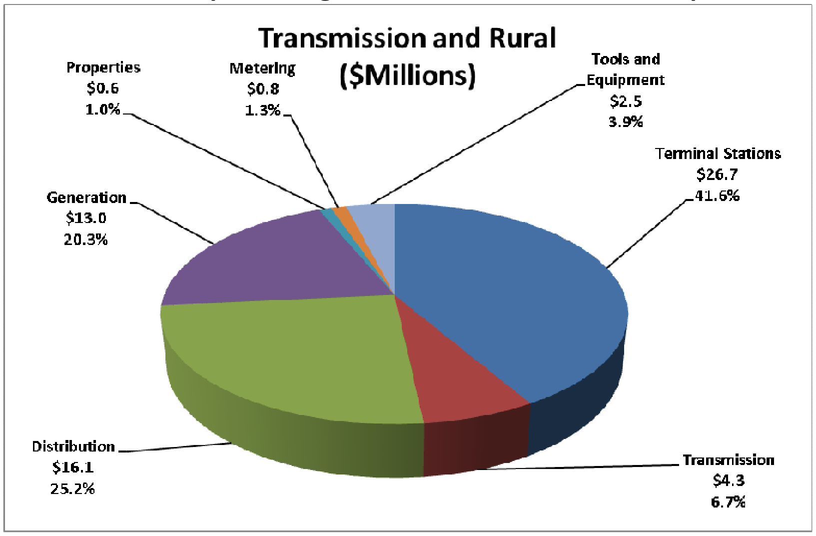
TRANSMISSION AND RURAL OPERATIONS

Hydro owns and operates diesel and gas turbine generation with 32.1 MW of net capacity on the Labrador Interconnected system; 14.7 MW of diesel generation on the Island Interconnected system; and diesel generation assets with 32.4 MW of net capacity in 21 isolated rural systems. On the Island Interconnected system, Hydro owns and operates 3,473 kilometers of transmission lines and more than 50 high voltage terminal stations operating at voltages of 230, 138 and 69/66 kV. On the Labrador Interconnected system, Hydro owns and operates 269 kilometers of 138 kV transmission line and the associated terminal stations interconnecting Happy Valley/Goose Bay to Churchill Falls. In addition, Hydro owns and operates approximately 3,397 kilometers of distribution lines, principally in rural Newfoundland and Labrador.

Hydro’s Transmission and Rural Operations assets are replaced based on age and condition, and require ongoing capital expenditures to maintain reliable service, to comply with environmental regulations, and to ensure the safety of employees, contractors, and the general public. As well, capital expenditures to provide service extensions are significant in many areas, particularly on the Labrador Interconnected system, the highest customer growth areas in Hydro’s distribution system.

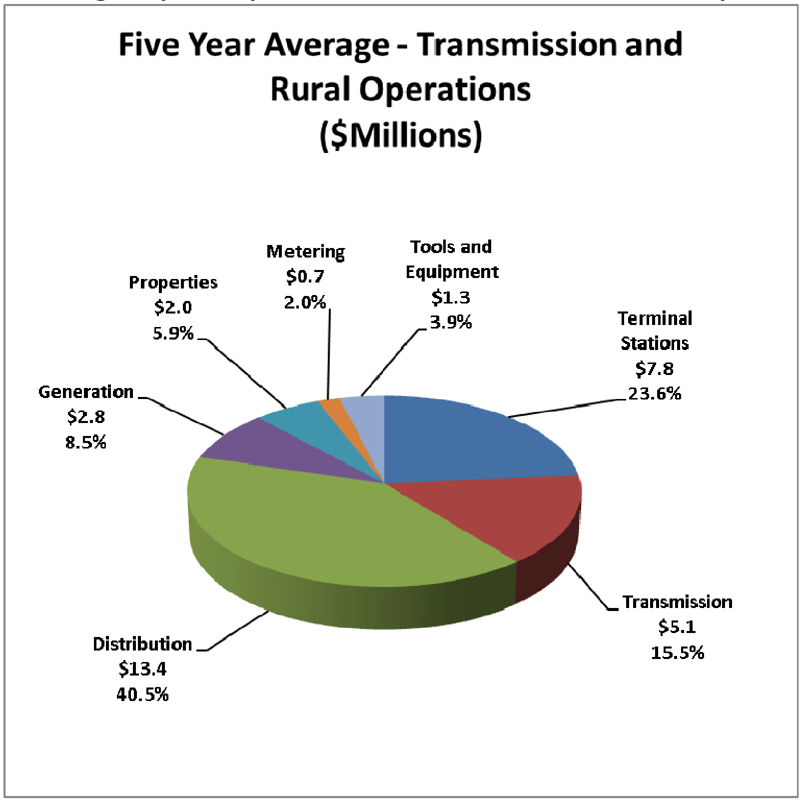
The Transmission and Rural Operations classification expenditures account for 64.9 percent of overall expenditures for 2014 and total $64 million.

Chart 4: 2014 Capital Budget - Transmission and Rural Operations



The division of the 2014 Capital Budget for Transmission and Rural Operations is shown in Chart 4. These expenditures are generally consistent with the five-year (2008 - 2012) average as shown in Chart 5, below. The addition of a transformer at Oxen Pond, begun in 2013, contributes to the increase in expenditure related to terminal stations in 2014 over the five year average expenditures. The increase in expenditure related to generation in 2014 over the five year average expenditures is mainly attributable to additions to isolated generation stations due to load growth.

Chart 5: Five-Year Average Capital Expenditures – Transmission and Rural Operations (2008 - 2012)



Terminal Stations and Transmission

Many of Hydro's transmission lines and terminal stations were constructed in the 1960s with expected useful lives in the 40 year range. Annual reconstruction and general upgrades are needed to ensure that Hydro can continue to provide customers with reliable electrical service. Within the 2014 submission, projects are proposed for the upgrade of power transformers and circuit breakers, as well as the replacement of insulators, surge arrestors, instrument transformers, disconnect switches, and breaker controls. Transmission line projects proposed include the continuation of the wood pole line management program, and the upgrade of tower foundations.

Distribution and Rural Generation

The 21 remote electrical systems along the coasts of Labrador and the Island are primarily served by diesel generation. Providing service to customers in these communities requires that the fuel storage, diesel generating units, facilities, and distribution systems all be kept in safe, reliable and environmentally responsible working order. This application includes projects specifically directed towards meeting load growth requirements, such as a substation upgrade in Hopedale. In addition, engine overhauls and replacements will be completed in various diesel plants.

Hydro also provides service to residential and general service customers on the Island and Labrador Interconnected Systems. Hydro has included projects in this application that are intended to ensure that distribution lines and equipment that require replacement due to age are replaced prior to failure, thereby reducing the probability of interrupting service to customers. These projects include the replacement of recloser control panels and upgrading of distribution systems. This Application also includes projects to provide service extensions to new customers throughout Hydro's service area.

GENERAL PROPERTIES

The General Properties classification expenditures account for 6.7 percent of overall expenditures for 2014 and total $6.6 million.

The General Properties classification includes projects related to Hydro's information systems, where technology is strategically deployed in a wide variety of business applications. This section of the Application also includes proposals for vehicle replacements and telecommunications system replacements which are all necessary for the provision of reliable and cost effective service to customers.

Charts 6 and 7 show the breakdown of the General Properties Capital Budget for 2014 and the previous five year average, respectively.

Chart 6: 2014 Capital Budget - General Properties

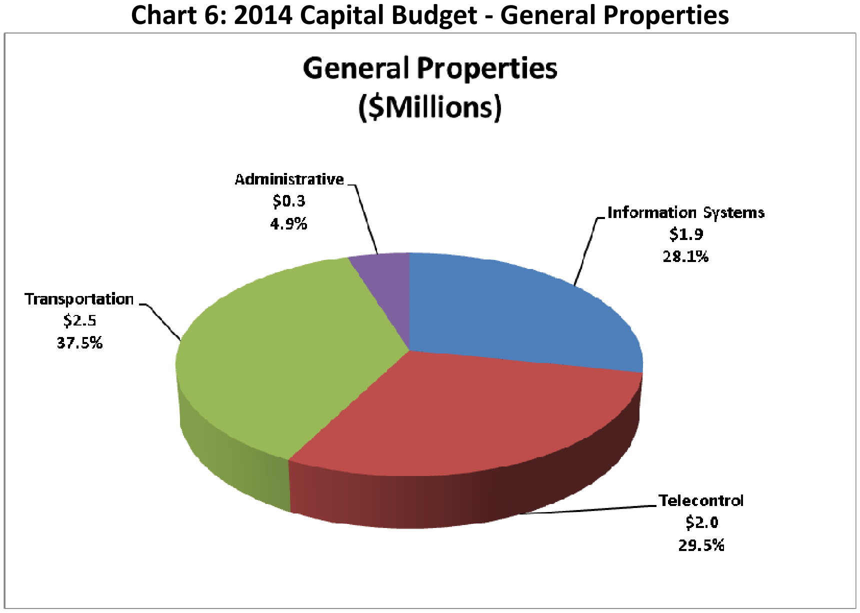
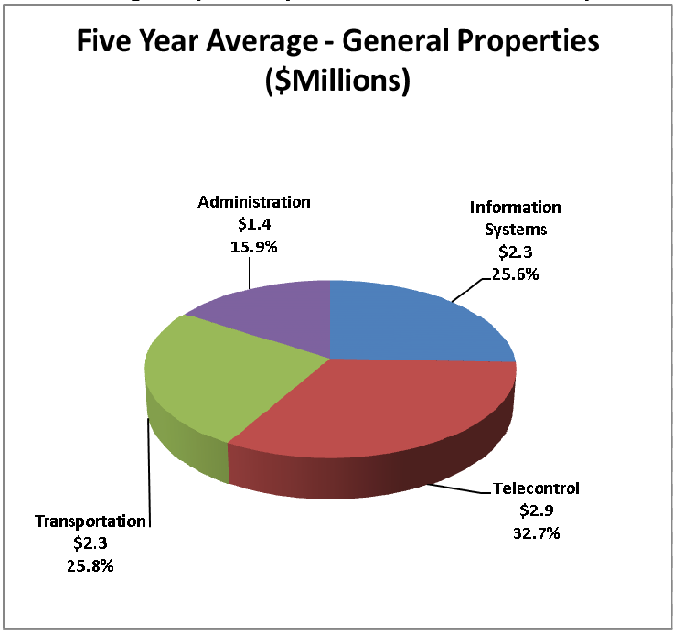


Chart 7: Five-Year Average Capital Expenditures - General Properties (2008 – 2012)



Information Systems

The Information Systems proposals are directed towards maintaining Hydro's computing capacity and associated infrastructure, ensuring that it remains current and reliable. Projects include upgrades to the software applications used throughout Hydro, as well as the replacement of personal computers and peripheral infrastructure.

Telecontrol

Operating an integrated electrical system requires reliable communication systems across Hydro's province-wide facilities both to control equipment and to support employee communications, many of whom work in remote locations. The 2014 capital budget proposals in this category include infrastructure replacements, ongoing replacement or refurbishment programs for such items as radomes, battery banks and chargers and network communications equipment.

General

Project Prioritization and Ranking

An overall ranking of 2014 projects is attached as Appendix A.

Phase 1 Engineering Costs

Hydro has advanced the Phase 1 engineering activities in 2013 to improve the quality of its 2014 capital budget submission. Hydro has tracked these Phase 1 engineering costs specific to each project and these costs form part of the 2014 capital budget submission. Therefore, Hydro's 2014 capital projects include Phase 1 engineering costs incurred in 2013 in association with those 2014 capital projects and Hydro proposes that the inclusion of those costs be approved.

Hydro has included Phase 1 costs in its capital budget proposals only in those cases in which the Phase 1 costs exceed $1,000 for that specific project. Phase 1 costs related to any specific project not receiving Board approval will not be capitalized. The total of these costs included in the 2014 capital budget submission is $253,600.

APPENDIX A

2014 Project Prioritization

PRIORITIZATION EXPLANATIONS

The following table shows the ranking of Hydro's 2014 capital projects. Rank 1 indicates the projects of the highest importance and in 2014, no projects with a ranking of more than 47 were included in the Application. The total of the projects included is determined based on balancing unit load, overall budget, and other logistical considerations. Projects that received the same score through the prioritization process have the same ranking. The nine projects which are Rank 1 are considered high priority projects required to address safety, mandatory or system load issues. Please note that the non-prioritized projects in the table are multi-year projects and necessary programs.

2014 Capital Budget and Five year Plan **2014 Project Prioritization** **Project Description**	**Cost ($000)**	**Rank**	**Cumulative Project Costs ($000)**
Multi-Year Projects (2014 is 2nd or 3rd year) (Non Prioritized)	39,137.9	*****	39,137.9
Service Extensions and Distribution Upgrades (Non Prioritized)	9,540.0	*****	48,677.9
Transportation (Non Prioritized)	4,390.2	*****	53,068.1
Tools and Equipment (Non Prioritized)	1,010.8	*****	54,078.9
Upgrade Public Safety Around Dams and Waterways – Bay d'Espoir	352.8	1	54,431.7
Upgrade Shoreline Protection – Cat Arm	55.3	1	54,487.0
Additions to Accommodate Load Growth - Hopedale	641.2	1	55,128.2
Install Fall Protection Equipment – Various Sites	199.2	1	55,327.4
Install Additional Washrooms – Various Sites	251.0	1	55,578.4
Remove Safety Hazards – Various Sites	257.8	1	55,836.2
Upgrade Waste Water Basin Building – Holyrood	136.7	1	55,972.9
Inspect Fuel Storage Tanks – Various Sites	495.0	1	56,467.9
Replace Continuous Opacity Monitors - Holyrood	49.3	1	56,517.2
Install Automated Meter Reading (2014-2015) – Various Sites	356.9	2	56,874.1
Rewind Stator Unit 3 – Bay d'Espoir	4,343.9	3	61,218.0
Replace Fall Arrest on Surge Tank 1 – Bay d'Espoir	142.8	4	61,360.8
Refurbish Surge Tank 3 – Bay d'Espoir	2,265.0	5	63,625.8
Complete Condition Assessment Phase 2 – Holyrood	1,476.8	6	65,102.6
Overhaul Diesel Engines – Various Sites	823.5	7	65,926.1
Overhaul Turbine/ Generator Units – Bay d'Espoir and Hinds Lake	485.0	7	66,411.1

2014 Capital Budget and Five year Plan **2014 Project Prioritization** **Project Description**	**Cost ($000)**	**Rank**	**Cumulative Project Costs ($000)**
Replace Generator Bearing Coolers Units 4 and 5 – Bay d'Espoir	199.0	7	66,610.1
Overhaul Turbine/Generator Unit 2 – Holyrood	5,147.0	7	71,757.1
Overhaul Cooling Water Pump East Unit 1 – Holyrood	98.4	7	71,855.5
Overhaul Extraction Pump South Unit 1 – Holyrood	96.8	7	71,952.3
Overhaul Boiler Feed Pump East Unit 3 – Holyrood	194.9	7	72,147.2
Replace Recloser Control Panels – Various Sites	111.3	8	72,258.5
Upgrade Power Transformers – Various Sites	1,904.4	9	74,162.9
Perform Wood Pole Line Management Program – Various Sites	2,564.2	10	76,727.1
Upgrade Circuit Breakers – Various Sites	3,695.4	11	80,422.5
Upgrade Distribution Systems – Various Sites (2014-2015)	2,499.8	12	82,922.3
Replace Surge Arrestors – Various Sites	181.9	14	83,104.2
Replace Disconnect Switches– Various Sites	815.9	15	83,920.1
Legal Survey of Primary Distribution Line Right of Way –Various Sites	156.8	16	84,076.9
Perform Minor Application Enhancements – Hydro Place	87.3	17	84,164.2
Upgrade Energy Management System- Hydro Place	187.9	17	84,352.1
Replace Personal Computers – Various Sites	489.8	17	84,841.9
Replace Peripheral Infrastructure – Various Sites	200.7	17	85,042.6
Upgrade Enterprise Storage Capacity – Hydro Place	326.2	17	85,368.8
Upgrade Server Technology Program – Hydro Place	286.0	17	85,654.8
Replace Radomes – Various Sites	324.9	18	85,979.7
Replace Network Communications Equipment – Various Sites	91.0	18	86,070.7
Replace Battery Banks and Charges – Various Sites	267.0	18	86,337.7
Upgrade Site Facilities – Various Sites	49.8	18	86,387.5
Replace Telephone System – Stephenville	139.9	18	86,527.4
Upgrade Underground Plant Drainage System - Holyrood	112.6	19	86,640.0
Upgrade Burnt Dam Spillway – Bay d'Espoir	110.2	20	86,750.2
Upgrade Victoria Control Structure – Bay d'Espoir	495.1	20	87,245.3
Upgrade IP SCADA Network – Various Sites	254.2	21	87,499.5
Replace Wescom Scanner – Corner Brook	81.7	21	87,581.2
Install Fire Protection Upgrades - Holyrood	56.6	21	87,637.8
Install Fire Protection - Nain	107.1	22	87,744.9
Upgrade Excitation Systems Units 1 and 2 - Holyrood	654.3	23	88,399.2
Upgrade Gas Turbine Plant Life Extension – Stephenville	2,995.0	24	91,394.2

2014 Capital Budget and Five year Plan **2014 Project Prioritization** **Project Description**	**Cost ($000)**	**Rank**	**Cumulative Project Costs ($000)**
Replace Optimho Relays on TL203 – Western Avalon to Sunnyside	89.1	25	91,483.3
Automate Generator Deluge Systems Units 3 and 6 – Bay d'Espoir	612.0	26	92,095.3
Raise Height of Earth Dam – Paradise River	98.7	27	92,194.0
Install Cold Reheat Condensate Drains and High Pressure Heater Trip Level Unit 3 – Holyrood	49.8	28	92,243.8
Replace DC Distribution Panels and Breakers - Holyrood	174.2	29	92,418.0
Refurbish Anchors and Footings TL202 and TL206 – Bay d'Espoir to Sunnyside	1,191.7	30	93,609.7
Upgrade Generator Bearings Unit 2 – Bay d'Espoir	18.9	31	93,628.6
Replace Automatic Greasing Systems Units 5 and 6 – Bay d'Espoir	233.4	31	93,862.0
Replace Economizer Inlet Valves - Holyrood	192.0	32	94,054.0
Upgrade Vibration Monitoring System - Holyrood	524.9	33	94,578.9
Install Automated Fuel Monitoring System at West Salmon Spillway – Bay d'Espoir	193.2	34	94,772.1
Upgrade Terminal Station Foundations – Various Sites	197.9	35	94,970.0
Upgrade North Cut-Off Dam Access Road – Bay d'Espoir	631.7	36	95,601.7
Replace Fuel Storage Tank – Ramea	234.2	37	95,835.9
Upgrade Spherical By Pass Valve Assemblies Units 1 and 2 – Bay d'Espoir	57.5	38	95,893.4
Upgrade Plant Elevators - Holyrood	533.2	39	96,426.6
Replace Engine on Emergency Lift System – West Salmon Spillway	67.1	40	96,493.7
Replace Turbine/Generator Cooling Water Flow Meters – Upper Salmon	139.7	41	96,633.4
Upgrade Ventilation System - Ramea	263.0	41	96,896.4
Replace Diesel Units – Port Hope Simpson and Mary's Harbour	208.9	42	97,105.3
Construct Storage Facility - Postville	183.8	43	97,289.1
Purchase Portable Vibration Testing Equipment – Various Sites	60.6	44	97,349.7
Upgrade Diesel Plant Production Data Collection Equipment – Various Sites	268.9	45	97,618.6
Install Hand Held Pendant to Overhead Crane – Bay d'Espoir	49.9	46	97,668.5

The table below presents the prioritization criteria and the assigned weights.

Criteria		Factors	Factor Weights
1	Work Classification (maximum weight = 85)	Normal Justifiable: Payback (70) Justifiable: Payback (40) Justifiable: Payback (10)	5 15 45 85
2	Net present Value (maximum weight = 85)	NPV ($0) NPV (<$100K) NPV (<$500K) NPV (<1M) NPV (>1M)	0 5 15 45 85
3	Goal 1: Safety (maximum weight = 100)	Minor Treatment Lost Time Disability	10 50 80 100
4	Goal 2: Environment (maximum weight = 100)	None Minor Moderate Significant	10 50 80 100
5	Goals 3-5: Alignment (maximum weight = 65)	None Maps but no documentation Maps but with documentation	15 40 65
6	Schedule Risk (maximum weight = 65)	External and internal conflicts Externals affecting completion No external but internal conflicts No conflicts	10 20 40 65
7	Continue service to customers (maximum weight = 70)	Can Can but with high costs Cannot	20 50 70
8	Number of customers impacted (maximum weight = 70)	<100 <1000 <10,000 >10,000	10 30 50 70
9	System Impact: Critical to … (maximum weight = 90)	None specific System with standby unit Plant or station Entire system	5 50 70 90
10	Impact intensity (maximum weight = 90)	Minor Moderate Significant High	4 40 70 90
11	Loss Type: Loss of …	No type	5

Criteria		Factors	Factor Weights
	(maximum weight = 90)	Equipment Facility Production Customer delivery	40 50 70 90
12	Loss mitigation (maximum weight = 90)	Redundant unit Backup option Nothing	30 60 90

A. <u>Level 1</u>

<u>Immediate HIGH Priority Projects</u>

- **Extreme Safety**

The project is required to prevent an incident that could cause a fatality or correct a condition that otherwise left unattended may lead to a fatality.

- **Mandatory**

A capital expenditure that Hydro is obliged to carry out as a result of Legislation, Board Order, Environmental or Safety risk.

- **Load Driven**

The project is needed to meet load requirements determined by Hydro's latest load forecasts. Without the project, Hydro's firm load and/or reliability criteria will be compromised.

B. <u>Level 2</u>

1. <u>Work Classification</u>

- **Normal**

A capital expenditure which is required based on an identified need or historical patterns of repair and replacement.

- **Justifiable**

A capital expenditure which is justified based on a positive cost savings for Hydro. A cost-benefit analysis is required for the project.

- **Payback (70)**

A cost-benefit analysis indicates that the payback period for the project is within 70 percent of the anticipated life of the project.

- **Payback (40)**

A cost-benefit analysis indicates that the payback period for the project is within 40 percent of the anticipated life of the project.

- **Payback (10)**

A cost-benefit analysis indicates that the payback period for the project is within 10 percent of the anticipated life of the project.

2. Net Present Value

- **NPV ($0)**

The capital proposal generates $0 cost savings to Hydro.

- **NPV (<$100K)**

A cost-benefit analysis indicates that the capital proposal generates a positive cost savings of less than $100K for Hydro.

- **NPV (<$500K)**

A cost-benefit analysis indicates that the capital proposal generates a positive cost savings of less than $500K for Hydro.

- **NPV (<$1M)**

A cost-benefit analysis indicates that the capital proposal generates a positive cost savings of less than $1M for Hydro.

- **NPV (>$1M)**

A cost-benefit analysis indicates that the capital proposal generates a positive cost savings of more than $1M for Hydro.

3. Goal 1: Safety

- **Minor**

The project has no or minor safety issues that are insignificant in impact.

- **Treatment**

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in the need for medical treatment.

- **Lost Time**

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in worker(s) incurring lost time for a short duration.

- **Disability**

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in worker(s) incurring long time leave due to inability to continue working on the job.

4. Goal 2: Environment

- **None**

The project has no environmental issues.

- **Minor**

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in an environmental impact that:
  - Is irreversible within 2 years; and/or
  - Will cost more than $10,000 to mitigate; and/or
  - Has aspects observed on Hydro's property (at point of impact); and/or
  - Is perceived as in conflict with specific individuals in the local community.

- **Moderate**

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in an environmental impact that:
  - Is irreversible within 4 years; and/or
  - Will cost more than $25,000 to mitigate; and/or
  - Has aspects observed within a 1 km radius of Hydro's property (from point of impact); and/or
  - Is perceived as in conflict with the local community or other industries.

- **Significant**

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in an environmental impact that:
  - Is irreversible within the foreseeable future; and/or
  - Will cost more than $50,000 to mitigate and/or
  - Has aspects observed at more than 5 km radius of Hydro's property (from point of impact); and/or
  - Is perceived as in conflict with the local community and the general public and other industries.

5. <u>Goals 3-5 Alignment</u>

- **None**

This project does not align with or support any department or corporate goals or objectives.

- **Maps but no Documentation**

This project does align with or support a department or corporate goal or objective but no documentation exists to describe how it maps to the goal or objective.

- **Maps but with Documentation**

This project does align with or support a department or corporate goal or objective and there is documentation that clearly describes how.

6. <u>Schedule Risk</u>

- **Externals and Internal Conflicts**

The project has external (to Hydro) dependencies that affect the completion of the project on time and on budget and has major interfaces with other internal initiatives. Examples of external dependencies are: non-Hydro projects that interfere with Hydro proceeding with its project; unavailability of external contractors.

- **Externals Affecting Completion**

The project has only external dependencies that affect the completion of the project on time and on budget.

- **NO Externals but Internal Conflicts**

The project conflicts with other internal initiatives that affect the completion of the project on time and on budget.

- **NO Conflicts**

The project will not encounter any external or internal conflicts that affect its completion.

7. <u>Continue Service to Customers</u>

- **Can**

Service to customers can continue whether or not this project proceeds. Customers can be defined as either internal or external to Hydro.

- **Can but with High Costs**

Service to customers can continue whether or not this project proceeds but a delay in the project will result in Hydro incurring costs. Customers can be defined as either internal or external to Hydro.

- **Cannot**

Service to customers cannot continue without this project. Customers can be defined as either internal or external to Hydro.

8. <u># Customers Impacted</u>

- **<100**

The project will impact up to 100 customers.

- **<1000**

The project will impact up to 1000 customers.

- **<10000**

The project will impact up to 10,000 customers.

- **>10000**

The project will impact more than 10,000 customers.

9. System Impact: Critical to.....

- **None Specific**

The project is not critical to any particular system.

- **System with Standby Unit**

The project is critical to a system that has a standby unit which could be used to maintain operation or support continued service in the event of failure.

- **Plant or Station**

The project is critical to the proper operation of a generating plant or a terminal station.

- **Entire System**

The project is critical to ensure the reliable operation of the Hydro system.

10. Impact Intensity

- **Minor**

If this project does not proceed, the repair time is ***less than half*** the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever comes first).

- **Moderate**

If this project does not proceed, the repair time is ***greater than the half but less than 90%*** of the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever is comes first).

- **Significant**

If this project does not proceed, the repair time is ***within plus or minus 10%*** of the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever is comes first).

- **High**

If this project does not proceed, the repair time ***exceeds by more than 10%*** the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever is comes first).

11. Loss Type: Loss of.....

- **No Type**

If the project does not proceed, no loss is expected.

- **Equipment**

If the project does not proceed, there exists a risk of the loss of some equipment.

- **Facility**

If the project does not proceed, there exists a risk of the loss of a facility.

- **Production**

If the project does not proceed, there exists a risk of the loss of production at a Hydro generating plant.

- **Customer Delivery**

If the project does not proceed, there exists a risk of being unable to deliver power to Hydro customer(s).

12. <u>Loss Mitigation</u>

- **Redundant Unit**

If the project does not proceed the expected loss will be mitigated by a redundant unit present on the system.

- **Back-up Option**

If the project does not proceed the expected loss will be mitigated by a back-up option which ensures that service continues.

- **Nothing**

This project is required because there is no available means to mitigate the expected loss.

<u>PROBABILITY</u>

- **Not Likely**

The risk of the impact is very low if the project does not proceed. It would be surprising that there is an impact.

- **Low Likelihood**

The risk of the impact is low if the project does not proceed. There is about 30 percent chance of the impact in the proposal year. It’s less likely to happen than not.

- **Likely**

The risk of the impact is possible if the project does not proceed. There is about 50 percent chance of the impact in the proposal year. It’s as likely to happen as not.

- **Highly Likely**

The risk of the impact is considerable if the project does not proceed. There is about 75 percent chance of the impact in the proposal year. It’s more likely to happen than not.

- **Near Certain**

The risk of the impact is almost certain if the project does not proceed. There is more than 90 percent chance of the impact in the proposal year. It would be surprising if the impact did not occur.

CONFIDENCE LEVEL

- **Low**

The confidence in the assessment of the impact is low. There are some uncertainties that could significantly change the assessment. The projects risks are not well defined.

- **Medium**

The confidence in the assessment of the impact is uncertain but most likely correct. There are some uncertainties that might moderately change the assessment. The project risks are defined but with some uncertainty.

- **High**

The confidence in the assessment of the impact is very high. The uncertainties won't measurably change the assessment. The project risks are well defined and well controlled.

A Report to the

Board of Commissioners of Public Utilities

2014 Capital Plan

Table of Contents

Introduction

In Board Order No. P.U. 30 (2007), Hydro was directed to file a five-year capital expenditure plan. The Board indicated the plan should focus on strategic spending priorities beginning with the current year of the Application. As well, the capital expenditure plan should identify shifts in spending priorities over the five-year period, the circumstances contributing to these shifts, and alternative approaches under consideration. Additionally, the Board requested a separate section concerning Holyrood, including the impacts of the Provincial Energy Plan, an impact statement concerning alternative development scenarios reflecting how decisions associated with each scenario might influence the physical plant, the environmental, operational and management imperatives, as well as forecast maintenance and capital requirements for the ensuing five years. Each individual project at the Holyrood plant contained in the annual capital budget submission could then be reconciled, justified and costed in respect of one or more development scenarios. Hydro developed and filed a five-year plan with the 2010 Capital Budget Application.

Hydro has a responsibility to provide safe, reliable, and least-cost service to meet the needs of its customers. Providing a reliable supply of electrical energy depends on maintaining assets in sound condition. Utility assets are kept in reliable working condition by routine maintenance and replacement when necessary. Asset additions are also determined through analysis of long term requirements to address future demands for power and energy.

The 1960s saw a vast expansion in assets to fulfill the mandate of the Newfoundland and Labrador Power Commission, Hydro’s predecessor, which was to electrify the province. Many of the assets constructed at that time, have reached or exceeded their expected service lives and many others are approaching that juncture. Other major assets have not reached their expected service lives but some of their components, auxiliary equipment and systems have, or are about to do so. This includes components of major facilities such as the Bay d’Espoir Generating Station, the Holyrood Thermal Generating Station, the Hardwoods and Stephenville gas turbines, the Holyrood gas turbine and much of Hydro’s transmission and distribution systems. Hydro has a responsibility to maintain this infrastructure to a level that continues to allow Newfoundlanders and Labradorians to live in a modern society, dependent on a safe, reliable and least cost supply of electricity for home and business use.

Five-Year Plan

Hydro's five year capital plan over the 2014 to 2018 period anticipates average annual capital expenditures of $162 million. Over the period 2008 to 2012, the average annual capital expenditure was $59.3 million. The increase in overall capital expenditure reflects inflation, the requirement for specific projects related to replacement and upgrade of deteriorating facilities, ensuring compliance with legislation, and most particularly additions required to meet load growth.

Hydro plans to invest $810 million in plant and equipment over the 2014 to 2018 period. Average annual expenditures are expected to be in the order of $162 million, ranging from a low of $140 million in 2018 to a high of $209 million in 2015.

Expenditures for new generation and transmission assets are included in these estimates, specifically for the upgrade of the transmission line corridor between Bay d'Espoir and Western Avalon and the addition of a new combustion turbine at Holyrood. These projects will be the subject of a separate filing.

Hydro's five-year plan is a living document and will be revised on an ongoing basis as new information about the condition of assets becomes available, as asset management strategies evolve, and as demands and priorities change within asset classes. During 2011, Hydro devoted significant effort to developing and refining the five year plans for the various asset classes. A key finding of this work is the general increase in sustaining capital required to continue to provide safe, reliable, least cost power to Hydro's customers. Furthermore, the work highlighted additional capital expenditures that will be required to address load growth.

Strategic Spending Priorities

Hydro's strategic spending priorities over the next five years are:

1. Mandatory Issues:
    - Ensuring the safety of Hydro personnel, its contractors, and the general public;
    - Compliance with legislative and regulatory requirements; and
    - Dealing with environmental risks.
2. Meeting projected load growth and customer requests;
3. Achieving cost efficiencies;
4. Asset Maintenance Philosophy
    - Maintaining reliability by addressing issues identified by:
        - ➢ Operating experience
        - ➢ Maintenance history
        - ➢ Condition assessments
        - ➢ Performance assessments
        - ➢ Familiarity with equipment
        - ➢ Operating and maintenance cost
        - ➢ Professional judgment
        - ➢ Asset Maintenance Strategy
        - ➢ Discussion between Regulated Operations and Technical Services
    - Reliability improvement

Hydro's detailed five year plan is presented in Appendix A.

The five year plan indicates an increasing trend in expenditures which has a number of key drivers:

- Age and condition of current infrastructure and assets;
- Continued load growth on the Avalon Peninsula; and
- Increasing cost of labour, materials, and contract work in the local market.

Generation

The requirement to invest sustaining capital in generation facilities began increasing several years ago as parts of Hydro's generating plants reached or surpassed their normally expected service lives. As each year passes, more assets reach this point in their operating lives, requiring increased expenditures to maintain reliability and to ensure that the maximum economic life is extracted from each asset. Primary drivers for these projects are the realization of end of service lives for equipment, reductions in reliability or performance, the availability of more efficient technology, and considerations for safety.

Hydraulic

Ensuring reliability is the primary priority for Hydro's five-year capital plan. In recent years, Hydro has detected deterioration in the condition of the stator windings of Units 1 through 4 in the Bay d'Espoir Generating Station. These four units, the oldest of the seven installed at Bay d'Espoir, were equipped with asphalt insulated windings, the standard insulation system of that time. These windings have deteriorated and begun to show signs of imminent failure. To address this issue, Hydro has completed stator rewinds on Units 1, 2 and 4. The rewind of the remaining unit, Unit 3, is included in the plan in 2014. The condition of auxiliary systems and equipment is as great a concern, as their failure could also remove a unit or plant from service. To address this concern, the 2014 Capital Plan includes projects to upgrade hydraulic structures and refurbish surge tanks.

Thermal

On December 17, 2012, the Government of Newfoundland and Labrador announced official sanction of the Muskrat Falls development. The Muskrat Falls in-feed, or the Labrador Island Link (LIL), is expected to be in service in 2017. Holyrood will be required for prime power production throughout the interim period (i.e., to the in-service date of the LIL) and it is intended that the facility remain fully available for generation in stand-by mode until the 2020–2021 timeframe. Unit 3 will operate primarily in synchronous condenser mode beginning in 2017, with the option to return to full generating mode. Post the 2020-2021 timeframe, Units 1 and 2 and the steam components of Unit 3 at Holyrood will be decommissioned, and Unit 3 will continue to operate in synchronous condenser mode only with no generation capability.

The Holyrood Generating Station Units 1 and 2 are now 44 years old while Unit 3 is 34 years old. The generally accepted life expectancy for thermal plants is 30 years. The Holyrood plant remains critical to the reliable power supply on the Island Interconnected system. The capital upgrades contained in this plan are necessary to replace assets which are at the end of their useful lives, and those which must be replaced to maintain reliability.

Also see the Holyrood Overview section for further discussion pertaining to the five year plan for Holyrood.

Gas Turbines

Maintaining the reliability of Hydro’s existing gas turbine assets, which are relied upon to provide emergency and peaking power and function as synchronous condensers to help control voltage on the Island and Labrador Interconnected Systems, is a priority. These facilities accumulate few operating hours generating electricity but are crucial sources of power and energy during emergencies and system peaks and provide voltage support, especially when operating as synchronous condensers. These plants, especially the 50 MW plants at Hardwoods and Stephenville, required relatively little capital expenditure until recent years. Despite their low operating hours, these units are beyond their normal life expectancy and are deteriorating, requiring an increase in capital expenditures to extend their reliable economic service lives to the greatest extent possible. A multiyear life extension project for the

Hardwoods plant was begun in 2010 and a similar project is planned for Stephenville, beginning in 2014. Hydro's newest gas turbine plant located at Happy Valley was constructed in 1992. This plant has required only minor upgrades since that time. Projects are planned in 2015 and 2018 to install a diesel automation and charger system and refurbish the generator and exciter winding, respectively.

A major project to add a nominal 60 MW gas turbine at Holyrood is required to meet the generation planning criteria between 2015 and completion of the Labrador Island Link.

Terminal Stations

Increasing load and maintaining reliability are the principal drivers for terminal station expenditures over the next five years.

Aging equipment is a major concern and is considered when reviewing short and long term plans. The five-year plan contains expenditures in the form of several programs to replace instrument transformers, surge arrestors, insulators, circuit breakers and disconnect switches among others. The plan also contains station specific projects such as upgrading the station service at Sunnyside Terminal Station and the expansion of the terminal station at Hawke's Bay. Hydro will, to the greatest extent possible, consolidate equipment replacements into multi year programs to ease the administrative effort for both the Board and Hydro.

Transmission

Reliability maintenance is the primary driver for transmission investment. The wood pole line management program forms the backbone of Hydro's asset management strategy for these facilities. This strategy has been in place for ten years and its effectiveness and value has been tested and demonstrated, enabling Hydro to realize the maximum useful life from these transmission systems. The program is based on periodic assessment of the wooden transmission poles and facilitates their replacement before failure, while extracting the maximum possible reliable life from each pole. During the next five years Hydro plans to upgrade various transmission lines along with other transmission line projects such as the refurbishment of footings and anchors on TL202 and TL206 from Bay d'Espoir to

Sunnyside. A major project to upgrade the transmission line corridor between Bay d'Espoir and Western Avalon is required to facilitate additional power and energy delivery to the East Coast growth area and meet transmission planning criteria. Safety of Hydro personnel, contractors, and the public is also a priority in the five-year plan for Transmission.

Distribution

New customer additions and reliability maintenance are the strategic areas addressed by the five-year capital plan for distribution assets. This equipment is subject to the same aging and wear as the generation and transmission assets and must be replaced periodically to ensure reliable service. The major portion of expenditures over the next five years is related to load growth in Labrador South. The majority of other distribution system expenditures for the next five years will consist of service extensions and upgrades to distribution systems, distribution pole replacement, and substation upgrading, all to maintain or improve system performance.

Rural Generation

The replacement of aging infrastructure is required to ensure reliability for Hydro's twenty-one isolated electrical systems which are supplied with electricity by diesel generating sets. Hydro's diesel generating sets have the shortest lives of all its generating assets, requiring replacement after approximately 100,000 hours of operation. Chart 1, provides the age distribution of the diesel engines in Hydro's rural generating plants. During the next five years Hydro plans to replace or add generating sets in various isolated diesel plants. These replacements and additions are required to ensure that reliable service is provided to Hydro's isolated rural customers. Many of Hydro's diesel plants have deteriorated to a great extent and will require renovation or replacement in the near to medium term. To prioritize this process, Hydro conducted a review of the condition of the older plants to assist in planning the replacement or modification in a logical sequence. Projects for the replacement and upgrade of diesel plant infrastructure and auxiliary systems are included over the coming five years.

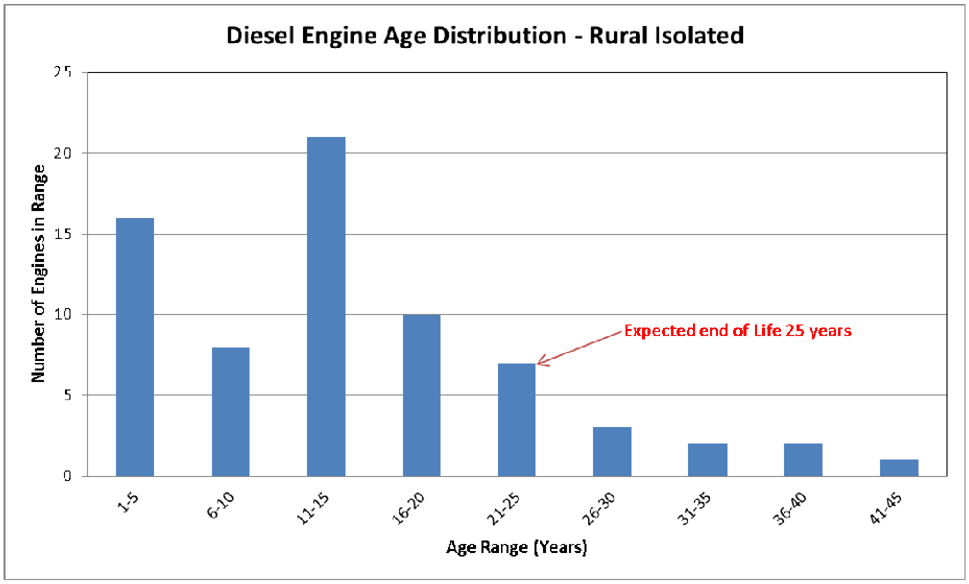


Chart 1: Diesel Engine Age Distribution – Rural Isolated System

Information Systems

Obsolete technology and aging hardware are the strategic drivers which most significantly contribute to the five-year plan for information systems. Hydro's information systems provide the data required to effectively manage and control the activities of the business. Expenditures on these systems and personal computers will average $2.2 million annually during the next five years.

Telecontrol

Obsolete technology and aging hardware are also the strategic reasons which most significantly contribute to the five-year plan for telecontrol assets. Hydro's communications network is vital to the operation and control of the power systems. Communications must be reliable and rapid to protect and control the generation, transmission and distribution equipment. It is expected that capital expenditures will average approximately $3.5 million annually for the next five years. The most significant of these projects will be the refurbishment of microwave sites, the replacement of obsolete radio equipment, power line carriers, mobile radio system and PBX phone systems.

Transportation

Hydro's vehicles and mobile equipment must continue to be both safe and reliable. Hydro operates a diversified and dispersed fleet of mobile equipment throughout the Province that is required to operate and maintain our facilities in a challenging and sometimes harsh physical environment. Hydro selects, operates and maintains this equipment in a manner designed to achieve the least life cycle cost and replacements are scheduled in accordance with criteria submitted to the Board on previous occasions. Hydro anticipates that expenditures on mobile equipment will average approximately $2.6 million annually over the next five years.

Administration

Safety, cost efficiencies, reliability and security are the primary drivers of the five-year administration capital plan. Hydro expects to spend an average of $1.0 million annually on items such as office equipment, building auxiliary systems, and building infrastructure, during the next five years.

APPENDIX A

Five-Year Capital Plan

	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
GENERATION	8,082.9	73,388.2	72,320.5	23,711.3	14,411.2	13,173.2	205,087.3
TRANSMISSION AND RURAL OPERATIONS	11,515.7	70,418.1	126,841.1	128,338.1	117,049.9	118,686.6	572,849.5
GENERAL PROPERTIES	2,261.6	6,643.0	8,846.6	11,151.5	12,093.4	7,581.4	48,577.5
CONTINGENCY FUND		1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	5,000.0
TOTAL CAPITAL BUDGET	**21,860.2**	**151,449.3**	**209,008.2**	**164,200.9**	**144,554.5**	**140,441.2**	**831,514.3**

***The Following Budget Proposals have not been included as part of this application since they will be filed separately later this year. However, they have been added to this Five-Year Plan as well as Section H.**

	Expended to 2013	2014	2015	2016	2017	2018	Total
Add Nominal 60 MW Gas Turbine - Holyrood	7,323.9	46,410.0	45,710.7				99,444.6
Install 230 KV Transmission Line - Bay d'Espoir to Western Avalon		6,370.8	74,626.5	62,602.1	60,758.6	63,642.0	268,000.0

	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
GENERATION							
Hydraulic Plant	0.0	10,501.3	16,167.7	5,979.9	8,892.1	8,911.5	50,452.5
Thermal Plant	697.6	12,157.2	7,351.8	15,163.3	5,497.6	3,500.0	44,367.5
Gas Turbines	7,385.3	50,533.6	48,580.2	2,546.9	0.0	750.0	109,796.0
Tools and Equipment	0.0	196.1	220.8	21.2	21.5	11.7	471.3
TOTAL GENERATION	8,082.9	73,388.2	72,320.5	23,711.3	14,411.2	13,173.2	205,087.3
TRANSMISSION AND RURAL OPERATIONS							
Terminal Stations	5,933.6	26,652.0	11,843.5	16,160.9	13,885.3	16,435.4	90,910.7
Transmission	350.1	10,656.7	78,996.8	72,209.7	76,381.8	78,747.1	317,342.2
Distribution	1,940.1	16,146.6	21,687.9	22,527.9	14,088.8	13,988.0	90,379.3
Generation	2,431.2	12,985.3	12,127.4	14,541.3	9,384.7	8,242.0	59,711.9
Properties	156.2	647.0	936.0	1,259.7	2,527.7	574.5	6,101.1
Metering	287.7	814.7	539.5	197.6	198.6	199.4	2,237.5
Tools and Equipment	416.8	2,515.8	710.0	1,441.0	583.0	500.2	6,166.8
TOTAL TRANSMISSION AND RURAL OPERATIONS	11,515.7	70,418.1	126,841.1	128,338.1	117,049.9	118,686.6	572,849.5
GENERAL PROPERTIES							
Information Systems	420.3	1,869.2	2,951.9	1,701.8	2,853.5	1,507.0	11,303.7
Telecontrol	539.0	1,961.8	2,045.1	4,934.2	5,740.3	2,816.9	18,037.3
Transportation	1,302.3	2,488.3	3,016.5	2,497.4	2,114.0	2,700.8	14,119.3
Administrative	0.0	323.7	833.1	2,018.1	1,385.6	556.7	5,117.2
TOTAL GENERAL PROPERTIES	2,261.6	6,643.0	8,846.6	11,151.5	12,093.4	7,581.4	48,577.5
CONTINGENCY FUND		1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	5,000.0
TOTAL CAPITAL BUDGET	21,860.2	151,449.3	209,008.2	164,200.9	144,554.5	140,441.2	831,514.3

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
HYDRAULIC PLANT							
Refurbish Surge Tanks - Bay d'Espoir		2,265.0	1,141.4	1,150.8	734.7		5,291.9
Rewind Stator Unit 3 - Bay d'Espoir		4,343.9					4,343.9
Overhaul Turbine/Generator Units - Various Sites		485.0	508.5	319.0	365.0	400.0	2,077.5
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir		352.8	361.7	370.1	378.0	385.6	1,848.2
Upgrade Victoria Control Structure - Bay d'Espoir		495.1	969.5				1,464.6
Automate Generator Deluge Systems Units 3 and 6 - Bay d'Espoir		612.0	751.3				1,363.3
Upgrade Burnt Dam Spillway - Bay d'Espoir		110.2	1,201.9				1,312.1
Install Automated Fuel Monitoring System - Various Sites		193.2			267.4	500.0	960.6
Upgrade Generator Bearings - Bay d'Espoir		18.9	396.0		190.0	200.0	804.9
Upgrade Shoreline Protection - Cat Arm		55.3	708.1				763.4
Upgrade North Cut-Off Dam Access Road - Bay d'Espoir		631.7					631.7
Replace Generator Bearing Coolers Units 4 and 5 - Bay d'Espoir		199.0	189.6	193.8			582.4
Replace Automatic Greasing Systems - Bay d'Espoir		233.4	196.7				430.1
Replace Spherical By Pass Valve Assemblies Units 1 and 2 - Bay d'Espoir		57.5	96.3				153.8
Replace Fall Arrest on Surge Tank 1 - Bay d'Espoir		142.8					142.8
Replace Turbine/Generator Cooling Water Flow Meters - Upper Salmon		139.7					139.7
Raise Height of Earth Dam - Paradise River		98.7					98.7
Replace Engine on Emergency Lift System - West Salmon Spillway		67.1					67.1
Replace Penstock and Auxiliaries - Venam's Bight			4,712.9				4,712.9
Refurbish Site Facilities - Bay d'Espoir			780.2	912.7			1,692.9
Refurbish Access Road(Topping and Culverts and Bin Wall) - Cat Arm			1,505.6				1,505.6
Refurbish Generation Unit - Snooks Arm			375.4	850.9			1,226.3
Install Hydrometeorological Stations - Various Sites			378.3	321.2			699.5
Replace ABB Exciter Unit 2 - Cat Arm			600.0				600.0
Replace Station Service Breakers - Cat Arm			500.0				500.0
Replace Site Pumphouse, Pumps and Controls - Bay d'Espoir			268.4				268.4
Replace Slip Ring Assembly - Hinds Lake			252.8				252.8
Install Infrared Viewports - Various Sites			108.8		112.9		221.7
Refurbish Unit Relay Protection - Paradise River			164.3				164.3
Replace Rectifier Transformer Unit 1 - Bay d'Espoir				75.0	740.5	433.9	1,249.4
Pilot Asset Health Monitoring Template - Upper Salmon				598.7	194.4	103.8	896.9
Install New Vent Chambers Units 1 to 6 - Bay d'Espoir				75.0	572.4		647.4
Refurbish Generation Unit - Venam's Bight				463.5			463.5
Refurbish Station Service Water Systems - Upper Salmon				344.0			344.0
Purchase Generator Bearing Cooler Sets - Various Sites				239.4			239.4
Purchase Turbine Bearing Cooler Set - Cat Arm				65.8			65.8
Replace Spherical Valve Control System - Cat Arm					883.0		883.0

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
HYDRAULIC PLANT (cont'd.)							
Replace Diesel Generator 2 at Victoria Control Structure - Bay d'Espoir					638.1		638.1
Refurbish Road Between Powerhouse and NS Spillway - Upper Salmon					556.5		556.5
Refurbish Salmon River Spillway - Bay d'Espoir					469.5		469.5
Refurbish EBBE Control Structure - Bay d'Espoir					456.5		456.5
Upgrade Powerhouse 1 and 2 Station Service - Bay d'Espoir					429.8		429.8
Replace 6 Slip Rings Unit 1 to 6 - Bay d'Espoir					341.3		341.3
Replace Main Generator Bearing - Upper Salmon					300.0		300.0
Upgrade Domestic Water System - Cat Arm					242.6		242.6
Replace Road Culverts - Granite Canal					220.3		220.3
Install Partial Discharge Monitors - Paradise River					197.0		197.0
Upgrade Sump Level System Powerhouse 2 - Bayd'Espoir					185.0		185.0
Replace Shaft Seal System - Upper Salmon					150.0		150.0
Replace Plant HP Compressor 1 - Upper Salmon					142.7		142.7
Install Permanent Monitoring Vibration System unit 7 - Bay d'Espoir					124.5		124.5
Refurbish Generator Rotor - Hinds Lake						1,701.5	1,701.5
Install Dynamic Air Gap Monitoring System - Upper Salmon and Hinds Lake						1,160.0	1,160.0
Resurface All On Site Roads - Bay d'Espoir						800.0	800.0
Make Improvements to Powerhouse 1 Ventilation - Bay d'Espoir						739.5	739.5
Replace Main Roof on Powerhouse 1 - Bay d'Espoir						534.3	534.3
Refurbish Relay Protection Units 5 to 7 - Bay d'Espoir						434.4	434.4
Replace Dry Air Compressor 1 and 2 Powerhouse 1 - Bay d'Espoir						320.6	320.6
Replace Sump Pumps 1 and 2 in Powerhouse 1 - Bay d'Espoir						317.9	317.9
Replace Underground Oily Water Separator - Bay d'Espoir						300.0	300.0
Replace Firewater Pumps - Upper Salmon						280.0	280.0
Replace Cooling Water Pumps Unit 7 - Bay d'Espoir						150.0	150.0
Install New Septic System - Snooks Arm						150.0	150.0
TOTAL HYDRAULIC PLANT		10,501.3	16,167.7	5,979.9	8,892.1	8,911.5	50,452.5

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
THERMAL PLANT							
Overhaul Steam Turbine/Generator Unit 2 - Holyrood		5,147.0					5,147.0
Install Variable Speed Drives on 6 Forced Draft Fans - Holyrood	697.6	2,659.7					3,357.3
Complete Condition Assessment Phase 2 - Holyrood		1,476.8					1,476.8
Upgrade Underground Plant Drainage System - Holyrood		112.6	1,342.9				1,455.5
Upgrade Waste Water Basin Building - Holyrood		136.7	981.0				1,117.7
Upgrade Excitation Systems Units 1 and 2 - Holyrood		654.3	456.6				1,110.9
Install Fire Protection Upgrades - Holyrood		56.6	312.5			250.0	619.1
Upgrade Plant Elevators - Holyrood		533.2					533.2
Upgrade Vibration Monitoring System - Holyrood		524.9					524.9
Replace Economizer Inlet Valves - Holyrood		192.0	329.1				521.1
Install Cold-Reheat Condensate Drains and High Pressure Heater Trip Level Unit 3 - Holyrood		49.8	467.4				517.2
Overhaul Boiler Feed Pump East Unit 3 - Holyrood		194.9					194.9
Replace DC Distribution Panels and Breakers - Holyrood		174.2					174.2
Overhaul Cooling Water Pump East Unit 1 - Holyrood		98.4					98.4
Overhaul Extraction Pump South Unit 1 - Holyrood		96.8					96.8
Upgrade Continuous Opacity Monitors - Holyrood		49.3					49.3
Overhaul Turbine Valves Unit 1 - Holyrood			1,218.0				1,218.0
Upgrade Powerhouse Roofing - Holyrood			456.1	385.6	373.6		1,215.3
Replace Powerhouse Overhead Doors - Holyrood			330.1	347.3			677.4
Upgrade Quarry Brook Dam Equipment - Holyrood			395.1				395.1
Upgrade Fire Protection(Outbuildings)- Holyrood			314.0				314.0
Replace Compressor #2 - Holyrood			288.1				288.1
Overhaul Boiler Feed Pump East Unit 1 - Holyrood			182.6				182.6
Replace DC Distribution Panels and Breakers - Holyrood			103.3				103.3
Overhaul Extraction Pump North Unit 1 - Holyrood			87.5				87.5
Overhaul Extraction Pump South Unit 3 - Holyrood			87.5				87.5
Rewind Generator Rotor and Install Rotor Flux Probe Unit 3 - Holyrood				8,402.4			8,402.4
Overhaul Steam Turbine/Generator Unit 3 - Holyrood				4,810.1			4,810.1
Upgrade Cranes and Hoists - Holyrood				600.0			600.0
Upgrade UPS 1 and 2 - Holyrood				254.1			254.1
Overhaul Boiler Feed Pump West Unit 1 - Holyrood				186.0			186.0

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
THERMAL PLANT (cont'd.)							
Overhaul Cooling Water Pump East Unit 2 - Holyrood				88.9			88.9
Overhaul Extraction Pump North Unit 2 - Holyrood				88.9			88.9
Replace Unit Switchgear and Transformers - Holyrood- Holyrood					1,705.9		1,705.9
Overhaul Turbine Valves Init 2 - Holyrood					1,456.2		1,456.2
Upgrade Plant Access Road - Holyrood					807.8		807.8
Replace Stage 2 Diesel - Holyrood					443.2		443.2
Upgrade UPS 3 and 4 - Holyrood					266.7		266.7
Overhaul Boiler Feed Pump Unit 2 - Holyrood					188.1		188.1
Overhaul Cooling Water Pump Unit 3 - Holyrood					89.9		89.9
Overhaul Extraction Pump Unit 3 - Holyrood					89.9		89.9
Install Visible Isolation for 600 V HVAC System Admin Area - Holyrood					76.3		76.3
Install New Raw Water Line - Holyrood						2,000.0	2,000.0
Install New Lube Oil / Seal Oil Systems - Holyrood						1,000.0	1,000.0
Revisit Condition Assessment Level 1 - Holyrood						250.0	250.0
TOTAL THERMAL PLANT	697.6	12,157.2	7,351.8	15,163.3	5,497.6	3,500.0	44,367.5

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
GAS TURBINES							
Add Nominal 60 MW Gas Turbine - Holyrood	7,323.9	46,410.0	45,710.7				99,444.6
Upgrade Gas Turbine Controls - Happy Valley	61.4	1,128.6					1,190.0
Upgrade Gas Turbine Plant Life Extension - Stephenville		2,995.0	2,660.6	2,546.9			8,202.5
Install Diesel Automation and Charger System - Happy Valley			208.9				208.9
Refurbish Generator and Exciter Winding - Happy Valley						750.0	750.0
TOTAL GAS TURBINE PLANTS	7,385.3	50,533.6	48,580.2	2,546.9	0.0	750.0	109,796.0
TOOLS AND EQUIPMENT							
Purchase Tools and Equipment Less than $50,000		146.2	50.0	21.2	21.5	11.7	250.6
Install Handheld Pendant to Overhead Crane - Bay d'Espoir		49.9	170.8				220.7
TOTAL TOOLS AND EQUIPMENT		196.1	220.8	21.2	21.5	11.7	471.3
TOTAL GENERATION	8,082.9	73,388.2	72,320.5	23,711.3	14,411.2	13,173.2	205,087.3

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
TERMINAL STATIONS							
Install New Transformer - Oxen Pond	3,823.6	15,310.4					19,134.0
Replace Instrument Transformers - Various Sites	593.2	552.8	538.4	1,511.7	471.9		3,668.0
Replace Compressed Air Systems - Various Sites	303.0	2,105.9			200.0	500.0	3,108.9
Upgrade Terminal Station - Wiltondale	697.7	1,173.3					1,871.0
Perform Grounding Upgrades - Various Sites	329.0	337.1	345.4	338.2	341.5		1,691.2
Replace Insulators - Various Sites	187.1	287.9					475.0
Upgrade Circuit Breakers - Various Sites		3,695.4	1,642.5	3,750.1	3,973.2	4,000.0	17,061.2
Upgrade Power Transformers - Various Sites		1,904.4	4,719.4	1,750.6	1,780.8	1,800.0	11,955.2
Replace Disconnect Switches - Various Sites		815.9	953.1	958.4	1,040.3	981.0	4,748.7
Upgrade Terminal Station Foundations - Various Sites		197.9	300.0	300.0	300.0	300.0	1,397.9
Replace Surge Arresters - Various Sites		181.9	186.1	250.7	148.7	195.4	962.8
Replace Optimho Relays on TL203 - Western Avalon to Sunnyside		89.1	96.9				186.0
Install 20 MVAR Reactor - Bottom Brook			1,241.7	2,572.8			3,814.5
Upgrade Terminal Station Protection and Control - Various Sites			631.0	631.0	631.0	631.0	2,524.0
Install Fire Protection in 230 kV Stations - Various Sites			70.0	650.0	650.0	650.0	2,020.0
Install Transformer On line Gas Monitoring - Various Sites			200.0	550.0	350.0		1,100.0
Replace Telecontrol Building and Upgrade Equipment - Daniels Harbour			55.9	752.8			808.7
Perform Site Work to Accommodate Mobile Transformer - Various Sites			100.0	350.3	192.8		643.1
Replace 66kV S/S Cable Feed to Plant - Holyrood			223.2				223.2
Upgrade Control Wiring Phase 1 to Terminal Station 1 - Bay d'Espoir			70.0	144.6			214.6
Install Support Structures C2 Capacitor Bank - Hardwoods			150.0				150.0
Replace Station Lighting - Bay d'Espoir			150.0				150.0
Install 2nd AC Station Service - Howley			101.5				101.5
Upgrade Transformer Differential Circuit on T1 - Grandy Brook			68.4				68.4
Upgrade Control Building for Staff Working Spaces - South Brook and Doyles				445.7	759.2		1,204.9
Upgrade Control Wiring Phase 2 to Terminal Station 1 - Bay d'Espoir				100.0	390.9		490.9
Upgrade Control Building - Indian River				405.6			405.6

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
TERMINAL STATIONS (cont'd.)							
Install Remote Control Sectionalizer TL251(2)(3) - Hampden				334.0			334.0
Upgrade Terminal Station for Mobile Substation - Cow Head				224.9			224.9
Terminal Stations Compressor Replacement Program - Various Sites				139.5			139.5
Construct 138 kV Terminal Station - Hawkes Bay					2,280.0	5,013.0	7,293.0
Upgrade DC Station Service - Bay d'Espoir					200.0		200.0
Upgrade Terminal Station for Mobile Substation - Howley and Daniels Harbour					175.0		175.0
Replace Outside Service - Holyrood						750.0	750.0
Install 66 kV Breaker By-Pass Switches - Various Sites						515.0	515.0
Install Drainage to Stop Surface Flooding - Various Sites						500.0	500.0
Upgrade Access Road with New Topping - Buchans						250.0	250.0
Upgrade Station Service for Oil Reclaimer - Oxen Pond						200.0	200.0
Upgrade Station Service - Sunnyside						150.0	150.0
TOTAL TERMINAL STATIONS	5,933.6	26,652.0	11,843.5	16,160.9	13,885.3	16,435.4	90,910.7

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
TRANSMISSION							
Replace Guy Wires Doyles to Grand Bay - TL215	350.1	530.0					880.1
Install 230 KV Transmission Line - Bay d'Espoir to Western Avalon		6,370.8	74,626.5	62,602.1	60,758.6	63,642.0	268,000.0
Perform Wood Pole Line Management Program - Various Sites		2,564.2	2,872.0	2,954.2	2,759.5	2,791.4	13,941.3
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside		1,191.7	988.2				2,179.9
Upgrade Transmission Lines - Various Sites			430.1	4,176.9	1,107.7	2,437.7	8,152.4
Replace Aircraft Markers at Grand Lake Crossing - TL228			80.0	715.4			795.4
Replace Transmission Lines - Various Sites				525.8	10,327.8	9,876.0	20,729.6
Construct Transmission Line Equipment Off-Loading Areas - Various Sites				887.8	506.4		1,394.2
Install 138 kV Transmission Line Cross Braces - Various Sites				71.0	637.9		708.9
Conduct LIDAR Surveys - Various Sites				276.5	283.9		560.4
TOTAL TRANSMISSION	350.1	10,656.7	78,996.8	72,209.7	76,381.8	78,747.1	317,342.2

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
DISTRIBUTION							
Upgrade Distribution Systems - Various Sites	1,940.1	6,495.3	5,182.1	3,211.4	2,219.0	2,379.0	21,426.9
Provide Service Extensions - All Service Areas		6,170.0	6,290.0	5,895.0	5,490.0	5,650.0	29,495.0
Upgrade Distribution Systems - All Service Areas		3,370.0	3,440.0	3,310.0	3,180.0	3,250.0	16,550.0
Replace Recloser Control Panels - Various Sites		111.3	84.4				195.7
Additions for Load Growth - Labrador South Interconnection - Various Sites			5,501.3	7,634.2			13,135.5
Replace Submarine Cable - Various Sites			45.0	400.8		850.0	1,295.8
Convert Section of Trition (L5) to 25kV - South Brook			521.1				521.1
Purchase Spare Transformer - Paradise River			50.0	450.0			500.0
Replace Hendrix Insulators - Farewell Head			500.0				500.0
Implement Geographical Information System - Various Sites			74.0				74.0
Additions for Load - Distribution Systems - Various Sites				1,056.9	2,045.4	1,000.0	4,102.3
Convert Section of Robert's Arm (L3) to 25 kV - South Brook				569.6			569.6
Extend Three Phase to St. Paul's - Cow Head					474.0		474.0
Construct Storage Buildings - Change Islands and Springdale					401.6		401.6
Install Mobile Diesel Quick Connect/Disconnect - Various Sites					178.8		178.8
Replace Transformer - Sally's Cove					100.0		100.0
Replace T1 2.5 MVA Transformer - Conne River						800.0	800.0
Replace L4 #4 Copper Wire Primary - Farewell Head						59.0	59.0
TOTAL DISTRIBUTION	1,940.1	16,146.6	21,687.9	22,527.9	14,088.8	13,988.0	90,379.3

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
GENERATION							
Additions for Load Growth - Isolated Generation Stations - Various Sites	2,040.2	9,999.1	5,583.8	7,562.6	4,125.9	1,200.0	30,511.6
Perform Arc Flash Remediation - Various Sites	391.0	401.8	413.1				1,205.9
Overhaul Diesel Engines - Various Sites		823.5	1,436.1	1,470.4	1,503.4	1,535.7	6,769.1
Replace Diesel Units - Various Sites		208.9	534.9	1,645.5	1,380.0	1,270.0	5,039.3
Inspect Fuel Storage Tanks - Various Sites		495.0	1,183.6	498.0	511.9	526.4	3,214.9
Install Fire Protection in Diesel Plant - Various Sites		107.1	992.2	500.0	500.0	500.0	2,599.3
Upgrade Diesel Plant Production Data Collection Equipment - Various Sites		268.9	269.8	280.7			819.4
Upgrade Ventilation Systems - Various Sites		263.0	50.0	100.0	100.0	100.0	613.0
Replace Fuel Tanks - Ramea and Port Hope Simpson		234.2	229.5				463.7
Construct Storage Facility - Postville		183.8					183.8
Perform Plant Improvements as Per 2012 FEED Project - Various Sites			500.0	1,700.0	250.0	250.0	2,700.0
Replace Programmable Logic Controllers - Various Sites			100.0	250.0	250.0	250.0	850.0
Upgrade Fuel Storage - Various Sites			514.4	125.3			639.7
Purchase Accommodations Trailers - Postville and Makkovik			120.0	120.0			240.0
Install Automatic Fuel Shut Off Valves - St Anthony			200.0				200.0
Upgrade Lighting System - Cartwright and Hopedale				157.9			157.9
Upgrade Station Service - Grey River				130.9			130.9
Replace Radiators - Various Sites					500.0	500.0	1,000.0
Install Fire Detection System - Norman Bay					100.0		100.0
Replace Underground Glycol Line - Francois					100.0		100.0
Insulate Diesel Plant - St Anthony					63.5		63.5
Install Unit Fuel Metering - Various Sites						600.0	600.0
Upgrade and Add Site Fencing - Lanse Au Loup and Port Hope Simpson						450.0	450.0
Build Roadway for Freight Delivery - Norman Bay						307.2	307.2
Install Nox Monitors at 2 Sites - Various Sites						302.7	302.7
Install Sectionalizing for Cold Load Pickup - Port Hope Simpson						250.0	250.0
Replace Diesel Plant - Rigolet						200.0	200.0
TOTAL GENERATION	2,431.2	12,985.3	12,127.4	14,541.3	9,384.7	8,242.0	59,711.9

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
PROPERTIES							
Legal Survey of Primary Distribution Line Right of Ways - Various Sites	156.2	196.8	197.8	197.3	197.4	197.3	1,142.8
Install Additional Washrooms - Various Sites		251.0	257.3	263.7	270.3	277.2	1,319.5
Install Fall Protection Equipment - Various Sites		199.2					199.2
Upgrade Line Depots - Various Sites			100.0	100.0	100.0	100.0	400.0
Replace Accomodations/Septic System at EBBE - Bay d'Espoir			380.9				380.9
Install Pole Storage Ramps - Various Sites				603.8	507.2		1,111.0
Upgrade Warehouse Lighting - Bishops Falls				94.9			94.9
Replace Warehouse - Bay d'Espoir					1,228.0		1,228.0
Construct Steel Storage Building - Makkovik					147.4		147.4
Upgrade Classroom and Boardroom in Main Office - Bishop Falls					77.4		77.4
TOTAL PROPERTIES	156.2	647.0	936.0	1,259.7	2,527.7	574.5	6,101.1
METERING							
Install Automated Meter Reading - Various Sites	287.7	615.7	340.2				1,243.6
Purchase Meters, Equipment and Metering Tanks - Various Sites		199.0	199.3	197.6	198.6	199.4	993.9
TOTAL METERING	287.7	814.7	539.5	197.6	198.6	199.4	2,237.5
TOOLS AND EQUIPMENT							
Replace Off Road Track Vehicles - Various Sites	416.8	1,322.8	1.1	406.6		410.0	2,557.3
Replace Light Duty Mobile Equipment - Various Sites		579.1	498.2	489.3	494.8		2,061.4
Purchase Tools & Equipment Less than $50,000 - Various Sites		553.3	210.7	216.0	88.2	90.2	1,158.4
Purchase Portable Vibration Testing Equipment - Various Sites		60.6					60.6
Replace Bulldozer - Bishop Falls				329.1			329.1
TOTAL TOOLS AND EQUIPMENT	416.8	2,515.8	710.0	1,441.0	583.0	500.2	6,166.8
TOTAL TRANSMISSION AND RURAL OPERATIONS	11,515.7	70,418.1	126,841.1	128,338.1	117,049.9	118,686.6	572,849.5

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
INFORMATION SYSTEMS							
SOFTWARE APPLICATIONS							
New Infrastructure							
Perform Minor Application Enhancements - Hydro Place		138.6	142.6	147.4	150.0	155.0	733.6
Cost Recoveries		(51.3)	(41.8)	(47.4)	(50.0)	(52.0)	(242.5)
Upgrade of Technology							
Upgrade Microsoft Office Products - Hydro Place	656.7	455.1	465.2	470.0	480.0	485.0	3,012.0
Cost Recoveries	(236.4)	(163.8)	(167.5)	(170.0)	(172.0)	(175.0)	(1,084.7)
Upgrade Energy Management System - Hydro Place		187.9	212.5	212.7	215.0		828.1
Upgrade Lotus Notes - Hydro Place			584.0				584.0
Cost Recoveries			(183.7)				(183.7)
Upgrade Customer Care System - Hydro Place			299.7				299.7
Upgrade Security Configuration Auditing - Hydro Place				140.8			140.8
Upgrade Showcase Suite - Hydro Place				192.4			192.4
Cost Recoveries				(65.4)			(65.4)
Upgrade Corporate Application Environment - Hydro Place					1,073.1		1,073.1
TOTAL SOFTWARE APPLICATIONS	420.3	566.5	1,311.0	880.5	1,696.1	413.0	5,287.4

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
COMPUTER OPERATIONS							
Infrastructure Replacement							
Replace Personal Conmputers - Various Sites		489.8	537.8	382.3	365.0	370.0	2,144.9
Replace Peripheral Infrastructure - Hydro Place		200.7	521.9	208.5	194.0	220.0	1,345.1
Upgrade Enterprise Storage Capacity - Hydro Place		517.8	309.8	182.0	300.0	400.0	1,709.6
Cost Recoveries		(191.6)	(103.5)	(61.9)	(96.0)	(148.0)	(601.0)
Upgrade of Technology							
Upgrade Server Technology Program - Hydro Place		328.0	568.1	167.2	580.0	400.0	2,043.3
Cost Recoveries		(42.0)	(193.2)	(56.8)	(185.6)	(148.0)	(625.6)
TOTAL COMPUTER OPERATIONS		1,302.7	1,640.9	821.3	1,157.4	1,094.0	6,016.3
TOTAL INFORMATION SYSTEMS	420.3	1,869.2	2,951.9	1,701.8	2,853.5	1,507.0	11,303.7

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
TELECONTROL							
NETWORK SERVICES							
Infrastructure Replacement							
Replace MDR4000 Microwave Radio (West) - Various Sites	539.0	706.9					1,245.9
Replace Radomes - Various Sites		324.9	183.2	192.0	196.0	196.0	1,092.1
Purchase Tools and Equipment Less than $50,000		46.4	46.4	47.6	48.7	49.7	238.8
Replace Mobile Radio System - Happy Valley			55.9	593.3			649.2
Construct Storage Facility - Deer Lake			410.2				410.2
Refurbish Microwave Shelter - Sandy Brook			90.0				90.0
Replace Power Line Carriers - Various Sites				2,321.0	2,942.0	1,720.0	6,983.0
Replace MDR 4000 Microwave Radio (East) - Various Sites				539.0	920.0		1,459.0
Replace Standby Generator - Sandy Brook				237.3			237.3
Refurbish Microwave Shelters - Mary March Hill and Blue Grass Hill					90.0	90.0	180.0
Replace GPS Clocks - Various Sites					52.8		52.8
Replace MDR 6000 Microwave Radio (East) - Various Sites						86.2	86.2
Network Infrastructure							
Replace Battery Banks and Chargers - Various Sites		267.0	398.0	302.0	305.0	250.0	1,522.0
Replace Network Communications Equipment - Various Sites		91.0	158.6	174.0	180.0	185.0	788.6
Install Substation Communications Management - Various Sites					237.8		237.8
Upgrade of Technology							
Upgrade IP SCADA Network - Various Sites		254.2	238.7				492.9
Replace Telephone Systems - Stephenville		139.9	98.1				238.0
Upgrade Site Facilities - Various Sites		49.8	48.0	48.0	48.0		193.8
Replace Wescom Scanner - Corner Brook		81.7					81.7
Replace WIFI Network - Various Sites			120.0				120.0
Replace GDC Metroplex - Stoney Brook			90.0				90.0
Replace DTI Phone Turrets in Energy Control Center - Hydro Place			60.0				60.0
Replace Wescom Transceivers - Various Sites			48.0				48.0
Replace PBX Phone Systems - Various Sites				480.0	360.0	240.0	1,080.0
Build Comunications Shelters - Various Sites					360.0		360.0
TOTAL TELECONTROL	539.0	1,961.8	2,045.1	4,934.2	5,740.3	2,816.9	18,037.3

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
				($000)			
TRANSPORTATION							
Replace Vehicles and Aerial Devices - Various Sites	1,302.3	2,488.3	3,016.5	2,497.4	2,114.0	2,700.8	14,119.3
TOTAL TRANSPORTATION	1,302.3	2,488.3	3,016.5	2,497.4	2,114.0	2,700.8	14,119.3
ADMINISTRATION							
Remove Safety Hazards - Various Sites		257.8	265.1	272.5	280.1		1,075.5
Purchase Office Equipment		65.9	68.0	131.0	71.1		336.0
Replace Cooling Tower and Auxiliaries - Hydro Place			500.0				500.0
Replace Roof - Hydro Place				1,400.0			1,400.0
Replace AC Unit 12A and Unit 14 - Hydro Place				214.6			214.6
Upgrade Fire System - Bishop Falls					799.6	556.7	1,356.3
Upgrade Outside Property - Various Sites					234.8		234.8
TOTAL ADMINISTRATION	0.0	323.7	833.1	2,018.1	1,385.6	556.7	5,117.2
TOTAL GENERAL PROPERTIES	2,261.6	6,643.0	8,846.6	11,151.5	12,093.4	7,581.4	48,577.5

A Report to the

Board of Commissioners of Public Utilities

Holyrood Overview

Future Operations and Capital Expenditure Requirements

July 2013

newfoundland labrador hydro
a nalcor energy company

BACKGROUND

The Board of Commissioners of Public Utilities (the Board), in Orders No. P.U. 5 (2012) and No. P.U. 4 (2013) directed Hydro to file, in conjunction with the 2014 Capital Budget Application, an overview in relation to the proposed capital expenditures for the Holyrood Thermal Generating Station. The Board required, that the overview include the following[1]:

1. An updated outlook regarding anticipated changes in the role of Holyrood on the system;

2. An updated schedule of anticipated changes in Holyrood operations that may reasonably be expected to have an impact on capital expenditure requirements;

3. A summary description of all proposed Holyrood capital projects, including an explanation of how such projects relate to one another and whether such projects may be impacted by decisions yet to be taken regarding Holyrood's role on the system;

4. A summary guide to all internal and external reports filed in support of the capital expenditure proposals, summarizing alternatives considered and recommendations made; and

5. An explanation of the necessity of all proposed capital expenditures in the context of the anticipated changes in Holyrood operations.

Hydro contacted, in April, 2013 the Consumer Advocate and legal counsel for the Industrial Customers. Neither party wished to add any specific requirement for the contents of this overview.

This report contains the requested Holyrood capital expenditure overview.

[1] *Order No. P.U. 5 (2012)*

INTRODUCTION

Newfoundland and Labrador Hydro's (Hydro) Holyrood Thermal Generating Station (Holyrood) is a critical part of the Island Interconnected System. With three oil fired generating units providing a total capacity of 490 MW (465 MW net), the plant represents approximately one third of Hydro's total Island Interconnected System generating capacity. Units 1 and 2 were commissioned in 1970 and 1971 respectively and Unit 3 in 1979. Units 1 and 2 were originally designed to produce 150 MW, but were upgraded to 175 MW in 1988 and 1989 respectively. Unit 3 retains its original configuration and is rated at 150 MW. In 1986, Unit 3 was retrofitted with synchronous condensing capability to provide voltage support on the eastern end of the Island Interconnected System during periods when power generation from the Holyrood station is not required.

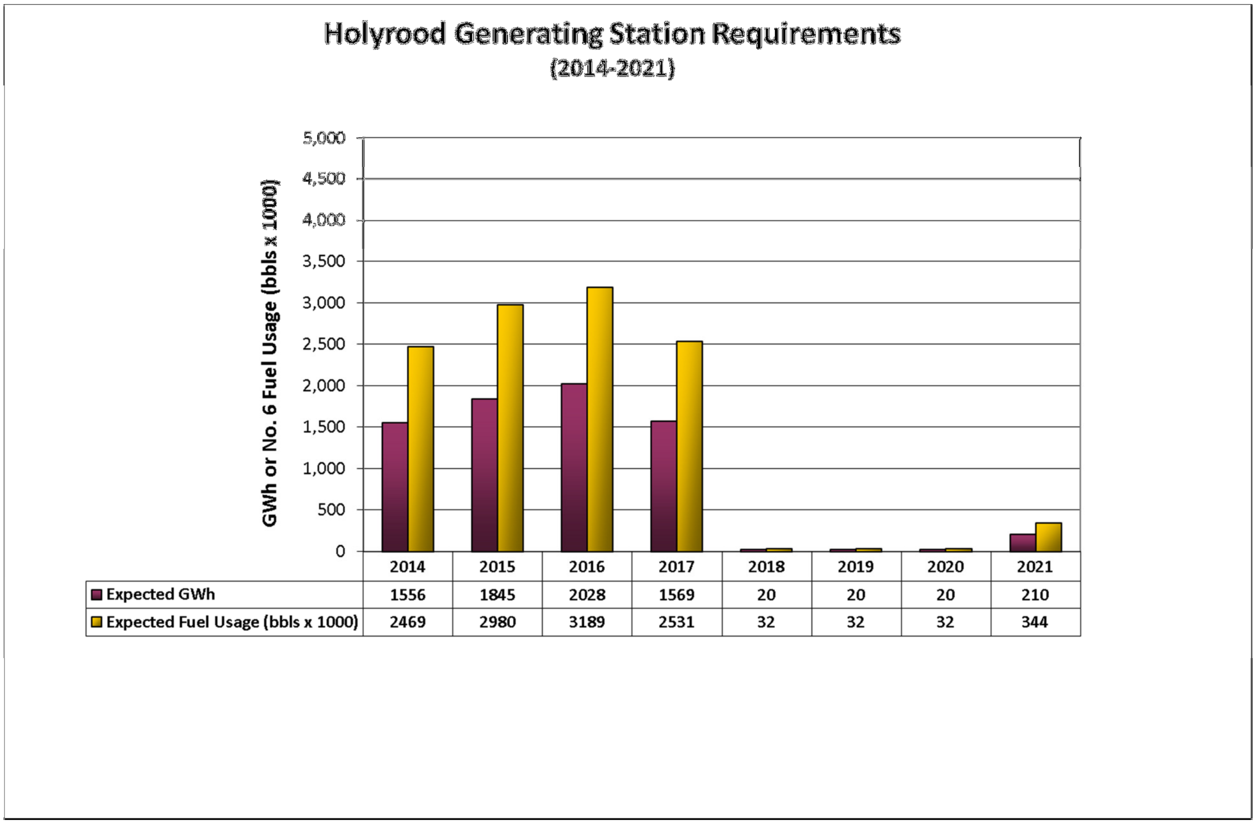
The three major components of the thermal generating process are the boiler, the turbine and the generator with supporting systems such as fuel storage and delivery, controls, and cooling and feed water supply systems. Through combustion of Bunker C fuel oil, the power boiler provides high energy steam to the turbine. The turbine is directly coupled to the generator and provides the rotating energy necessary for the generator to produce rated output power to the Island Interconnected System. The generator itself is pressurized and cooled by hydrogen gas to provide maximum efficiency both in heat transfer and reduced windage losses.

The Holyrood Generating Station is essential for meeting winter peak demand as well as overall island annual energy requirements. Hydro's hydro-electric generation is dependent on rainfall and inflows to the reservoirs. Holyrood is required to supply the difference between what is produced by Hydro's other generation sources (including purchases from non-utility generators) and what is required to meet the Island load. During a period of reduced inflows and low water storage levels, this may be significant.

Figure 1: Holyrood Thermal Generating Station

UPDATED OPERATIONAL OUTLOOK AND SCHEDULE

On December 17, 2012, the Government of Newfoundland and Labrador announced official sanction of the Muskrat Falls development. The Muskrat Falls development, and the Labrador Island Link (LIL), are expected to be in service in 2017. Holyrood will be required for prime power production throughout the interim period (i.e., to the in-service date of the LIL) and it is intended that the facility remain fully available for generation in stand-by mode until the 2020–2021 timeframe. Unit 3 will operate primarily in synchronous condenser mode beginning in 2017, with the option to return to full generating mode. Post the 2020-2021 timeframe, Units 1 and 2 and the steam components of Unit 3 at Holyrood will be decommissioned, and Unit 3 will continue to operate in synchronous condenser mode only with no generation capability.



	2014	2015	2016	2017	2018	2019	2020	2021
Expected GWh	1556	1845	2028	1569	20	20	20	210
Expected Fuel Usage (bbls x 1000)	2469	2980	3189	2531	32	32	32	344

Figure 2: Holyrood Annual Production Requirements

Figure 2 indicates the forecasted Holyrood annual production requirements for the eight year period from 2014 to 2021. This forecast is based on average Island hydrologic inflow conditions. By 2017, the LIL is expected to be in-service to supply the Island Interconnected System with power and energy from Muskrat Falls. From 2017 to the 2020-2021 timeframe, it is assumed that the plant will produce 20 GWh in each year while operating in standby mode. In the 2020-2021 timeframe, the remaining fuel inventory will be consumed.

It should be noted that the production at Holyrood may vary from that forecast for the 2014 to 2017 period depending on the hydrologic conditions which influence Hydro's hydraulic energy supply capability. During a high inflow period, production from the Holyrood plant would be kept to minimum levels, with units operated only as required for System capacity and Avalon Peninsula transmission security considerations. Production during this period could be less than 1,000 GWh annually. During a repeat of the critical dry sequence,[2] annual required production from Holyrood would be significant, up to 3,000 GWh per year. This requires that all units be operated at maximum capacity outside of their annual planned and maintenance outage requirements.

In summary, the specific phases of operation and the timeframes for each phase are anticipated to be as follows:

Phase 1 (2013 through 2017): All three units are available for generation with Unit 3 also available for synchronous condenser operation as required

Phase 2 (2017 to the 2020-2021 timeframe): Units 1 and 2 are in standby generation mode and Unit 3 is operated in synchronous condenser mode but available for conversion to generation mode as required

Phase 3 (Post 2020-2021 timeframe): Unit 3 continues to operate as a synchronous condenser only to the end of its service life

Phase 1 – Normal Production Phase

Prior to full commissioning of the Muskrat Falls development and the Labrador Island Link, there will be continued demands on Holyrood to serve increasing system load requirements. Over the past several years, industrial demand has declined due to the closure of two paper mills and reduction of operation at a third. There is, however, continued growth in Utility customer requirements, particularly on the Avalon Peninsula. Industrial load growth is also expected to occur specifically with the expected startup of a nickel processing facility at Long Harbour. Total customer demand in the short to medium term is expected to exceed the levels which were experienced prior to the downturn of the paper industry.

Holyrood remains critical to the reliable supply of power to the Island Interconnected System, as it serves the base load of the system and will be required to do so in the short to medium term. Holyrood will remain a critically important facility during construction and full commissioning of the Muskrat Falls development and the Labrador Island Link. During this phase of operation, the capability to operate

[2] *The dry period experienced during the late 1950s into the early 1960s spanning more than three years*

Holyrood at full production is essential to meeting the energy and capacity requirements of the island portion of the province.

During Phase 1 of Holyrood's future operation, few changes are expected in terms of maintenance strategy since the plant is generally expected to produce with high reliability through 2017.

Phase 2 – Standby Production Phase

Following the full commissioning of the Muskrat Falls development and the Labrador Island Link, the Holyrood plant will continue to be an essential component of the Provincial electrical grid. Initially, the plant will function as a fully capable standby facility during the early years of operation of the Muskrat Falls Generating Plant and the LIL between Labrador and Newfoundland, until the 2020-2021 timeframe. In this capacity, it can be called upon to provide energy and capacity to the Island in the event of a loss of supply from Labrador.

During the standby phase, it is assumed that the plant will produce 20 GWh in each year to test the units to ensure that they are available if required.

During Phase 2 of Holyrood's future operation, few changes are expected in terms of maintenance strategy since the plant must be fully available for emergency use until the 2020-2021 timeframe.

Phase 3 – Synchronous Condenser Operation Phase

Following the standby phase, the thermal aspect of the station will be decommissioned. At that time Unit 3 will continue to operate as a synchronous condenser. The final generation availability is currently projected to be in the 2020-2021 timeframe.

Systems that are no longer required will be decommissioned, including:

- The fuel storage and delivery system, including the tank farm and day tank;
- the boilers, including air systems and emission monitoring systems;
- feedwater and condensate systems, including the deaerator systems; and
- the marine terminal.

Systems required following the standby phase include:

- Unit 3 synchronous condenser specific equipment including the unit generator and exciter; and
- Auxiliary systems including electrical, controls, cooling water, fire protection, etc.

Assets with operational requirements beyond the 2020-2021 timeframe will continue to be optimally maintained with re-investment reflecting that continued requirement.

HOLYROOD 2014 CAPITAL PLAN SUMMARY

The complexity of thermal generating units, along with the age of the Holyrood plant, necessitates a rigorous review of the assets to ensure its future generating requirements can be met. In order to ensure that critical systems receive the appropriate level of refurbishment Hydro has been concentrating on condition assessments and the formulation of requirements to get Holyrood to the end of its life as a generating facility, several years after the LIL comes in-service, and to operate in synchronous condenser mode beyond that time.

Following sanction of the Lower Churchill Project near the end of 2012, Hydro reviewed the 2014 capital plan for Holyrood in light of the future role of the plant. Projects were removed or adjusted as appropriate to ensure the work proposed is critical to safe and reliable production.

The review resulted in the following adjustments to the projects previously identified to begin in 2014:

- Upgrade Powerhouse Roofing: The project scope and schedule were adjusted to align with the reduced infrastructure to remain at Holyrood to support single unit synchronous condenser operation.
- Replace Powerhouse Overhead Doors: The project scope and schedule were adjusted to align with the reduced infrastructure to remain at Holyrood to support single unit synchronous condenser operation.
- Refurbish Fuel Storage Facility, Tank 1: This project was removed because it was deemed that the risk of operating without the fourth tank refurbishment was not high enough to warrant the investment between now and 2020-2021.
- Complete Engineering Review to Determine Systems for Synchronous Condenser Operation Units 1 and 2: This project was removed because Units 1 and 2 at Holyrood are no longer required to be converted to synchronous condenser operation.

In addition to those projects directly affected by the Lower Churchill sanction, the project to replace the fuel oil heat exchangers on Units 1 and 2 was removed in favour of adding one heat exchanger to inventory and replacing a heat exchanger if required during the operating season.

Four projects which were submitted in the 2013 Capital Budget Application were withdrawn to review their continued viability in light of the future operation of the Holyrood facility. This review was completed during the winter months of 2013 and three of these projects are deemed necessary to ensure the safe and reliable operation of the generating units and they have been resubmitted in 2014. Specifically, these projects are:

1. Install Cold Reheat Condensate Drains and High Pressure Heater Trip Level;
2. Upgrade Vibration Monitoring System; and
3. Install Fire Protection Upgrades.

The following tables summarize the projects included in the 2014 capital plan for Holyrood. The plan was prepared in recognition of the anticipated completion of the in-feed from Muskrat Falls in 2017 and in support of Holyrood availability requirements until 2020-2021. The plan was prepared considering asset condition, equipment obsolescence (both end of life and availability of support) and forecast production requirements, to identify the necessary rehabilitation and replacement projects to ensure customer needs can be met.

Table 1 provides a summary description of all proposed Holyrood capital projects for 2014. All of the proposed projects are required to ensure that the Holyrood facility is available to operate at full production which is essential to meeting the energy and capacity requirements of the Island portion of the province through the construction and commissioning of the Muskrat Falls development and the Labrador Island Link.

The first six projects listed are projects related to plant common support systems and infrastructure which are required to ensure the plant can continue to be operated safely, reliably and with regulatory compliance through the normal operation and standby production phases to 2020-2021. These systems support the overall operation of the plant and ensure environmental compliance with respect to the collection and treatment of waste water.

The next seven projects relate directly to the major components of the power generation process, the boiler, turbine and generator, and their supporting systems. The first four of these projects are related to the boiler feedwater systems for the generating units. The remaining three projects relate to the steam turbines and generators and monitoring systems required for their safe operation and shut down.

The final project listed, Condition Assessment and Life Extension, will provide the data necessary to enable the determination and optimization of future projects at the facility through the 2020-2021 timeframe.

Table 2 provides a summary guide to all internal and external reports filed in support of the capital expenditure proposals summarizing the alternatives considered and recommendations made.

Table 3 provides an explanation of the necessity of all proposed capital expenditures in the context of the changes in Holyrood operation.

Table 1: Holyrood Projects Included in 2014 Capital Plan

Project	Scope Summary	Proposal Location
Install Fire Protection Upgrades	Installation of curbing, automatic fuel shut-off valve, and fireproofing of pipe supports	D-76
Upgrade Waste Water Basin Building	Inspection and recommendation of solution	E-69
Upgrade Underground Plant Drainage System	Inspection and recommendation of solution	E-73
Upgrade Plant Elevators	Upgrade Plant and Administration Elevators	C-24, Tab 10
Replace DC Distribution Panels and Breakers	Replacement of DC 129 V and 258 V distribution panels and breakers (Units 1 and 2)	E-66
Overhaul Cooling Water Pump East Unit 1	Pump rehabilitation - 12 year frequency	E-76
Install Cold-Reheat Condensate Drains and High Pressure Heater Trip Level-Unit 3	Installation of condensate collection system	C-30, Tab 13
Replace Economizer Inlet Valves Units 1 and 2	Replace economizer inlet valves Units 1 and 2	C-28, Tab 12
Overhaul Boiler Feed Pump East Unit 3	Pump rehabilitation - 7 year frequency	E-53
Overhaul Extraction Pump South Unit 1	Pump rehabilitation - 12 year frequency	E-88
Upgrade Excitation Systems Units 1 and 2	Upgrade exciter controls on units 1 and 2	C-22, Tab 9
Upgrade Unit Vibration Monitoring System	Upgrade to generators only. Removed parts will be used as spares for turbines	C-26, Tab 11
Overhaul Steam Turbine Generator Unit 2	Steam turbine rehabilitation - 9 year frequency	C-18, Tab 7
Condition Assessment and Life Extension	Condition assessment of critical components	C-20, Tab 8

Table 2: Reports Filed in Support of Project Proposals

Project	Reports filed	Alternatives Considered	Recommendation
Install Fire Protection Upgrades	FM Global Risk Report - Fire and Natural Hazards Special Risk Evaluation, Holyrood Thermal Plant, August 24, 2011	FM Global recommendation	FM Global Recommendation - Target 08-10-001
Install Cold-Reheat Condensate Drains and High Pressure Heater Trip Level-Unit 3	1. FM Global Risk Report - Equipment Hazards Interim Risk Evaluation, Holyrood Thermal Plant, May 12, 2011 2. Extract from ASME Standard TDP-1-1998, Section 3	FM Global recommendation	FM Global Recommendation - Target 06-01-003
Replace Economizer Inlet Valves Units 1 and 2	1. Extract from ASME PCC-2-2011, Part 4 - Nonmetallic and Bonded Repairs, Article 4.1: Nonmetallic Composite Repair Systems: High Risk Applications 2. Extracts from API 570, Section 1- Scope and Section 8 - Repairs, Alterations, and Rerating of Piping Systems	Replacement of existing valves	Replacement of existing valves
Upgrade Waste Water Basin Building	None	Inspection and Phase 1 Engineering	Inspection and Phase 1 Engineering
Upgrade Underground Plant Drainage System	None	Inspection and Phase 1 Engineering	Inspection and Phase 1 Engineering
Upgrade Plant Elevators	1. Amusement Rides and Elevating Devices Regulations under the Public Safety Act (O.C.)96-429, Newfoundland and Labrador Regulation 118/96 2. Public Safety Act, Amended, 2010 c.28; 2012 c38 s13	Upgrade of existing equipment only	Upgrade of existing equipment only
Upgrade Excitation Systems Units 1 and 2	Unitrol P Life Cycle Management - ABB	1. Purchase of available spare parts 2. Upgrade controls on one unit and use the removed components for spares 3. Upgrade controls on both units	Upgrade controls on both units
Replace DC Distribution Panels and Breakers	None	Replace existing equipment	Replace existing equipment
Upgrade Vibration Monitoring System	Product Life Cycle Suport Notices - Bently Nevada: 1. 3300 Monitoring System moving to Phase 5 2. Data Manager 2000 Software Now in Phase 5 3. TDXnet External Communication Processor to Phase 4 4. 3300 Monitoring System Transitioning to Phase 4	1. Complete systems upgrade to 3500 Encore 2. Complete systems upgrade to 3500 3. Generator upgrades to 3500 with removed components used as spares for turbines	Generator upgrades to 3500 with removed components used as spares for turbines
Condition Assessment and Life Extension	1. EPRI On-Line Boiler Conditon Assessment Guideline 2. Generation Planning Issues November 2012	Inspection and testing of existing systems	Inspection and testing of existing systems
Overhaul Steam Turbine Generator Unit 2	1. AMEC Condition Assessment and Life Extension Study 2. General Electric Major Overhaul Report FRS Number 20350952 Unit 2 Steam Turbine Inspection Report May - September 2005 3. Hartford Steam Boiler (HSB) Turbine Outage Optimization Program (TOOP) - Executive Summary	Overhaul steam turbine and generator	Overhaul steam turbine and generator
Overhaul Boiler Feed Pump East Unit 3 Overhaul Extraction Pump South Unit 1 Overhaul Cooling Water Pump East Unit 1	Flowserve Review, May 24, 2011	Overhaul pumps	Overhaul pumps

Table 3: Project Necessity in the Context of Changing Role of Holyrood

Major System or Subsystem	Project	Phase 1	Phase 2	Phase 3
Fuel Storage & Delivery	Install Fire Protection Upgrades	Needed	Needed	Not needed
Feedwater & Condensate	Install Cold-Reheat Condensate Drains and High Pressure Heater Trip Level-Unit 3	Needed	Needed	Not needed
	Overhaul Boiler Feed Pump East Unit 3	Needed	Needed	Not needed
	Overhaul Extraction Pump South Unit 1	Needed	Needed	Not needed
Boiler	Replace Economizer Inlet Valves Units 1 and 2	Needed	Needed	Not needed
Turbine Generator	Overhaul Steam Turbine Generator Unit 2	Needed	Needed	Not needed
Cooling Water Systems	Overhaul Cooling Water Pump East Unit 1	Needed	Needed	Not needed
Buildings & Grounds	Upgrade Plant Elevators	Needed	Needed	Needed
	Upgrade Waste Water Basin Building	Needed	Needed	Needed
	Upgrade Underground Plant Drainage System	Needed	Needed	Needed
Electrical & Controls	Upgrade Vibration Monitoring System	Needed	Needed	Needed[1]
	Upgrade Excitation Systems Units 1 and 2	Needed	Needed	Not needed
Common Systems	Replace DC Distribution Panels and Breakers	Needed	Needed	Not Needed
	Condition Assessment and Life Extension	N/A	N/A	N/A

[1] Unit 3 generator only

Holyrood 2015-2018 Capital Expenditures Outlook

To ensure continued security of supply, capital investment will be necessary throughout the period 2015 to 2018 to ensure Holyrood can provide the level of service required in either generation or synchronous condenser operation. Various types of investments and expenditures for the Holyrood facility are anticipated, including refurbishment, upgrade or replacement of failed equipment and general plant infrastructure work.

The Holyrood Generating Station continues to be a critical asset that must be maintained in a reliable least cost manner to meet demand and energy requirements of the Island Interconnected System.

In reviewing future capital projects for Holyrood going forward, Hydro has considered the three phases discussed previously and will submit for approval only those projects necessary for the safe and reliable operation of the plant as a generator up to the time of decommissioning. Additional capital investment requirements will continue through to synchronous condenser operation.

Capital projects being proposed as part of this and upcoming future budget submissions have been, and will continue to be, reviewed in light of the future plant requirements and are considered to be the minimum amount that is essential to fulfill Hydro's mandate to serve its customers and meet safety and environmental requirements.

The maintenance strategy for Holyrood going forward to its end of life as a generating station is to extend the life of the existing assets at least cost through continued preventative maintenance, repair and rehabilitation where critical to providing safe and reliable energy at the forecast levels. In cases where repair and rehabilitation are not viable alternatives, and where the associated assets remain critical to operation, assets will be renewed in the least cost manner that meets the need. For Phases 1 and 2 of Holyrood's future operation, few changes are expected in terms of maintenance strategy since the plant is generally expected to produce with high reliability through 2017 and must be fully available for emergency use until the 2020–2021 timeframe. Non-critical assets will receive minimal attention and may be allowed to degrade where such action does not significantly increase risk to safe and reliable production. Assets with operational requirements beyond 2020-2021 will continue to be optimally maintained with re-investment reflecting that continued requirement. Data will be collected from inspections, on line monitoring and formal condition assessments and used to determine the right work, on the right assets, at the optimal time in light of the changing role of Holyrood.

Figure 3 provides the planned level of expenditure for Holyrood over the 2014 to 2018 period. The annual average expenditure is $8.7 million, ranging from a high of $15.2 million in 2016 to a low of $3.5 million in 2018. With the exception of 2016, planned capital expenditures show a decreasing trend over the next five years. The increased level of expenditure in 2016 is related to expenditures of $4.8 million and $8.4 million for the overhaul of Unit 3 turbine generator and the rewind of Unit 3 generator rotor and installation of a rotor flux probe, respectively. Planned expenditures for the period total $43.7 million.

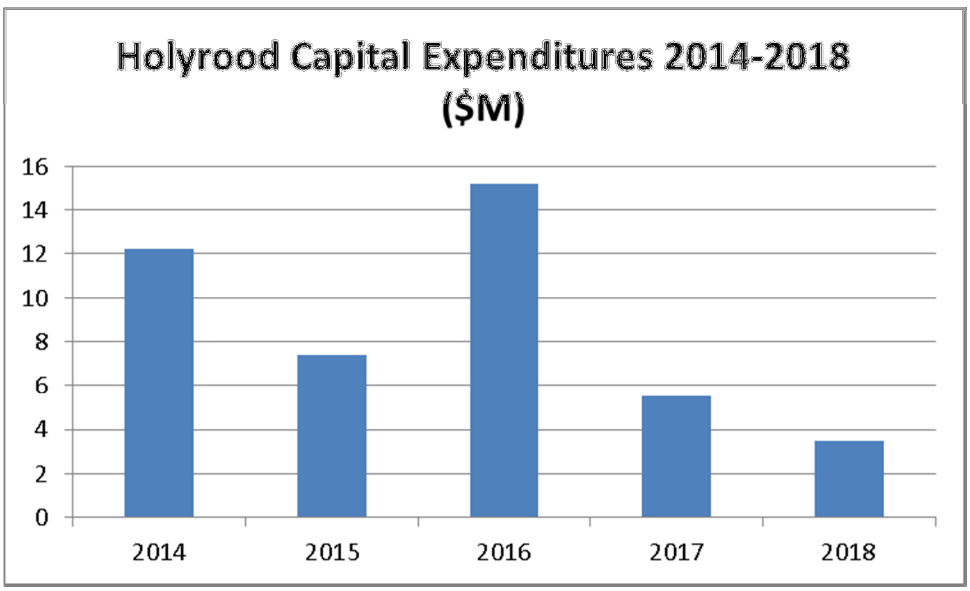


Figure 3: Holyrood Capital Expenditures 2014 to 2018

	Expended to 2013	2014	Future Years	Total
			($000)	
GENERATION	759.0	26,978.2	4,138.7	31,875.9
TRANSMISSION AND RURAL OPERATIONS	11,515.7	64,047.3	16,012.7	91,575.7
GENERAL PROPERTIES	2,261.6	6,643.0	2,025.4	10,930.0
ALLOWANCE FOR UNFORESEEN ITEMS		1,000.0		1,000.0
TOTAL CAPITAL BUDGET	14,536.3	98,668.5	22,176.8	135,381.6

	Expended to 2013	2014	Future Years	Total
		($000)		
GENERATION				
Hydraulic Plant		10,501.3	2,402.3	12,903.6
Thermal Plant	697.6	12,157.2	1,565.6	14,420.4
Gas Turbines	61.4	4,123.6		4,185.0
Tools and Equipment		196.1	170.8	366.9
TOTAL GENERATION	759.0	26,978.2	4,138.7	31,875.9
TRANSMISSION AND RURAL OPERATIONS				
Terminal Stations	5,933.6	26,652.0	5,476.0	38,061.6
Transmission	350.1	4,285.9	988.2	5,624.2
Distribution	1,940.1	16,146.6	4,934.5	23,021.2
Generation	2,431.2	12,985.3	4,233.5	19,650.0
Properties	156.2	647.0	40.3	843.5
Metering	287.7	814.7	340.2	1,442.6
Tools and Equipment	416.8	2,515.8		2,932.6
TOTAL TRANSMISSION AND RURAL OPERATIONS	11,515.7	64,047.3	16,012.7	91,575.7
GENERAL PROPERTIES				
Information Systems	420.3	1,869.2	297.7	2,587.2
Telecontrol	539.0	1,961.8	636.7	3,137.5
Transportation	1,302.3	2,488.3	1,091.0	4,881.6
Administrative		323.7		323.7
TOTAL GENERAL PROPERTIES	2,261.6	6,643.0	2,025.4	10,930.0
ALLOWANCE FOR UNFORESEEN ITEMS		1,000.0		1,000.0
TOTAL CAPITAL BUDGET	14,536.3	98,668.5	22,176.8	135,381.6

PROJECT DESCRIPTION	Expended to 2013	2014	Future Years	Total	Page Ref
			($000)		
HYDRAULIC PLANT					
Rewind Stator Unit 3 - Bay d'Espoir		4,343.9		4,343.9	C - 3
Refurbish Surge Tank 3 - Bay d'Espoir		2,265.0		2,265.0	C - 5
Upgrade Burnt Dam Spillway - Bay d'Espoir		110.2	1,201.9	1,312.1	C - 8
Upgrade Shoreline Protection - Cat Arm		55.3	708.1	763.4	C - 11
Upgrade North Cut-Off Dam Access Road - Bay d'Espoir		631.7		631.7	C - 13
Automate Generator Deluge Systems Units 3 and 6 - Bay d'Espoir		612.0		612.0	C - 15
Upgrade Victoria Control Structure - Bay d'Espoir		495.1		495.1	D - 2
Overhaul Turbine/Generator Units - Bay d'Espoir and Hinds Lake		485.0		485.0	D - 29
Upgrade Generator Bearings Unit 2 - Bay d'Espoir		18.9	396.0	414.9	D - 34
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir		352.8		352.8	D - 56
Replace Automatic Greasing Systems Units 5 and 6 - Bay d'Espoir		233.4		233.4	D - 68
Replace Generator Bearing Coolers Units 4 and 5 - Bay d'Espoir		199.0		199.0	E - 2
Install Automated Fuel Monitoring System at West Salmon Spillway - Bay d'Espoir		193.2		193.2	E - 5
Replace Spherical By Pass Valve Assemblies Units 1 and 2 - Bay d'Espoir		57.5	96.3	153.8	E - 17
Replace Fall Arrest on Surge Tank 1 - Bay d'Espoir		142.8		142.8	E - 22
Replace Turbine/Generator Cooling Water Flow Meters - Upper Salmon		139.7		139.7	E - 33
Raise Height of Earth Dam - Paradise River		98.7		98.7	E - 37
Replace Engine on Emergency Lift System - West Salmon Spillway		67.1		67.1	E - 50
TOTAL HYDRAULIC PLANT		10,501.3	2,402.3	12,903.6	

PROJECT DESCRIPTION	Expended to 2013	2014	Future Years	Total	Page Ref
			($000)		
THERMAL PLANT					
Overhaul Turbine/Generator Unit 2 - Holyrood		5,147.0		5,147.0	C - 18
Install Variable Speed Drives on 6 Forced Draft Fans - Holyrood	697.6	2,659.7		3,357.3	
Complete Condition Assessment Phase 2 - Holyrood		1,476.8		1,476.8	C - 20
Upgrade Excitation Systems Units 1 and 2 - Holyrood		654.3	456.6	1,110.9	C - 22
Upgrade Plant Elevators - Holyrood		533.2		533.2	C - 24
Upgrade Vibration Monitoring System - Holyrood		524.9		524.9	C - 26
Replace Economizer Inlet Valves - Holyrood		192.0	329.1	521.1	C - 28
Install Cold-Reheat Condensate Drains and High Pressure Heater Trip Level Unit 3 - Holyrood		49.8	467.4	517.2	C - 30
Install Fire Protection Upgrades - Holyrood		56.6	312.5	369.1	D - 76
Overhaul Boiler Feed Pump East Unit 3 - Holyrood		194.9		194.9	E - 53
Replace DC Distribution Panels and Breakers - Holyrood		174.2		174.2	E - 66
Upgrade Waste Water Basin Building - Holyrood		136.7		136.7	E - 69
Upgrade Underground Plant Drainage System - Holyrood		112.6		112.6	E - 73
Overhaul Cooling Water Pump East Unit 1- Holyrood		98.4		98.4	E - 76
Overhaul Extraction Pump South Unit 1 - Holyrood		96.8		96.8	E - 88
Replace Continuous Opacity Monitors - Holyrood		49.3		49.3	
TOTAL THERMAL PLANT	697.6	12,157.2	1,565.6	14,420.4	
GAS TURBINES					
Upgrade Gas Turbine Plant Life Extension - Stephenville		2,995.0		2,995.0	C - 33
Upgrade Gas Turbine Controls - Happy Valley	61.4	1,128.6		1,190.0	
TOTAL GAS TURBINES	61.4	4,123.6		4,185.0	
TOOLS AND EQUIPMENT					
Install Handheld Pendant to Overhead Crane - Bay d'Espoir		49.9	170.8	220.7	D - 98
Purchase Tools and Equipment Less than $50,000		146.2		146.2	
TOTAL TOOLS AND EQUIPMENT		196.1	170.8	366.9	
TOTAL GENERATION	759.0	26,978.2	4,138.7	31,875.9	

PROJECT DESCRIPTION	Expended to 2013	2014	Future Years	Total	Page Ref
			($000)		
TERMINAL STATIONS					
Install New Transformer - Oxen Pond	3,823.6	15,310.4		19,134.0	
Upgrade Circuit Breakers - Various Sites		3,695.4	1,642.5	5,337.9	C - 35
Replace Instrument Transformers - Various Sites	593.2	552.8	2,522.0	3,668.0	
Replace Compressed Air Systems - Stoney Brook and Sunnyside	303.0	2,105.9		2,408.9	
Upgrade Power Transformers - Various Sites		1,904.4		1,904.4	C - 38
Upgrade Terminal Station - Wiltondale	697.7	1,173.3		1,871.0	
Perform Grounding Upgrades - Various Sites	329.0	337.1	1,025.1	1,691.2	
Replace Disconnect Switches - Various Sites		815.9	189.5	1,005.4	C - 40
Replace Insulators - Various Sites	187.1	287.9		475.0	
Upgrade Terminal Station Foundations - Various Sites		197.9		197.9	E - 100
Replace Optimho Relays on TL203 - Western Avalon to Sunnyside		89.1	96.9	186.0	E - 104
Replace Surge Arrestors - Various Sites		181.9		181.9	E - 116
TOTAL TERMINAL STATIONS	5,933.6	26,652.0	5,476.0	38,061.6	
TRANSMISSION					
Perform Wood Pole Line Management Program - Various Sites		2,564.2		2,564.2	C - 42
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside		1,191.7	988.2	2,179.9	C - 44
Replace Guy Wires Doyles to Grand Bay - TL-215	350.1	530.0		880.1	
TOTAL TRANSMISSION	350.1	4,285.9	988.2	5,624.2	
DISTRIBUTION					
Upgrade Distribution Systems - Various Sites (2014-2015)		2,499.8	4,850.1	7,349.9	C - 48
Provide Service Extensions - All Service Areas		6,290.0		6,290.0	C - 50
Cost Recoveries		(120.0)		(120.0)	
Upgrade Distribution Systems - Various Sites (2013-2014)	1,940.1	3,995.5		5,935.6	
Upgrade Distribution Systems - All Service Areas		3,422.0		3,422.0	C - 52
Cost Recoveries		(52.0)		(52.0)	
Replace Recloser Control Panels - Various Sites		111.3	84.4	195.7	E - 123
TOTAL DISTRIBUTION	1,940.1	16,146.6	4,934.5	23,021.2	

PROJECT DESCRIPTION	Expended to 2013	2014	Future Years	Total	Page Ref
			($000)		
GENERATION					
Additions for Load Growth - Isolated Generation Stations - Various Sites	2,040.2	9,357.9		11,398.1	
Replace Diesel Units - Port Hope Simpson and Mary's Harbour		208.9	2,377.7	2,586.6	C - 56
Perform Arc Flash Remediation - Various Sites	391.0	401.8	413.1	1,205.9	
Install Fire Protection System - Nain		107.1	892.2	999.3	C - 58
Upgrade Diesel Plant Production Data Collection Equipment - Various Sites		268.9	550.5	819.4	C - 60
Overhaul Diesel Engines - Various Sites		823.5		823.5	C - 62
Additions To Accomodate Load Growth - Hopedale		641.2		641.2	C - 64
Inspect Fuel Storage Tanks - Various Sites		495.0		495.0	D - 114
Upgrade Ventilation System - Ramea		263.0		263.0	D - 135
Replace Fuel Storage Tank - Ramea		234.2		234.2	D - 152
Construct Storage Facility - Postville		183.8		183.8	E - 139
TOTAL GENERATION	2,431.2	12,985.3	4,233.5	19,650.0	
PROPERTIES					
Install Additional Washrooms - Various Sites		251.0		251.0	D - 160
Install Fall Protection Equipment - Various Sites		199.2		199.2	E - 196
Legal Survey of Primary Distribution Line Right of Ways - Various Sites (2014-2015)		156.8	40.3	197.1	E - 207
Legal Survey of Primary Distribution Line Right of Ways - Various Sites (2013-2014)	156.2	40.0		196.2	
TOTAL PROPERTIES	156.2	647.0	40.3	843.5	
METERING					
Install Automated Meter Reading - Various Sites (2014-2015)		356.9	340.2	697.1	C - 66
Install Automated Meter Reading - Various Sites (2013-2014)	287.7	258.8		546.5	
Purchase Meters, Equipment and Metering Tanks - Various Sites		199.0		199.0	E - 212
TOTAL METERING	287.7	814.7	340.2	1,442.6	
TOOLS AND EQUIPMENT					
Replace Off Road Track Vehicles - Various Sites (2013-2014)	416.8	1,054.1		1,470.9	
Replace Light Duty Mobile Equipment - Various Sites		579.1		579.1	C - 68
Purchase Tools & Equipment Less than $50,000 - Various Sites		553.3		553.3	
Purchase Track Mounted Backyard Radial Boom Derrick - Bishop Falls		158.7		158.7	E - 231
Replace Excavator - St. Anthony		110.0		110.0	E - 233
Purchase Portable Vibration Testing Equipment - Various Sites		60.6		60.6	E - 235
TOTAL TOOLS AND EQUIPMENT	416.8	2,515.8		2,932.6	
TOTAL TRANSMISSION AND RURAL OPERATIONS	11,515.7	64,047.3	16,012.7	91,575.7	

PROJECT DESCRIPTION	Expended to 2013	2014	Future Years	Total	Page Ref
			($000)		
INFORMATION SYSTEMS					
SOFTWARE APPLICATIONS					
New Infrastructure					
Perform Minor Application Enhancements - Hydro Place		138.6		138.6	E - 237
Cost Recoveries		(51.3)		(51.3)	
Upgrade of Technology					
Upgrade Microsoft Office Products - Hydro Place	656.7	455.1	465.2	1,577.0	
Cost Recoveries	(236.4)	(163.8)	(167.5)	(567.7)	
Upgrade Energy Management System - Hydro Place		187.9		187.9	E - 239
TOTAL SOFTWARE APPLICATIONS	420.3	566.5	297.7	1,284.5	
COMPUTER OPERATIONS					
Infrastructure Replacement					
Replace Personal Computers - Various Sites		489.8		489.8	D - 169
Upgrade Enterprise Storage Capacity - Hydro Place		517.8		517.8	C - 70
Cost Recoveries		(191.6)		(191.6)	
Replace Peripheral Infrastructure - Various Sites		200.7		200.7	D - 174
Upgrade of Technology					
Upgrade Server Technology Program - Hydro Place		328.0		328.0	D - 179
Cost Recoveries		(42.0)		(42.0)	
TOTAL COMPUTER OPERATIONS		1,302.7		1,302.7	
TOTAL INFORMATION SYSTEMS	420.3	1,869.2	297.7	2,587.2	

PROJECT DESCRIPTION	Expended to 2013	2014	Future Years	Total	Page Ref
			($000)		
TELECONTROL					
NETWORK SERVICES					
Infrastructure Replacement					
Replace MDR4000 Microwave Radio (West) - Various Sites	539.0	706.9		1,245.9	
Replace Radomes - Various Sites		324.9		324.9	D - 185
Purchase Tools and Equipment Less than $50,000		46.4		46.4	
Network Infrastructure					
Replace Battery Banks and Chargers - Various Sites		267.0	398.0	665.0	C - 76
Replace Network Communications Equipment - Various Sites		91.0		91.0	E - 241
Upgrade of Technology					
Upgrade IP SCADA Network - Various Sites		254.2	238.7	492.9	D - 198
Replace Telephone System - Stephenville		139.9		139.9	E - 243
Upgrade Site Facilities - Various Sites		49.8		49.8	
Replace Wescom Scanner - Corner Brook		81.7		81.7	E - 245
TOTAL TELECONTROL	539.0	1,961.8	636.7	3,137.5	
TRANSPORTATION					
Replace Vehicles and Aerial Devices - Various Sites (2014-2015)		1,809.1	1,091.0	2,900.1	C - 78
Replace Vehicles and Aerial Devices - Various Sites (2013-2014)	1,302.3	679.2		1,981.5	
TOTAL TRANSPORTATION	1,302.3	2,488.3	1,091.0	4,881.6	
ADMINISTRATION					
Remove Safety Hazards - Various Sites		257.8		257.8	D - 204
Purchase Office Equipment		65.9		65.9	
TOTAL ADMINISTRATION		323.7		323.7	
TOTAL GENERAL PROPERTIES	2,261.6	6,643.0	2,025.4	10,930.0	

	2014
GENERATION	21,749.9
TRANSMISSION AND RURAL OPERATIONS	18,586.7
GENERAL PROPERTIES	2,473.2
ALLOWANCE FOR UNFORESEEN EVENTS	1,000.0
TOTAL PROJECTS UNDER $50,000	910.9
MULTI-YEAR (2013 Expenditures):	
Multi-year Projects Commencing in 2014	13,076.6
Multi-year Projects Commencing in 2013	39,602.3
Multi-year Projects Commencing Prior to 2013:	
Replace Guy Wires Doyles to Grand Bay - TL215	530.0
Perform Arc Flash Remediation - Various Sites	401.8
Perform Grounding Upgrades - Various Sites	337.1
TOTAL CAPITAL BUDGET	**98,668.5**

PROJECT DESCRIPTION	2014
Generation	
HYDRAULIC PLANT	
Rewind Stator Unit 3 - Bay d'Espoir	4,343.9
Refurbish Surge Tank 3 - Bay d'Espoir	2,265.0
Upgrade North Cut-Off Dam Access Road - Bay d'Espoir	631.7
Automate Generator Deluge Systems Units 3 and 6 - Bay d'Espoir	612.0
Upgrade Victoria Control Structure - Bay d'Espoir	495.1
Overhaul Turbine/Generator Units - Bay d'Espoir and Hinds Lake	485.0
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir	352.8
Replace Automatic Greasing Systems Units 5 and 6 - Bay d'Espoir	233.4
Replace Generator Bearing Coolers Units 4 and 5 - Bay d'Espoir	199.0
Install Automated Fuel Monitoring System at West Salmon Spillway - Bay d'Espoir	193.2
Replace Fall Arrest on Surge Tank 1 - Bay d'Espoir	142.8
Replace Turbine/Generator Cooling Water Flow Meters - Upper Salmon	139.7
Raise Height of Earth Dam - Paradise River	98.7
Replace Engine on Emergency Lift System - West Salmon Spillway	67.1
THERMAL PLANT	
Overhaul Turbine/Generator Unit 2 - Holyrood	5,147.0
Complete Condition Assessment Phase 2 - Holyrood	1,476.8
Upgrade Plant Elevators - Holyrood	533.2
Upgrade Vibration Monitoring System - Holyrood	524.9
Overhaul Boiler Feed Pump East Unit 3 - Holyrood	194.9
Replace DC Distribution Panels and Breakers - Holyrood	174.2
Upgrade Waste Water Basin Building - Holyrood	136.7
Upgrade Underground Plant Drainage System - Holyrood	112.6
Overhaul Cooling Water Pump East Unit 1 - Holyrood	98.4
Overhaul Extraction Pump South Unit 1 - Holyrood	96.8
GAS TURBINES	
Upgrade Gas Turbine Plant Life Extension - Stephenville	2,995.0
TOTAL GENERATION	21,749.9

PROJECT DESCRIPTION	2014
Transmission and Rural Operations	
TERMINAL STATIONS	
Upgrade Power Transformers - Various Sites	1,904.4
Upgrade Terminal Station Foundations - Various Sites	197.9
Replace Surge Arresters - Various Sites	181.9
TRANSMISSION	
Perform Wood Pole Line Management Program - Various Sites	2,564.2
DISTRIBUTION	
Provide Service Extensions - All Service Areas	6,170.0
Upgrade Distribution Systems - All Service Areas	3,370.0
GENERATION	
Overhaul Diesel Engines - Various Sites	823.5
Additions to Accommodate Load Growth - Hopedale	641.2
Inspect Fuel Storage Tanks - Various Sites	495.0
Upgrade Ventilation System - Ramea	263.0
Replace Fuel Storage Tank - Ramea	234.2
Construct Storage Facility - Postville	183.8
PROPERTIES	
Install Additional Washrooms - Various Sites	251.0
Install Fall Protection Equipment - Various Sites	199.2
METERING	
Purchase Meters, Equipment and Metering Tanks - Various Sites	199.0
TOOLS AND EQUIPMENT	
Replace Light Duty Mobile Equipment - Various Sites	579.1
Purchase Track Mounted Backyard Radial Boom Derrick - Bishop Falls	158.7
Replace Excavator - St. Anthony	110.0
Purchase Portable Vibration Testing Equipment - Various Sites	60.6
TOTAL TRANSMISSION AND RURAL OPERATIONS	18,586.7

PROJECT DESCRIPTION	2014
General Properties	
INFORMATION SYSTEMS	
SOFTWARE APPLICATIONS	
New Infrastructure	
Perform Minor Application Enhancements - Hydro Place	138.6
Cost Recoveries	(51.3)
Upgrade of Technology	
Upgrade Energy Management System - Hydro Place	187.9
COMPUTER OPERATIONS	
Infrastructure Replacement	
Replace Personal Computers - Various Sites	489.8
Upgrade Enterprise Storage Capacity - Hydro Place	517.8
Cost Recoveries	(191.6)
Replace Peripheral Infrastructure - Various Sites	200.7
Upgrade of Technology	
Upgrade Server Technology Program - Hydro Place	328.0
Cost Recoveries	(42.0)
TELECONTROL	
NETWORK SERVICES	
Infrastructure Replacement	
Replace Radomes - Various Sites	324.9
Network Infrastructure	
Replace Network Communications Equipment - Various Sites	91.0
Upgrade of Technology	
Replace Telephone System - Stephenville	139.9
Replace Wescom Scanner - Corner Brook	81.7
ADMINISTRATION	
Remove Safety Hazards - Various Sites	257.8
TOTAL GENERAL PROPERTIES	2,473.2
TOTAL SINGLE YEAR PROJECTS OVER $50,000	**42,809.8**

Multi-year Projects Commencing in 2014

PROJECT DESCRIPTION	2014	2015	2016	2017	2018	Total
Upgrade Distribution Systems - Various Sites (2014-2015)	2,499.8	4,850.1				7,349.9
Upgrade Circuit Breakers - Various Sites	3,695.4	1,642.5				5,337.9
Replace Vehicles and Aerial Devices - Various Sites (2014-2015)	1,809.1	1,091.0				2,900.1
Replace Diesel Units - Port Hope Simpson and Mary's Harbour	208.9	2,377.7				2,586.6
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside	1,191.7	988.2				2,179.9
Upgrade Burnt Dam Spillway - Bay d'Espoir	110.2	1,201.9				1,312.1
Upgrade Excitation Systems Units 1 and 2 - Holyrood	654.3	456.6				1,110.9
Replace Disconnect Switches - Various Sites	815.9	189.5				1,005.4
Install Fire Protection System - Nain	107.1	892.2				999.3
Upgrade Diesel Plant Production Data Collection Equipment - Various Sites	268.9	269.8	280.7			819.4
Upgrade Shoreline Protection - Cat Arm	55.3	708.1				763.4
Install Automated Meter Reading - Various Sites (2014-2015)	356.9	340.2				697.1
Replace Battery Banks and Chargers - Various Sites	267.0	398.0				665.0
Replace Economizer Inlet Valves - Holyrood	192.0	329.1				521.1
Install Cold-Reheat Condensate Drains and High Pressure Heater Trip Level Unit 3 - Holyrood	49.8	467.4				517.2
Upgrade IP SCADA Network - Various Sites	254.2	238.7				492.9
Upgrade Generator Bearings Unit 2 - Bay d'Espoir	18.9	396.0				414.9
Install Fire Protection Upgrades - Holyrood	56.6	312.5				369.1
Install Handheld Pendant to Overhead Crane - Bay d'Espoir	49.9	170.8				220.7
Legal Survey of Primary Distribution Line Right of Ways - Various Sites (2014-2015)	156.8	40.3				197.1
Replace Recloser Control Panels - Various Sites	111.3	84.4				195.7
Replace Optimho Relays on TL203 - Western Avalon to Sunnyside	89.1	96.9				186.0
Replace Spherical By Pass Valve Assemblies Units 1 and 2 - Bay d'Espoir	57.5	96.3				153.8
Total Multi-Year Projects over $50,000 commencing in 2014	**13,076.6**	**17,638.2**	**280.7**	**0.0**	**0.0**	**30,995.5**

Multi-year Projects Commencing in 2013

PROJECT DESCRIPTION	Expended to 2013	2014	2015	2016	2017	2018	Total
Install New Transformer - Oxen Pond	3,823.6	15,310.4					19,134.0
Additions for Load - Isolated Generation Stations - Various Sites	2,040.2	9,357.9					11,398.1
Upgrade Distribution Systems - Various Sites	1,940.1	3,995.5					5,935.6
Replace Instrument Transformers - Various Sites	593.2	552.8	538.4	1,511.7	471.9		3,668.0
Install Variable Speed Drives on 6 Forced Draft Fans - Holyrood	697.6	2,659.7					3,357.3
Replace Compressed Air Systems - Stoney Brook and Sunnyside	303.0	2,105.9					2,408.9
Replace Vehicles and Aerial Devices - Various Sites	1,302.3	679.2					1,981.5
Upgrade Terminal Station - Wiltondale	697.7	1,173.3					1,871.0
Upgrade Microsoft Office Products - Hydro Place	656.7	455.1	465.2				1,577.0
Replace Off Road Track Vehicles - Various Sites	416.8	1,054.1					1,470.9
Replace MDR4000 Microwave Radio (West) - Various Sites	539.0	706.9					1,245.9
Upgrade Gas Turbine Controls - Happy Valley	61.4	1,128.6					1,190.0
Install Automated Meter Reading - Various Sites	287.7	258.8					546.5
Replace Insulators - Various Sites	187.1	287.9					475.0
Legal Survey of Primary Distribution Line Right of Way - Various Sites	156.2	40.0					196.2
Cost Recoveries	(236.4)	(163.8)	(167.5)				(567.7)
TOTAL MULTI-YEAR PROJECTS OVER $50,000 COMMENCING 2013	**13,466.2**	**39,602.3**	**836.1**	**1,511.7**	**471.9**	**0.0**	**55,888.2**

PROJECT DESCRIPTION	Expended to 2013	2014	Future Years	Total	Page Ref
	($000)				
GENERATION					
Rewind Stator Unit 3 - Bay d'Espoir		4,343.9		4,343.9	C - 3
Refurbish Surge Tank 3 - Bay d'Espoir		2,265.0		2,265.0	C - 5
Upgrade Burnt Dam Spillway - Bay d'Espoir		110.2	1,201.9	1,312.1	C - 8
Upgrade Shoreline Protection - Cat Arm		55.3	708.1	763.4	C - 11
Upgrade North Cut-Off Dam Access Road - Bay d'Espoir		631.7		631.7	C - 13
Automate Generator Deluge Systems Units 3 and 6 - Bay d'Espoir		612.0		612.0	C - 15
Overhaul Turbine/Generator Unit 2 - Holyrood		5,147.0		5,147.0	C - 18
Install Variable Speed Drives on 6 Forced Draft Fans - Holyrood	697.6	2,659.7		3,357.3	
Complete Condition Assessment Phase 2 - Holyrood		1,476.8		1,476.8	C - 20
Upgrade Excitation Systems Units 1 and 2 - Holyrood		654.3	456.6	1,110.9	C - 22
Upgrade Plant Elevators - Holyrood		533.2		533.2	C - 24
Upgrade Vibration Monitoring System - Holyrood		524.9		524.9	C - 26
Replace Economizer Inlet Valves - Holyrood		192.0	329.1	521.1	C - 28
Install Cold-Reheat Condensate Drains and High Pressure Heater Trip Level Unit 3 - Holyrood		49.8	467.4	517.2	C - 30
Upgrade Gas Turbine Plant Life Extension - Stephenville		2,995.0		2,995.0	C - 33
Upgrade Gas Turbine Controls - Happy Valley	61.4	1,128.6		1,190.0	
TOTAL GENERATION	759.0	23,379.4	3,163.1	27,301.5	
TRANSMISSION AND RURAL OPERATIONS					
Install New Transformer - Oxen Pond	3,823.6	15,310.4		19,134.0	
Upgrade Circuit Breakers - Various Sites		3,695.4	1,642.5	5,337.9	C - 35
Replace Instrument Transformers - Various Sites	593.2	552.8	2,522.0	3,668.0	
Replace Compressed Air Systems - Stoney Brook and Sunnyside	303.0	2,105.9		2,408.9	
Upgrade Power Transformers - Various Sites		1,904.4		1,904.4	C - 38
Upgrade Terminal Station - Wiltondale	697.7	1,173.3		1,871.0	
Perform Grounding Upgrades - Various Sites	329.0	337.1	1,025.1	1,691.2	
Replace Disconnect Switches - Various Sites		815.9	189.5	1,005.4	C - 40
Perform Wood Pole Line Management Program - Various Sites		2,564.2		2,564.2	C - 42
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside		1,191.7	988.2	2,179.9	C - 44
Replace Guy Wires Doyles to Grand Bay - TL215	350.1	530.0		880.1	
Upgrade Distribution Systems - Various Sites (2014-2015)		2,499.8	4,850.1	7,349.9	C - 48
Provide Service Extensions - All Service Areas		6,170.0		6,170.0	C - 50
Upgrade Distribution Systems - Various Sites (2013-2014)	1,940.1	3,995.5		5,935.6	
Upgrade Distribution Systems - All Service Areas		3,370.0		3,370.0	C - 52
Additions for Load Growth - Isolated Generation Stations - Various Sites	2,040.2	9,357.9		11,398.1	
Replace Diesel Units - Port Hope Simpson and Mary's Harbour		208.9	2,377.7	2,586.6	C - 56
Perform Arc Flash Remediation - Various Sites	391.0	401.8	413.1	1,205.9	
Install Fire Protection System - Nain		107.1	892.2	999.3	C - 58
Upgrade Diesel Plant Production Data Collection Equipment - Various Sites		268.9	550.5	819.4	C - 60
Overhaul Diesel Engines - Various Sites		823.5		823.5	C - 62
Additions to Accomodate Load Growth - Hopedale		641.2		641.2	C - 64
Install Automated Meter Reading - Various Sites (2014-2015)		356.9	340.2	697.1	C - 66
Install Automated Meter Reading - Various Sites (2013-2014)	287.7	258.8		546.5	
Replace Off Road Track Vehicles - Various Sites (2013-2014)	416.8	1,054.1		1,470.9	
Replace Light Duty Mobile Equipment - Various Sites		579.1		579.1	C - 68
TOTAL TRANSMISSION AND RURAL OPERATIONS	11,172.4	60,274.6	15,791.1	87,238.1	

PROJECT DESCRIPTION	Expended to 2013	2014	Future Years	Total	Page Ref
			($000)		
GENERAL PROPERTIES					
Upgrade Microsoft Office Products - Hydro Place	420.3	291.3	297.7	1,009.3	
Upgrade Enterprise Storage Capacity - Hydro Place[1]		326.2		326.2	C - 70
Replace MDR4000 Microwave Radio (West) - Various Sites	539.0	706.9		1,245.9	
Replace Battery Banks and Chargers - Various Sites		267.0	398.0	665.0	C - 76
Replace Vehicles and Aerial Devices - Various Sites (2014-2015)		1,809.1	1,091.0	2,900.1	C - 78
Replace Vehicles and Aerial Devices - Various Sites (2013-2014)	1,302.3	679.2		1,981.5	
TOTAL GENERAL PROPERTIES	2,261.6	4,079.7	1,786.7	8,128.0	
TOTAL PROJECTS $500,000 AND OVER	14,193.0	87,733.7	20,740.9	122,667.6	

[1] Project is over $500,000 before cost recoveries. Shown net of cost recoveries in this schedule.

Project Title: Rewind Stator Unit 3

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is for the replacement of a stator winding on Unit 3 at the Bay d'Espoir Hydroelectric Station. This project is the final stator winding replacement on stage 1 of the plant, as Units 1, 2 and 4 were completed in 2010, 2012 and 2013 respectively. This project includes an upgrade to the generator protection, the remediation of confirmed asbestos from the stator components and the refurbishment of other generator components such as the rotor poles. This work is required to ensure the new stator winding will operate at its full capability.

The budget estimate for this project is shown in Table 1 below.

Table 1: Project Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	662.9	0.0	0.0	662.9
Labour	503.0	0.0	0.0	503.0
Consultant	7.0	0.0	0.0	7.0
Contract Work	2,148.7	0.0	0.0	2,148.7
Other Direct Costs	80.4	0.0	0.0	80.4
Interest and Escalation	261.5	0.0	0.0	261.5
Contingency	680.4	0.0	0.0	680.4
TOTAL	**4,343.9**	**0.0**	**0.0**	**4,343.9**

Operating Experience:

The hydro generating Units 1, 2, 3 and 4 in the Bay d'Espoir Generating Station are designed for continuous operation with each unit varying its load to meet system requirements. With the exception of maintenance outages, these four units have been operating continuously since they were commissioned in 1967-1968.

Project Justification:

This project is required to maintain system reliability and to complete the replacement of stator windings on stage 1 units. The stator windings on Units 2 and 4 were replaced in 2010 and 2012, respectively, on budget and on schedule. The Unit 1 stator winding is being replaced in 2013 with cost and schedule expected to be as planned. Unit 3 is showing similar indicators of deterioration both physically and through electrical testing as Units 2, 4 and 1 did previously.

Hydro, in its objective to provide reliable and safe electricity, must be prudent to prevent the failure of major equipment. The failure of a stator winding during operation would have a significant impact on providing reliable electricity, as the outage period for an unplanned stator winding replacement could be a minimum of six to 12 months along with the additional cost of completing unplanned work versus planned work. Presently, there are spare stator coils on site, but not in a quantity sufficient to complete a stator winding replacement. Thus, the failure to plan the replacement of the stator winding would impair Hydro's ability to provide least-cost, reliable electricity.

The life expectancy for a Class B asphalt mica stator winding is estimated to be 40 years. Since the stator winding on Unit 3 has exceeded this time period, the Unit 3 stator winding is beyond its useful service life and a replacement is required.

During the Unit 2 stator replacement work completed in 2010, it was determined that movement or migration of the stator core laminations had occurred. Although stator core migration was not discovered on Unit 4 in 2012, there is still concern that this condition may exist on Unit 3. The migration of the stator core is a serious condition that can lead to a failure of the stator winding. The uncertainty of this condition on a stator winding that is beyond its useful service life indicates the winding should be replaced.

Future Plans:

None.

Attachments:

See report entitled "Rewind Stator Unit 3" located in Volume I, Tab 1, for further project details.

Project Title: Refurbish Surge Tank 3

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project outlines a refurbishment of Surge Tank 3 at the Bay d'Espoir Hydroelectric Generating Station.

This scope of the project involves refurbishment and upgrade of the following components of the surge tank:

- Refurbish all exterior surfaces, including surface preparation and coating of the surge tank exterior, and structural supports, including containment of material removed during surface preparation;
- Refurbish the compression ring and part of the top balcony;
- Refurbish the turnbuckles, rod bracing and leg foundation anchor bolts;
- Assess the roof anchor point system and replace with certified anchor points as required;
- Install a gate at the ladder access point to the lower balcony;
- Replace the roof ladder including the painters post with a fixed ladder;
- Refurbish the damaged insulation on the hot water heating system piping and re-flashing at the top of the insulation at the inlet to the surge tank;
- Replace the obstruction lighting on top of the tank; and
- Install wear plates at the intersection of the cross braces.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	87.0	0.0	0.0	87.0
Consultant	66.0	0.0	0.0	66.0
Contract Work	1,610.0	0.0	0.0	1,610.0
Other Direct Costs	30.5	0.0	0.0	30.5
Interest and Escalation	112.8	0.0	0.0	112.8
Contingency	358.7	0.0	0.0	358.7
TOTAL	**2,265.0**	**0.0**	**0.0**	**2,265.0**

Operating Experience:

Surge Tank 3 was built from 1969 to 1970 and has operated without incident during its time in service. There are over 1,300 tons of steel in the surge tank. This steel needs continuous protection and is starting to corrode as indicated in the professional engineering report by Hatch (See Appendix A in the accompanying report) entitled “Bay d’Espoir Surge Tank No. 3 Condition Assessment”. There has been a complete coating failure of the roof of the surge tank, leaving the steel exposed to the elements. The extent of coating failure over the remainder of the surge tank is not as severe, but will become more severe if recoating is not performed now. This tank is 43 years old and in order to continue with reliable, uninterrupted operation, and avoid a potentially significant increase in rehabilitation cost from accelerating degradation rates, it needs to be promptly refurbished. Failure to undertake this work could lead to deterioration of the steel components which could eventually lead to a failure.

Project Justification:

Surge Tank 3 is in the worst condition of the three surge tanks at Bay d’Espoir. The existing coating system was applied in 1985 whereas the other two tanks were recoated in the early 1990s. This project is justified on the requirement to replace failing or deteriorated infrastructure in order for Hydro to provide safe and reliable operation of Surge Tank 3 and generating Units 5 and 6 at the Bay d’Espoir Hydroelectric Generating Station. A condition assessment study performed by a professional engineering firm, Hatch, in 2012 identified significant deterioration of the surge tank and made a number of recommendations for repair and refurbishment.

A significant leak in this structure would require an immediate repair. It has the potential to create downtime for the operation of generating Units 5 and 6, with a combined capacity of 150 MW, which would impact Hydro’s ability to meet the electrical demand on the Island Interconnected System. The design and construction of these surge tanks are unique and repair of components after a failure would require special arrangements and fabrication. This specialty work would increase costs associated with repair. Costs to carry out refurbishment and upgrades, in advance of any major problems will be considerably less, considering there will be no damage to remediate and that downtime will be eliminated or at least reduced. By undertaking this work now, the life of the tank can be extended and system reliability can be ensured.

Future Plans:

Surge Tanks 1 and 2 will have to be refurbished in 2017 and 2016 respectively.

Attachments:

See report entitled "Surge Tank 3 Refurbishment" located in Volume I, Tab 2, for further project details.

Project Title: Upgrade Burnt Dam Spillway

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is the final two years of a five year program to upgrade the Burnt Dam Spillway Structure. Equipment at the spillway is at or near the end of its useful life and/or is in a deteriorated condition. After this upgrade is completed, the Burnt Dam Spillway will be in a condition to operate safely and reliably for another 25 years. This project involves replacement, refurbishment and upgrade of various components at the Burnt Dam Spillway. The scope of work for this phase of the project includes the following;

- Permanently install the existing portable emergency hydraulic drive in a new enclosure and install permanent piping to the drives of each gate hoist;
- Replace the existing 25 kW and 75 kW diesel generating sets and associated switchgear;
- Replace the DC disconnect switches in the diesel building with non-fusible disconnects fitted with viewing windows;
- Replace the cables from the diesel building to the spillway gates control building;
- Raise and seal the cable penetrations through the exterior walls to prevent water ingress and flooding inside the diesel building;
- Modify the existing diesel generator exhaust stacks to achieve acceptable dispersion of exhaust emissions; and
- Modify each diesel generator's cooling system to protect the cooling vents from snow blockage during winter operation.

The total budget estimate for this project is $1,312,100. Engineering work is scheduled to start in September 2014 with construction taking place from July to October 2015.

The budget estimate for this project is shown in Table 1.

Table 1: Project Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	226.0	0.0	226.0
Labour	45.0	370.6	0.0	415.6
Consultant	35.0	13.6	0.0	48.6
Contract Work	0.0	148.0	0.0	148.0
Other Direct Costs	24.5	142.5	0.0	167.0
Interest and Escalation	5.7	100.2	0.0	105.9
Contingency	0.0	201.0	0.0	201.0
TOTAL	**110.2**	**1,201.9**	**0.0**	**1,312.1**

Operating Experience:

In 2006, there was an incident whereby the gates at Burnt Dam Spillway failed to operate when required. A crew was dispatched from Bay d'Espoir to perform emergency work on both gates but could not get either of the gates open to the position requested by Hydro's Energy Control Centre (ECC) in order to lower the reservoir water level. This is a serious situation during times of high reservoir levels as there is a potential to cause a fuse plug failure. The incident in 2006 did not result in a fuse plug failure, however, it did cause the loss of a significant amount of reservoir water when both gates could not be closed when required for a period of time. It was estimated at that time that the lost water and subsequent lost generation value was $2.6 million (based on replacing the energy with generation from the Holyrood Thermal Generating Station and oil at $50 per barrel).

Project Justification:

The availability and reliable operation of the diesel generators is critical for heating and operation of the spillway gates and also for supplying power to the accommodations which are occupied on a year round basis. In 2009 one of the diesel generators was replaced. The other two are now 45 and 25 years old and are no longer reliable. During the last five years there have been a number of equipment failures caused by oil leaks, governor and turbocharger failures.

In addition to the diesel generators, the emergency hydraulic drive system is also critical to the reliable operation of the spillway gates. If all the diesel generators were not available during a flood situation, the emergency drive would be required to open the gates. The other upgrades to be completed as part of this project are necessary to address other safety, environment and reliability issues.

Future Plans:

This is the final two years of a five year program to upgrade Burnt Dam Spillway. The third year of this program is 2013 and the work includes a detailed inspection of components that are difficult to access. This will take place in late 2013 and depending on the results of that inspection another capital proposal may be required to remedy any deficiencies.

Attachments:

See report entitled "Upgrade Burnt Dam Spillway Structure" located in Volume I, Tab 3, for further project details.

Project Title: Upgrade Shoreline Protection

Location: Cat Arm

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

The 127 MW Cat Arm Hydroelectric Development (Cat Arm), situated on the east side of the Great Northern Peninsula, was completed in 1984. Access to the plant is via a 25 km long gravel road off route 420 near Jackson’s Arm. An 80 m section of this road near the powerhouse at Devil’s Cove is seriously deteriorated and requires upgrading. The project scope of work involves upgrading of an armour stone wave barrier at the waterline edge for wave protection and the placement of rock fill material to re-establish a stable road embankment.

The project will require approvals from the Provincial Department of Environment and Conservation, Provincial Department of Natural Resources and the Federal Department of Fisheries and Oceans. The work will be performed under contract with site supervision by a consultant. The budget estimate for the project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	19.0	48.8	0.0	67.8
Consultant	16.0	68.0	0.0	84.0
Contract Work	0.0	400.0	0.0	400.0
Other Direct Costs	16.8	14.0	0.0	30.8
Interest and Escalation	3.5	60.8	0.0	64.3
Contingency	0.0	116.5	0.0	116.5
TOTAL	**55.3**	**708.1**	**0.0**	**763.4**

Operating Experience:

The gravel road provides the only access to Cat Arm for operating and maintenance personnel. Wind and wave action continue to cause significant erosion along various sections of this road. One of these areas is at an armour stone shoreline protection barrier that was constructed in 2005. Storms in the area have removed all of the armour stone along an 80 m section of this barrier which provides protection for the blast rock and filter material in the upgraded road embankment section. With the protection material removed, the remaining blast rock and filter material is left unprotected and erodes easily into the ocean.

As part of other road work undertaken in 2012, Hydro submitted an application for Permission to Occupy to Crown Lands in 2012. Hydro subsequently applied for a Crown Easement to the road lands in October 2012. At the time Hydro was informed that this process could take up to 12 months. It is anticipated that the easement should be received prior to the end of 2013. This easement form of title has been determined to be appropriate for Hydro's needs as Hydro does not need to exclude others from using the road. Hydro does require the legal right to have secure access in order to make improvements to the road and to build and maintain structures such as guide rails, bridges and culverts. Major work and upgrades completed on the Cat Arm access road since original construction consists of road repairs and slope stabilization measures.

Project Justification:
The road is used on a daily basis by Hydro's operating staff and at regular intervals by maintenance personnel. Vehicles transporting personnel and maintenance material must travel this access road.

The most recent review of the shoreline protection barrier by Hydro staff and a geotechnical consultant, AMEC Earth and Environmental (AMEC), has concluded that on-going erosion is anticipated during periods of high waves combined with storm surges or higher tides and should be repaired to prevent further erosion of the embankment. The erosion will progress to the point where the re-built road section will become degraded such that the road driving surface will again be reduced to a single lane. In a worst case scenario, this access for operational and maintenance personnel could be lost, which could have an impact on plant reliability and power supply to Hydro's customers.

A permanent and safe access road is required for the long term reliable operation of Cat Arm.

Future Plans:
None.

Attachments:
See report entitled "Upgrade Shoreline Protection " located in Volume I, Tab 4, for further project details.

Project Title: Upgrade North Cut-off Dam Access Road

Location: Bay d'Espoir

Category: Generation – Hydraulic

Definition: Other

Classification: Normal

Project Description:

Work under this project involves the completion of upgrades to North Cut-Off Dam access road. The work will consist of:

- Remove vegetation;
- Clean and reshape drainage ditches along the shoulders of the roadway;
- Supply and install eight storm culverts;
- Supply and install rip rap headwall/tail wall;
- Supply, place and compact 1,100 tons of Granular B subgrade material; and
- Supply, place and compact 12,150 tons of Granular A road topping material.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	47.6	0.0	0.0	47.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	449.9	0.0	0.0	449.9
Other Direct Costs	4.5	0.0	0.0	4.5
Interest and Escalation	29.3	0.0	0.0	29.3
Contingency	100.4	0.0	0.0	100.4
TOTAL	**631.7**	**0.0**	**0.0**	**631.7**

Operating Experience:

The North Cut-off Dam access road permits vehicular access to critical hydraulic structures. These structures require regular visits for the completion of routine inspection and maintenance. The road is utilized year round.

The condition of the roadway has deteriorated over time, accelerated by storm events of recent years. Drainage and road topping have now degraded to the point where safe usage has been impacted and the road has become impassable at times. To facilitate continued access to the North Cut-Off Dam and prevent accelerated deterioration of the road base, the road has to be restored to normal standards. Repairs involve the engagement of an external contractor to import and place granular material at the affected areas.

Project Justification:

The access road was constructed during Stage 1 of the Bay d'Espoir Hydroelectric Development in the mid 1960s. No major upgrades or work have been completed on the roadway since its original construction. Routine maintenance has been carried out to keep the road open and passable, however, it is has reached the end of its service life and requires an upgrade.

Over the past 50 years, the road topping has deteriorated to the point that the sub-grade material is exposed. This creates a very uneven, rough driving surface which is difficult to drive over safely and promotes increased wear on vehicles and risk to Hydro personnel.

Furthermore, the road drainage systems have deteriorated over time resulting in frequent washouts of the roadway and accelerated erosion damage. Some drainage issues stem from collapsed culverts and plugged drainage ditches. The resulting washouts make the road impassable during rain events and necessitate repairs in order to permit safe and reliable vehicular access to the destination structures, a requirement of safe and reliable operations.

Future Plans:

None.

Attachments:

See report entitled "Upgrade North Cut-Off Dam Access Road" located in Volume I, Tab 5 for further project details.

Project Title: Automate Generator Deluge Systems Units 3 and 6

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

As part of the 2013 Capital Budget, a project entitled Automate Generator Deluge Systems Units 5 and 6 was approved by Order No. P.U.4 (2013). However, due to unforeseen changes in generating unit outage schedules, Hydro is unable to perform that work on Units 5 and 6 in 2013 and the planned installations will be completed on Units 4 and 7 instead.

The scope of work for this project is to complete the installations on Units 3 and 6 in 2014. It will replace the existing manually operated generator deluge system on generating Units 3 and 6 with a modern fully automatic deluge system. A new deluge control cabinet will be installed along with a new deluge valve; the sprinkler distribution ring will be reused. The distribution ring is a system of pipes that surround the generator and deliver water to spray nozzles in the event of a fire. When the system is activated, water flows immediately through all nozzles at once. An outage on each generating unit will be required to complete the new installations. The outages will take place during the annual maintenance period and will be two to four weeks in duration.

The budget estimate for this project is shown in Table 1.

Table 1: Project Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	35.4	0.0	0.0	35.4
Labour	99.8	0.0	0.0	99.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	334.0	0.0	0.0	334.0
Other Direct Costs	8.6	0.0	0.0	8.6
Interest and Escalation	38.5	0.0	0.0	38.5
Contingency	95.5	0.0	0.0	95.5
TOTAL	**612.0**	**0.0**	**0.0**	**612.0**

Operating Experience:

The current generator fire protection system in Bay d'Espoir is a manual system that remains in a stand-by state until it can be activated by operations personnel. The system is tested every year to ensure there is water flow to the deluge valve. However, since it is not practical to wet the generator windings with water, the actual spray rings inside the generating unit are not flow tested. Applying water to a generator in a non-fire condition is not practical because it can cause damage to the unit.

In the time taken for an operator to respond to a fire alarm on a generating unit a potentially small fire could turn into something much larger, thus leading to more equipment damage and increased replacement costs. An automatic system is more effective because there is no delay in responding to an alarm, thereby ensuring a greater potential for extinguishing a fire before major equipment damage occurs. This project was identified by Hydro's insurer, FM Global in 2007 and Hydro believes that this project is warranted to mitigate the risk from a fire.

Project Justification:

This project is justified on the need for Hydro to upgrade the existing equipment to reduce exposure to harm by operations personnel and reduce the potential for damage to equipment in the event of a fire on a generator.

The FM Global Risk Report for Bay d'Espoir indicates the hazard associated with a manual system is the ability of a generator fire to spread rapidly during the time it takes an operator to respond to the initial alarm. A longer response time to a fire could result in more extensive damage to the equipment and increased cost of repairs. A large fire could also prevent access to the manual valves altogether leading to greater damage with potential loss of 450 MW of generating capacity to the Island Interconnected System for a period of time ranging in duration from several months to over a year.

Hydro has not experienced a fire on any of its seven generating units at Bay d'Espoir. However, the existing manual system poses a significant risk if there is a fire. It is required that the deluge systems for each generating unit be upgraded to a fully automatic system to limit employee exposure to harm and reduce potential equipment damage in the event of a fire.

Future Plans:

This would be the second year of a four year project to replace the manual deluge system on all seven units in Bay d'Espoir. The plan is to do two units in each of the first three years and then one unit in the fourth year 2016.

Attachments:

See report entitled "Automate Generator Deluge Systems" located in Volume II, Tab 6 for further project details.

Project Title: Overhaul Turbine/Generator Unit 2

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is required to perform a scheduled major overhaul of Unit 2 Turbine, Generator and auxiliary systems located at the Holyrood Thermal Generating Station. This major overhaul consists of total dismantling of all turbine stages, removal of the generator rotor, and internal inspections of all auxiliary equipment. The work will be completed by contracted services with assistance from plant personnel as required. The contracted work consists of technical services, labor, materials and supervision. Plant support is required for work protection application and services, removal of specific monitoring and control systems, overall project supervision and liaison with Hydro's management personnel.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	475.0	0.0	0.0	475.0
Labour	350.0	0.0	0.0	350.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	3,250.0	0.0	0.0	3,250.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	257.0	0.0	0.0	257.0
Contingency	815.0	0.0	0.0	815.0
TOTAL	**5,147.0**	**0.0**	**0.0**	**5,147.0**

Operating Experience:

The operating hours for Unit 2, up to March 2013, are 172,632. Assuming the generator operates for approximately 5,000 hours per year until 2014, it is expected to attain approximately 180,000 hours before the next major inspection in 2014. Unit 2 has undergone scheduled major and valve overhauls on a six-year and three-year basis respectively from 1971 to 2005.

Project Justification:

This project is justified on the requirement to maintain the generating equipment in its optimal operating condition for Hydro to provide safe, least-cost, reliable electrical service to its customers. The purpose of the major overhaul is to return the turbine, generator and auxiliary systems to design specifications such that they can perform safely, efficiently, and reliably to meet system demands. The overhaul will also identify any internal conditions that if not corrected or controlled could lead to premature failure of the equipment.

Future Plans:

None.

Attachments:

See report entitled "Overhaul Steam Turbine Generator Unit 2" Located in Volume I, Tab 7 for further details.

Project Title: Complete Condition Assessment Phase 2

Location: Holyrood

Category: Generation – Thermal

Definition: Other

Classification: Normal

Project Description:

This project is the third year of Phase 2 of a condition assessment and life extension program that began as Phase 1 in 2009 and was completed in March 2011. Phase 2 is a three year project. The scope of work is to perform more detailed internal investigation on select equipment/systems as identified by Phase 1 to determine the actions required to ensure that reliable and safe operation of the Holyrood plant will be maintained into the future with consideration to the plant's projected operating requirements. The first and second years of Phase 2 were approved by the Board for 2012 and 2013 for completion under Hydro's capital program.

Table 1 provides the budget estimate for this project.

Table 1: Project Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	60.2	0.0	0.0	60.2
Consultant	280.0	0.0	0.0	280.0
Contract Work	818.0	0.0	0.0	818.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	87.0	0.0	0.0	87.0
Contingency	231.6	0.0	0.0	231.6
TOTAL	**1,476.8**	**0.0**	**0.0**	**1,476.8**

Operating Experience:

The Holyrood plant has been in operation since 1970 and operates under a seasonal regime. Full generating capacity is required during the winter months and no generation is required during the summer. During the spring and fall seasons the plant generation load varies but is normally less than full plant capacity. In late spring, when power generation is not required, generating Unit 3 is converted to synchronous condenser mode of operation. Synchronous condensing is required during the summer to provide voltage support and ensure stability of the Island Interconnected System.

Project Justification:

The Holyrood Thermal Generating Station is over 40 years old and is past its expected life to provide reliable, least cost power. Considering the operating hours it has incurred, there are areas that need to undergo detailed investigation to determine what actions, if any, should be taken to ensure that equipment can continue to remain in service from a safety and reliability perspective. This project will provide information that will enable Hydro to make informed decisions as it plans for the projected operational requirements of the plant, with consideration to the implications of the Lower Churchill project, and to ensure a safe, reliable operation that can deliver least cost power as needed. Phase 2 will provide information to assist Hydro in identifying the long term cost of energy produced by this facility for comparison with other alternatives to ensure power is provided to customers at the least possible cost.

Future Plans:

Upon completion of Phase 2 of the condition assessment and life extension program in 2014, the future operating requirements of the Holyrood plant will be considered. A decision will be made as to whether Phase 3 of the condition assessment and life extension program should be pursued and what its scope should be.

Attachments:

See report entitled "Condition Assessment and Life Extension" located in Volume II, Tab 8 for further project details.

Project Title: Upgrade Excitation Systems Units 1 and 2

Location: Holyrood

Category: Generation – Thermal

Definition: Other

Classification: Normal

Project Description:

This project is to replace the control section of the existing ABB Inc. Unitrol P exciters on Units 1 and 2 at Holyrood with the modern Unitrol 6080 controls. The existing control cabinet and external wiring will be reused and a panel containing the new controls will be mounted in the cabinet. Hydro will provide project management and support services for the installation and commissioning. ABB will supply the updated control panels, install them and commission the controls with assistance from Holyrood personnel.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	5.0	5.0	0.0	10.0
Labour	154.0	114.0	0.0	268.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	437.0	79.9	0.0	516.9
Other Direct Costs	13.4	11.8	0.0	25.2
Interest and Escalation	44.9	81.9	0.0	126.8
Contingency	0.0	164.0	0.0	164.0
TOTAL	**654.3**	**456.6**	**0.0**	**1,110.9**

Operating Experience:

The ABB Unitrol P controllers have worked well since their installation on Unit 2 in 1999 and Unit 1 in 2000. No forced shutdowns due to the exciter controls have been recorded.

Project Justification:

The ABB Unitrol P exciter is in the Limited Phase of the Life Cycle Plan where "product support will be conditional to service support availability and spare part deliveries are limited to the existing stock and have long lead times". This phase will continue until 2015 when it enters the “Obsolete Phase” where the manufacturer ABB states "where product support cannot be guaranteed and spare parts are either limited to the existing stock or have been discontinued." ABB recommends "its customers to carry out a Control Upgrade to the new Unitrol 6000 Excitation System" before entering the Obsolete Phase.

Future Plans:

None.

Attachments:

Please see report entitled "Upgrade Excitation Systems Unit 1 and 2" located in Volume II, Tab 9 for further project details.

Project Title: Upgrade Plant Elevators

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project involves the upgrade of the two elevators located in the power house and administration area at Holyrood Thermal Generating Station. The scope of work for each elevator upgrade will include a new drive system, control system, motor, door operator, telephone system and emergency system. Upgraded elevator systems are required to remedy the safety and reliability issues. This project will extend the service life of the two elevators at the Holyrood facility.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	30.1	0.0	0.0	30.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	380.0	0.0	0.0	380.0
Other Direct Costs	5.6	0.0	0.0	5.6
Interest and Escalation	34.4	0.0	0.0	34.4
Contingency	83.1	0.0	0.0	83.1
TOTAL	**533.2**	**0.0**	**0.0**	**533.2**

Operating Experience:

The plant and administration elevators at Holyrood have been malfunctioning, causing disruption in service and creating safety concerns. The biggest concerns are for people becoming trapped inside the elevator between floors and for an elevator car incurring an uncontrolled drop in elevation.

Project Justification:

This project is justified by the requirement for safe and reliable elevator systems at Holyrood.

Both elevators have seen an increase in downtime and have stalled when travelling between floors while transporting Hydro personnel or contractors. While there were no reports of physical harm in these incidents, there is a risk of severe injury or loss of life. These occurrences are made more dangerous with the possibility of a concurrent emergency requiring elevator use. The probability of this event occurring is low, however, the consequences could be severe.

The project will improve the performance of the elevator systems at Holyrood and reduce the risk of injury to plant workers due to failure of elevator systems.

Future Plans:

None.

Attachments:

See report entitled “Upgrade Plant Elevators” located in Volume II, Tab 10, for further project details.

Project Title: Upgrade Vibration Monitoring System

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project involves the upgrade of the Bently Nevada 3300 series Turbine Supervisory Instrumentation (TSI) system to the 3500 series for the synchronous condensing part of the plant. The modules that monitor the synchronous condenser part of the plant and diagnostics software of the existing system will be removed and replaced with an upgrade. The removed modules will be used as spares for the existing system that monitors the turbines. The upgrade will utilize the existing probes.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	2.0	0.0	0.0	2.0
Labour	128.5	0.0	0.0	128.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	285.0	0.0	0.0	285.0
Other Direct Costs	2.9	0.0	0.0	2.9
Interest and Escalation	22.8	0.0	0.0	22.8
Contingency	83.7	0.0	0.0	83.7
TOTAL	**524.9**	**0.0**	**0.0**	**524.9**

Operating Experience:

The existing Bently Nevada 3300 Turbine Supervisory Instrumentation system for vibration and machine condition monitoring was installed in the early 1990s. The system provides monitoring, diagnostics and machine protection for generating Units 1 and 2 at Holyrood. The system also provides monitoring, diagnostics and machine protection for generating Unit 1 while in generate and synchronous condenser mode. The system has performed well with no requirement for upgrades until now.

Project Justification:

The Bently Nevada 3300 Turbine Supervisory Instrumentation system is in the life cycle phase that provides only for repair or exchange of components. This upgrade should be undertaken prior to the components entering into the obsolescence phase of the product life cycle so that the vibration monitoring system for the Holyrood units is not placed at risk of inoperability in the event of a failed component. The obsolescence life cycle phase is one in which all support for the Bently Nevada 3300 series system will cease.

Future Plans:

None.

Attachments:

See report entitled "Upgrade Unit Vibration Monitoring System" located in Volume II, Tab 11, for further project details.

Project Title: Replace Economizer Inlet Valves

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Mandatory

Project Description:

This project will replace the economizer inlet valve on each boiler for generating Units 1 and 2 at Holyrood Thermal Generating Station and will be completed over two years. The ten inch diameter economizer inlet valves have been in service since they were commissioned in 1969 and operate at 2,950 psig and 500 degrees F. They have a delivery time of approximately eight months. For this reason the valves will be ordered and received in 2014 and installed in 2015 during regular planned outages.

The project includes the following activities:

- Procure two new economizer inlet valves;
- Prepare technical specification for installation including piping stress analysis; and
- Remove the existing economizer inlet valves and installation of the new valves.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	160.0	0.0	0.0	160.0
Labour	22.4	15.0	0.0	37.4
Consultant	0.0	42.0	0.0	42.0
Contract Work	0.0	151.6	0.0	151.6
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	9.6	42.3	0.0	51.9
Contingency	0.0	78.2	0.0	78.2
TOTAL	**192.0**	**329.1**	**0.0**	**521.1**

Operating Experience:

The Unit 2 economizer inlet valve developed a leak up through its hand wheel packing gland. In 2010 a leak repair, known as the Furmanite process, was applied to the valve and it was successful in stopping the leak. However, it rendered the valve inoperable in that it could not be moved to the closed position. In addition Unit 1 economizer inlet valve became inoperable in 2007 as the opening/closing mechanism started to bind and the valve seized in the open position. The valves were designed for manual actuation but when they were functioning properly they required a large physical effort to turn the hand wheel to open/close them.

Project Justification:

This project is justified on the requirement to replace the deteriorated economizer inlet valve on each boiler for Units 1 and 2 in order for Hydro to provide safe, least cost and reliable power generation and meet regulatory requirements. It will re-establish system operation to the original design.

Unit 2 economizer inlet valve was temporarily repaired in 2010 using the Furmanite process to stop a leak coming through its packing gland and discharging to the work area outside the valve body. The repair of the economizer inlet valve using the Furmanite process has restricted rotation of the stem thereby preventing the valve from being moved to the closed position. Also during a repair to Unit 2's economizer inlet valve in 2010 it was found that its seat has corroded and could not be repaired or replaced. When in the closed position a damaged seat prevents a valve from closing tight and stopping the flow of water.

Unit 1 economizer inlet valve has seized in the open position and therefore plant personnel are unable to close it. As Unit 1 valve is of the same age as Unit 2 it is expected that its seat is also in the same corroded condition.

To ensure regulatory compliance it is necessary to restore the economizer valves to proper condition and functionality as governed by the Boiler, Pressure Vessel and Compressed Gas Regulations, Province of Newfoundland and Labrador.

Replacement of the two economizer valves is required to restore feed water system reliability and eliminate safety concerns.

Future Plans:

None.

Attachments:

See report entitled "Replace Economizer Inlet Valves Units 1 and 2" located in Volume II, Tab 12, for further project details.

Project Title: Install Cold-Reheat Condensate Drains and High Pressure Heater Trip Level Unit 3

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

The purpose of this project is to install a condensate collection system (drain pots) on the cold reheat piping near the steam turbine of Unit 3. The drain pots will have automatic drain valves that are controlled by water level switches. Also, high-high water level switches will be programmed to alarm the control room operator whenever the water level in the drain pots is higher than normal.

A new vent valve and drain pipe on the high pressure heater for Unit 3 will also be installed under this project. This will enable in-situ testing of the condensate level switches so that these switches can be tested quarterly.

A steam-side outage on Unit 3 is required to complete this work. All work will take place during the annual Unit 3 outage.

The budget estimate for this project is shown in Table 1.

Table 1: Project Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	15.0	30.0	0.0	45.0
Labour	14.0	124.8	0.0	138.8
Consultant	17.5	0.0	0.0	17.5
Contract Work	0.0	190.0	0.0	190.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	3.3	44.3	0.0	47.6
Contingency	0.0	78.3	0.0	78.3
TOTAL	**49.8**	**467.4**	**0.0**	**517.2**

Operating Experience:

Since the presence of condensate in the cold reheat lines can damage steam turbines, condensate drain pots were installed on the cold reheat lines for Unit 1 (2010) and Unit 2 (2009) at the recommendation of FM Global. The condensate drain pots operate by collecting condensate in a large pipe. The bottom section of each drain pot has an automatic valve that opens to drain off the condensate once sufficient quantities are collected.

Unit 3 does not have condensate drain pots installed on its cold reheat lines. According to Hydro's insurer, FM Global, this puts Unit 3 at risk of experiencing water-induced steam turbine damage.

Also at the recommendation of FM Global, modifications were made to the piping arrangements on Unit 1 and Unit 2 so that in-situ testing of the condensate level switches on the high pressure heaters serving these units is possible. With the current equipment arrangement, in-situ testing of these condensate level switches is not possible. Therefore, the switches must be removed from service for testing. As a result, these switches can only be tested during plant outages and cannot be tested at intervals recommended by FM Global (once every three months). The operation of these switches is critical because the level of condensate in the high pressure heaters is also monitored with them. If the level switch has unknowingly failed and condensate is obstructed from draining properly, then condensate may build up inside the heater. This condensate can migrate back into the cold reheat lines. Water in the cold reheat lines can be induced into the steam turbine and cause severe damage to the turbine's internal components.

Project Justification:

FM Global has reported that the presence of water in cold reheat piping has been attributed to numerous occurrences of water damage to steam turbines. FM Global has recommended that Hydro install a condensate collection system (drain pots) on the bifurcated section of the cold reheat line near the steam turbine on Unit 3 complete with automatic drain valves, high water level switches, and high-high water level switches. FM Global has also reported that feedwater heaters (such as the Unit 3 high pressure heater), in particular, represent the most frequent source of potential water induction into a steam turbine. In the worst case, water induction may result in thermal shock and distortion of the turbine and cause blade failure and further damage downstream of the turbine. FM Global recommends that Hydro test the condensate level switches on all high pressure heaters every three months. With the current equipment arrangement, in-situ testing of the Unit 3 high pressure heater condensate level switches is not possible when the generating unit is in operation so testing is unable to take place every three months.

The American Society of Mechanical Engineers (ASME) also recommends installing condensate collection systems on cold reheat lines and installing provisions for in-situ testing of condensate level switches on feedwater heaters to prevent water induction into steam turbines.

Future Plans:

None.

Attachments:

See report entitled "Install Cold-Reheat Condensate Drains and High Pressure Trip Modifications Unit 3" located in Volume II, Tab 13 for further project details.

Project Title: Upgrade Gas Turbine Plant Life Extension

Location: Stephenville

Category: Generation - Gas Turbines

Definition: Other

Classification: Normal

Project Description:

This project is to refurbish equipment and systems at the Stephenville Gas Turbine Plant (Stephenville). It is the first year of a three year program to complete upgrades. The scope of work for the program was developed giving consideration to two sources of information as follows:

- A report prepared in 2007 by engineering firm, Stantec Inc. (Stantec), titled *Condition Assessment and Life Cycle Cost Analysis – Hardwoods and Stephenville Gas Turbine Facilities*.

- Stephenville's operating history and equipment failures since 2007 and Hydro's experience gained from a similar upgrade program that took place at Hardwoods Gas Turbine Plant (Hardwoods) between 2009 and 2012.

The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	355.0	0.0	0.0	355.0
Labour	400.2	0.0	0.0	400.2
Consultant	92.4	0.0	0.0	92.4
Contract Work	1,589.0	0.0	0.0	1,589.0
Other Direct Costs	12.0	0.0	0.0	12.0
Interest and Escalation	159.0	0.0	0.0	159.0
Contingency	387.6	0.0	0.0	387.6
TOTAL	**2,995.0**	**0.0**	**0.0**	**2,995.0**

Operating Experience:

The Stephenville Gas Turbine operates approximately 85 percent of the time as a synchronous condenser to provide voltage support to the Island Interconnected System. It operates in generating mode less than one percent of the time, mainly at times of peak system load or for emergency purposes during unplanned outages.

Project Justification:

The gas turbine plant at Stephenville is over 38 years old. In recent years it has experienced sudden failures to major pieces of equipment and one failure resulted in a 10 month forced outage. The condition assessment and life cycle cost analysis study on Stephenville, completed by Stantec in 2007, provided recommendations to extend the life of the plant as a reliable facility for at least another 15 years. It is important that this upgrade program take place over the next three years so that voltage on the Island Interconnected System will continue to be stable, and peak and emergency power generation will be available when needed.

Future Plans:

This project is to complete work scheduled for the first year of the three year upgrade program for the Stephenville gas turbine plant. Separate project proposals will be submitted to the Board in future applications.

Attachments:

See report entitled "Upgrade Gas Turbine Plant Life Extension" located in Volume II, Tab 14, for further project details.

Project Title: Upgrade Circuit Breakers

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Pooled

Classification: Normal

Project Description:

Hydro has been working to maximize the service life of its circuit breakers. In recent years Hydro has been upgrading air blast circuit breakers, refurbishing operating mechanisms on Sulphur Hexafluoride (SF_6) circuit breakers, and phasing out Polychlorinated Byphenol (PCB) bushings associated with oil circuit breakers.

This project is to replace and refurbish air blast and SF_6 circuit breakers, and to replace oil circuit breakers throughout Hydro's Island Interconnected System. Hydro has many circuit breakers that have been in service for more than 30 years and are approaching the end of their service life. The refurbishment and replacement of all the circuit breakers are given a priority; this priority is represented as a year for the refurbishment or replacement to be completed. These priorities are determined by the criteria or plan for each circuit breaker type.

The plan for each type of circuit breaker is as follows:

<u>Air Blast Circuit Breakers</u>

Complete one refurbishment on each air blast circuit breaker at the 35 to 40 year period, with a replacement to be completed 10 to 15 years after the refurbishment, typically at the 50 year service period.

<u>Oil Circuit Breakers</u>

For oil circuit breakers containing sealed bushings which have the possibility of containing PCBs greater than 50 mg/kg, Hydro has a plan to replace all oil circuit breakers prior to 2025.

<u>SF_6 Circuit Breakers</u>

Complete one overhaul on SF_6 circuit breakers at the 20 years of service. Hydro has two groups for this criterion: those currently older than 20 years and those approaching 20 years of service. Units in service for greater than 20 years have been given priority for refurbishment. Once these are completed, the plan is to begin refurbishing those approaching 20 years of service. Replacement of SF_6 circuit breakers will typically be after 40 years of service.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	2,025.0	0.0	0.0	2,025.0
Labour	297.8	433.0	0.0	730.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	1,045.0	0.0	0.0	1,045.0
Other Direct Costs	104.4	194.0	0.0	298.4
Interest and Escalation	223.2	410.7	0.0	633.9
Contingency	0.0	604.8	0.0	604.8
TOTAL	**3,695.4**	**1,642.5**	**0.0**	**5,337.9**

Operating Experience:

The average age of the overall population of circuit breakers is well past the estimated utility circuit breaker's midlife of 20 years, and is approaching the manufacturers' specified design end-of-life of 40 years. Presently, 60 circuit breakers have a service life greater than 40 years.

Hydro has experienced increased maintenance problems and the unavailability of circuit breakers which include:

- air blast circuit breakers with air leaks and sticking valves; and
- SF_6 circuit breakers with SF_6 gas leaks and problems with the operating mechanism.

These problems experienced by Hydro are common in the utility industry and owners of these circuit breakers have addressed such problems though similar upgrading programs.

In the past ten years there have been refurbishments completed on air blast circuit breakers and the operating mechanism associated with selected SF_6 circuit breakers. These refurbishments have proven to maintain the reliability of the equipment and extend the service life of the circuit breakers by 10 to 15 years.

There has been no major refurbishment work associated with oil circuit breakers. The plan is to replace all oil circuit breakers by 2025 to ensure Hydro is compliant with the latest PCB regulations.

Project Justification:
This project is justified on the requirement to replace failing or deteriorated circuit breakers in order for Hydro to provide safe, reliable electrical service, and to comply with PCB regulations.

To maintain the reliability of in-service circuit breakers, Hydro has to implement a plan to address the aging circuit breaker fleet. To balance the financial impacts and system outage constraints, Hydro has developed a long term asset management plan for circuit breaker replacement and refurbishment.

The plan will see all the current in-service air blast circuit breakers replaced by 2031, all current in-service SF_6 circuit breakers overhauled at mid-life and replaced at or near age 40, and all oil circuit breakers replaced by 2023.

Future Plans:
Other circuit breaker replacements will be proposed in future capital budget applications.

Attachments:
See report entitled “Upgrade Circuit Breakers” located in Volume II, Tab 15, for further project details.

Project Title: Upgrade Power Transformers

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This proposal is for the upgrading of power transformers which includes refurbishment or a replacement based upon a number of condition assessment techniques. The replacement of a transformer is based on the degree of degradation of the cellulose insulation and the amount of dissolved gas present in the transformer oil. The budget estimate for this project is shown below in Table 1.

Table 1: Project Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	656.0	0.0	0.0	656.0
Labour	349.3	0.0	0.0	349.3
Consultant	14.0	0.0	0.0	14.0
Contract Work	292.3	0.0	0.0	292.3
Other Direct Costs	185.1	0.0	0.0	185.1
Interest and Escalation	108.4	0.0	0.0	108.4
Contingency	299.3	0.0	0.0	299.3
TOTAL	**1,904.4**	**0.0**	**0.0**	**1,904.4**

Operating Experience:

Approximately 71 percent of all 230 kV, 138 kV and 66 kV power transformers are at an age of 30 years or greater. Recent experience has shown the need to upgrade the transformers as problems with oil quality, tap changers, gasket systems, bushings, radiators and protective devices can lead to failure during operation.

Project Justification:

Power transformers are critical components of the transmission system. To maintain reliable operation of the transformer fleet Hydro uses condition assessment techniques to selectively target weak units or problem areas within a unit for upgrading. The recommended upgrades will serve to extend the service lives of the transformers and decrease the probability of an unplanned outage. The targeted transformers are based on condition as per Hydro’s evaluation program.

Future Plans:

Future power transformer upgrades will be proposed in future capital budget applications.

Attachments:

See report entitled “Upgrade Power Transformers” located in Volume II, Tab 16, for further project details.

Project Title: Replace Disconnect Switches

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Pooled

Classification: Normal

Project Description:

This project is part of an ongoing program to replace aging 69 kV, 138 kV and 230 kV disconnect switches in Hydro's terminal stations on the Island Interconnected System. This project proposal is for the purchase and replacement of disconnect switches targeted for replacement in 2014 and for the purchase only of disconnects targeted for replacement in 2015. The schedule for this work will be planned over a two year period and will involve engineering and material procurement in the first year and construction and commissioning in the second year.

The budget estimate for this work is shown in the table below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	376.0	7.5	0.0	383.5
Labour	234.9	124.9	0.0	359.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	19.4	9.0	0.0	28.4
Interest and Escalation	59.5	19.8	0.0	79.3
Contingency	126.1	28.3	0.0	154.4
TOTAL	**815.9**	**189.5**	**0.0**	**1,005.4**

Operating Experience:

The disconnect switches included in the replacement plan no longer perform their intended function. Faulty or damaged disconnect switches may be tagged inoperative, which means the switch cannot be opened or closed. As a result, equipment cannot be isolated by the inoperative disconnect switch and adjacent disconnect switches must be operated in order to isolate the equipment. This decreases system reliability and performance since additional equipment and customers will be included in the outage/isolation for a longer duration of time. This scenario also increases the safety risk to personnel who have to execute a more complicated switching order, involving a remote disconnect switch not typically included in the isolation of the equipment.

Project Justification:

Disconnect switches are used to isolate equipment either for maintenance activities or system operation and control. Proper operation of these switches is essential for a safe work environment and for reliable and secure system operation. Faulty and/or malfunctioning disconnect switches that do not operate properly prevent reliable and secure system operation and create a safety hazard. The switches scheduled for replacement have problems such as inoperable mechanical linkages, misalignment of switch blades, broken insulators, and seizing of moving parts. Additionally, the switches have reached the end of their service life and replacement parts are not available.

The only exception is the disconnect switch at Deer Lake. The installation of this new switch will improve operation and reliability of TL225.

Future Plans:

Other disconnect switch replacements will be proposed in future capital budget applications.

Attachments:

See report entitled “Replace Disconnect Switches” located in Volume II, Tab 17, for further project details.

Project Title: Perform Wood Pole Line Management Program

Location: Various Sites

Category: Transmission and Rural Operations - Transmission

Definition: Pooled

Classification: Normal

Project Description:

The objective of this program is to maintain a comprehensive pole inspection and testing program using the conventional sound and bore methods supplemented by Non Destructive Evaluation (NDE), periodic full scale tests of poles removed from service, and remedial treatment application. Structural analysis to assess the line reliability, taking into account the system concept, is applied against all inspection information. Any replacement and/or refurbishment will be based on the assessment of quantitative risk with respect to in-service pole strength. The budget estimate for the project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**TOTAL**
Material Supply	386.1	0.0	0.0	386.1
Labour	1,451.9	0.0	0.0	1,451.9
Consultant	100.0	0.0	0.0	100.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	76.0	0.0	0.0	76.0
Interest and Escalation	147.4	0.0	0.0	147.4
Contingency	402.8	0.0	0.0	402.8
TOTAL	**2,564.2**	**0.0**	**0.0**	**2,564.2**

Operating Experience:

Hydro operates approximately 2,400 kilometers of wood pole transmission lines, including approximately 26,000 poles. Hydro inspects 20 percent of a line each year using visual inspections and a rule-of-thumb approach to identify the health of a typical pole. Previous intensive inspections that targeted lines for specific issues on the Avalon Peninsula showed that decay and preservative retention were becoming an issue, showed extremely low preservative levels which are below minimum acceptable levels, and indicated that rot is becoming more prevalent in the 30-40 year old poles.

Project Justification:

Previous pole inspections indicate that almost half of the poles sampled did not meet the minimum preservative retention levels and full scale pole tests of selected poles completed at Memorial

University since 1999 indicate a 25 percent reduction of average pole strength over a 35 year period. When combined, these facts justify the strong need for a well managed wood pole inspection and treatment program that detects and corrects any dangerous poles in the system which will ensure safety as well as reliability.

Future Plans:

The program is based on two 10 year inspection cycles beginning in 2005. It provides an annual report to identify problem areas for the regional asset managers and to develop recommendations for appropriate pole replacements, as well as other components in the following years. Please see five-year capital plan (Capital Plan 2014 Tab, Appendix A).

Attachment:

See report entitled "Wood Pole Line Management" located in Volume II, Tab 18, for further project details.

Project Title: Refurbish Anchors and Footings TL202 and TL206

Location: Bay d'Espoir to Sunnyside

Category: Transmission and Rural Operations - Transmission

Definition: Other

Classification: Normal

Project Description:

This project involves the refurbishment of TL202 and TL206 through the replacement of corroded guy anchors and the refurbishment of deteriorating concrete footings and steel connections. The project scope includes the following:

- Excavate, replace and backfill 52 anchors;
- Improve drainage of surface water around submerged anchors (where practicable);
- Refurbish 22 concrete footings; and
- Refurbish steel connections at ground level on structures 195, 208 and 216 on TL206.

The budget estimate for this project is shown in Table 1.

Table 1: Project Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	117.5	0.0	0.0	117.5
Labour	177.3	121.3	0.0	298.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	520.0	520.0	0.0	1,040.0
Other Direct Costs	152.2	139.6	0.0	291.8
Interest and Escalation	31.3	51.1	0.0	82.4
Contingency	193.4	156.2	0.0	349.6
TOTAL	**1,191.7**	**988.2**	**0.0**	**2,179.9**

Figures 1 to 3 depict examples of deteriorated anchors, footings and joints on these lines.

Figure 1: Corroded Anchor Rods on Structures 71 and 73 of TL202

Figure 2: Deteriorated Concrete Footing on Structure 52 of TL202

Figure 6: Failed Bolt Connection on Structure 216 of TL206

Operating Experience:

TL202 and TL206 are in continuous operation transmitting power from the Bay d'Espoir Hydro Generating Plant to the Sunnyside Terminal Station. Due to the amount of power transmitted over these lines, it is difficult to obtain a planned outage on these lines to perform maintenance work. This in itself speaks to the extent of problems that would arise from an unplanned outage due to a tower failure on one of these lines.

A visual climbing inspection of each transmission line is performed every five years to evaluate the condition of the line. This inspection is completed by Hydro personnel and any corrective maintenance required is reported, scheduled and completed. The components presented in this report as requiring replacement or refurbishment were identified by Hydro personnel during regular climbing inspections of TL202 and TL206 in 2010 and 2011, respectively.

Project Justification:

TL202 and TL206 were originally constructed over 40 years ago. The line components, still in operation, were installed at the time of original construction and are approaching the end of their economic life span. As a result of inspections performed on these lines in 2010 and 2011, a number of anchors and concrete footings have been found to be in deteriorated condition and need to be refurbished to meet design standards. This deterioration increases the risk of failure. TL202 and TL206 are the main lines that transmit power through the Sunnyside Terminal Station to the Burin and Avalon Peninsulas. A fallen transmission line tower may result in unplanned power outages to customers at a time when required repairs may be hampered by severe weather conditions. The extent of damage caused by a failed transmission tower could take anywhere from days to months to repair, and would require alternate generation to supply power to customers while repairs are performed. It may not be possible to obtain alternative generation quickly and if available, the costs associated with alternative generation would be significant.

Deteriorated anchors and footings pose a risk to the safety of those who may be performing climbing activities to conduct regular inspections, maintenance work, etc. If a steel guy-wire were to break away from a corroded anchor, it would have the potential to kill or seriously injure a person in the event of contact. Deteriorating anchors and footings also create the possibility of a falling tower, a severe safety threat to anyone working on or in the vicinity of the tower. Physical impact from a falling tower or electrocution due to fallen power lines may result in death.

The work to replace and refurbish deteriorating anchors and footings must be performed proactively in order to prevent a major failure of the line, and maintain high reliability performance. The proactive refurbishment and/or replacement of deteriorating transmission tower components such as anchors and footings is common among utility companies to prevent failures, safety hazards and subsequent unplanned outages.

Future Plans:

Regularly scheduled climbing inspections of TL202 and TL206 will continue in the future, and observed deteriorated components of the lines will be replaced or refurbished as required.

Attachments:

See report entitled “Refurbishment of Anchors and Footings on TL202 and TL206” Located in Volume II, Tab 19 for further details.

Project Title: Upgrade Distribution Systems

Location: Various Sites

Category: Transmission and Rural Operations – Distribution

Definition: Pooled

Classification: Normal

Project Description:

Hydro provides service to residents in rural communities within the province through the use of existing distribution systems. The distribution systems typically consist of a substation coupled with a wood pole distribution line that directs power from the station to service drops throughout the community. This project will be focused on distribution lines located in the distribution systems of Conne River, Bay d'Espoir, Barachoix, Hampden, McCallum, Plum Point, Main Brook, Daniel's Harbour, Happy Valley and Nain that have been identified as requiring upgrades to the existing infrastructure. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	510.0	1,114.0	0.0	1,624.0
Labour	820.0	660.0	0.0	1,480.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	675.0	1,775.0	0.0	2,450.0
Other Direct Costs	0.0	75.0	0.0	75.0
Interest and Escalation	162.8	432.3	0.0	595.1
Contingency	332.0	793.8	0.0	1,125.8
TOTAL	**2,499.8**	**4,850.1**	**0.0**	**7,349.9**

Operating Experience:

The distribution lines to be upgraded were originally constructed over 40 years ago. Most of the line components were installed at the time of original construction and have exceeded the expected service lives. In addition, standardized inspection and testing procedures indicate line components are deteriorated and have remaining life spans of only one to five years before widespread failure occurs.

Project Justification:

This project is justified based on reliability. The conditions of the components could result in system failures and have a negative effect on the safety and reliability performance of the line. The failure of a line may also result in unplanned power outages to customers at a time when required repairs may be hampered by severe weather conditions.

Future Plans:

Future distribution line upgrades will be proposed in future capital budget applications. See five-year capital plan (Capital Plan 2014 Tab, Appendix A).

Attachments:

See report entitled "Distribution Upgrades" located in Volume II, Tab 20, for further project details.

Project Title: Provide Service Extensions

Location: All Service Areas

Category: Transmission and Rural Operations – Distribution

Definition: Pooled

Classification: Normal

Project Description:

This project is an annual allotment based on past expenditures to provide for service connections including street lights to new customers.

Table 1 identifies the total budget for the Central, Northern and Labrador operating regions

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	2,772.0	0.0	0.0	2,772.0
Labour	2,351.0	0.0	0.0	2,351.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	200.0	0.0	0.0	200.0
Other Direct Costs	160.0	0.0	0.0	160.0
Interest and Escalation	265.0	0.0	0.0	265.0
Contingency	542.0	0.0	0.0	542.0
Sub-Total	6,290.0	0.0	0.0	6,290.0
Cost Recoveries	(120.0)	0.0	0.0	(120.0)
TOTAL	**6,170.0**	**0.0**	**0.0**	**6,170.0**

Operating Experience:

An analysis of average historical expenditures on new customer connections by region was developed. All historical dollars were converted to 2012 dollars using the Statistics Canada Utility Distribution Line Construction index.

The five year actual expenditures for service extensions by region are shown in Table 2.

Table 2: Five Year Expenditures

Expenditures ($000)											
	2008		2009		2010		2011		2012		2013
Region	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**
Central	910	1,186	1,028	1,133	1,001	1,448	1,045	1,886	1,200	1,231	1,437
Northern	637	803	758	1,432	768	1,356	1,092	1,040	1,267	1,728	1,371
Labrador	612	1,340	653	1,446	659	2,051	1,248	2,665	1,705	3,073	2,198
Total	2,159	3,329	2,439	4,011	2,428	4,855	3,385	5,591	4,172	6,032	5,006

Project Justification:

In recent years, rural areas of the province have experienced increased expenditures for service extensions due to higher customer growth and economic activity. Because of this, for 2014, the 2012 expenditure was used to determine the service extension budget for the Labrador region and a two year historical average was used to determine the service extension budget for the Northern regions. These expenditures are forecast to decline across the next three to four years. A five year historical average was used for the Central region. The 2014 budget was developed assuming distribution line costs escalation of approximately two percent over 2013. The budget by region is shown in Table 3 below.

Table 3: Budget for Distribution System

Region	**2014 Budget ($000)**
Central	1,490
Northern	1,460
Labrador	3,220
Total	**6,170**

Future Plans:

This is an annual allotment which is adjusted from year to year depending on historical expenditures. Please see the five-year capital plan (2014 Capital Plan Tab, Appendix A).

Project Title: Upgrade Distribution Systems

Location: All Service Areas

Category: Transmission and Rural Operations - Distribution

Definition: Pooled

Classification: Normal

Project Description:

This project is annual allotment based on historical expenditures to provide for the replacement of deteriorated poles, substandard structures, corroded and damaged conductors, corroded and overloaded transformers/street lights/reclosers and other associated equipment. This upgrading is identified through preventive maintenance inspections or when there is damage caused by storms and adverse weather conditions and salt contamination.

The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	1,817.0	0.0	0.0	1,817.0
Labour	1,034.0	0.0	0.0	1,034.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	132.0	0.0	0.0	132.0
Other Direct Costs	2.0	0.0	0.0	2.0
Interest and Escalation	145.0	0.0	0.0	145.0
Contingency	292.0	0.0	0.0	292.0
Sub-Total	3,422.0	0.0	0.0	3,422.0
Cost Recoveries	(52.0)	0.0	0.0	(52.0)
TOTAL	**3,370.0**	**0.0**	**0.0**	**3,370.0**

Operating Experience:

An analysis of average historical expenditures on distribution upgrades by region was performed. All historical dollars were converted to 2012 dollars using the Statistics Canada Utility Distribution Line Construction index.

The five-year expenditures for distribution upgrades by region are shown in Table 2.

Table 2: Five Year Expenditures

Expenditures ($000)										
	2008		2009		2010		2011		2012		2013
Region	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**
Central	915	782	1,050	1,028	1,032	1,037	998	1,365	993	1,854	1,095
Northern	969	1,140	1,026	1,148	1,072	1,071	1,051	1,489	1,089	1,010	1,237
Labrador	409	313	450	484	468	191	450	548	426	270	458
Total	2,293	2,235	2,526	2,660	2,572	2,299	2,499	3,402	2,508	3,134	2,790

Other specifically approved projects for 2008 – 2013B are listed in Table 4.

Project Justification:

Based on the five-year average for distribution system upgrades for the period 2008 – 2012 the budget shown in Table 3 was developed for Northern and Labrador regions. The budget for the Central area was developed using a two year average. The 2014 budget was developed assuming distribution line cost escalation in 2014 of approximately two percent over 2013.

Table 3: Budget for Distribution System

Region	2014 Budget ($000)
Central	1,700
Northern	1,270
Labrador	400
Total	**3,370**

Future Plans:

This is an annual allotment which is adjusted from year to year depending on historical expenditures. See the five-year capital plan (2014 Capital Plan Tab, Appendix A).

Table 4 shows the history of other specific distribution system upgrades that have been completed over the past five years as well as the budget for 2013.

Table 4: Historical Information

Year	Project Description	Budget ($000)	Actuals ($000)
2013B	Upgrade Distribution Feeder - Line 1 St. Lewis (Year 1 of 2)	76.9	
	Upgrade Distribution Feeder - Line 1 and 3 Roddickton (Year 1 of 2)	98.4	
	Upgrade Distribution System - Charlottetown (Year 1 of 2)	27.8	
	Upgrade Distribution System - South Brook (Year 1 of 2)	76.3	
	Upgrade Distribution Feeder - Line 1 Grey River (Year 1 of 2)	32.5	
	Upgrade Distribution Feeder - Line 1 Cow Head	665.6	
	Upgrade Distribution Feeder - Line 1 St. Brendan's	330.2	
	Upgrade Distribution Feeder - Line 1 Holyrood	632.4	
	Upgrade Distribution Feeder - Line 11 Wabush	400.8	
	Upgrade Distribution Voltage - Line 6 St. Anthony	641.9	
	Upgrade Distribution Feeder - Line 6 Farewell Head	961.9	
	Upgrade Distribution Feeder - Line 5 Farewell Head	1,110.1	
	Upgrade Distribution Feeder - Line 2 Plum Point (Year 2 of 2)	1,110.5	
	Upgrade Distribution Feeder - Line 2 Glenburnie (Year 4 of 4)	596.6	
2012	Upgrade Distribution Feeder - Line 1 Bay d'Espoir	856.6	896.9
	Upgrade Distribution Feeder - Line 2 Bay d'Espoir	952.9	811.2
	Upgrade Distribution Feeder - Line 1 Francois	329.4	650.4
	Upgrade Distribution Feeder - Line 1 Parson's Pond	381.9	344.7
	Upgrade Distribution Feeder - Line 2 Plum Point (Year 1 of 2)	50.4	33.2
	Upgrade Distribution Feeder - Line 7 Happy Valley	1,260.1	1,163.6
	Upgrade Distribution Feeder - Line 2 Glenburnie (Year 3 of 4)	2,114.6	1,895.0
	Reconfigure Feeders – Wabush	55.4	55.4
	Upgrade Distribution Feeder - Line 1 Rigolet (Year 2 of 2)	652.4	658.5
	Upgrade Distribution Feeder - Line 1 Makkovik (Year 2 of 2) - (Materials ordered in 2011)	666.8	612.6
2011	Replace Poles – Westport	256.4	279.3
	Replace Poles - Grandy Brook	286.4	312.4
	Replace Poles - Farewell Head	339.6	393.9
	Upgrade Distribution Feeder - Line 1 Rigolet (Year 1of 2)	72.0	10.5
	Upgrade Distribution Feeder - Line 1 Francois	440.9	116.0
	Upgrade Distribution Feeder - Line 8 Happy Valley	553.5	488.2
	Upgrade Distribution Feeder - Line 4 Roddickton (Year 2 of 2)	902.6	1,106.2
	Upgrade Distribution Feeder - Line 1 Makkovik (Year 2 of 2)	742.4	137.3
	Upgrade Distribution Feeder - Line 2 Glenburnie (Year 2 of 4)	578.2	527.8

Year	Project Description	Budget ($000)	Actuals ($000)
2010	Replace Poles - English Harbour West	274.8	249.8
	Replace Poles - Line 1 Fleur De Lys	269.2	246.9
	Replace Poles – Barachoix	273.3	256.1
	Upgrade Distribution System - Line 1 Makkovik (Year 1 of 2)	57.1	25.1
	Upgrade Distribution System - Line 4 Roddickton (Year 1 of 2)	160.6	98.4
	Upgrade Distribution System - Line 2 Glenburnie (Year 1 of 4)	267.3	134.8
	Upgrade Distribution System - Line 4 Happy Valley	265.3	251.6
2009	Upgrade Distribution System - Line 7 St. Anthony	689.3	503.6
	Replace Insulators - Line 1 and Line 2 Jackson's Arm, Hampden	691.5	590.6
	Replace Insulators - Line 2 Little Bay Islands	182.7	120.8
	Replace Poles - Line 1 and Line 2 Jackson's Arm	433.7	416.1
	Replace Poles - Line 1 Hampden	263.1	243.6
	Upgrade Distribution Feeder - Line 36 Wabush	498.0	466.1
2008	Replace Distribution Line - Line 1 South Brook	987.4	1,056.4
	Upgrade Distribution System - Line 1 Glenburnie	533.9	405.5
	Upgrade Distribution System - Line 3 St Anthony	480.1	445.0
	Upgrade Distribution System - Mary's Harbour	263.5	215.6
	Upgrade Distribution System - Port Hope Simpson	205.4	215.6
	Upgrade Distribution System - Line 4 Bear Cove	149.8	96.8
	Upgrade Distribution Line - Line 11 Wabush	107.2	115.3
	Replace Insulators - Upper Salmon	236.8	194.9
	Replace Insulators - Line 1 Hind's Lake	168.7	158.0
	Replace Insulators - Coney Arm	126.8	132.1
	Replace Insulators - Line 2 Westport	90.2	87.2
	Replace Poles - South Brook	377.5	331.2
	Replace Poles - Bay d'Espoir	322.7	257.3

Project Title: Replace Diesel Units

Location: Port Hope Simpson and Mary's Harbour

Category: Transmission and Rural Operations – Generation

Definition: Pooled

Classification: Normal

Project Description:

The purpose of this project is to replace Unit 2042, a 455 kW diesel generating unit (genset) in Port Hope Simpson with a 725 kW unit as well as to replace Unit 2037, a 545 kW diesel genset in Mary's Harbour with the same size unit. This proposal consolidates all costs associated with the procurement and installation of the new diesel units. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	108.4	728.7	0.0	837.1
Labour	50.8	698.6	0.0	749.4
Consultant	14.5	158.4	0.0	172.9
Contract Work	0.0	20.0	0.0	20.0
Other Direct Costs	23.6	164.1	0.0	187.7
Interest and Escalation	11.6	214.5	0.0	226.1
Contingency	0.0	393.4	0.0	393.4
TOTAL	**208.9**	**2,377.7**	**0.0**	**2,586.6**

Operating Experience:

Hydro replaces a diesel genset when its operating hours have surpassed 100,000 hours. The timing of the upgrade is determined by the year in which the unit is expected to surpass 100,000 hours. In systems where the demand occurs in the winter, the upgrade must be completed by the fall of the previous year. This ensures the work can be completed prior to peak season when all units are required to be available. Unit 2042 in Port Hope Simpson and Unit 2037 in Mary's Harbour will surpass 100,000 operating hours by 2015.

Project Justification:

This project is justified on the requirement to satisfy Hydro's current asset management strategy and planning criteria to replace gensets when they approach 100,000 operating hours. Unit 2042 at the Port Hope Simpson plant and Unit 2037 at the Mary's Harbour Plant are forecasted to incur 100,000 hours by 2015 requiring replacement units to be procured and installed across 2014 and 2015.

The increase in unit size for Port Hope Simpson is justified based on a positive cost benefit analysis from improving overall plant efficiency. A larger unit will reduce the overall usage of all diesel units in the plant, thereby decreasing individual annual operating hours per diesel engine, which will ultimately reduce fuel consumption, overall operating and maintenance costs and capital replacement costs for diesel units.

Future Plans

Other diesel unit replacements will be proposed in future capital budget applications.

Attachment:

See report entitled "Replace Diesel Units" located in Volume II, Tab 21, for further project details.

Project Title: Install Fire Protection System

Location: Nain

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Normal

Project Description:

This is a two year project that will provide the engineering design, procurement and installation of automatic fire suppression systems to protect the diesel generating plant in the community of Nain, Labrador. A high pressure water mist system will be installed in the generator hall and an inert gas/chemical system will be installed in other critical areas of the plant, including the supervisory control room and the lubricant/coolant storage room. The engineering design will be completed in 2014 by the supplier of the fire suppression systems. Equipment procurement will take place in 2015 along with installation by a certified contractor. The estimated budget for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	231.0	0.0	231.0
Labour	31.0	117.3	0.0	148.3
Consultant	65.6	0.0	0.0	65.6
Contract Work	0.0	228.0	0.0	228.0
Other Direct Costs	3.0	82.9	0.0	85.9
Interest and Escalation	7.5	81.2	0.0	88.7
Contingency	0.0	151.8	0.0	151.8
TOTAL	**107.1**	**892.2**	**0.0**	**999.3**

Operating Experience:

Nain will be the first of Hydro’s diesel generating plants to be equipped with an automatic fire protection system. There have been a number of fires at the Nain diesel plant in the past. In 1973, the original plant was destroyed by fire when it was under the ownership of Labrador Services Division. The plant was rebuilt and in 1993 there was another major fire caused by a catastrophic engine failure. In 2006, a new plant was constructed at a different site near the community and it experienced a major fire in 2008. That fire destroyed one generating unit, damaged the other two, and caused significant damage to the auxiliary equipment and building finishes. Total cost of the refurbishment was approximately $5,000,000.

Other Hydro diesel plants that have received extensive damage in the past due to fire include Recontre East's diesel plant in 2002, Happy Valley/Goose Bay North plant in January 2012 and Black Tickle's diesel plant in March 2012.

Project Justification:

This project is justified to increase the protection of critical assets at Nain's diesel plant from the catastrophic consequences of a fire. As the plant is not manned 24 hours per day seven days a week, the potential for a fire to be left unchecked for a period of time is a significant risk. The result could be the community being left without power for an extended period of time which would have both operational and health and safety concerns for the community. Hydro has recognized the vulnerability of these communities, having experienced a number of fires in the past. After the 2008 fire in Nain, Hydro engaged Hatch to complete a study and recommend measures that could be taken to reduce the risk of a major fire and minimize fire damages. In addition, Hydro's insurer, Factory Mutual Global, in a number of their reports has recommended that diesel plants be equipped with automatic fire suppression systems.

Future Plans:

Hydro owns and operates 25 diesel plants. It is anticipated that proposals will be submitted to the Board in future years to install automatic fire suppression systems in other plants.

Attachments:

See report entitled "Install Fire Protection" located in Volume II, Tab 22 for further project details.

Project Title: Upgrade Diesel Plant Production Data Collection Equipment

Location: Various Sites

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Normal

Project Description:

This is a three year project to upgrade the production data collection method from telephone communications to network communications for various remote diesel plants in coastal Newfoundland and Labrador and install network communications where there is no existing metering data communications. This data will be automatically collected and stored on the corporate data management system for access by Engineering and Operations and an automated monthly report generated. A total of 21 diesel plants are scheduled to be done: seven plants in 2014, seven plants in 2015 and seven plants in 2016.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**2016**	**Total**
Material Supply	24.0	20.0	22.0	66.0
Labour	129.0	129.0	129.0	387.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	58.0	57.0	55.0	170.0
Interest and Escalation	15.7	22.6	33.5	71.8
Contingency	42.2	41.2	41.2	124.6
TOTAL	**268.9**	**269.8**	**280.7**	**819.4**

Operating Experience:

Presently, a server at Hydro Place in St. John's is configured to retrieve the production data from diesel plants but telephone communications required by this system have not been reliable. Personnel have to record values at the meters and submit the information or the meters have to be manually polled until the data is retrieved. The data currently retrieved is typically on a monthly basis and does not provide the sampling rate to provide daily plant load profiles required to support effective analysis. A reliable automation platform for data collection is required.

Project Justification:

The driver for this project is to provide load data for each of Hydro's diesel plants as input for planning future plant upgrades and engine sizing and to enable analysis to ensure that each plant is operating properly, in the most efficient manner and with minimal emissions.

Future Plans:

A total of 21 diesel plants are scheduled to be completed; seven plants in 2014, seven plants in 2015 and seven plants in 2016.

Attachments:

See report entitled “Upgrade Diesel Plant Production Data Collection Equipment” located in Volume II, Tab 23, for further project details.

Project Title: Overhaul Diesel Engines

Location: Various Sites

Category: Transmission and Rural Operations - Generation

Definition: Pooled

Classification: Normal

Project Description:

This project is required to overhaul the diesel engines at diesel generating plants. The project consists of 55 overhauls over the next five years. Specifically, seven engines are planned for overhaul in 2014 with 12 planned for overhaul in each of the four following years. The overhaul schedule is based on the engines being overhauled every 20,000 hours of operation (with the exception of the 100,000 hours milestone at which point the engine is replaced instead of being overhauled). The overhaul schedule is a projection based on the estimated annual operating hours of each engine. On average, an engine accumulates 20,000 operating hours every 6.3 years but the actual time depends on the usage of the engine. As such, this schedule is subject to change and the year for which an engine is projected to become due for an overhaul can vary depending on the difference between an engine's actual operating hours and its estimated operating hours. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	445.0	0.0	0.0	445.0
Labour	170.0	0.0	0.0	170.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	13.1	0.0	0.0	13.1
Other Direct Costs	74.7	0.0	0.0	74.7
Interest and Escalation	50.4	0.0	0.0	50.4
Contingency	70.3	0.0	0.0	70.3
TOTAL	**823.5**	**0.0**	**0.0**	**823.5**

Operating Experience:

Isolated diesel generation plants operate continuously since they are the primary source of electricity to isolated communities. A given unit is not in service continually since the number of units in service varies based on the system demand. In automated plants the engine mix is automatically controlled by a control system to maximize fuel efficiency while in a manual plant this control is completed by the operator. In any of the plants, the operator has the flexibility to shut down engines for maintenance provided there is another engine available to take the load for that time. As a result, outages to engines can occur without outages to customers.

Project Justification:

Hydro's asset management philosophy is to complete an engine overhaul on diesel engines after 20,000 operating hours. This philosophy was established as a result of a 2003 review of maintenance tactics and failure history. Performing overhauls too frequently results in additional expenditure for negligible improvement in reliability. An overhaul interval of 20,000 hours is considered by Hydro to be the optimum interval for providing least-cost, reliable electrical service.

The seven units to be overhauled are Charlottetown 2087, Cartwright 2086, Francois 570, McCallum 2064, Port Hope Simpson 2043, Port Hope Simpson 2073 and Postville 573. These are the engines projected to reach, in 2014, 20,000 operating hours since their last overhaul.

Future Plans:

The overhaul of diesel engines is a continuous program that will need to continue as long as there are prime power diesel generating plants. The 20 year plan for diesel engine overhauls (2014 - 2033) projects 207 overhauls (which is an average of 10.3 overhauls annually) and is based on an overhaul interval of 20,000 operating hours. The 20 year plan is based on the present-day operating conditions which are subject to change as the loading on a plant or other factors may change with time. Changes to the operating conditions can change the average number of annual overhauls.

Attachments:

See report entitled "Overhaul Diesel Engines" located in Volume II, Tab 24, for further project details.

Project Title: Additions to Accommodate Load Growth

Location: Hopedale

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Normal

Project Description:

This will be a one year project addressing growing demand in Hopedale and will involve the replacement of the substation transformers and service conductors. It is forecasted that the growing demand of Hopedale will result in an overload on the substation transformers and service conductors by the winter of 2014/2015. This proposal consolidates all costs associated with the procurement and installation of four 500 kVA transformers (one plus a spare) and three runs per phase of 750 kcmil copper RW90 service cables. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	188.9	0.0	0.0	188.9
Labour	106.2	0.0	0.0	106.2
Consultant	20.0	0.0	0.0	20.0
Contract Work	140.0	0.0	0.0	140.0
Other Direct Costs	47.1	0.0	0.0	47.1
Interest and Escalation	38.6	0.0	0.0	38.6
Contingency	100.4	0.0	0.0	100.4
TOTAL	**641.2**	**0.0**	**0.0**	**641.2**

Operating Experience:

Substation upgrades at the Hopedale Generating Station are required by the winter of 2014/2015 to prevent overloading on specific electrical equipment. According to the 2013 Operating Load Forecast, the forecasted net peak in Hopedale is growing and will be 1,117 kW by the winter of 2014. At that time the peak load will exceed the rated capacity of the service conductors and substation transformers.

Project Justification:

This project is justified on the requirement to meet growing electricity needs of Hydro's customers serviced by the Hopedale Generating Station. The existing electrical equipment in Hopedale must support the forecasted peak. Otherwise, when the load exceeds the equipment capacity ratings, a power outage may result which would reduce the overall reliability of the system. The integrity of the equipment is also jeopardized once it becomes overloaded, which poses a higher risk of a fire hazard and potentially increases operating and maintenance costs.

Future Plans:

None.

Attachment:

See report entitled "Additions to Accommodate Load Growth" located in Volume II, Tab 25, for further project details.

Project Title: Install Automated Meter Reading

Location: Various Sites

Category: Transmission and Rural Operations - Metering

Definition: Other

Classification: Justifiable

Project Description:

This project is required to implement Automatic Meter Reading (AMR) in various Hydro customer service areas. The service areas will depend on meter reader retirement and/or maintenance of current meter reader work loads. This capital budget proposal is based on the service areas of English Harbour West and Barachoix. The AMR functionality is proposed for all customers in these service areas. The work includes:

- Replace existing customer meters with AMR equipped meters;
- Install data collectors in the substations in these service areas;
- Communicate to the AMR server located in St. John's; and
- Configure the AMR central server to include customers in these service areas.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	300.0	8.8	0.0	308.8
Labour	35.7	108.4	0.0	144.1
Consultant	0.0	48.0	0.0	48.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	4.0	17.5	0.0	21.5
Interest and Escalation	17.2	53.0	0.0	70.2
Contingency	0.0	104.5	0.0	104.5
TOTAL	**356.9**	**340.2**	**0.0**	**697.1**

Operating Experience:

The AMR system will replace (i) manual handheld devices used to collect meter readings at each customer's site; (ii) supporting infrastructure (computers and modems) used to retrieve the data; and, (iii) a requirement for personnel to travel to each customer location to read meters. Previous AMR projects have been completed by Hydro in a number of other the service areas. The AMR system being implemented has proven to be reliable and accurate.

Project Justification:

This project is primarily justified on the results of a cost-benefit analysis which shows that the new AMR system has economic benefits over the existing system through a reduction in controllable costs. The new system also provides benefits in customer service through improvements in accuracy, frequency and detail of reporting. Implementation of AMR will also enhance safety by reducing employee risk exposure and will provide a benefit to the environment as a result of less vehicle usage.

Future Plans:

This proposed project is part of an ongoing program to implement AMR in Hydro's service areas.

Attachments:

See report entitled "Install Automated Meter Reading" located in Volume II, Tab 26, for further project details.

Project Title: Replace Light-Duty Mobile Equipment

Location: Various Sites

Category: General Properties - Transportation

Definition: Other

Classification: Normal

Project Description:

This project proposes the addition of eight pole trailers for remote communities and the replacement of 11 all-terrain vehicles, 18 snowmobiles, six light-duty trailer, three heavy-duty trailers, and one forklift in accordance with Hydro's established replacement criteria as follows:

- Snowmobiles/All-Terrain Vehicles: Transmission Line crews 3-5 years
- Snowmobiles/All-Terrain Vehicles: Other 5-7 years
- Light-Duty Trailers 6-8 years
- Heavy-Duty Trailers 12-15 years

The budget estimate for this project is shown in Table 1 below.

Table 1: Project Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	527.0	0.0	0.0	527.0
Labour	4.2	0.0	0.0	4.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	21.3	0.0	0.0	21.3
Contingency	26.6	0.0	0.0	26.6
TOTAL	**579.1**	**0.0**	**0.0**	**579.1**

Operating Experience:

The Transportation Department of Hydro maintains a close liaison with other Canadian utilities through participation on the Canadian Utility Fleet Council and has established mobile equipment replacement guidelines, which consider the age and operating conditions for the equipment.

Project Justification:

Hydro operates a fleet of light-duty mobile equipment comprised of approximately 120 snowmobiles, 70 all-terrain vehicles, 120 trailers, ten forklifts and ten miscellaneous attachments (for example, lawn mowers, backhoes, salt spreaders, snow plows).

The addition of eight pole trailers for remote communities is required for safety reasons. The use of pole trailers allows for safe transport of poles through communities during pole replacement and installation work. The remaining equipment is being replaced in accordance with Hydro's established criteria, either due to its age or condition.

The mobile equipment fleet is strategically distributed across Hydro's operating areas throughout the Province and is utilized on a daily basis to support staff engaged in the maintenance and repair of the electrical system.

Future Plans:

Future replacements of light duty mobile equipment will be proposed in future capital budget applications.

Attachments:

See report entitled "Replace Light Duty Mobile Equipment" located in Volume II, Tab 27, for further project details.

Project Title: Upgrade Enterprise Storage Capacity

Location: Hydro Place

Category: General Properties - Information Systems

Type: Other

Classification: Normal

Project Description:

This project is to provide 72 Terabytes (TB) of disk storage to the Storage Area Network (SAN) to serve the Intel Enterprise Servers and replace the switches to which the SAN are attached, which are at end of vendor support. Hydro's V7000 (installed in 2011) and DS4800 (installed in 2008) storage devices provide management and permit growth of the disk storage for the Intel Servers.

This project covers the replacement of the production DS4800 storage controller currently in service in Hydro. The unit is critical to the operation of Hydro information systems and will be six years old in 2014. A total of 72 Terabytes (TB) of storage capacity will be added to the V7000 storage system to accept data migrated from the DS4800.

This project also covers the replacement of the switches, currently in service in Hydro. These units are critical to the operation of Hydro systems and will be six years old in 2014. The six switches will be replaced by two higher density switches.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	385.1	0.0	0.0	385.1
Labour	27.2	0.0	0.0	27.2
Consultant	7.0	0.0	0.0	7.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	14.6	0.0	0.0	14.6
Contingency	83.9	0.0	0.0	83.9
Sub-Total	517.8	0.0	0.0	517.8
Cost Recoveries	(191.6)[1]	0.0	0.0	(191.6)
TOTAL	**326.2**	**0.0**	**0.0**	**326.2**

Project Justification:

The factors that are driving Hydro's proposal to upgrade its storage environment include:

- Address the obsolescence/maintaining vendor support;
- Manage the infrastructure; and
- Support the virtualization of application servers.

Obsolescence/Vendor Support – Without vendor support, the applications reliant on storage infrastructure is at risk. As a result, Hydro's ability to support and ensure continuation of the storage functions and services is impeded. The storage systems provide critical functionality to the server systems used by Hydro employees to provide support in running the business on a daily basis. Loss of availability of these services would have a negative effect on employee productivity by not allowing access to software applications and the data housed within the storage system.

Managing the storage infrastructure effectively is aided by using the appropriate tools to configure, alert on errors, and report on usage trends. Hydro requires software based storage management tools to maintain and improve the stability of the storage systems and allow for better management, planning, and anticipation of issues with the storage system.

Increased virtualization of servers within the Hydro system reduces the number of physical servers which must be maintained with power, cooling, networking and rack space in Hydro data centers. With increased virtualization, there are higher demands on enterprise storage in terms of capacity (volume of

[1] *The Information Systems shared services methodology for calculating appropriate chargebacks to non-regulated components of Nalcor is based on a ratio considering the average of the number of full time equivalents and Lower Churchill contractors, email users, personal computers and JD Edwards users across each line of business.*

data no longer stored within physical servers which must be stored on the enterprise storage system) and the performance of the storage, a key component of delivering adequate application response time to the business user. The shift to virtualization requires modern, high performance, enterprise storage systems and storage area network.

Existing System:

There are two enterprise storage systems (IBM V7000 and DS4800) which provide shared storage services to Hydro servers used to run various applications for the organization. Applications that depend on Hydro enterprise storage include Hydro business applications, enterprise resource planning, file-print, database and email systems in addition to other applications which comprise the operating environment.

The DS4800 is at the end of its service life of six years and will be decommissioned in 2014. The data currently stored on the DS4800 will be migrated to the V7000 system which requires additional storage capacity to handle this migrated data. Hydro is focusing on V7000 technology to satisfy enterprise storage requirements of the organization over the next four years.

The storage area network includes fibre channel (FC) switches and fibre optic cabling used to interconnect the servers with the storage systems. Hydro's SAN switches currently operate at 4GBps (Gigabits per second), have been in service for over five years and are at the end of support with IBM. The technology has advanced from Hydro's currently deployed equipment, running at a data speed of 4GBps, to today's standard 8GBps and 16GBps. The advance in speed enables the higher data throughput and response time demands of virtualized systems and large data exchanges for systems such as GIS systems (Geographical Information Systems).

Replacement of the current SAN with modern equipment will be performed with equipment capable of 16GBps speeds, but will be deployed with the lower cost yet adequate 8GBps data speed. Upgrade to the 16GBps standard is available with this equipment should higher capacity systems or applications require such speeds in the future.

Table 1: Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2013	Build storage capacity in the V7000 for current and upcoming workloads	Completed in 2013 Capital program.
2011	Additional DS5100 SAN Installed	New Controller and capacity installed.

Operating Experience:

As this budget proposal is for routine replacement of hardware and software related to the enterprise storage infrastructure, the following items are not relevant to this proposal:

- Maintenance History;
- Outage Statistics;
- Safety Performance; and
- Environmental Performance.

Reliability Performance

Disk capacity growth fluctuates from year to year depending on the activities of the business. A general growth rate of approximately 30 percent per year is used when planning storage requirements for the coming year and has been a satisfactory indicator in recent years. Operating experience has been to add more disks as the existing space is used. Due to the growing need for storage, it is imperative that Hydro have ample reserve storage.

Hydro's enterprise storage system is used on a continuous basis. The storage enclosures, disks and switches are active for the life of the unit once placed in service. Hydro standardizes on enterprise grade hardware for both corporate and energy management applications. Hydro has had very satisfactory performance and reliability levels from this hardware as a result.

Industry Experience

Hydro must keep its systems current in order to adequately support and protect the information technology infrastructure required to operate its business. Failure to keep this infrastructure current will put Hydro at risk of unplanned information system outages, possible data loss, and possible data corruption. The replacement, addition and upgrading of hardware components to achieve this goal requires investment over the lifecycle of the infrastructure.

Vendor Recommendations

IBM Software Support Lifecycle Policy applies to the software which powers systems including the enterprise storage subsystems, SAN switches, firmware and management tools. As described in the policy, '5+3' Support – a minimum of five full years of standard support from the date the product release was made generally available by IBM, with the option to get support extensions for an additional three years following a product's end of support (EOS) date for an extra charge set by IBM.

Maintenance or Support Arrangements

Support and maintenance on storage systems is generally purchased at acquisition for a five year period, with one year of additional support purchased for the sixth year. While extended support offerings are available, the maintenance programs become increasingly more expensive as the hardware become older and parts are in shorter supply.

After the initial five year warranty, the system is placed on a Gold Card Maintenance program with IBM that is renewed yearly until the system is replaced.

Historical Information

Table 2 shows the historical costs of the enterprise storage upgrade project.

Table 2: Five-Year Historical Information[2]

Year	Budget ($000)	Actual ($000)	Comments
2013B	194.9		Added capacity
2012	306.3	298.1	Added capacity and installed three new storage units for Energy Management and three LTO-4 tape units
2011	226.6	225.6	Added capacity and installed new storage system unit
2010	241.4	240.6	Five TB capacity increase and replace eight LTO-4 tape drives
2009	N/A	N/A	No capacity increase required

Anticipated Useful Life

Industry standards indicate that most information systems hardware has a useful life of five years. Beyond this timeframe, technology advancements, hardware reliability and support cost and parts availability issues may become problematic. The age of the equipment being replaced is six years.

[2] *Price varies on a year to year basis due to storage requirements.*

Development of Alternatives:

The alternative to an Enterprise Storage upgrade program is to replace systems as they fail. This would put the infrastructure at risk of unplanned outages, possible data loss, and data corruption. This is not a viable alternative.

Conclusion:

This is an ongoing refresh program to maintain the Enterprise Storage systems.

Project Schedule:

The project is scheduled to start in February 2014 and be completed by the end of December 2014.

Future Plans

Future replacements and upgrades will be proposed in future budget applications.

Project Title: Replace Battery Banks and Chargers

Location: Various Sites

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This project is part of Hydro's ongoing program to replace stationary batteries and chargers at generating sites, terminal stations and telecommunications microwave sites. These batteries are the source of power for telecommunications and protection and control equipment during the loss of station service. The batteries are either a direct current (DC) power source and thus require a charging system that converts alternating current (AC) to direct current (DC) or UPS batteries that also convert back to AC. See the project proposal report for details.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	137.0	137.1	0.0	274.1
Labour	94.8	92.2	0.0	187.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	17.9	18.0	0.0	35.9
Interest and Escalation	17.3	51.3	0.0	68.6
Contingency	0.0	99.4	0.0	99.4
TOTAL	**267.0**	**398.0**	**0.0**	**665.0**

Operating Experience:

Hydro generally inspects its battery banks semi-annually but more often as needed depending on age and condition. From these inspections and testing, Hydro determines which banks need to be replaced. The rate of battery deterioration increases with age and reaches a point where they are unable to provide the required power level to operate equipment in the event of an outage. See the project proposal report for details.

Project Justification:

When the capacity of a battery falls to 80 percent of its rated capacity it has to be replaced as recommended by IEEE standards 450 and 1188. The batteries to be replaced are near the end of their useful lives when they have deteriorated to the 80 percent capacity level. Batteries have to be replaced before total failure occurs to ensure continued reliable operation. See the project proposal report for details.

Future Plans:

Replacement of battery banks and chargers will be proposed in future capital budget applications.

Attachments:

See report entitled "Replace Battery Banks and Chargers" located in Volume II, Tab 28, for further project details.

Project Title: Replace Vehicles and Aerial Devices

Location: Various Sites

Category: General Properties - Transportation

Definition: Other

Classification: Normal

Project Description:

This project proposes the replacement of 32 light-duty vehicles and seven heavy-duty vehicles in accordance with the established replacement criteria for vehicle age and kilometers (km) as follows:

- Light-duty vehicles: 5-7 years or 150,000 km
- Heavy-duty work vehicles:
  - Class 4, 5 and 6 6-8 years or 200,000 km
  - Class 7 and 8 6-8 years or 250,000 km

All vehicles that meet the criteria are being replaced. In addition, two light duty vehicles and two heavy duty vehicles were added to the list because they meet the replacement criteria. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	1,725.0	900.0	0.0	2,625.0
Labour	6.0	2.0	0.0	8.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	6.0	3.0	0.0	9.0
Interest and Escalation	72.1	53.9	0.0	126.0
Contingency	0.0	132.1	0.0	132.1
TOTAL	**1,809.1**	**1,091.0**	**0.0**	**2,900.1**

Operating Experience:

Hydro’s transportation section maintains a close liaison with other utilities across Canada and has established the replacement criteria based on industry standards and Hydro's operating experience. Extension of the service life of a vehicle beyond the replacement criteria result in increased operating and maintenance costs.

Project Justification:

This project provides for the normal replacement of on-road fleet vehicles based on projected age and kilometers at disposal. The transportation vehicles are subjected to a lease, or purchase cost/benefit analysis during the tender process, to determine the least cost alternative.

The cost benefit analysis is best done in the year of replacement to ensure consideration of current year fleet incentives offered by the manufacturers. This proposal provides the funding required to purchase the projected replacements and will be adjusted to reflect the outcome of the lease or purchase cost/benefit analysis.

The light duty vehicles are an average of six years old with 172,000 km and the heavy duty vehicles are nine years old with 225,000 km.

Future Plans:

Future replacements of vehicles and aerial devices will be proposed in future capital budget applications.

Attachments:

See report entitled "Replace Vehicles and Aerial Devices" located in Volume II, Tab 29 for further project details.

PROJECT DESCRIPTION	Expended to 2013	2014	Future Years	Total	Page Ref
			($000)		
GENERATION					
Upgrade Victoria Control Structure - Bay d'Espoir		495.1		495.1	D - 2
Overhaul Turbine/Generator Units - Bay d'Espoir and Hinds Lake		485.0		485.0	D - 29
Upgrade Generator Bearings Unit 2 - Bay d'Espoir		18.9	396.0	414.9	D - 34
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir		352.8		352.8	D - 56
Replace Automatic Greasing Systems Units 5 and 6 - Bay d'Espoir		233.4		233.4	D - 68
Install Fire Protection Upgrades - Holyrood		56.6	312.5	369.1	D - 76
Install Handheld Pendant to Overhead Crane - Bay d'Espoir		49.9	170.8	220.7	D - 98
TOTAL GENERATION		1,691.7	879.3	2,571.0	
TRANSMISSION AND RURAL OPERATIONS					
Replace Insulators - Various Sites	187.1	287.9		475.0	
Inspect Fuel Storage Tanks - Various Sites		495.0		495.0	D - 114
Upgrade Ventilation System - Ramea		263.0		263.0	D - 135
Replace Fuel Storage Tank - Ramea		234.2		234.2	D - 152
Install Additional Washrooms - Various Sites		251.0		251.0	D - 160
TOTAL TRANSMISSION AND RURAL OPERATIONS	187.1	1,531.1		1,718.2	
GENERAL PROPERTIES					
Replace Personal Computers - Various Sites		489.8		489.8	D - 169
Replace Peripheral Infrastructure - Various Sites		200.7		200.7	D - 174
Upgrade Server Technology Program - Hydro Place		286.0		286.0	D - 179
Replace Radomes - Various Sites		324.9		324.9	D - 185
Upgrade IP SCADA Network - Various Sites		254.2	238.7	492.9	D - 198
Remove Safety Hazards - Various Sites		257.8		257.8	D - 204
TOTAL GENERAL PROPERTIES		1,813.4	238.7	2,052.1	
TOTAL PROJECTS OVER $200,000 AND UNDER $500,000	187.1	5,036.2	1,118.0	6,341.3	

Project Title: Upgrade Victoria Control Structure

Location: Victoria Lake

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project is the first year of a three-year program to upgrade the Victoria Control Structure. Equipment at Victoria Control Structure is at or near the end of its service life or is in a deteriorated condition. After this upgrade is completed, Victoria Control Structure, shown in Figure 1 and located on the map in Figure 2, is expected to be in a condition to operate safely and reliably for another 25 years.

Figure 1: Victoria Control Structure and Diesel Building

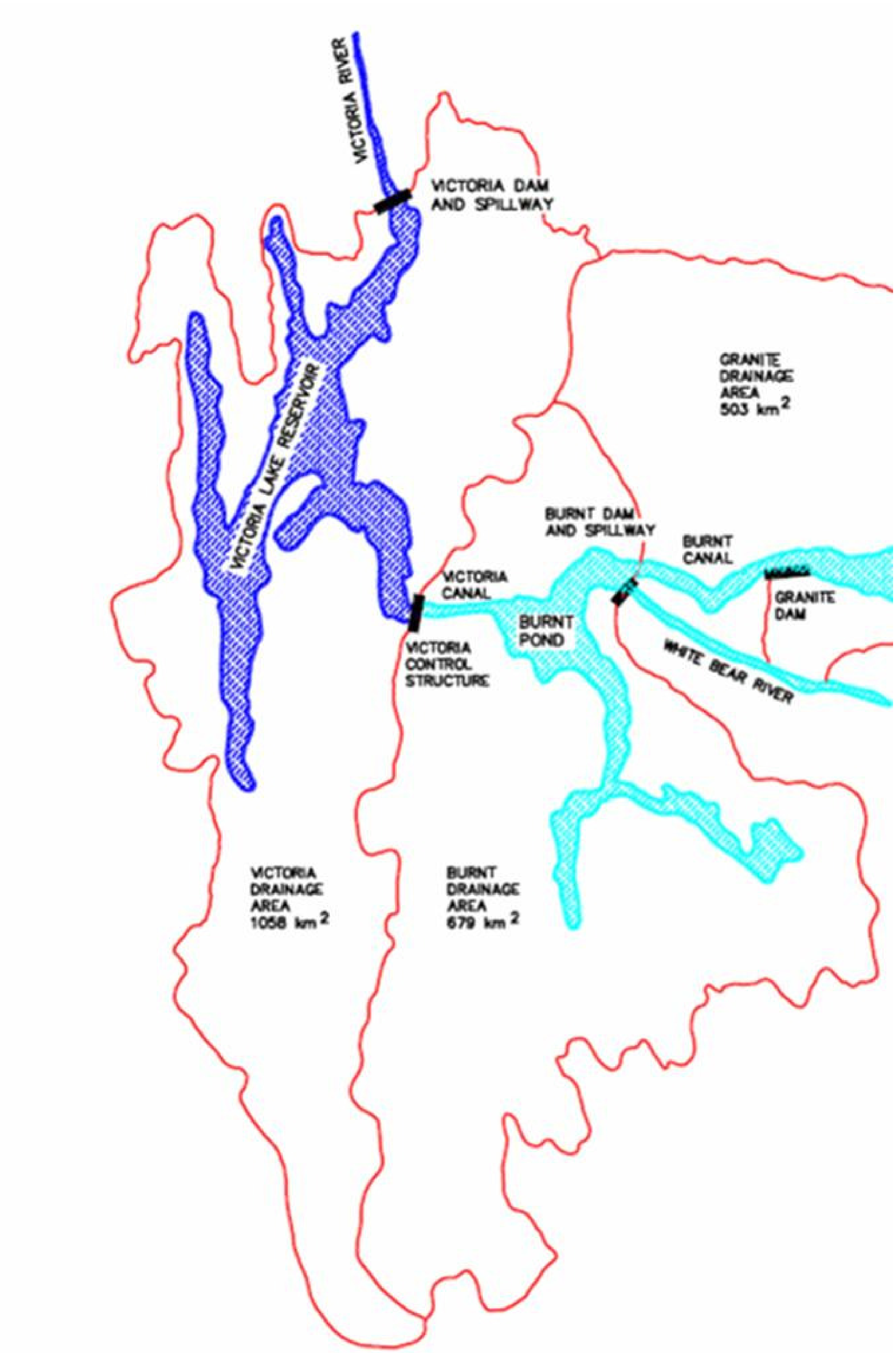


Figure 2: Victoria Lake and Burnt Pond Reservoirs

This project involves refurbishment, replacement and detailed inspection of components and equipment at Victoria Control Structure. The scope of work for this project includes the following:

- Replacement and upgrading of all deteriorated electrical panels (see Figure 3) and transformers;
- Replacement of power cables between the electrical panels and the four gate actuators;
- Refurbishment and/or replacement of gate screws, stems, wedges, guides and limits;
- Detailed inspection of gate actuators (motors and drives) (see Figure 4), gates and embedded parts by the original manufacturer (Flowserve Limitorque) and an engineering consultant (RD Energy) to determine upgrade requirements for a future year;
- Detailed inspection and evaluation of the concrete structure and water passages by an Engineering consultant; and
- Refurbishment of the balancing valve.

Figure 3: Victoria Control Structure - Electrical Panels and Power Cables

Figure 4: Victoria Control Structure – Actuators and Balancing Valve

The budget estimate for this project is $495,100. Work will be completed by a combination of internal and external engineering and labor forces. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	20.5	0.0	0.0	20.5
Labour	152.9	0.0	0.0	152.9
Consultant	25.0	0.0	0.0	25.0
Contract Work	150.9	0.0	0.0	150.9
Other Direct Costs	43.3	0.0	0.0	43.3
Interest and Escalation	24.0	0.0	0.0	24.0
Contingency	78.5	0.0	0.0	78.5
TOTAL	**495.1**	**0.0**	**0.0**	**495.1**

Justification:

This project is required to refurbish a 43 year old water control structure in order for Hydro to provide safe, reliable, controlled water release and flood management from the Victoria Lake reservoir. Controlled release of water from Victoria Reservoir to meet both long and short term production and storage targets is contingent upon the successful upgrade of Victoria Control Structure. A condition assessment study performed by a professional engineering firm, Hatch, in 2008 (see Appendix A) identified Victoria Control Structure as having the second lowest overall Health Index (68 versus 66 for Burnt Dam Spillway) when compared to four other hydraulic structures of similar vintage within the Bay d'Espoir Development. The Hatch report recommended replacing the electrical panels and transformer, refurbishing gate wedges and thimbles, and refurbishing the balancing valve operator extension stem. Burnt Dam Spillway which had the lowest overall Health Index is presently in the third year of a four-year upgrade program. When the three-year upgrade program of Victoria Control Structure is completed, this hydraulic structure will be in a condition to operate safely and reliably for another 25 years.

Existing System:

Victoria Control Structure was placed in service in 1970 and is now is 43 years old. The majority of the equipment is original and the structure has never been subjected to a major refurbishment. It regulates the flow of water from the Victoria Lake Reservoir to Burnt Pond in Hydro's Bay d'Espoir water control system. The structure consists of four, two meter square slide gates with single electric screw actuators. An additional four gates with manual actuators are mounted upstream to act as bulkhead gates. The structure is in a remote location, 230 km mostly by dirt road from Grand Falls and is powered by diesel generators which are manually started whenever the gates need to be opened or closed. Normally, once or twice per week one or two gates are required for the controlled release of water from Victoria Lake Reservoir with the additional requirement of up to four gates during a major flood situation. The weekly operation of the gates is undertaken by Hydro's labor crews who are stationed at Burnt Dam Spillway on a year round basis. Access is normally by road from nearby Burnt Dam Spillway using a truck, snowmobile or ATV and by helicopter when road conditions are unsuitable for safe travel or when maintenance crews from Bay d'Espoir are required for monthly PMs or breakdowns.

Operating Experience:

Over the years there have been isolated incidents where one of the gates at Victoria Control Structure could not be opened for normal release of water but none have resulted in serious consequences since there are four gates and only two are required for normal water management of Victoria Reservoir. Failure of the diesel generator to start was an immediate cause for some incidents whereas others were caused by mechanical or electrical problems associated with the gate actuators and screw assemblies. Also, due to erosion of the concrete and wear of the gate thimbles, all of the electrically actuated gates have some water leakage due to wear and erosion damage when fully closed as shown in Figure 5. This water leakage will continue to deteriorate the gate and concrete, accelerating the deterioration of the asset.

Figure 5: Victoria Control Structure – Gate Leakage

Reliability Performance

Due to its importance for water release and flood management of Victoria Lake Reservoir the reliability of Victoria Control Structure must be kept at a high level. When it was commissioned in 1970, it was remotely controlled but due to frequent failures of the remote control equipment and the need to guarantee operational reliability it was converted to manual operation in 1976. Operators who are stationed at nearby Burnt Dam Spillway on a year round basis travel to Victoria Control Structure as required (twice per week on average) to start the diesel generators to provide power for opening and closing the gates. In order to maintain 100% reliability of this structure, refurbishment of this structure is required over the next three years.

Outage Statistics

Outage statistics for Victoria Control Structure are not recorded. A review of the work order history over the last five years indicates that there have been a six occasions when a gate could not be opened due to mechanical or electrical problems with the gate actuators or screw assemblies. There have also been four occasions when the diesel generators would not start and a gate would have to be opened using the backup portable gas generator and electric drill unit.

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements for this project.

Safety Performance

Victoria Control Structure is the main spillway for Victoria Lake Reservoir. During a major flood all control gates must be available for operation to spill excess water to prevent a dam breech at Victoria Spillway which was converted to an overflow spillway in the late 1980s. Failure of the dam at Victoria Spillway would have significant consequences as it relates to the environment and population downstream. The Victoria River feeds Red Indian Lake which feeds the Exploits River. A dam breech would result in catastrophic flooding in the communities of Badger, Grand Falls and Bishop Falls.

Environmental Performance

Failure of all gates to open during major flood conditions could result in a dam breech at Victoria Spillway which would result in major environmental damage downstream of the structures. The Victoria River Valley and the Exploits River Valley would be flooded.

Industry Experience

Throughout North America as hydraulic structures age the requirement for refurbishment is undertaken by most utilities including the largest, Hydro Quebec. Churchill Fall Labrador Corporation whose spillways, intakes and control structures are approximately 40 years old are also presently involved in a rehabilitation program.

Maintenance or Support Arrangements

Routine preventive and corrective maintenance is performed by Hydro personnel.

Maintenance History

The five year maintenance history for Victoria Control Structure is provided in Table 2.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2012	4.0	9.2	13.2
2011	2.6	0.5	3.1
2010	1.4	0.5	1.9
2009	5.9	2.5	8.4
2008	3.0	3.1	6.1

Historical Information

A program to upgrade all structures on the original Bay d'Espoir water control system started with Burnt Dam Spillway in 2011. Victoria Control Structure will be the second structure to be upgraded. Several modifications to various structures have been completed in the past as follows:

- Victoria Spillway; converted to an overflow spillway in 1988;
- Salmon River Spillway; increased height of gates in 1988; and
- Ebbegunbaeg; replaced screw hoists on Gate 2 with cable hoist in 2004.

At Burnt Dam, many of the upgrades for 2011 and 2012 are still ongoing and will not be completed until 2013 including replacement of the stop log hoist and enclosure, installation of a new stop log storage system and overhaul of the two gate drives. Upgrade of electrical panels and safeties and detailed inspection of each gate and the civil structure is also scheduled in 2013.

Anticipated Useful Life

It is anticipated that the service life of Victoria Control Structure will be extended by 25 years when the upgrade program is completed.

Development of Alternatives

There are no viable alternatives to refurbishing Victoria Control Structure. This structure is critical for water management on the Bay d'Espoir Reservoir system. Further deterioration of this structure will result in future reliability issues which will impact Hydro's ability to produce least cost power.

Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to this project.

Conclusion:

Victoria Control Structure is a critical structure for regulating water in Hydro's Bay d'Espoir reservoir system. It controls the flow of water from Victoria Lake Reservoir for both water management and flood control and must be well maintained to ensure a high level of reliability. This project is the first year of a three-year program to upgrade the equipment and components of the structure at Victoria Control Structure.

Project Schedule:

The anticipated schedule for this project is provided in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Open work order; prepare detailed schedule; assign engineers; conduct meetings	January 2014	September 2014
Design	Site visit, prepare drawings, design transmittal	February 2014	April 2014
Procurement	Procure materials, consultants and contractors	March 2014	July 2014
Construction	Electrical and mechanical work along with detailed inspections	August 2014	September 2014
Commissioning	Electrical and mechanical upgrades	September 2014	September 2014
Closeout	Lessons learned, finalize drawings, closeout	October 2014	October 2014

Future Plans:

This is a three-year program and will continue until 2016. In 2015, the program will include replacement of the backup diesel generator and switchgear and any other electrical equipment at an estimated cost of $300,000. In 2016 the program will include upgrading the remaining deteriorated items, currently estimated at $450,000, as determined during the detailed inspections of the structure's equipment and water passages in 2014.

APPENDIX A

HYDRAULIC STRUCTURE LIFE EXPECTANCY STUDY – FINAL REPORT (HATCH)

(Excerpts and pictures applicable to Victoria Control Structure)

7.2.1.3 Heaters

No gate heating is provided at either of the four Victoria Control Gates and there is neither an air bubbler system nor up-lifters. De-icing of the gates is carried out by gain heating at Gates 1 and 2.

Gain heating for Gates 1 and 2 consists of two sets of gain heaters rated at 2kW, 208/240 V, 1-phase, one each installed on the east and west side gains of the control gates. In addition, a sill heater rated at 2kW, 240V, 3-phase is provided and installed in the gate bottom sill. No gain heaters are provided in Gates 3 and 4.

The gain heating equipment, which appears to be original, is corroded and has no provision for thermostatic control including high and low current operation during winter and summer. Further, the gain heating controls do not have a provision for remote alarm and indication. Since the site is remote and power is generated locally (by a diesel generator) to feed the control gate motor operators on an as-required basis, replacing the gain heating controls with a thermostatic control requires further investigation. As a minimum requirement, thermostatic controls would still be required in order to regulate the gain heater temperatures during winter.

Gates 3 and 4 have provision for installation of gain heaters and installation of gain heating and controls on these gates may be further investigated.

Functional testing was carried out on the gain heating system at Gates 1 and 2 during the site visit. The heaters were switched on, and currents and voltages of each component were recorded. Gain heaters on the east side of the control structure and the sill heaters for Gates 1 and 2 were disconnected and therefore in operable.

7.2.1.4 Instrumentation, Control and Communication

Presently head pond measurements are reported to the system control centre at St. John's from an Environment Canada flow and level measurement station located upstream of the Victoria Control Structure. Further, head pond water levels can also be observed manually from a staff gauge installed permanently at the upstream side wall of the control structure. Since Hydro does not have a real time data measuring device on water level at Victoria Control Structure, an independent solar operated device is required with provision for remote water level data transfer capability to the system control centre at St. John's using satellite or radio communication systems.

Gate position sensing equipment installed at the four control gates could not be verified during the site visit. However, by visual inspection it appears gate limits and auxiliary limit switches required for safe operation of the gates are installed and part of the control circuitry. The performance of the gate position sensing equipment should be further investigated and installed or replaced, if required.

Victoria Control structure is a remote station and therefore no controls and communication exists between this structure and system control centre at St. John's. All gate regulation is performed by local operators available 24/7 and located 10 km downstream of the control structure at Burnt Dam

Spillway. No telephones are provided at the spillway gate enclosure, and any communication can only be done over VHF radio or satellite telephones.

No remote camera is installed at the spillway gate locations to provide real time security in the control structure and the dam area and surroundings.

Functional tests on gate instrumentation were performed on Gates 1 and 2, for local indication only. However, operation of the upper and lower cut off limit switches could not be verified.

7.2.2 Mechanical

7.2.2.1 Gates

The cast iron gates are robust and durable. All four main gates were accessible after closing the upstream bulkhead gates and climbing down with the help of access ladders. The downstream water level was sufficiently low to permit close examination.

The coatings on Gates 3 and 4 appear to be more deteriorated than those on Gates 1 and 2. This may be due to use patterns or a different coating system. Significant leakage was observed from downstream on all four gates, but visible sections of brass seals did not show signs of significant damage.

The stem-to-gate attachment blocks appeared to be in good condition, and movement of the block was observed as the hoist changed from lifting to lowering mode.

7.2.2.2 Thimbles

The thimbles do not appear to be in as good condition as the gates. There are no wedge blocks on the top of the gates, several wedge set screws are bent, and there is a wedge missing on Gate 1. The poor condition of the wedge blocks is probably the largest contributor to the poor sealing. There are signs of erosion at the top of the thimble on Gate 1, and there is a separation between concrete and thimble at Gate 4 through which water is leaking.

7.2.2.3 Hoists

The main gate hoists appear to be in satisfactory mechanical working condition. Gate 3 opening was timed and was found to require 8 minutes to fully open. It was noticed that the stem jumped on Gate 4 at the time of final closure. This may be due to limit switches being set incorrectly or some obstruction preventing the gate from fully closing. The bulkhead gate hoists were operated with a portable electric drill, which is adequate for maintenance purposes.

7.2.2.4 Civil/Structural General

The arrangement of the Victoria Control Structure allowed closer examination of the water passages than of the other sites. Several areas of concern were noted.

- The ladders are in poor condition and should be either replaced or removed altogether and temporary ladders used when needed.
- The balance valve operator extension stem needs refurbishment – the mid span bracket is loose and new bushings are required.
- There are signs of concrete deterioration and, as noted above, water is leaking around the thimble at Gate 4. A closer civil examination of the structure is warranted which would include a diving inspection of all 8 piers and preparation of a repair plan, if necessary.

7.3 Maintenance Records Review

There are relatively few maintenance work orders recorded on the Victoria Control Structure Gates since 2003 and only three refer to inability to operate gates.

There are annual and bi-annual preventative maintenance routines for the gates; however the existing PM routines are not written for cast-iron slide gates and make reference to rollers and rubber seals, of which there are none. There are no checks for the bulkhead gates or the gain heaters. There is no program of adjusting wedge blocks or checking limit switch settings. The preventative maintenance program should therefore be re-written.

7.4 Health Index

The Heath Index score for the Victoria Control Gates is 68, which corresponds to a condition of Good.

Components	Weight	Condition Rating	Weighted Score
Gate	6	3	18
Thimble	8	2	16
Gate Hoist	4	3	12
Cubicles, Enclosures & Buildings	1	1	1
Distribution Panel	3	1	3
Branch Panels	2	1	2
Transformer	3	1	3
Gate Hoist Electrical	4	2	8
Cables	3	2	6
Total of Observed Components	34		69
Maximum Possible Score	34	3	102
Health Index	(69/102)*100		68

7.5 HydroVantage Analysis Results

Four components were studied with HydroVantage: a Limitorque motor, the distribution panel, an electric screw stem hoist, and a manual screw stem hoist.

For analysis purposes, it was assumed that there was no consequence cost to a gate operation failure. The presence of bulkhead gates upstream of the main gates permits closure of the water passage with very little delay. Also, since there are four gates, there is low risk of not being able to open either gate or needing all four open and a failure occurring.

The results of the HydroVantage Analysis using 2007 average fuel cost are as follows:

- Operate Limitorque motors to failure.
- Operate the distribution panel to failure.
- Operate the electric screw stem hoists to failure.
- Operate the manual screw stem hoists to failure.

Since there is no consequence cost of operational failure, the results do not change with the cost of fuel.

Victoria Control Structure is an important component in the Bay d'Espoir Hydroelectric Development but one that has little risk associated with gate failure because it was built with redundant gates. Based on risk alone, equipment upgrades to the facility cannot be justified.

7.6 Recommendations, Victoria Control Structure

7.6.1 Short Term (0-2 Years)

51. Replace the 600 V distribution panel.
52. Replace the 600:208 V step-down transformer.
53. Replace the 120/208 V distribution panel and eliminate the 120/240 V distribution transformer. All 120 V and 208 V loads can be supplied from one distribution panel.
54. Replace gain heating controls and control cables for Control Gates 1 and 2 with provision for thermostatic temperature controls.
55. Replace defective gain heaters and sill heaters.
56. Investigate the installation of a solar operated head pond level measuring device with facilities for transmission of data via satellite or VHF radio communication systems.
57. Verify the operation of upper and lower limit cut-off switches.
58. Conduct a civil examination of the water passages.
59. Rewrite the preventative maintenance routines.
60. Repair the wedges on the gates.

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7.6.2 *Medium Term (2-7 Years)*

61. Investigate the installation of gain and sill heaters and controls on Control Gates 3 & 4 based on operating history and requirements.
62. Inspect the bulkhead gates.
63. Replace the Limitorque motors and controls.
64. Investigate the performance of the gate position sensing equipment and installed or replacement by infrared or digital encoders, if required.

7.6.3 *Long Term (Beyond 7 Years)*

65. Investigate the requirement of a new broadband system communication system for automatic transfer of gate position data, and other parameters such as intrusion alarm, status and indication including video signals and reporting to remote control centre.
66. Investigate the requirement of a video camera fitted with defrosting visor at the Control Structure for real time surveillance and security against illegal intrusions.

HATCH™

Victoria Control Structure

Short Term Recommendations (0-2 Years)			Medium Term Recommendations (2-7 Years)			Long Term Recommendations (Beyond 7 Years)		
No.	Brief Description	Budget Cost	No.	Brief Description	Budget Cost	No.	Brief Description	Budget Cost
51	600 V Distribution Panel	10,000	61	Investigate Heating Gates 3,4	5,000	65	Broad Band Communications	100,000
52	Step-Down Transformer	5,000	62	Inspect Bulkhead Gates	25,000	66	Video Camera	50,000
53	120/208 Distribution Panel	5,000	63	Motors and Controls	80,000			
54	Gain Heating Controls	10,000	64	Investigate Gate Positioning	5,000			
55	Gain Heaters	30,000						
56	Water Level Measurement	25,000						
57	Limit Switches	0						
58	Civil Inspection	50,000						
59	Revamp PM Routines	0						
60	Wedges	10,000						
		145,000			115,000			150,000

Total for Victoria Control Structure $410,000

Short Term Total 1,232,000 Medium Term Total 402,000 Long Term Total 465,000

Total of All Recommendations $2,099,000

Notes:

1. The budget costs provided are Class 4, +40/-20%.
2. Items with $0 are routine maintenance items.
3. Some recommendations could be combined for cost savings, for example investigations of gate positioning or gate heating at several structures.

Photo 98: Victoria - Downstream View of Victoria Control Structure - Notice Leakage from Gates

Photo 99: View of Victoria Control Gate 2 in Open Position

Photo 100: View of Brass Seals on Victoria Control Gate 2

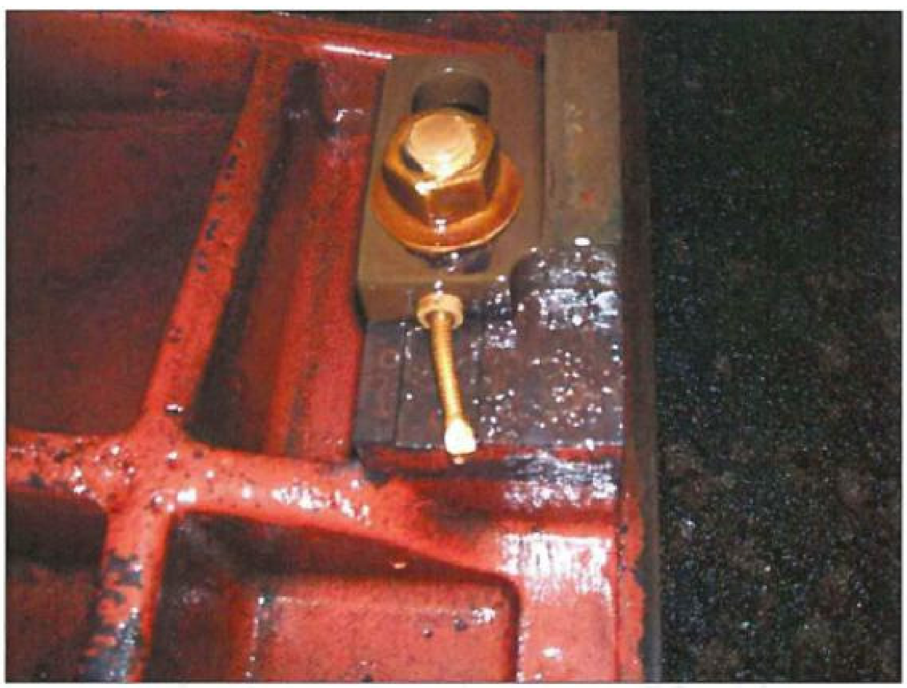


Photo 101: Bent Wedge Set Screw on Victoria Control Gate 2

Photo 102: Victoria Control Gate 1 - Notice Missing Wedge Block in Centre of Photograph

Photo 103: General Arrangement of Victoria Control Gates 1 and 2

Photo 104: Corrosion on Victoria Control Gate 4

Photo 105: Leakage Past Bulkhead Gates Upstream of Victoria Control Gates 3 and 4

Photo 106: Victoria Control Structure Overhead Supply from Diesel Building

Photo 107: Victoria Control Structure - Gate Structure Service Mast

Photo 108: Victoria Control Structure - Exposed Grounding Conductors

Photo 109: Victoria Control Structure - Exposed Grounding Conductors

Photo 110: Victoria Control Structure - Cables Exiting Conduits

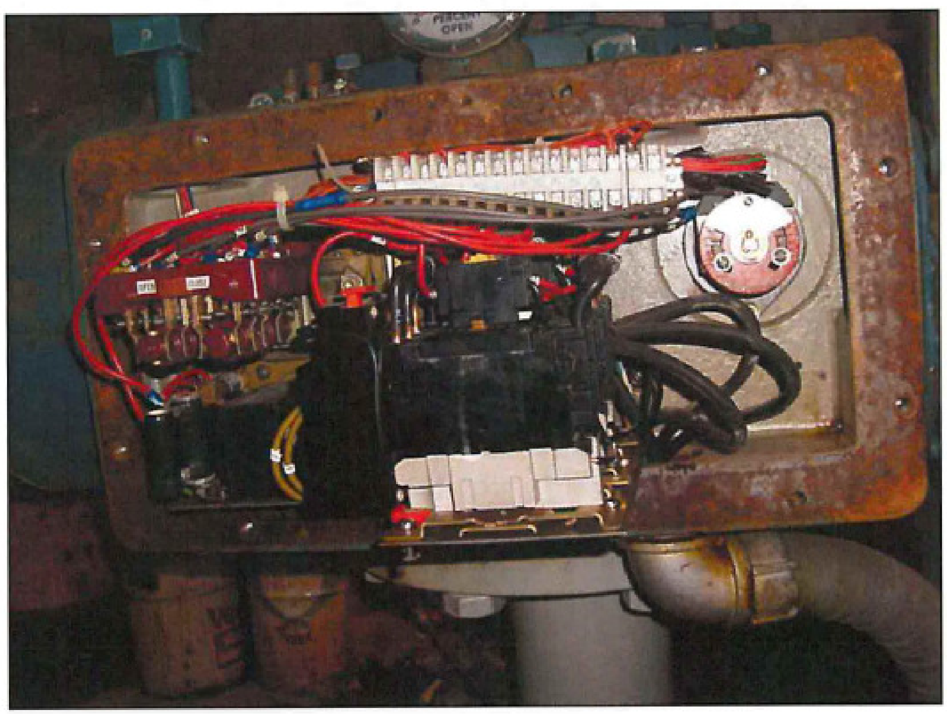


Photo 111: Victoria Control Structure - Limitorque Junction Box Internals

Photo 112: Victoria Control Structure - 600V Distribution Panel

Photo 113: Victoria Control Structure - 120/240V Distribution Panel

Photo 114: Victoria Control Structure - 120/208V Distribution Panel

Photo 115: Victoria Control Structure - Step-Down Transformer

Photo 116: Victoria Control Structure - Lighting Ballasts

Project Title: Overhaul Turbine/Generator Units

Location: Bay d'Espoir and Hinds Lake

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project is required to partially dismantle the Bay d'Espoir Unit 3 and Hinds Lake turbine/ generator units to inspect, test, clean, repair and replace equipment components. This overhaul involves cleaning and inspection of rotor and stator assembly, electrical testing on rotor/stator assembly, calibration and testing of turbine and generator protection devices, inspection of bearing and seal clearances and a thorough inspection of turbine, draft tube and penstock. The intake inspection will require a diving team. The budget estimate for the project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	26.9	0.0	0.0	26.9
Labour	289.2	0.0	0.0	289.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	6.3	0.0	0.0	6.3
Other Direct Costs	61.4	0.0	0.0	61.4
Interest and Escalation	24.4	0.0	0.0	24.4
Contingency	76.8	0.0	0.0	76.8
TOTAL	**485.0**	**0.0**	**0.0**	**485.0**

Justification:

These large turbine/generator units are required to be operating efficiently and effectively. During the winter months these units are collectively required to be available nearly 100 percent of the time in order to meet the electricity demands of the Island Interconnected System. In order to achieve this, these units need to have all major components inspected, tested and/or refurbished on a six year frequency to minimize forced outages, forced de-ratings or unplanned maintenance outages, which result in customer interruptions. This frequency is based on the recommendations outlined in Hydro's Asset Maintenance Strategy (AMS) Management Program. In addition, these inspection/ overhaul programs are re-evaluated regularly by Hydro's Long Term Asset Planning team and maintenance groups to ensure they are efficient and effective by reviewing forced, de-rating and unplanned maintenance outages annually and determining their root causes, reviewing maintenance procedures and performing budget reviews accordingly based on required scope of work.

Existing System:

Hydro has hydroelectric generating units at Bay d'Espoir, Upper Salmon, Hinds Lake, Cat Arm, Paradise River, Granite Canal, Snook's Arm, Roddickton and Venam's Bight, for a total installed capacity of 939 MW. All hydro electric generators, intakes, spillways, control structures and plant auxiliary equipment are inspected annually but major inspections/ overhauls are conducted on a six year frequency.

Age of Equipment or System

The following are the Unit in-service dates:

- Bay d'Espoir Unit 3 – 1967, and
- Hinds Lake Unit – 1980.

Table 2: Major Work or Upgrades – Bay d'Espoir Unit 3

Year	Major Work/Upgrade
2004	Spherical valve controls upgrade
1999	Turbine bearing cooling coil install.
1999	Generator bearing cooling coil install.
1997	Exciter Replacement
1994	Runner replacement
1982	Auto-greasing system installed

Table 3: Major Work or Upgrades – Hinds Lake

Year	Major Work/Upgrade
2012	Replacement of static exciter
2000	Replacement of high pressure compressor 1
1998	Installation of mini trash racks on gates 1 and 2.
1996	Replacement of battery bank
1995	Replacement of control structure Programmable Logic Controller

Operating Experience:

Bay d'Espoir Unit 3 and Hinds Lake turbine/generator units are two of sixteen hydraulic generating units that Hydro operates and maintains to meet system load requirements. These units went into service in 1967 and 1980, respectively.

All turbine/generator excluding mini-hydro units are given a major inspection every six years which is based on the experience and manufacturer recommendations as described in the Industry Experience section below.

Reliability Performance

Tables 4 and 5: Outage Statistics

Bay d'Espoir Unit 3

Year	Forced Outages	Maintenance Outages	Planned Outages
2012	2	2	1
2011	0	0	1
2010	2	0	1
2009	0	3	1
2008	0	0	1

Hinds Lake

Year	Forced Outages	Maintenance Outages	Planned Outages
2012	3	0	1
2011	7	2	1
2010	2	2	1
2009	3	2	1
2008	1	2	1

Safety Performance

The activities that take place during inspections are well documented and defined. Any tasks that have been identified as critical with respect to safety have safety work methods available to follow to ensure all safety hazards are controlled or eliminated.

Environmental Performance

There are no environmental issues with the overhaul of these units.

Industry Experience

Work performed during major inspections and overhauls is based on operational experience and manufacturer recommendations.

Vendor Recommendations

Vendor maintenance recommendations were considered and applied where applicable when the major inspection programs were developed.

Maintenance or Support Arrangements

Maintenance of hydroelectric generators is conducted by Hydro employees. Contractors and consultants are typically utilized only to perform large, exceptional pieces of work where the skill sets are lacking internally.

Maintenance History

The five-year maintenance history for Bay d'Espoir Unit 3 is shown in Table 6.

Table 6: Five-Year Maintenance History – Bay d'Espoir Unit 3

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2012	49.4	35.2	84.6
2011	30.5	15.3	45.8
2010	40.0	70.3	110.3
2009	67.5	36.2	103.7
2008	22.6	17.3	39.9

The five-year maintenance history for Hinds Lake is shown in Table 7.

Table 7: Five-Year Maintenance History – Hinds Lake

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2012	23.4	39.0	62.4
2011	31.4	218.5	249.9
2010	36.8	115.6	152.4
2009	94.7	22.7	117.4
2008	19.1	16.7	35.8

There are relatively high corrective maintenance costs associated with the years 2010 and 2011. In 2010, turbine runner repairs were required and exciter problems were experienced which resulted in the high maintenance costs. In 2011, the rotor experienced high ground faults due to conductive dust from the brushes and slip ring requiring cleaning and machining of the slip rings. Also the exciter failed in 2011 requiring repairs. It was replaced in 2012.

<u>Historical Information</u>

Hydraulic turbine/generator overhauls are typically performed on a six year frequency. Typically two hydraulic turbine/generator units are overhauled every year. In 2012, unit overhauls were completed in Granite Canal and in Upper Salmon. The budget for this project was $456,600 and the actual cost was $384,100.

<u>Anticipated Useful Life</u>

The overhaul of the turbine/generator units is completed every six years. Therefore, the useful life of this overhaul is six years.

Development of Alternatives:

There are no viable alternatives to overhauling the units.

Conclusion:

Hydroelectric generators are required to operate in an efficient manner and are required to be reliable in order to meet system load requirements on a daily basis. Major inspections and overhauls are essential and critical to the reliability of the Island Interconnected System.

Project Schedule:

Major inspections and overhauls are performed by Hydro employees. The schedule varies between three and four weeks. At times, planned outages have to be extended up to an additional week to deal with corrective maintenance items. The anticipated project schedule is shown in Table 8.

Table 8: Project Schedule

Activity		Start Date	End Date
Planning	Inclusion into the Annual Master Work Plan	November 2013	December 2013
Design	Detailed plan for the overhaul outage	January 2014	May 2014
Procurement	Specify material requirements	March 2014	September 2014
Construction	Perform the major inspection/ overhaul	May 2014	November 2014
Commissioning	Return the unit to service	July 2014	November 2014
Closeout	Closeout the project	November 2014	December 2014

Project Title: Upgrade Generator Bearings Unit 2

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

Hydro is seeking approval for this two year project starting in 2014. It is the second unit of a multi-year program to perform guide bearing and maintenance access hatch upgrades to generating Units 1 to 6 at Bay d'Espoir. The program, which began in 2013, with approval in Board Order No. P.U. 4 (2013) to perform the upgrades to Unit 4, will continue until 2020 when all six units are upgraded. Modifications to the guide bearings and maintenance access hatches will eliminate oil loss from the generator bearing housing caused by emissions of vaporized oil and leaks from seals, gaskets and fittings. Work by the original equipment manufacturer will include technical support, machining of all guide bearing segments, fabrication and supply of new maintenance access hatches and supply of all other materials necessary to complete these modifications. It will also include all work by Hydro's internal forces for engineering and installation of the modified guide bearing segments and new maintenance access hatches. As future work plans are developed along with future outage schedules, the sequencing of units to be upgraded in specific years could change, but the scope of the overall program will not. The budget estimate for the project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**2015**	**Total**
Material Supply	0.0	10.0	0.0	10.0
Labour	16.0	179.2	0.0	195.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	102.5	0.0	102.5
Other Direct Costs	2.0	12.2	0.0	14.2
Interest and Escalation	0.9	27.7	0.0	28.6
Contingency	0.0	64.4	0.0	64.4
TOTAL	**18.9**	**396.0**	**0.0**	**414.9**

Justification:

Generating Units 1 to 6 at Bay d'Espoir were commissioned from 1967 to 1970 and due to the bearing design have always had oil emission problems (see Table 3 for summary of last five years and Appendix A for 2012) arising from vaporized lubricating oil escaping from the guide bearing seals (see Figure 1) and between the maintenance access hatches (see Figure 2). Shortly after commissioning modifications to the bearing housings were undertaken to help contain and collect oil emissions resulting from the vaporization of oil. These modifications were only partially successful and did not eliminate the problem. Since commissioning, maintenance activities have resulted in wear and tear of the clamps used to secure the maintenance access hatches. Leaks through the hatch seals are a recurring problem and cannot be corrected without modifying the original design of the hatches. These oil emissions and leaks contaminate the entire unit and of particular concern is the generator's rotor and stator. Contamination has an accelerated deterioration effect on these major electrical components and has the potential of contributing to a major fault. It also creates safety, fire, and environmental hazards which results in the need for frequent unit cleaning. An inspection of Unit 2 in May 2012, by Voith Hydro found the unit heavily contaminated with a mixture of oil and carbon dust. Voith Hydro, who rewound the stator in June/July 2010, stated in their inspection report (see Appendix A) that the bottom of the unit looks like it has been in service for ten years rather than just two years. This buildup of oil and carbon dust also clogs the ventilation ducts of the stator core over time, increasing the temperature rise in the stator.

A major stator failure with significant damage to the windings could put a unit out of service for one to two months or even longer if sufficient spare windings are not available.

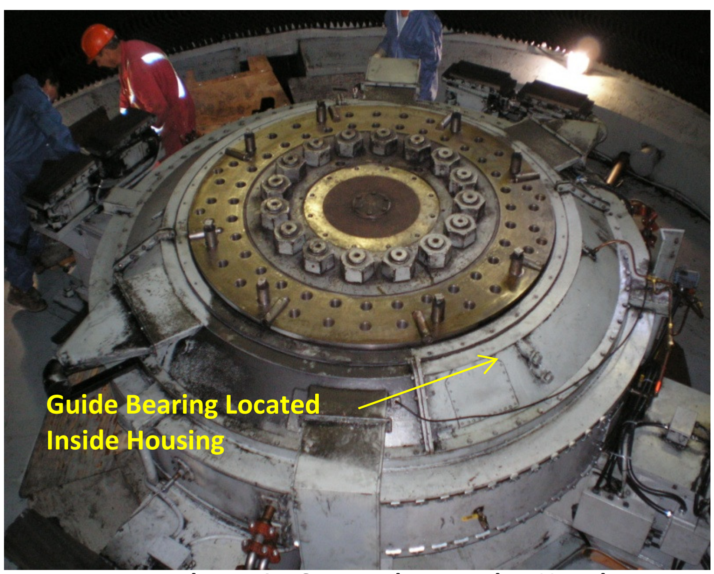


Figure 1: Generating Bearing Housing

Figue 2: Bearing Access Hatches

Existing System

Generating Units 1 to 6 at Bay d'Espoir were supplied by Canadian General Electric (CGE) and commissioned from 1967 to 1970. When they are in operation the generator thrust and guide bearings are oil lubricated continuously inside the bearing housing (see Figure 1). Units 1 and 3, which also supply power for the all equipment in the power house are normally in continuous service whereas the other four units are normally cycled on a daily basis for system loading. The generator bearings are now all approximately 45 years old and all six units have oil leakage problems (see Table 3 and Section C in Appendix A). In the past, attempts to repair leaks have been made, normally during annual and major inspections or overhauls but new leaks develop. Modifications to the bearings to control oil emissions from vaporization were completed shortly after the generating units were originally commissioned but reduced the emissions but were not totally effective. Due to difficulty in finding a suitable design to solve this problem, there have been no major modifications since to resolve the emission problem. Table 2 summarizes the upgrades made to the generator bearings in the early 1970s.

Table 2: Major Guide Bearing Upgrades

Year	Major Work/Upgrade	Comments
1971-1975	Modifications made to Units 1-6 generator bearings and bearing housings to control oil emissions.	The modifications were only 50% successful.

Operating Experience:

Generating Units 1 to 6 at Bay d'Espoir have generator guide bearings that leak oil and contaminate each unit which creates a reliability concern, an open fuel supply in the event of a fire, safety and environmental hazards. Periodic cleaning of components, walls and walking surfaces frequently take place, most notably during the annual unit maintenance shut-down period. Cleaning of the rotor and stator is normally done during major generator overhauls which take place approximately every six years. Alarms due to low/high bearing oil levels are also occasionally experienced (over 20 in 2012) and require maintenance outages to correct the issue. When significant leaks of one litre/day occur the units are normally removed from service when loading permits. Repairs are normally completed during unplanned or planned maintenance outages. Many of the significant leaks occur around the joints between the bearing housing and the maintenance hatch door seals. The oil vapors are usually emitted through the clearances between the top of the generator bearing housing and the generator shaft.

<u>Reliability Performance</u>

Contamination of a unit with oil can affect the reliability of a generating unit, however to this point in time, oil leaks have not resulted in a stator failure. The probability of an outage caused by oil contamination of a unit, and in particular an electrical fault due to deterioration of the windings, increases with time which can have an adverse effect on reliability. Partially due to the deterioration of the windings from oil contamination, a program involving the rewinding of the generator stators for Units 1-4 which have or had asphalt windings has been ongoing in recent years. Unit 2 was completed in 2010, Unit 1 in 2012, Unit 4 is scheduled for 2013 and Unit 3 is planned for 2014. In addition, oil leaks can have an effect on the availability of a generating unit as cleaning and repairs due to oil leaks often have to be completed during a maintenance outage. Contamination of the unit also increases the operating temperature of the stator windings by clogging the ventilation ducts which also can prematurely age the windings.

<u>Outage Statistics</u>

During the last five years Unit 3 has had three recorded forced outages and Unit 1 has had one recorded outage to repair major oil leaks. Oil is normally replenished for the units when they are off line. As the generating units are not deemed to be unavailable during this time, a forced outage is not recorded by the system operations group. A summary for addition of oil to the generator bearings on Units 1-4 at Bay d'Espoir for the last six years is shown in Table 3.

Table 3: Addition of Oil to Generator Bearings Due to Leakage (litres)

Year	Unit 1	Unit 2	Unit 3	Unit 4
2012	279	97	114	28
2011	22	81	32	26
2010	20	18	110	8
2009	10	7	140	35
2008	20	26	110	12
2007	27	12	47.5	16

Legislative or Regulatory Requirements

Any oil leakage from the unit has some potential of entering a natural body of water which is prohibited by Environmental Regulations.

Safety Performance

Due to the air flow inside the generator and turbine pits oil emissions and leaks from the generator bearing are discharged onto walking surfaces creating potential slipping hazards. To combat this, the grating in the turbine pits has been replaced with serrated grating and utility personnel frequently clean these areas. However slipping hazards, caused by oil residue, cannot be totally eliminated until the oil leaks are eliminated. In the last five years there have been four recorded observations of slipping hazards due to oil. Fortunately, there have been no incidents where personnel have been injured.

Environmental Performance

At the Bay d'Espoir powerhouses the drainage systems for the generating units do not have an oil interceptor tank and all fluids that enter the collection sumps are pumped directly into the tailrace. Some of the oil leaking from the generator bearings eventually make its way into the drainage sump and from there has the potential of being pumped into an outside water body if not closely monitored and removed from the sumps on a timely basis. Environmental regulations prohibit the discharge of oil into natural water bodies. Prior to 2000 with the implementation of ISO 14001 and stricter environmental controls there were some isolated incidents where small amounts of oil were discovered in the tailrace. These incidents happened during major work when the sump levels were lowered well below the normal operating levels.

Any oil loss from a generating unit due to leakage has an effect on the environment. The oil must eventually be cleaned up with the cleanup materials normally ending up in land fill sites. This project will minimize the amount of such material needing to be disposed. For example for Hydro Generation in 2012 approximately one roll (150' long x 30"wide) of oil absorbent material was consumed each week.

Industry Experience

Other utilities with CGE units have had similar issues with oil contamination due to emissions from the generator bearings. The units at BC Hydro's Mica generating station had modifications made to their generator bearings to control oil emissions in 2006. The proposed modifications were also implemented by Andritz Hydro, a generator maintenance company, to resolve oil emission problems at generation stations owned by Ontario Power Generation and Hydro-Quebec.

Vendor Recommendations

Andritz Hydro, which now owns the former CGE, completed engineering work for Hydro in 2011 to provide advice on how to remedy the generating unit oil leaks and emissions. They recommended the modifications (see Appendix A) which are proposed to be completed in this project.

Maintenance or Support Arrangements

Normal generating unit maintenance work is completed by Hydro personnel and this will continue after the bearing modifications have been completed.

Maintenance History

During annual maintenance inspections and major overhauls, attempts have been made to repair the leaks by replacing and trying different types of hatch cover seals but oil contamination due to new leaks continues to be a problem. The bearings have always had emissions problems due to their original design and leaks have developed due to wear and tear of the clamping system used to secure the hatch covers. The five-year maintenance history for Units 1-4 to clean up and repair oil leaks and replace seals is shown in Table 4.

Table 4: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2012	0.0	17.0	17.0
2011	0.0	6.4	6.4
2010	0.0	11.6	11.6
2009	0.0	8.5	8.5
2008	0.0	1.7	1.7

Historical Information

There have been no major modifications to control oil leaks and emissions from the generator bearings in the last five years. Different types of seals have been tried but have been unsuccessful. In 2013 work will begin related to Unit 4 which will be the first unit to undergo major modifications to the bearings since the 1970s.

Anticipated Useful Life

The generator bearing has an estimated service life of 50 years.

Forecast Customer Growth

This project is not required to accommodate customer growth.

Development of Alternatives

There are no alternatives.

Energy Efficiency Benefits

There are no energy efficiency benefits to be realized from this project.

Conclusion:

This project is necessary to eliminate oil emissions and leaks from the generators on Units 1 to 6 at Bay d'Espoir. Elimination of the emissions and leaks will help reduce the potential for electrical faults from the deterioration of the stator windings and reduce potential fire, safety and environmental hazards. Elimination of oil emissions and leaks will also help reduce the time and manpower requirements to clean a unit. Hydro is seeking approval for the second year of this program to modify Unit 2 generator bearing and access hatches.

Project Schedule:

The anticipated project schedule is shown in Table 5.

Table 5: Project Schedule

Activity		Start Date	End Date
Planning	Open project; review and develop schedule	September 2014	May 2015
Design	Review and update any design of Hatches and modifications to guide bearings;	October 2014	November 2014
Procurement	Prepare tenders, machining of guide bearings and fabrication of Hatches	November 2014	April 2015
Construction	Installation of modified guide bearings and new maintenance hatches	May 2015	June 2015
Commissioning	Testing of modifications	June 2015	June 2015
Closeout	Close out of project; documentation and lessons learned	July 2015	August 2015

APPENDIX A

A. Voith Hydro Inspection Report – Bay d'Espoir Unit 2 Stator Winding

B. Pictures of Contamination of Unit 2 Stator Windings - April 2013

C. Operator's Record of Oil added to Unit Bearings - 2012

D. Andritz Hydro – Proposed Bearing Modifications

VOITH

Voith Hydro

NALCOR / Bay d'Espoir, G2	
Inspection Report for the bottom of the stator winding CNT000564713-01-GSV0226	2600-00994397
	Revision -

Inspection report for the bottom of the stator winding
NALCOR / Bay d'Espoir, G2

Description	Created by	Approved by	Date

Executing OU	Created by		Checked by		Approved by		Issue Date
VHMS	Dino M. Slijepcevic		Dino M. Slijepcevic		Dino M. Slijepcevic		2012-06-05

2600-00994397 - Inspection Report for bottom of the winding.doc Page 1 of 3

VOITH

Voith Hydro

NALCOR / Bay d'Espoir, G2	
Inspection Report for the bottom of the stator winding CNT000564713-01-GSV0226	2600-00994397 Revision -

1. Introduction

During the inspection on unit G2, performed May 29, 2012 we observed that the mixture of oil and carbon dust deposited on the lower end of the coils by approximately double, since the last inspection that was performed in October 2011.

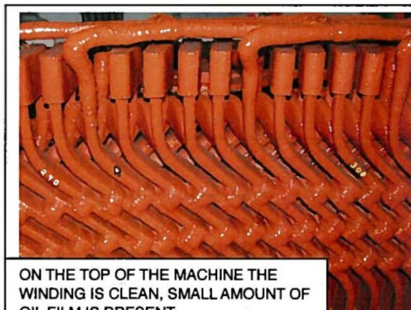
2. Conductive contamination over the end winding on the bottom of the unit

Inspection below the rotor on unit G2 revealed that no action was taken to clean diamonds of the coils since last inspection performed on the unit in October of 2011. Due to the layout of the machine (braking system, baffles, thrust bearing, piping,) below the rotor, 2/3 of the winding is heavily contaminated with a mixture of the oil and carbon dust. Present condition of the winding is creating a conductive surface over the diamond spacers for tracking, so there is the possibility to have phase to phase PDA activity recorded by the Hydro Guard (see Report from Iris, Ref. D17193.00). The winding on the bottom of the unit looks like it has already been in operation for 10 years (rewind was done in June / July 2010).

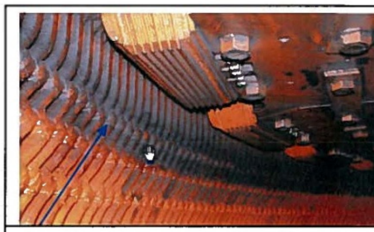
3. Recommendation

We recommend cleaning the end winding on the bottom of the unit with Simple Green solution and linen rags, before the unit would go back on line. Further we recommend to:
- repair the oil lines or other source of oil leak
- due the fact that collector rings are above the thrust bearing, installation of a carbon dust collection system would improve performance of the unit and lower the cost of maintenance on stator winding.

Otherwise build up of the mixture of the oil and carbon dust will clog up the ventilation ducts in stator core over time, increasing the temperature rise of the stator winding.



ON THE TOP OF THE MACHINE THE WINDING IS CLEAN, SMALL AMOUNT OF OIL FILM IS PRESENT.



MIXTURE OF OIL AND CARBON DUST SPREAD OVER 2/3 OF THE WINDING ON THE BOTTOM OF THE MACHINE CREATES A CONDUCTIVE SURFACE FOR TRACKING.

Executing OU	Created by		Checked by		Approved by		Issue Date
VHMS	Dino M. Slijepcevic		Dino M. Slijepcevic		Dino M. Slijepcevic		2012-06-05

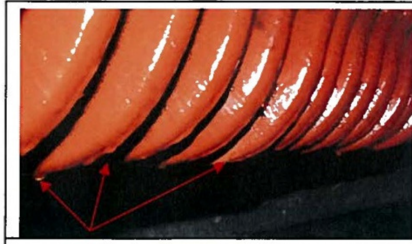
2600-00994397 - Inspection Report for bottom of the winding.doc

Page 2 of 3

VOITH

Voith Hydro

NALCOR / Bay d'Espoir, G2	
Inspection Report for the bottom of the stator winding CNT000564713-01-GSV0226	2600-00994397 Revision -



OIL DRIPPING FROM COIL NOSE AT THE BOTTOM OF THE UNIT

HEAVY COLLECTION OF OIL AND BREAK PADS DUST OVER CYLINDERS OF THE BRAKING SYSTEM

Dino M. Slijepcevic, P. Eng.

Executing OU	Created by	Checked by	Approved by	Issue Date
VHMS	Dino M. Slijepcevic	Dino M. Slijepcevic	Dino M. Slijepcevic	2012-06-05

2600-00994397 - Inspection Report for bottom of the winding.doc

Page 3 of 3

Contamination of Unit 2 Stator Windings – April 2013

Section B

RECORD OF OIL ADDED TO UNIT BEARINGS

OPER-43

File No. 100.40.00/4.5.1.2

Issue Date:
Rev. 1
Rev. Date: Dec. 17, 2009

DATE	UNIT	TURBINE BEARING	GENERATOR BEARING	LITRES	LIQUID
2011-11-07	1		✓	8	added
2011-11-07	2		✓	4	"
2011-12-01	3		✓	10	added (90)
2011-12-03	5	✓		5	added.
2011-12-05	5	✓		25	added (225)
2011-12-07	5	✓		25	Removed metering refilled z
2011-12-14	2	✓		20	(260) added
2011-12-14	3	✓		10	(260) added.
2011-12-19	1		✓	14	added (
2011-12-19	3		✓	10	added.
2011-12-19	4		✓	8	added.
2011-12-19	6		✓	8	added.
2011-12-29	2		✓	225	added 70mm
2012-01-03	2 ✓		✓	10	REMOVED (62mm)
2012-01-03	1 ✓		✓	15	added (99mm
2012-01-04	2 ✓		✓	35	added (80mm)
2012-01-04	2 ✓		✓	20	" (57mm)
2012-01-05	2 ✓		✓	70	removed.
2012-01-12	1 ✓		✓	12	added (101mm)
2012-01-12	4 ✓		✓	10	added (100mm)
2012-01-19	1 ✓		✓	10	added (102mm)
2012-01-19	3 ✓		✓	10	added (101mm)
2012-01-19	6 ✓		✓	8	added (100mm)
2012-01-29	1 ✓		✓	20	added (100)
2012-02-06	1 ✓		✓	20	added (103mm)
2012-02-13	1 ✓		✓	15	added (97mm)
2012-02-23	1 ✓		✓	20	added (95mm)
2012-02-29	1 ✓		✓	25	added (106)
2012-02-29	3 ✓	✓		16	added (260)
2012-03-05	1 ✓		✓	9	*Recovered
2012-03-11	1 ✓		✓	24	added (104)
2012-03-18	1 ✓		✓	25	added (103)
2012-03-23	1 ✓		✓	20	added 104
2012-03-28	1 ✓		✓	20	added 104
2012-04-02	1 ✓		✓	20	added (103mm)
2012-04-07	1 ✓		✓	20	added (102 mm)
2012-04-11	1 ✓		✓	15	added (100 mm)
2012-04-13	3 ✓		✓	5	added (100)
2012-06-13	2 ✓	✓		25	added

RECORD OF OIL ADDED TO UNIT BEARINGS

OPER-43

File No. 100.40.00/4.5.1.2

Issue Date:
Rev. 1
Rev. Date: Dec. 17, 2009

DATE	UNIT	TURBINE BEARING	GENERATOR BEARING	LITRES	LIQUID
2012-07-05	6 ✓	✓		10	Added
2012-07-19	4 ✓	✓		8	Added.
2012-07-19	4 ✓		✓	10	Removed.
2012-07-19	1 ✓		✓	16	Removed
2012-09-04	2 ✓		✓	10	ADDED
2012-09-07	3 ✓		✓	11	added (103 mm
2012-09-17	3 ✓		✓	20	added (95mm)
2012-09-20	3 ✓		✓	5	added (103mm)
2012-09-26	3 ✓		✓	10	" (106)
2012-10-03	3 ✓		✓	20	added (102)
2012-10-12	5 ✓		✓	9	added (102)
2012-10-12	6 ✓		✓	12	added (103)
2012-10-15	2 ✓		✓	15	added (100)
2012-11-01	2 ~~6~~ • x		*		*
2012-11-07	6 ✓		✓	10	added (98)
2012-11-08	6 ✓		✓	5	added (103)
2012-11-14	6 ✓	✓		4	added (
2012-11-20	5 ✓	✓		10	added (254)
2012-11-20	4 ✓		✓	12	added (111 mm).
2012-11-27	3 ✓	✓		10	added (263)
2012-11-28	1 ✓		✓	10	added (103)
2012-11-28	3 ✓		✓	15	added (108)
2012-11-28	6 ✓		✓	25	added (102)
2012-12-	6 ✓		✓	15	added (96)
2012-12-13	2 ✓		✓	5	add (94)
2012-12-20	3 ✓		✓	10	add (103)
2012-12-20	2 ✓		✓	12	add (99)
2012-12-26	5 ✓	✓		10	added (263)
2012-12-27	4 ✓		✓	6	added (105)
2013-01-04	3 ✓		✓	8	added (102)
2013-01-08	1 ✓	✓		6	added (260)
2013-01-08	3 ✓	✓		4	added (250)
2013-01-15	1		✓	10	added
2013-01-15	5		✓	12	added.
2013-01-21	3		✓	20	added (108)
2013-01-23	3	✓		4	added (255)

* All oil removed from unit #2 Gen Brg due Contamination by water
1230 litres of new oil added. New level Cold - 62.5 mm
After 40 minutes - 96.0 mm.

Section C

ANDRITZ Hydro

Mr. Trevor Arbuckle
Engineer - Mechanical
Newfoundland and Labrador Hydro
A Nalcor Energy company

Date: December 6th, 2011

Subject: Bay D'Espoir – Bearing modifications

Dear Mr. Arbuckle,

Please find below our comments and description of the proposed work.

1. Guide bearing

The purpose of these modifications is to reduce oil mist and spray from the guide bearing inside the oil baffler. Tests have shown that in our older design, which was used on Bay D'Espoir, the drainage grooves in the guide bearing were overloaded which resulting in oil leaking past the grooves to the top of the bearing. This oil was thrown off by the rotor surface, creating excessive mist or oil droplets inside the baffler. By increasing the gap between segments, allowing the oil supply to enter the feed groove between segments from the oil pot rather than the rotor pumping holes, and installing a deflector over the gap between segments we have been able to make a large reduction in the oil spray from the guide bearing. This proposed design has been used on all of our recent jobs like Toulnustouc, Seven Mile, and Lower Mattagami. In addition we have carried out similar modification on the old Mica units #1-4 machines.

This new design can be incorporated into Bay D'Espoir with the following modifications:

- increase depth of circumferential supply groove
- increase gap between segments
- plug holes from drain groove
- install new sealing sticks between segments
- install deflector over gap between segments
- plug pump holes in rotor

An example of this scope of work is provided in Annex A which shows the pre-modification drawings for Mica units #1-4 while Annex B shows the post modifications drawings.

These modifications require machining of the segments both individually on a milling machine and as an assembly on a vertical boring mill.

2. Technical supervision at site

Andritz can provide site technical assistance for this work. If you wish to use our services, please let us know ahead of time so we can schedule one of our supervisors to be available. We can also provide a complete team, including supervisor and necessary labour, upon request.

3. Pricing

Andritz can execute the bearing modification as a fixed price in a Canadian machine shop. Please let us know when Nalcor plans to do the work and how much time will be available during the outage. Site work can be done as a fixed price or with an hourly rate. We would use 2011 Andritz rates if the work is scheduled at the beginning of 2012. Let us know your needs and we will send you the pricing and an execution plan.

We hope that this description of work is to your satisfaction. If you need further clarifications, please do not hesitate to contact us.

Best regards

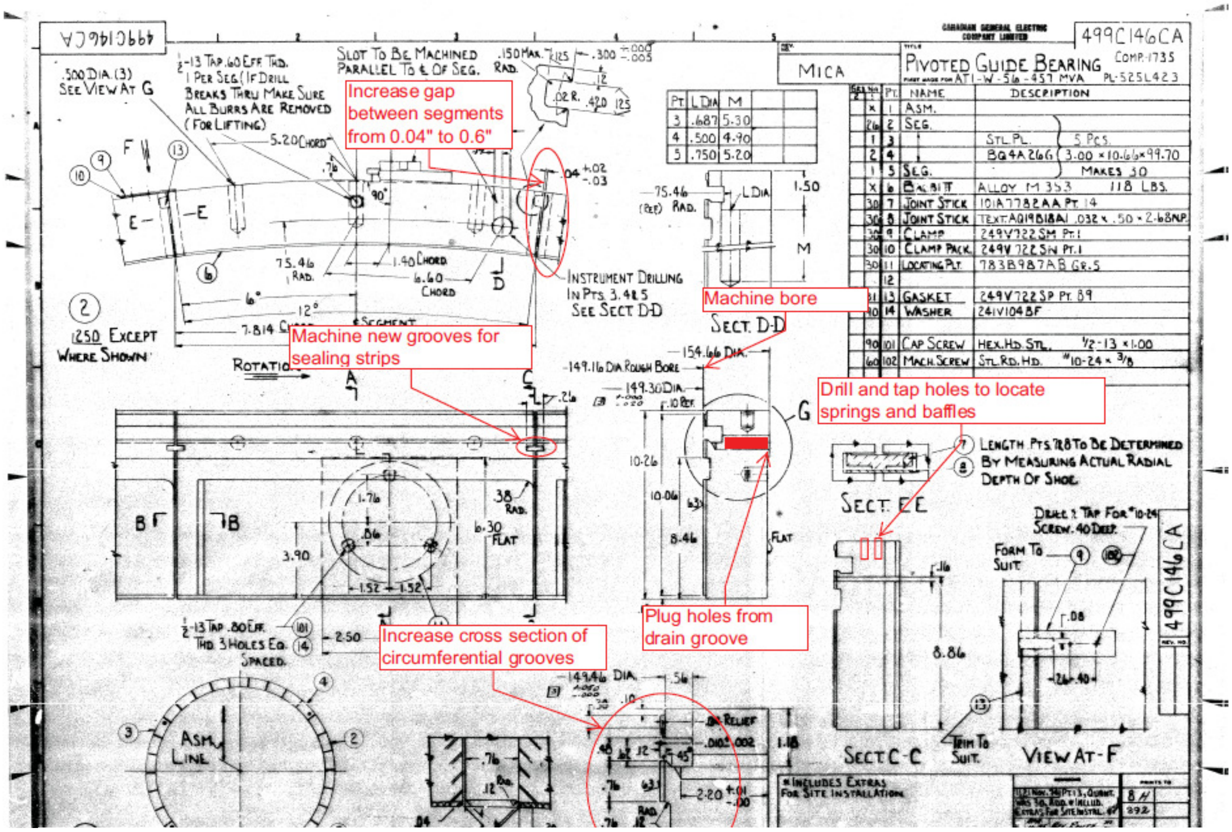
Daniel Gotti

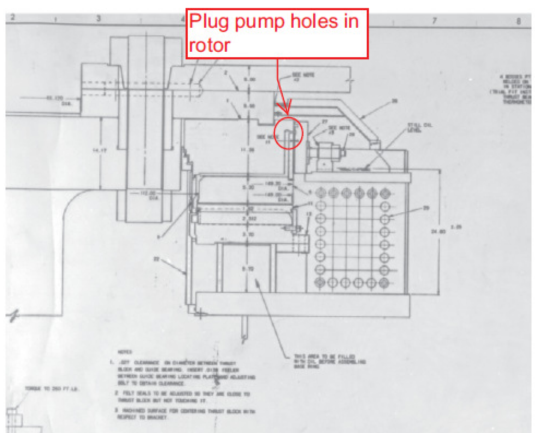
cc: Vilem Chladek   Dave Cole
Sarmad Elahi   Ray Smith

ANDRITZ HYDRO LTD.
6100 Trans Canada Hwy.
Pointe Claire, Quebec
Canada, H9R 1B9

ANDRITZ Hydro

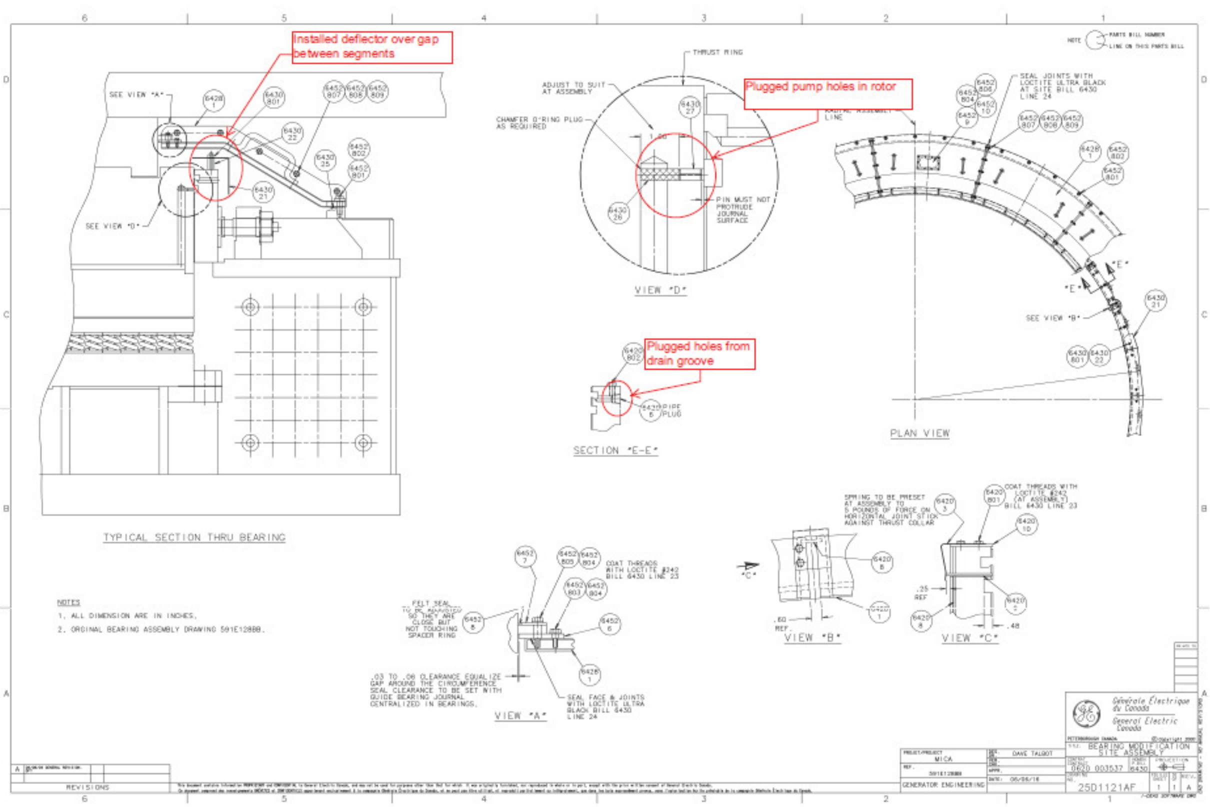
ANNEX A – Mica pre-modification drawings

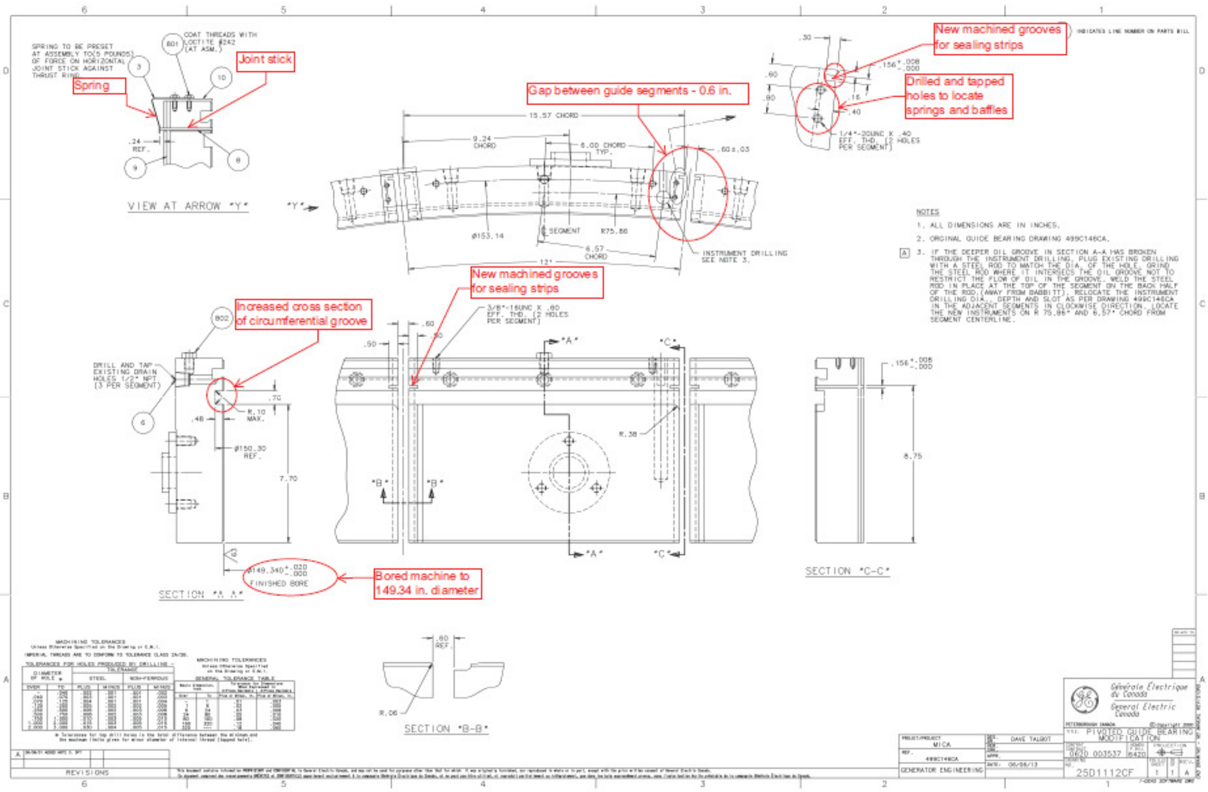

499C146CA
Pivoted Guide Bearing
Mica
Increase gap between segments from 0.04" to 0.6"
Machine bore
Machine new grooves for sealing strips
Drill and tap holes to locate springs and baffles
Plug holes from drain groove
Increase cross section of circumferential grooves
Sect. D-D
Sect. E-E
Sect C-C
View At F


Plug pump holes in rotor

ANDRITZ Hydro

ANNEX B – Mica post-modification drawings


Installed deflector over gap between segments
Plugged pump holes in rotor
Plugged holes from drain groove
VIEW "D"
PLAN VIEW
SECTION "E-E"
TYPICAL SECTION THRU BEARING
VIEW "A"
VIEW "B"
VIEW "C"


New machined grooves for sealing strips
Joint stick
Spring
Gap between guide segments - 0.6 in.
Drilled and tapped holes to locate springs and baffles
New machined grooves for sealing strips
Increased cross section of circumferential groove
Bored machine to 149.34 in. diameter
VIEW AT ARROW "Y"
SECTION "A-A"
SECTION "B-B"
SECTION "C-C"
PIVOTED GUIDE BEARING MODIFICATION
25D1112CF

Project Title: Upgrade Public Safety Around Dams and Waterways

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Pooled

Classification: Normal

Project Description:

This project is a continuation of a program that started in 2011 that enables Hydro to comply with the Canadian Dam Association Guidelines pertaining to public safety around dams and associated waterways. The guidelines apply to appropriate signage, alarms, warnings, buoys, waterway booms and public awareness as a result of public interaction around dams and waterways. The Canadian Dam Association recognized a need for guidelines pertaining to public safety around dams so that dam owners could meet their responsibilities to protect the public as a result of increased public interaction around dams. This increased presence by the public has led to incidents at dams, the most notable occurring at an Ontario Power Generation Facility in 2002 in which two people drowned and seven more were injured during release of water from one of their reservoirs.

The work plan is dictated by a phased approach to risk treatment. The plan is as follows:

- 2012 Conduct Public Safety Risk Assessment of structures on the Meelpaeg Reservoir in Bay d’Espoir.
- 2013 Purchase and install higher cost control improvements on the Long Pond Reservoir structures that were identified in the 2011 risk assessment.
- 2013 Purchase and install lower cost control improvements on the Meelpaeg Reservoir structures that were identified in the 2012 risk assessment.
- 2013 Conduct Public Safety Risk Assessment of structures at the Granite Canal Development and other upstream structures on the Bay d’Espoir Development.
- 2014 Purchase and install higher cost control improvements on the Meelpaeg Reservoir structures that were identified in the 2012 risk assessment.
- 2014 Purchase and install lower cost control improvements at the Granite Canal Development and other upstream structures on the Bay d’Espoir Development that will be identified in the 2013 risk assessment.
- 2014 Conduct Public Safety Risk Assessment at Paradise River Generating Station

Typical control improvements are as follows:

- Public education;
- Operational control measures;
- Effective signage;
- Spillway emergency signals;
- Fencing;
- Buoys; and
- Safety Booms

Of those mentioned above, lower cost control improvements include effective signage and fencing, whereas control improvements such as buoys and safety booms would fall under the category of higher cost control improvements.

The Meelpaeg Public Safety Audit was completed by Hydro personnel in December 2012. The audit report included a number of recommendations that are attached as Appendix A.

The budget estimate for the project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	60.0	0.0	0.0	60.0
Labour	58.5	0.0	0.0	58.5
Consultant	70.0	0.0	0.0	70.0
Contract Work	78.0	0.0	0.0	78.0
Other Direct Costs	9.0	0.0	0.0	9.0
Interest and Escalation	22.2	0.0	0.0	22.2
Contingency	55.1	0.0	0.0	55.1
TOTAL	**352.8**	**0.0**	**0.0**	**352.8**

Introduction:

The Canadian Dam Association (CDA) is recognized as the leading authority in Canada when it comes to dam safety issues. They published the Canadian Dam Safety Guidelines in 2007 dealing with the safe operation, surveillance and maintenance of dams. Utilities across Canada have adopted these CDA guidelines, in the absence of Provincial Regulations, to manage their Dam Safety Programs. These guidelines address the various hazards which can lead to failure of a dam and present methods for management of those risks.

A CDA guideline entitled "Guidelines for Public Safety Around Dams"[1] was released in 2011. The document provides guidance for dam owners to meet their responsibilities to protect the public. Guidance in this matter is needed for the following reasons:

- Increased public interaction;
- Perceived right of the public to access sites;
- Increased public interest in extreme sports;
- Improved access by use of recreational vehicles;
- Public unawareness of the hazards;
- Remote operation of dams and Hydro stations; and
- Occurrence of fatalities and serious injuries.

These guidelines address the risk of accidents or incidents in which a member of the public encounters a hazard created by the presence or operation of a dam.

Because the nature of this project is to facilitate Hydro making improvements to enable it to meet the CDA guidelines to enhance the public awareness of safety around dams and waterways, there is no relevant information for the following:

- Age of Equipment or System;
- Major Work and/or Upgrades;
- Anticipated Useful Life;
- Maintenance History;
- Outage Statistics;
- Maintenance or Support Arrangements;
- Vendor Recommendations;
- Availability of Replacement Parts;
- Environmental Performance;
- Operating Regime;
- Net Present Value;
- Levelized Cost of Energy;
- Cost Benefit Analysis;
- Forecast Customer Growth;

[1] *Refer to a similar 2012 submission on Upgrading Public Safety Around Dams and Waterways.*

- Energy Efficiency Benefits;
- Losses during Construction; and
- Alternatives.

Justification:

Dam owners are responsible for assessing and managing the risks to the public caused by the presence and operation of a dam. The first principle of the CDA guidelines identifies this responsibility. It states ”*The dam owner is responsible for managing the public safety risks caused by a dam, as far upstream and downstream as the owner has property rights. Beyond this property, the dam owner may have additional responsibility to assess locations where the hazards are known by the owner to result directly from the dam or its operations and to inform the public and other affected property owners of these hazards”.*

Accidental deaths have occurred around dams and associated structures in North America. The cause of these deaths is often an unawareness of the hazards in the area. Hydro does not have any documented cases of near misses or incidents on its systems. However, Hydro has a obligation to offer protection to the general public from potential hazards around dams and waterways. Therefore, Hydro needs to proceed with a managed system to make people more aware of the hazards around dams but to also protect them from those hazards when they interact with dams and waterways.

Operating Experience:

Hydro currently operates approximately 90 dams, dykes and hydraulic structures on the island of Newfoundland. During the 2012 Public Safety Audit of the Meelpaeg Reservoir, gaps were identified at the seven dams, and two flow control structures, in the form of inadequate control measures warning the public of potential safety hazards. The accepted standard for proper control measures has evolved in light of incidents experienced over the past ten years at other utilities. As such, the original design of the Bay d’Espoir system did not address these measures.

This Public Safety Audit was a continuation of the program started by Hydro in 2011 to look more closely at existing control measures that were in place. The Meelpaeg Reservoir is the largest reservoir on the Bay d’Espoir Development and even though it is considered remote, is accessed by fishermen and hunters and other occasional users. The risk assessment completed in 2012 identified the lack of appropriate signage, alarms and/or warning systems that alert the public to potential safety hazards and further identified the need for control measures at dams and structures on the Meelpaeg Reservoir.

The 2012 assessment noted that there was a complete lack of signage at the two flow control structures on the Meelpaeg reservoir.

Industry Experience

As noted earlier, in 2002, downstream of an Ontario Power Generation facility, seven people sustained injuries and two people drowned during release of water from a reservoir. As a result of this, Ontario Power Generation started a comprehensive program addressing the safety of the public around their hydroelectric facilities. Additional research by Ontario Power Generation has identified more than 300 incidents associated with fatalities, injuries or rescues at dams throughout North America since 2003. As a result of these fatalities, larger utilities have taken an active role in assessing hazards at their hydroelectric facilities and installing control measures to either mitigate or eliminate identified hazards.

Safety Performance

This project is being done to protect the public from hazards associated with the normal operation of hydroelectric facilities including dams and waterways. There are inherent hazards around these facilities such as fast moving water, remotely operated gates and extreme changes in water levels of which the public may be unaware. This project will help educate and thus protect the public from those hazards.

Legislative and Regulatory Requirements

Although there are no specific legislative or regulatory requirements, Hydro follows the industry accepted CDA guidelines.

Status Quo

The only control measures that Hydro has in place to alert the public of hazards are some signs that are inconsistent in the messaging and sizing as well as others that are faded or have words that are worn off. Not all sites have signage and where there are signs they lack sufficient visibility due to their size and do not conform to the CDA guidelines. In addition, some water control structures and spillways have audible alarms. There are no larger control measures such as buoys and booms in place. Fencing upgrades and additions are also required.

Historical Information

Similar project costs that have been incurred to date are included in Table 2 below.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)
2013B	298.1	-
2012	48.3	50.1
2011	49.4	48.4

Conclusion:

Hydro has been following the CDA "Dam Safety Guidelines" pertaining to dam safety for more than ten years as part of an overall dam safety program and have also made a decision to follow the new CDA guideline entitled, "Guidelines for Public Safety Around Dams", dealing with public safety around dams, which was released in 2011.

Incidents involving the public have occurred at hydroelectric facilities in North America. This is a concern for utilities and as a result, utilities have accepted the responsibility to protect the public by making them aware of hazards around dams, waterways and hydroelectric facilities. Hydro recognizes this trend in the industry and is putting a program in place that addresses those responsibilities.

By following the CDA guidelines, Hydro is taking a proactive approach to ensure that the public is aware of hazards around hydroelectric facilities and to install protection from those hazards. Hydro plans to undertake risk assessments of hazards around hydroelectric facilities, rank the hazards in order of significance, evaluate the need for control measures, such as signage, fencing, alarms, buoys and/or safety booms and install control measures. This project is a continuation of that effort started in 2011. The risk assessment done at Meelpaeg Reservoir was a continuation of a program that started in 2011 and will be continuing for the next several years and the 2014 program primarily involves the implementation of significant control measures at the Meelpaeg Reservoir in addition to continuing with risk assessments at other Hydro dams and waterways.

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Open project file	March 2014	March 2014
Design	Conduct risk assessment	April 2014	May 2014
Procurement	Purchase materials for control measures	May 2014	June 2014
Construction	Install control measures	June 2014	September 2014
Closeout	Finalize payments and prepare closeout documentation	October 2014	November 2014

Future Plans:

Hydro plans to continue risk assessments on an annual basis to identify risks to public safety and install necessary control improvements. The most significant control improvements are the installation of safety booms. Normally, after a site is identified with the need for safety booms, it takes two years to complete the purchase and installation of these booms. The plan is to complete this process of conducting risk assessments, installing lower cost control improvements such as signs and fencing and higher cost control improvements such as buoys and safety booms, as required, for each reservoir on Hydro's system.

APPENDIX A

RISK ASSESSMENT - RECOMMENDATIONS

Table 4.1: Recommendations for Public Safety Risk Treatments

Location	Area	Activity	Current Risk Rating Level	Recommended Risk Treatments	Anticipated Risk Rating
MD-FCS[2]	Headpond	Fishing from Boat	Medium (5)	It is recommended that an appropriately sized public safety boom be placed upstream of the structure. This will delineate the extent of the dangerous water zone. Appropriately messaged and sized red Danger signage should be installed at both ends of the boom near each shoreline anchor point, facing upstream.	Low (2)
MD-FCS	Headpond	Boating (under power)	Medium (5)	It is recommended that an appropriately sized public safety boom be placed upstream of the structure. This will delineate the extent of the dangerous water zone. Appropriately messaged and sized red Danger signage should be installed at both ends of the boom near each shoreline anchor point, facing upstream.	Low (2)
MD-FCS	Headpond	Fishing from Shore	High (20)	It is recommended that a new chain link fence be installed along each bank of the water way, tying into the upstream boom. The fence should continue along the downstream edge of the concrete gated structure and at this location should have a locked gate for access. Appropriately messaged and sized red Danger signage should be attached to the new fence and gate. The signage would include both Danger and No Trespassing messaging.	Medium (8)
MD-FCS	Structure	Walking	High (15)	It is recommended that a new chain link fence be installed along each bank of the waterway, tying into the upstream boom. The fence should continue along the downstream edge of the concrete gated structure and at this location should have a locked gate for access. Appropriately messaged and sized red Danger signage should be attached to the new fence and gate. The signage would include both Danger and No Trespassing messaging.	Medium (5)

[2] *MD-FCS: Meelpaeg Dam – Fisheries Compensation Structure*

Location	Area	Activity	Current Risk Rating Level	Recommended Risk Treatments	Anticipated Risk Rating
MD-FCS	Structure	ATV/Dirt Biking	High (10)	It is recommended that appropriately messaged and sized yellow Information signs be placed on either side of the embankment along the roadway leading to the embankment structure notifying the public that this is a dam and that it is not maintained as a road. It could typically read, "Warning - Persons Crossing this Dam Do So At There Own Risk. Slow Down And Drive Safely".	High (10)
MD-FCS	Structure	Driving	High (10)	It is recommended that appropriately messaged and sized yellow Information signs be placed on either side of the embankment along the roadway leading to the embankment structure notifying the public that this is a dam and that it is not maintained as a road. It could typically read, "Warning - Persons Crossing this Dam Do So At There Own Risk. Slow Down And Drive Safely".	High (10)
MD-FCS	Outlet	Fishing from Shore	Low (4)	This is a low risk item and no control measures are required.	Low (4)
MD-2[3]	Structure	ATV/Dirt Biking	High (20)	It is recommended that yellow post mounted Warning signs be installed on both approaches to the dam crest. The signs should typically read, “Warning – Persons Crossing The Dam Do So At Their Own Risk – Slow Down and Drive Safely”.	High (20)
MD-2	Structure	Driving	High (20)	It is recommended that yellow post mounted Warning signs be installed on both approaches to the dam crest. The signs should typically read, “Warning – Persons Crossing The Dam Do So At Their Own Risk – Slow Down and Drive Safely”.	High (20)
MD-2	Structure	Snowmobili ng	Medium (5)	It is recommended that yellow post mounted Warning signs be installed on both approaches to the dam crest. The signs should typically read, “Warning – Persons Crossing The Dam Do So At Their Own Risk – Slow Down and Drive Safely”.	Medium (5)
MD-1S[4]	Headpond	Boating (under power)	High (10)	It is recommended that a public safety boom be installed upstream of the control structure. Also, appropriately sized and messaged red Danger signs should be installed on each side of the boom, facing upstream. The messaging should typically read, “Danger – Keep Out – Access Beyond This Point May Result In Drowning”.	Low (5)

[3] *MD-2: Meelpaeg Dam 2*
[4] *MD-1S: Meelpaeg Dam – Ebbegunbaeg Structure*

Location	Area	Activity	Current Risk Rating Level	Recommended Risk Treatments	Anticipated Risk Rating
MD-1S	Headpond	Fishing from Shore	High (10)	It is recommended that a new chainlink fence be installed on either side of the control structure, extending from the control structure upstream to tie into the upstream boom. Additionally, a number of red Danger signs should be installed on the fence with appropriate wording such as, “Danger – Keep Out – Access Beyond This Point May Result In Drowning”.	Low (5)
MD-1S	Structure	Fishing	High (25)	It is recommended that access to this site be restricted by installing a new chainlink fence with a locked gate, on the north side of the control structure deck. The fencing should tie into and extend down the top of the wingwall. Additionally, appropriately messaged signage should be installed on the fence/gate in the form of yellow “No Trespassing” signs. Signage should also be installed at Noel Paul’s Brook in the form of information signs, stating that fishing at the Ebbe Control Structure is prohibited and access is restricted. In addition, it is recommended that appropriately messaged signs be installed at the control structure stating that there is an audible alarm that sounds when the gates are operated and explaining what the alarms mean.	Low (5)
MD-1S	Structure	ATV/Dirt Biking	High (25)	It is recommended that access to this structure be restricted by installing a new chainlink fence with a locked gate, on the north side of the control structure deck. The fencing should tie into and extend down the top of the wingwall. Additionally, appropriately messaged signage should be installed on the fence/gate in the form of yellow “No Trespassing” signs.	Low (5)

Location	Area	Activity	Current Risk Rating Level	Recommended Risk Treatments	Anticipated Risk Rating
MD-1S	Outlet	Fishing from Shore	High (25)	It is recommended that new chainlink fencing be installed to restrict access to this dangerous area. The fence should enclose the "cove" area that is located off the north side of the canal and extend down the north side of the canal for a distance of 200 m. Additionally, appropriately sized and messaged signage should be installed at numerous locations on the fence. The wording should reflect the hazards in the area and should be a red Danger sign stating "Danger – Keep Out – Access Beyond This Point May Result In Drowning". Signage should also be installed at Noel Paul's Brook in the form of information signs, stating that fishing at the Ebbe Control Structure is prohibited and access is restricted.	Low (5)
MD-1S	Dstream	Fishing from Shore	High (15)	It is recommended that a number of Warning signs be installed along the north bank of the canal, downstream of the dangerous area. They should typically be yellow Warning signs indicating that there is a structure upstream and water flows and levels can change rapidly. Signage should also be installed at Noel Paul's Brook in the form of information signs, stating that fishing at the Ebbe Control Structure is prohibited and access is restricted. In addition, it is recommended that appropriately messaged signs be installed at the control structure stating that there is an audible alarm that sounds when the gates are operated and explaining what the alarms mean.	Medium (9)
MD-1A, B, C, D	Structure	ATV/Dirt Biking	High (15)	It is recommended that yellow post mounted Warning signs be installed on both approaches to the dam crest. The signs should typically read, "Warning – Persons Crossing The Dam Do So At Their Own Risk – Slow Down And Drive Safely".	High (12)

Project Title: Replace Automatic Greasing Systems Units 5 and 6

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Normal

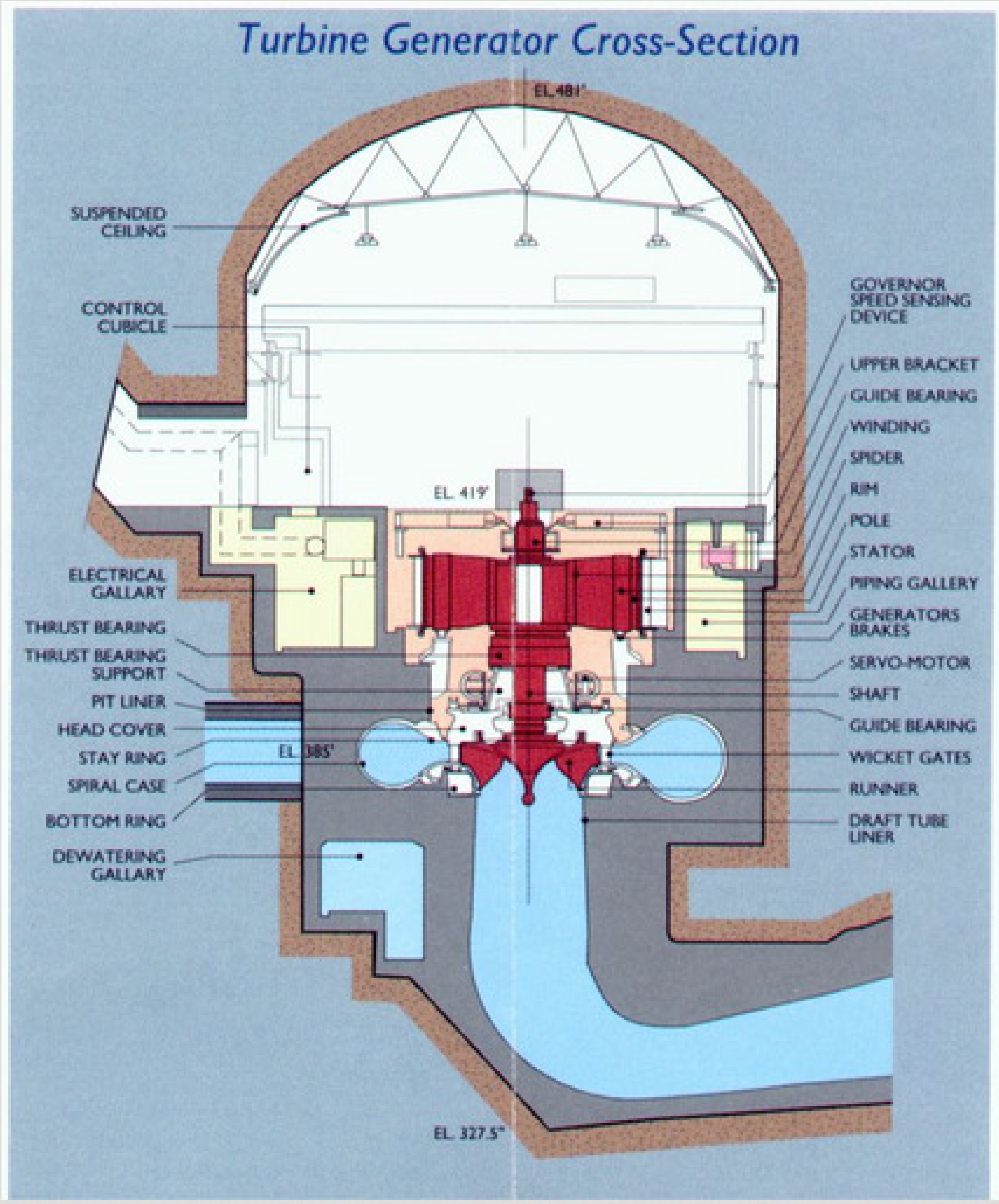
Project Description:

This project is required to replace the automatic greasing systems on Units 5 and 6 in the Bay d'Espoir Hydroelectric Generating Station (Bay d'Espoir). The auto greasing system provides grease to key turbine components, including the servomotor link pins, operating ring linkages, headcover bushings, and guidepads on the operating ring and headcover (see Figure 1 for reference). Each system will be replaced in its entirety, including the pump station, piping and stainless steel tubing, and controls. The removal of the old equipment and the installation of the new will be performed by Hydro internal labour.

The budget estimate for the project is provided in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	75.0	0.0	0.0	75.0
Labour	94.6	0.0	0.0	94.6
Consultant	9.8	0.0	0.0	9.8
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	3.0	0.0	0.0	3.0
Interest and Escalation	14.5	0.0	0.0	14.5
Contingency	36.5	0.0	0.0	36.5
TOTAL	**233.4**	**0.0**	**0.0**	**233.4**



Cross Section Turbine Generator (Churchill Fall (Labrador) Corporation Limited)

Figure 1: Cross-Section of Turbine Generator
(Churchill Falls Unit, similar to Bay d'Espoir Units but larger)

Justification:

This project is justified on the need for Hydro to upgrade existing equipment to decrease the number and frequency of maintenance problems. The maintenance problems can be tracked to the type and age of the equipment currently in use. In order to ensure that the equipment remains operational, to reduce the potential for unplanned outages, and to ensure system reliability, Hydro must replace the existing original systems with more modern ones that are compatible with the environmentally friendly canola-based grease currently being used today.

Existing System:

Bay d'Espoir is Hydro's largest Hydroelectric Generating Station on the Island Interconnected System. Powerhouse 1 has six generating units, each having a rated capacity of 75 megawatts (MW). Each unit is equipped with an automatic greasing system that provides grease to key components of the turbine. The system works as a single line, one way system with lubrication flowing from the pump to the master assembly (Figure 2).

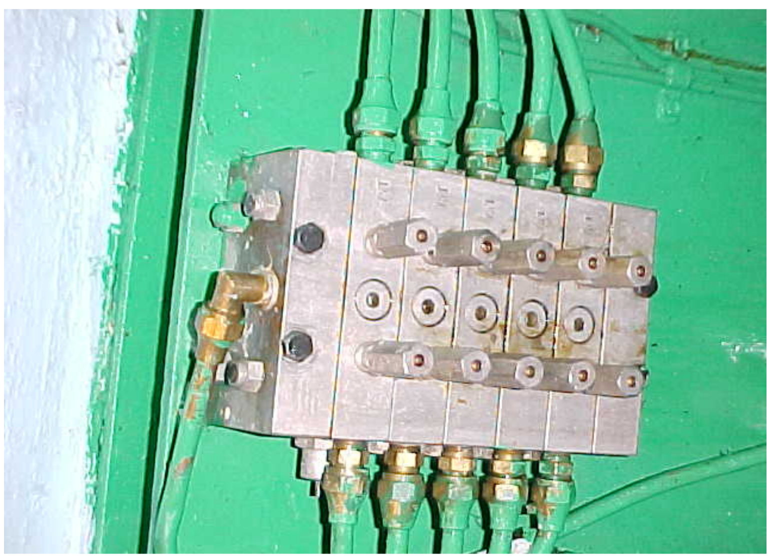


Figure 2: Master Assembly

The master assembly accepts lubrication from the pump and distributes it to the secondary assemblies (Figure 3).

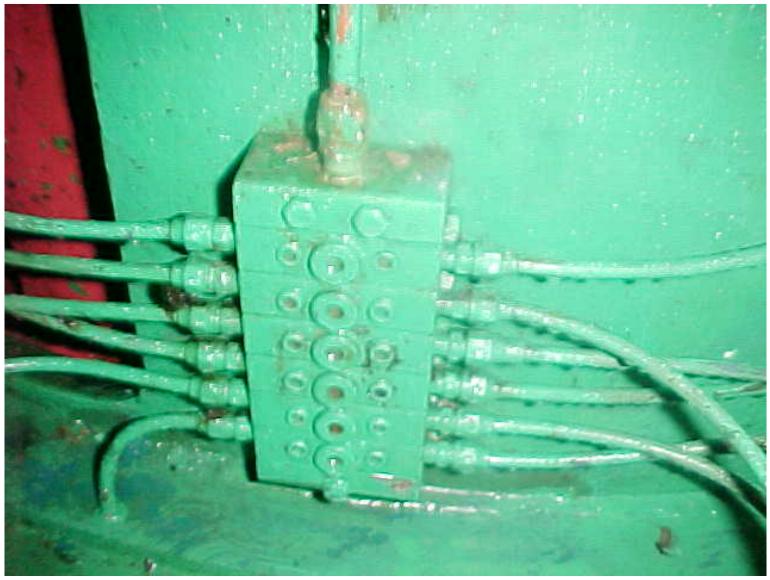


Figure 3: Secondary Assembly

The pump is operated at the desired frequency and flow rates, by a controller (Figure 4).

Figure 4: Controller

The greasing system is the original one installed in the 1960s, but had some modifications throughout the years as described below in Table 2. The system was modified in the late seventies and in the early eighties to make the wicket gate and bottom bushings lubrication sections independent of the rest of the system. This modification minimizes the amount of excess grease accumulating in the turbine pit. During the runner replacement program in the nineties the controller, which controls the frequency and rate of the grease applied to the system, was replaced. In 2006, due to an environmental concern that excess grease could find its way into the tailrace, the type of grease was changed to canola-based grease called Vane Spindle Grease (VSG) which is a biodegradable, environmentally friendly lubricant. This change aligned with Hydro's comment to the environment and the ISO 14001 registration.

Table 2: Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2006	Grease type changed to VSG type	Environmentally friendly lubricant
1995	Controller replaced on Unit 1	Non programmable type
1995	Controller replaced on Unit 1	Non programmable type
1975	System modified to isolate the wicket gate lubrication	To minimize excess grease in the turbine pit

A project titled "Replace Auto Greasing Systems Units 2 and 3 for $260,100 was approved as part of the 2013 Capital Budget by Order No. P.U. 4(2013).

Operating Experience:

These auto greasing systems were installed in the mid-1960s. The only equipment change/upgrade has been to the controllers, replaced in the 1990s during the runner replacement program, and the modifications done in the late seventies and early eighties. There have been similar, repetitive problems including damaged timers, damaged switches, solenoid failures, high pressure trips, leaking, plugged and broken grease lines, leaking and plugged terminal/control blocks, and alarm faults. The age of the systems has contributed to the problems, particularly with respect to the tubing, as the tubing is original to the system installed in the mid-sixties. Another problem is that some of the replacement parts are difficult to obtain because the system was manufactured in the 1960s and there are compatibility issues with some of the components in the newer systems. The controller, although newer than the remainder of the system, is not the programmable type, which has also contributed to the problems since there is no way to modify or adjust the system if a change is required in controlling the flow of grease. In 2006, the hydrocarbon-based grease was replaced with environmentally friendly canola-based grease, and since that time, the problem of plugged lines has increased. At the time of the grease change, it was unknown if the mixture of the two different greases would hinder the system and during the initial installation, there were many problems with clogged lines which cause some of the reoccurring problems such as solenoid failures, high pressure trips, leaking and plugged lines. The consequence of not updating the system, although the probability is very low, could be losing control of the generating unit. If the grease going to the wicket gates gets shut off, there is a chance for the wicket gates to become stuck in their bushings. This could cause the generating unit to go into run-away-speed[5] if the wicket gates are bound in the opened position, and until the head gate is closed, there could be heavy damage to the turbine and generator guide bearings and other components in the unit.

Reliability Performance

The reliability of the system has decreased over the years due to reoccurring problems with damaged timers, damaged switches, solenoid failures, high pressure trips, leaking, plugged, and broken grease lines, leaking and plugged terminal/control blocks, and alarm faults.

Environmental Performance

The new system will be more compatible with the environmentally friendly grease in use today.

Industry Experience

Hydro is not aware of a lubrication system standard throughout the hydro generation industry. However, the use of VSG lubricant is common in the industry. Other hydroelectric companies have switched to this grease including Churchill Falls (Labrador) Company in 2002, BC Hydro in 1996, and Parker Dam in 1995.

Maintenance or Support Arrangements

Maintenance of the auto greasing systems in Bay d'Espoir has been completed by Hydro's personnel. Maintenance of the new system will also be provided by Hydro personnel.

Maintenance History

The five-year maintenance history for the auto greasing systems for Units 5 and 6 is shown in Table 3. It must be noted that there are times when unplanned work on this system is corrected without tracking the work on a work order, where costs are collected. Every day operations personnel perform visual inspections of the six units in Bay d'Espoir. There are times when an operator identifies deficiencies on these systems have the system fixed immediately, and without a work order. Therefore the numbers below for the accumulative corrective history is incomplete and does not show the total amount of attention the automatic greasing systems receive.

[5] *Run-away-speed is the rotational speed of the turbine with no load; all units have a set design rated max run-away-speed rating. If this design rating is exceeded (due to operational problems such as ceases wicket gates) the* generating unit could suffer significant damage.

Table 3: Five-Year Maintenance History

Year	Unit 5 Corrective Maintenance ($000)	Unit 6 Corrective Maintenance ($000)
2012	1.3	1.6
2011	-	0.7
2010	1.2	1.1
2009	0.5	0.5
2008	-	0.1

Note: Preventative Maintenance (PM) cost is not provided as it is combined with the overall turbine PM costs and is not broken out by individual system.

Anticipated Useful Life

A new auto greasing system has an estimated service life of 50 years.

Development of Alternatives

The only alternative to this project is to leave the existing system as it is. The status quo is not a viable option as most of the current system has original components installed in the mid-sixties and it is now at the end of its service life. To ensure a high degree of reliability, and stable performance of an environmentally friendly greasing system, the existing system needs to be replaced.

Conclusion:

The replacement of the auto greasing system is required to ensure continued reliability of the greasing system which provides essential lubrication to key components of the turbine. The existing system has reached its end of service life and the only way to minimize repetitive issues with these systems including damaged timers, damaged switches, solenoid failures, high pressure trips, leaking, plugged, and broken grease lines, leaking and plugged terminal/control blocks, and alarm faults, is to replace the entire system. Partial upgrades in the past do not work as the distribution aspect of the system, the copper tubing, is original and is in need to be replaced. The new system would continue to use the environmentally friendly grease that was changed in 2006 to minimize any environmental impact.

The anticipated schedule for this project is provided in Table 4.

Project Schedule:

Table 4: Project Schedule

Activity		Start Date	End Date
Planning	Review scope Confirm schedule Review budget	March 2014	March 2014
Design	Submit design transmittal Risk workshop	March 2014	March 2014
Procurement	Confirm schedule Tender materials / review tenders Award tender for supply	April 2014	April 2014
Construction	Safety meetings Schedule meetings Risk / change management Site safety tour	June 2014 July 2014	June 2014 July 2014
Commissioning	Safety meeting	June 2014	June 2014
Closeout	Financial closeout Post implementation review	October 2014	October 2014

Project Title: Install Fire Protection Upgrades

Location: Holyrood

Category: Generation – Thermal

Type: Other

Classification: Normal

Project Description:

The purpose of this project is to implement measures to reduce the likelihood that fuel originating from the No. 6 fuel oil system will feed an existing fire at the Holyrood Thermal Generating Station (Holyrood). These measures include the installation of concrete curbing around Unit 1 and Unit 3 fuel-pumping skids, the installation of an automatic fuel shut-off valve on the 16 inch diameter No. 6 fuel oil supply pipe from the tank farm, and the application of fireproofing on the pipe supports that carry the indoor section of the 16 inch diameter fuel supply pipe. By implementing these measures at Holyrood, the station will be in a better position to quickly recover from a fire.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	12.5	5.0	0.0	17.5
Labour	40.0	67.0	0.0	107.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	151.0	0.0	151.0
Other Direct Costs	0.0	3.0	0.0	3.0
Interest and Escalation	4.1	30.8	0.0	34.9
Contingency	0.0	55.7	0.0	55.7
TOTAL	**56.6**	**312.5**	**0.0**	**369.1**

Justification:

The following sections have been removed from the Justification section of this document because they do not pertain to this project: Forecast Customer Growth, Development of Alternatives, and Evaluation of Alternatives.

FM Global, Hydro's insurer, has noted their concern with risk associated with the No. 6 fuel oil systems at Holyrood in their report *FM Global Risk Report, Fire and Natural Hazards Special Risk Evaluation, Holyrood Thermal Plant, Aug 24, 2011* (see Appendix A, pages A-7 and A-8 (target 08-10-001)). Due to the large quantities of No. 6 fuel oil that is present inside the plant, FM Global has recommended a number of measures that if installed, will reduce the likelihood that the fuel system will feed an existing fire. The measures that FM Global has proposed are concrete curbing, an automatic fuel shut-off valve, and fireproofing.

FM Global has recommended that Hydro install concrete curbing around the fuel pumping skids for Units 1 and 3 to stop any leaked fuel from flowing into adjacent areas. Concrete curbing (see Figure 1) is a short wall that is typically installed around systems that have a potential to leak a hazardous liquid such as No. 6 fuel oil or diesel. The curbing acts as a barrier that blocks any leaks originating from the system from flowing along the floor into adjacent areas. Curbing is especially important if the liquid being contained within the curbing is on fire or can feed a fire.

FM Global has also recommended that Hydro install an automatic fuel shut-off valve on the No. 6 fuel oil supply pipe from the tank farm. Automatic valves are preferred over manual valves because they are capable of quickly shutting off the fuel supply without engaging plant personnel.

Lastly, FM Global has recommended that Hydro apply 2-hour-rated fire proofing on all indoor pipe supports and hangers that carry the 16 inch No. 6 fuel oil supply pipe. Fire proofed pipe supports will not collapse under the intense heat of a fire as quickly as pipe supports without fire proofing applied. This will increase the possibility that the pipe racks and hangers that carry the fuel line will not collapse during a fire and leave the piping unsupported. If left unsupported, the piping could eventually collapse resulting in a major spill of fuel. This fuel could possibly feed the fire and make it a lot worse. Implementing these measures will help reduce the impact that the No. 6 fuel oil system may have on feeding a fire that has occurred inside the plant.

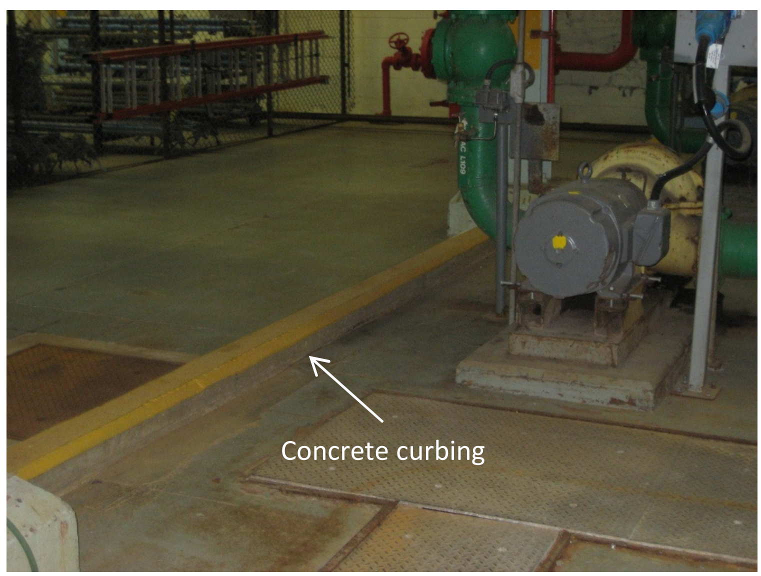


Figure 1: Concrete Curbing

Existing System:

Holyrood burns No. 6 fuel oil (heavy fuel oil) to generate steam that is used to turn turbines to produce power. With a flash point[6] of only 100 to 160 degrees Fahrenheit, heavy fuel oil does not require significant heating to ignite its vapors. Once burning, this fuel will produce flames with temperatures in the range of 2,000 degrees Fahrenheit. As it burns, it produces a thick, black, and oily smoke that hampers visibility during firefighting.

Figure 2: No. 6 Fuel Oil Shut-off Valve

No. 6 fuel oil is offloaded from tankers at the plant's marine terminal and pumped to the fuel storage facility (tank farm) at the south end of the plant. A 16 inch diameter pipe line conveys the fuel by gravity from the tank farm to the plant. The 16 inch fuel line contains a manual shut-off valve that allows an operator to manually stop the flow of fuel supplied to the plant. This shut-off valve is located in the underground section of fuel pipe where the fuel line enters the plant. See Figure 2. Once inside the plant, the fuel oil supply pipe is routed through the water treatment plant and main boiler hall to the day tank. The pipe is supported by pipe racks and hangers (see Figure 3) that are not fireproofed.

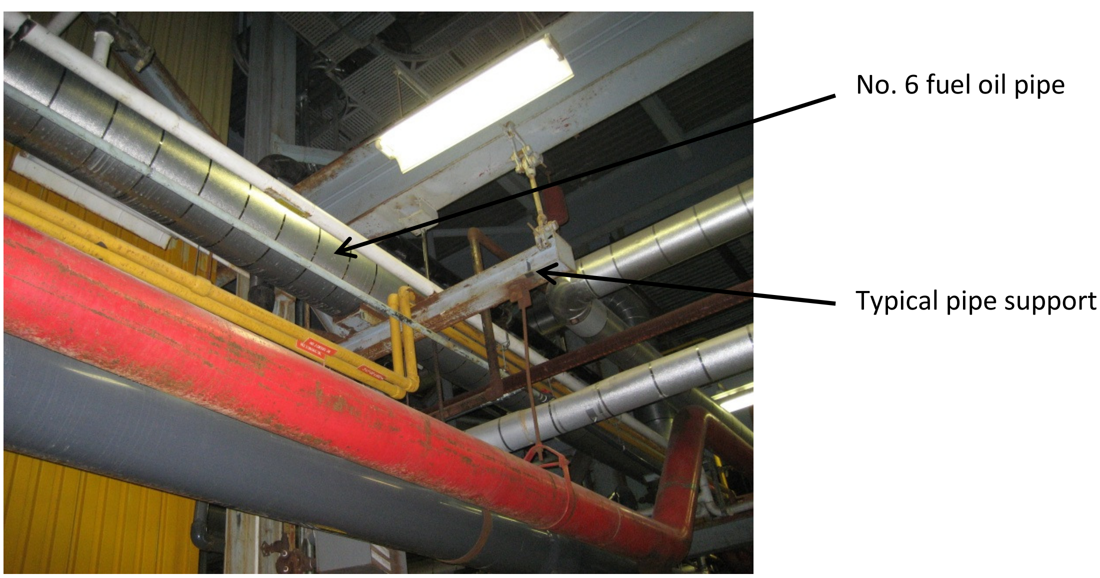


Figure 3: Typical Pipe Support for No. 6 Fuel Oil Piping

[6] *Flash point is the lowest temperature at which a material can vaporize to form an ignitable mixture in air.*

At Holyrood, Unit 2 has concrete curbing installed around its fuel-pumping skid. However, the fuel-pumping skids for Units 1 and 3 do not have curbing.

Operating Experience

Fortunately, the existing equipment arrangements being upgraded under this project have not contributed to loss. However, as discussed below, it is a real possibility.

In the event of a powerhouse fire, an operator would most likely be required to close the manual shut-off valve on the No. 6 fuel oil supply pipe in order to shut off the fuel supply to the plant. If the valve was automatic, the fuel supply to the plant could be shut off automatically from the control room resulting in a much faster shut down of the fuel supply. Having an automatic fuel shut-off valve may save plant assets during a fire situation because the fuel supply can be shut down faster. Without an automatic fuel shut-off valve, more assets than necessary may be lost in the event of a fire.

The intense heat generated by a fire in the powerhouse may cause the existing pipe supports and hangers that carry the 16 diameter fuel oil pipe to fail. A failing pipe support system will result in the eventual collapse of the piping system. When the pipe collapses, its contents will be spilled throughout the plant. Spilling fuel may add fuel to the fire that is in progress. Applying 2-hour rated fireproofing to the indoor pipe supports and hangers will provide two hours of additional time before the piping system collapses during a fire situation. This may provide enough time to extinguish the fire and save plant assets. Without fire proofing, the fuel piping system will collapse two hours sooner resulting in spilled fuel that will feed the fire and possibly result in the loss of more assets than necessary during a fire situation.

Leaking No. 6 fuel oil from the fuel-pumping skids serving Units 1 and 3 can migrate into other areas because there is no containment curbing installed around these skids. Because fuel leaking from these skids can migrate throughout the plant, the fuel could possibly feed a fire that is occurring in an adjacent area. This may result in a loss of more assets than necessary during a fire situation.

<u>Industry Experience</u>

FM Global has recommended that Hydro install measures to mitigate the effect that the No. 6 fuel system has on spreading a fire throughout the plant. These recommendations are attached as Appendix A.

Maintenance or Support Arrangements

All equipment associated with this project is maintained by plant personnel and contractors.

Anticipated Useful Life

The anticipated useful life of the assets under this project has been forecasted to 2020.

Conclusion:

The upgrades proposed under this project were recommended by FM Global to reduce the likelihood that fuel originating from the No. 6 fuel oil system will feed an existing fire at Holyrood. The upgrades include:

- Installation of concrete curbing around Unit 1 and Unit 3 fuel-pumping skids;
- Installation of an automatic fuel shut-off valve on the 16 inch diameter No. 6 fuel oil supply pipe from the tank farm; and
- Application of fireproofing on the pipe supports that carry the indoor section of the 16 inch diameter fuel supply pipe.

By completing this project, major risks associated with the No. 6 fuel oil system at Holyrood will be reduced. This will serve to minimize asset damage caused by a fire in the plant so power production can be restored as quickly as possible.

Project Schedule:

The anticipated schedule for this project is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Initiate project Prepare resource plan and schedule	February 2014	March 2014
Design	Complete detailed engineering design	April 2014	June 2014
Procurement	Prepare tender and award contract	July 2014	November 2014
Construction	Install systems	June 2015	October 2014
Commissioning	Commission systems	October 2015	October 2015
Closeout	Complete project documentation and perform project closeout	November 2015	November 2015

APPENDIX A

FM GLOBAL RISK REPORT

Fire and Natural Hazards - Special Risk Evaluation

August 24, 2011

FM Global Risk Report

Focus Visit Summary

Nalcor Energy

Holyrood Thermal Plant
Route 60
Holyrood, Newfoundland and Labrador A0A 2R0
Canada

Fire & Natural Hazards
Special Risk Evaluation

Visit by:	Joanne M. D'Abreu
Visit date:	24 August 2011
Conference with:	Mr. Terry LeDrew, P.Eng, Manager, Thermal Generation

Index: 000009.36-02 / **Account:** 1-74568 / **Order ID:** 676515-69

FM Global Risk Report — Nalcor Energy

Visit Objective

This special visit was made to follow up on risk improvement and discuss the new diesel fire pump installation. This insured is well aware of the key hazards associated with turbine generator mineral-oil fires. Many improvements have been made to minimize these hazards and efforts are on-going to improve the training on emergency shutdown procedures to ensure oil pump shutdown in the event of a fire.

An emergency response plan has been developed to identify various fire scenarios involving lube oil; however, operator training has been made on 2 shifts and is still needed on the remaining three shifts. This should be fully completed by March, 2012.

A significant hazard continues to exist with respect to the potential for a major flammable liquid fire in the fuel oil supply, pumping and piping arrangement in the lower level of the Turbine/Boiler Building. Ignition of the heated fuel oil/vapors from a leaking flange or fitting will create a severe hydrocarbon fire. Automatic safety shutoff valves should be installed and interlocked with heat detection devices over the oil pumping skids. In addition, the steel support hangers for the 16-in. supply fuel oil feed line should also be fire proofed. Mr. Terry LeDrew, Plant Manager, has agreed to providing an automatic safety shutoff valve on the fuel feed line to ensure the valve will shut upon sprinkler water flow or heat detection. The insured also intends to fire proof the steel support hangers on the fuel supply line as soon as possible.

A new diesel fire pump is soon to be installed. This installation has gone through the FM Global plan review services and all FM Approved equipment is to be installed. The installation should be completed within the next month at which time a full fire pump acceptance test will need to be scheduled and completed.

Although this was a special visit to evaluate risk improvement, all recommendations have been included in this report with updated insured's comments.

Target Recommendations are those that the Account Engineer has selected as part of the account risk improvement priorities.

Location Overview

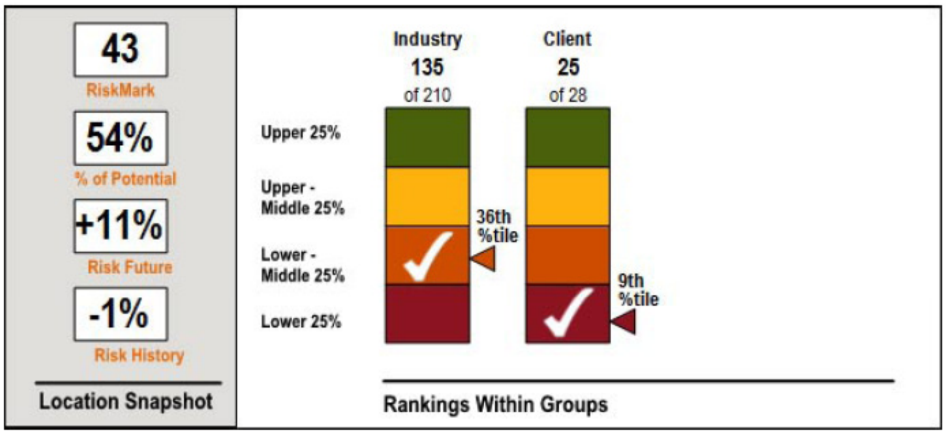
The following display(s) show Risk*Mark* information for this location. Note that the Risk*Mark* scores and displays are different than in the past. Risk*Mark* was recalibrated and enhanced to now include Equipment Hazards and an emphasis on Human Element programs. Risk*Mark* will now provide additional points for risk improvement in these and other areas. Your contacts at FM Global can help you to see the advantages of this more comprehensive benchmarking tool.

FM Global Risk Report — Nalcor Energy

Location Overview continued

Risk*Mark* Snapshot

This display provides a snapshot of the risk quality of this location, including a summary of the current Risk*Mark* score, the percentage of the potential score, the history of risk improvement, the projected risk improvement in the future, as well as risk quality rankings within various groups of locations.



The Industry used in the above chart is Fossil Fuel Power Plant.

The Risk Future number is the per year improvement in your percentage of potential score, projected to 01 July 2014. The Risk History number is the per year improvement in your percentage of potential score, since 01 July 2009.

Risk*Mark* (Risk Quality Benchmarking)

Through the analysis of various components of loss prevention, FM Global has rated the risk quality of the location against:

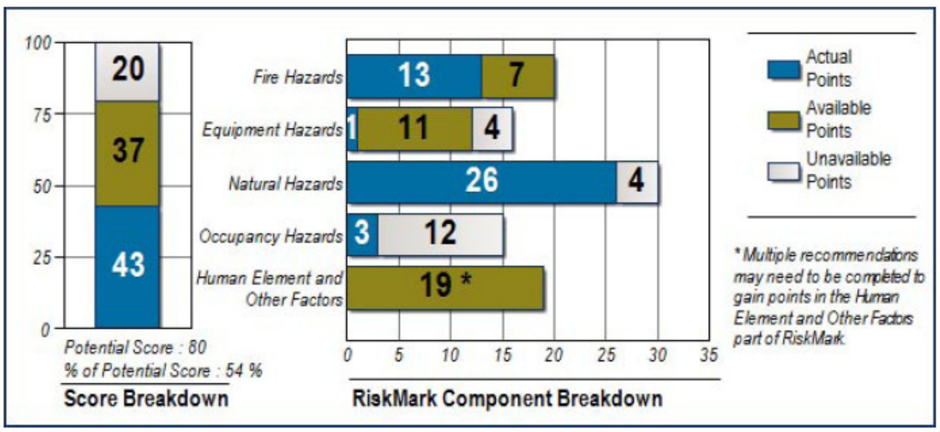
- All locations of a similar Occupancy/Industry
- All locations within your entire organization

The following displays show Risk*Mark* information for this location. Note that the Risk*Mark* scores and displays are different than in the past. Risk*Mark* was recalibrated and enhanced to now include Equipment Hazards and an emphasis on Human Element programs. Risk*Mark* will now provide additional points for risk improvement in these and other areas. Your contacts at FM Global can help you to see the advantages of this more comprehensive benchmarking tool.

Risk*Mark* Breakdown

This display shows a breakdown of your Risk*Mark* score by its logical components, including opportunities for risk improvement and the points to be gained. Refer to the other parts of this report for specific risk improvement recommendations related to each of the listed components.

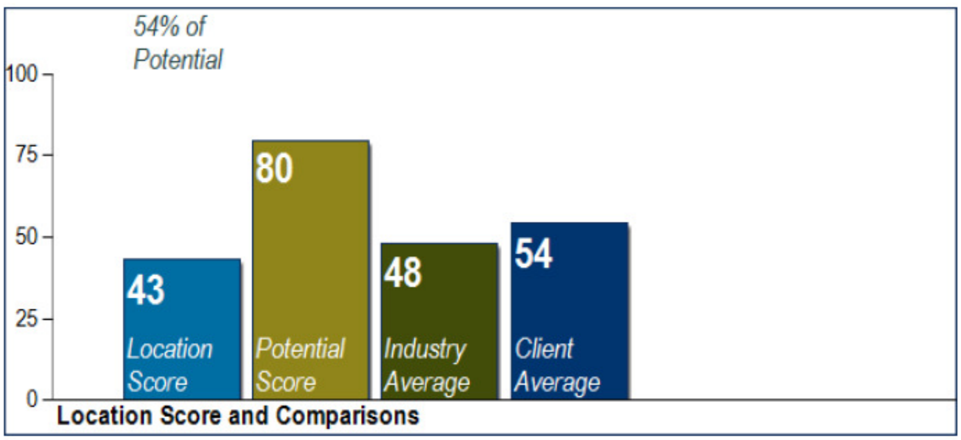
Component part scores are rounded. Therefore, the parts may not always add up the total score.



Risk*Mark* continued

Risk*Mark* Comparisons

This display shows a comparison of your Risk*Mark* to the average scores of other groups as noted in the display. Note that your potential score and percent of potential scores are included. The "Potential Score" is the highest possible score at the location assuming all recommendations are completed. The "Potential Score" is typically less than 100 because Risk*Mark* includes factors to measure the inherent risk at a location (for example, natural hazards or hazards associated with the industry). For a measure of the risk quality that is within the control of the location, refer to the "Percent of Potential" number, which removes the "inherent" risk factors from the metric.



The Industry used in the above chart is Fossil Fuel Power Plant.

There is a direct correlation between loss experience and Risk*Mark* scores. Total losses at locations in the "Lower" quartile are over eight times higher than those in the "Upper" quartile. Similarly, losses occur at locations in the "Lower" quartile more than four times as often as they do at locations in the "Upper" quartile.

The Risk*Mark* scores and averages are estimates based on the available information at the time of this evaluation. The results are subject to further engineering analysis. Your Client Service Team can provide additional details upon request.

Management of Exposures

Certain potential hazards and conditions were evaluated at this facility. Completion of the following items will help lower both the frequency and severity of losses and minimize the possibility of costly interruptions to your business.

The recommendations in this report are directly related to the context of this visit. For example, Equipment Hazard visits will typically not include Fire Hazard recommendations and vice versa. Similarly, Focus visits may be done to cover very specific subjects. Thus it is important to note that this is not a list of all recommendations for this location. The author of the report determines what specific recommendations to display. For a full list of recommendations please contact your account engineer.

Target Recommendations

Experience shows that the majority of all losses in this type of facility can be prevented or minimized by addressing the Target Recommendations, which are flagged below.

08-10-001
Target

Provide automatic fuel oil shutoff valves.

a. Fuel oil pumps and distribution systems should be equipped with automatic safety shutoff valves, interlocked with fire detection systems, to automatically shut off in the event of a fire. In addition, fuel pump remote shutoff switches should be installed in a location readily accessible during a fire. As welded pipe is not considered a likely release source, automatic shutoff valves are not needed on welded pipe but only where likely releases are expected to occur.

b. Curbing should be provided around Boiler Nos. 1 and 3 fuel oil pumping skids.

c. The steel hangers and supports on the 16-inch fuel supply line should be fire proofed. This should be done on the fuel line entering the Power House, before it splits to feed the three separate units.

The Hazard	Fuel oils are flammable liquids with flash points ranging between 100-160°F. Heated No. 6 fuel oil has similar characteristics. It does not require significant heating for ignition to occur and once burning, it will produce flame temperatures in the range of 2,000°F and thick, black, oily smoke. Due to high pressures in pumping systems, high-intensity spray fires are likely. Unprotected steel and equipment in the plant will be significantly damaged by the high temperatures. Due to the intense heat and smoke, manual firefighting will be difficult. Promptly shutting off the fuel supply pumps is a simple, quick and cost-effective way to minimize this hazard.
Technical Detail	Positive displacement pumps on a gravity liquid system are typically considered adequate without additional shutoff valves. Shutoff valves provide an additional level of protection for a failure in fuel piping as it enters the Main Building from the outside large fuel oil tanks. Fuel is fed by gravity from the main tank farm, located at the south end of the

08-10-001 continued

Technical Detail	facility, to the 185,000-gallon outside day tank, located north of the Power House. However, piping goes through the water treatment plant at ceiling level and then through the Main Boiler Hall before feeding the outside day tank. FM Approved fire safe shutoff valves should also be provided on the fuel supply line from the day tank into the Main Building, as well as on the main fuel line from the tank farm just before it enters the water treatment section of the plant. A method of automatically shutting off the fuel flow that supplies Bunker C and No. 2 fuel oil to the boilers should be provided for each of the three units. This can be done by installing FM Approved heat-actuated devices over the oil pumping skids and interlocking automatic safety shutoff valves to shut if the heat-actuated devices activate. Another method would be to interlock the sprinkler water flow alarms for each of these protected areas to any main supply fuel shutoff valves leading to the three units. It was previously indicated that there could be hold-up of about 500 barrels of oil within the fuel oil piping running inside the building. Potential leakage sources and location of automatic safety shutoff valves would need to be identified. There is less concern for leaks in welded piping. Fireproofing for the fuel oil supports should be accomplished by coating the supports with an FM Approved 2-hour fire-rated coating. Alternatively, the horizontal 16-inch supply line can be supported from the floor with fire-resistive concrete supports.
Risk*Mark* Points	Completion of only this recommendation will result in a Risk*Mark* score increase of 4.88 Points.
Status	Mr. Terry LeDrew indicated that curbing around the fuel oil pumping skids and fireproofing the pipeline steel supports can be completed most probably by the end of 2012. In addition, he will consider automating the main fuel feed shutdown upon detection of a fire.

10-03-001

Expedite operator training on the new emergency shutdown procedure.

a. Operator (shift supervisor) training/communication should be expedited on the newly implemented emergency shutdown procedure, highlighting oil pump shutdown in the event of a turbine building fire.

b. There should be an addendum to the existing plan to include shutdown of fuel in the event the fire involves fuel piping.

The Hazard	The shift supervisors are responsible for implementing the new emergency shutdown procedure. However, there has been only limited training.

10-03-001 continued

Risk*Mark* Points	To significantly increase the location Risk*Mark* score, multiple recommendations must be completed.
Status	According to Mr. Ron LeDrew, formal training has been completed for 2 scenarios on 2 different shifts but for completion, all 5 shifts need to be trained on the three outlined scenarios of the emergency shutdown procedure. This should be completed by March, 2012.

07-10-004 Target

Submit roof details of buildings, and history and details of roof repairs.

a. Plans and specifications for any roofing or roof repairs should be forwarded to FM Global for review and comment prior to the start of the work.

b. Details of all roofing repairs to the Power House and details of standing seam roofs should be submitted to FM Global for review.

The Hazard	It is reported that roof repairs to the Power House have been consistently carried out throughout the years. Previously, the building's roof was classified as steel deck class 1 (essentially non-combustible). These changes may affect loss prevention and could put the facility at risk. Presently, there is no automatic sprinkler protection at ceiling level throughout the Main Building. The best form of defense against a fire involving a combustible roof is automatic sprinkler protection. Once roof details are submitted, this situation will be further analyzed. In addition, FM Global loss history shows that the lack of adequate purlin (C or Z) bracing for standing seam roofs can result in collapse during heavy snow storms.
Technical Detail	Preliminary information has been provided on the original roof construction details; however, additional information is required as follows: - manufacturer of the components - how components are put together, either mechanically fastened or hot mopped with asphalt - thickness of the gypsum board for the inverted membrane - any details on roof repairs made over the years - standing seam roof details for other than the main plant buildings The insured has indicated that Tremco was involved in the roof repairs, which has occurred over the past 10 years. Efforts will also be made to obtain roof construction details directly from Tremco. In addition, a plan of all the roof repairs would be needed. Sections of the main roof were detailed according to different letters. The following has been

07-10-004 continued

Technical Detail	confirmed: - Sections E1, D1, M, S were done by Tremco and were Inverted Therm 100 roof systems. - Sections A, B, B1, C, D, G, F1, I, J, J1, K and L are Therm 100 roof systems. Additional details are needed as discussed with Ms. Dalton. Standing-seam systems use concealed clip fasteners to attach the metal roof panels to the building purlins and, in some cases, to provide the necessary lateral support for the purlins. The effectiveness of the deck and clip to laterally support the purlin depends on the tightness and strength of the specific clip and deck design. In the past, some manufacturers simply assumed adequate tightness, while others used testing methods that may have given misleading results. As a result, many such roofing systems cannot support the entire design load due to inadequate lateral bracing. The roof snow loading on these buildings will be closely monitored; however, it is reported that there is minimal snow buildup during the winter months. Buildings with standing seam roofs include the gas turbine building, water treatment plant next to the office, pipe shop, warehouse buildings and training centre.
Risk*Mark* Points	To significantly increase the location Risk*Mark* score, multiple recommendations must be completed.
Status	Great efforts have been made to analyze and document all work done on the various sections of roof. A civil engineer, Ms. Dana Dalton, has been hired and is presently researching all past work and upgrades done. Some details have been provided and additional information is expected shortly.

07-10-005

Improve automatic sprinkler protection in the various storage areas.

Adequate sprinkler protection is needed for storage areas, namely the Main Warehouse and the Stores Room within the Main Building.

The Hazard	The presence of solid shelving, a metal grated mezzanine or storage of boxes arranged such that it creates solid shelves, will all restrict proper water flow distribution from overhead ceiling sprinklers. Therefore, a fire in lower tiers will grow horizontally rapidly and thus involve the entire rack structure before ceiling sprinklers can operate and provide the proper control. This will lead to more damages and an excessive amount of sprinkler heads operating. With proper flue spaces in the racks, the fire will grow vertically, and allow the overhead ceiling sprinklers to quickly penetrate the fire plume and provide adequate control.

07-10-005 continued

Part A. **Upgrade protection in the Main Warehouse Building (Warehouse No. 3).**

a. Install automatic sprinkler protection below the metal grated mezzanine.

b. Remove solid shelving in the racks such that there are adequate flue spaces (continuous from floor to top of rack - at least 6 inches net every 9 feet) and a maximum solid shelf area of 64 sq. ft.

Note: All plans of the proposed sprinkler system improvements should be forwarded to FM Global for review prior to the letting of contracts.

The Hazard	 **Sprinklers are needed below the grated mezzanine in the Main Warehouse.**
Technical Detail	Apart from the area occupied by the grated mezzanine, there are two racks along each side wall. Presently, the storage is mostly metal parts in boxes or other Class 2 and 3 commodities. The overhead ceiling sprinkler system can generally protect Class 2 and 3 commodities to a height of approximately 15 ft. If any plastic material is stored in these racks, the overhead ceiling sprinkler system will need to be reinforced for adequate protection. Solid shelving should be removed as recommended and adequate flue spaces maintained.
Risk*Mark* Points	Completion of <u>only</u> this recommendation will result in a Risk*Mark* score increase of less than one point. Completing this recommendation along with other risk improvement efforts can result in more significant improvements to the Risk*Mark* score.
Status	A quotation has been obtained for installation of sprinklers below the mezzanine and this should be completed before the end of this year.

07-10-005 continued

Part B. **Improve automatic sprinklers in the Stores Room of Main Building.**

a. Because of the excessive clearance to the overhead ceiling sprinkler system, one level of in-rack automatic sprinkler protection should be provided at the approximate mid-height or above the 8-ft. high racks. Alternatively, the ceiling sprinkler system should be reinforced (this may require removing open top plastic trays from the top tiers).

b. Adequate flue spaces (continuous from floor to top of rack - at least 6 inches net every 9 feet) should be provided.

c. Ensure that the single-row-rack that is equipped with solid shelving has a maximum solid shelf area of 64 sq. ft.

d. The small quantities of flammable liquids (oils) should be relocate inside an FM Approved flammable liquid cabinet.

The Hazard	There are various types of commodities; however, a large amount of storage is in open top plastic trays.  **Parts in Plastic Trays in Racks in Stores Room**
Risk*Mark* Points	Completion of <u>only</u> this recommendation will result in a Risk*Mark* score increase of less than one point. Completing this recommendation along with other risk improvement efforts can result in more significant improvements to the Risk*Mark* score.
Status	Mr. Ron LeDrew said that adequate flue spaces will be provided, however, further sprinkler system improvements will be considered only after improvements are made to the Main Warehouse.

00-11-004 **Provide remote hydrogen venting capability.**

A means for remote hydrogen venting and purge from the generator (preferably from the control room) should be provided to ensure that the unit can be secured as quickly as possible.

The Hazard	The panel containing the hydrogen vent is located directly below the unit and would be inaccessible in the event of a fire in the area. The shutdown for the DC lube oil pumps is located on a mid-mezzanine below the operating floor but would not be considered accessible in the event of a serious fire. Remotely venting and purging hydrogen from the generator could minimize the damage from a hydrogen fire at the bearing in the event of a seal failure.
Technical Detail	This has been completed for Unit No. 1 only as follows: • Two motorized vent valves and a shutoff valve have been installed. During normal operation, replacement automatic vent valves for the existing vent valves will be normally closed and the new automatic supply valve will be open. During an emergency situation, replacement automatic valves for vent valves will open and the new automatic supply shutoff valve will close, allowing the generator hydrogen gas to vent to the atmosphere when the push buttons in the control room are activated. At this time, there will be a full purge with CO2. • The power cable/control cable for the automatic valves are fire rated and are the Pyrotenax 2200 cable which has the outer seamless 850 alloy metal sheathing. The valve actuator power supply is on a battery back-up with the UPS system. • A new HMI screen has been installed on the DCS whereby the operators in the control room are able to see the position of these three new valves.
Risk*Mark* Points	Completion of only this recommendation will result in a Risk*Mark* score increase of less than one point. Completing this recommendation along with other risk improvement efforts can result in more significant improvements to the Risk*Mark* score.
Status	This was completed on Unit No. 1 in September 2009. There were plans to complete this for Unit Nos. 2 and 3 in 2012, however, there have been changes on those involved in this project. This may delay the completion of this recommendation.

FM Global Risk Report | Nalcor Energy

11-05-002 Conduct an obstruction investigation on all wet-pipe automatic sprinkler systems.

An obstruction investigation should be conducted on all wet-pipe automatic sprinkler systems every 5 years through visual inspection and/or hydraulic flushing investigation methods. Where automatic sprinkler systems have pendent style automatic sprinkler systems, physically remove several sprinklers at multiple locations on the system and check for obstructions in the sprinkler and any pipe drops.

Where the second flushing investigation (at 10 years) determines there are no obstruction problems in the automatic sprinkler systems, the investigation frequency can be extended to every 10 years. However, if problems are observed while flowing water through fire pumps, yard mains, 2-inch drains or Inspector's Test Connections, the 5-year flushing investigation frequency should be reinstated.

The Hazard	Whenever water supplies for fire protection service are supplied from an open body of water, the potential for obstructing material to enter fire protection piping systems will exist. The exposure level will vary depending on multiple factors such as construction features of the water containment body, arrangement and protection features of the intake piping/wet pits, surrounding terrain, frequency of cleaning activities, etc.
Technical Detail	FM Global Data Sheet 2-81 and a flushing job aid were previously forwarded to Mr. Ron LeDrew.
Risk*Mark* Points	To significantly increase the location Risk*Mark* score, multiple recommendations must be completed.
Status	Mr. Ron LeDrew has agreed to investigate the oldest wet-pipe system first. The flushing investigation was done on System 19-1 by Simplex Grinnell a few weeks ago. After receipt of these results, he will investigate doing this procedure on all others.

11-05-001 Isolate the control room from the turbine building with fire-rated construction.

The control room should be isolated from the turbine building with 1-hour fire-rated walls and ceiling. Wired glass or rolling steel fire-rated shutters or an automatic water spray protection system should be provided for any windows facing the interior of the turbine building.

The Hazard	The control room is located in the turbine building. The operators are expected to remain in the control room during a fire. There are large regular windows facing the turbine/generators.
Risk*Mark* Points	Completion of <u>only</u> this recommendation will result in a Risk*Mark* score increase of less than one point. Completing this recommendation along with other risk improvement efforts can result in more significant improvements to the Risk*Mark* score.
Status	Mr. Terry LeDrew indicated that the control room will be revamped in a few years, and the prescribed enhancements will be included in the project. However, it will be expected at the earliest in 2017.

Index: 000009.36-02 / Account: 1-74568 / Order ID: 676515-69 13

Management of Exposures continued

Point estimates are approximated by assuming only the recommendation in question is completed. Multiple recommendations may need to be completed to affect the location score. For a more accurate estimate, contact your Client Servicing Team.

Comments

FM Approved Ramco shields were installed on many fittings on the operating floor for Unit Nos. 1 and 2 where turbine mineral oil spray fire hazards exist. These shields had to be modified for most fittings because of the lack of proper clearances next to equipment, etc. These shields will minimize the possibility of a spray fire and with adequate overhead sprinkler protection, a fire in this area is now expected to be controlled.

During this visit, discussions with Mr. Ron LeDrew, were held on an existing sprinkler system impairment. This exists for the deluge sprinkler system of Zone 13A-3 which protects Fuel Oil Set #3 and is isolated because maintenance personnel had to remove a section of sprinkler piping to install a blow down tank. Discussions were held on all the needed precautions while the plant is dealing with this impairment. Additional security rounds will be made in the affected area and smoking will be prohibited outside by the day tank. Protection should be restored over the next couple of weeks.

Ongoing Services

FM Global is available to provide support in all areas of property loss prevention. These services include:

- Development of specifications for projects such as new construction, automatic protection systems and process safeguards
- Review of related project plans
- Assistance in implementing and managing loss prevention programs
- On site review and acceptance of completed projects
- Assistance in managing impaired protection systems

Depending on your organization's insurance program, you may also have access to the FM Global *My*Risk website. If so, you will find additional risk management tools that can help with your risk improvement strategy at:

https://myrisk.fmglobal.com

For access to these services, contact one of the following:

Montreal Operations:
FM Global
14e étage
600, rue De La Gauchetière Ouest
Montréal (Québec) H3B 4L8
Canada
[1] (514) 876 7400

John-John Laxa, Account Engineer:
165 Commerce Valley Drive West
Suite 500
Thornhill, Ontario, L3T 7V8
Canada
[1] (905) 763 5555

FM Global Risk Report

Nalcor Energy

Reference Information

Focus Visit Summary

Nalcor Energy
Holyrood Thermal Plant
Route 60
Holyrood, Newfoundland and Labrador A0A 2R0
Canada

Fire & Natural Hazards
Special Risk Evaluation

Visit by:	Joanne M. D'Abreu
Visit date:	24 August 2011
Site Contact:	Mr. Darren Marsh, AON - Risk Control Services, darren.marsh@aon.ca
Final Conference Attendees:	Mr. Terry LeDrew, P.Eng, Manager, Thermal Generation; Mr. Ron LeDrew, Emergency Response Coordinator; Michel N. Burbaud, FM Global; Ms. Marilyn Leonard, Risk Manager; Mr. Evan Cabot, Operations Specialist; Mr. Christian Thangasamy, Plant Mechanical Engineer
Location Index Number:	000009.36-02
Account Number:	1-74568

Risk*Mark* Information included in this report is current as of 01 September 2011.

Project Title: Install Handheld Pendant to Overhead Crane

Location: Bay d'Espoir

Category: Generation - Tools and Equipment

Type: Other

Classification: Normal

Project Description:

The overhead crane in Bay d'Espoir Powerhouse 1 is used to move heavy equipment such as generator rotors. The operator controls are located in a small cab hanging beneath one end of the crane. Figure 1 is a photo of the overhead crane with the cab to lower right of the crane.

Figure 1: Hepburn Overhead Crane in Powerhouse 1

A remote handheld pendant and base station will be installed to supplement the local controls located within the cab of the crane. This will allow experienced operators to manipulate the crane controls, including both auxiliary and main hoists, from a safe location on the floor. The pendant station will be a wireless radio frequency type with the controlling base station mounted in the vicinity of the control circuitry and interfaced to the existing controls.

The existing control panel in the cab will be equipped with a keyed local/remote selector switch to prevent the crane from being controlled simultaneously from both locations. The handheld pendant will be equipped with all applicable controls required to manipulate all possible crane movements including an emergency stop pushbutton.

The existing hydraulic brake system in the cab will also be replaced by an electric brake system for connection to the remote control station.

Figure 2 is an example of a wireless base station that will be installed in operator cab and interfaced to the existing controls. The wireless handheld pendant communicates with the base station. The remote control station shown in Figure 3 is a model similar to one that is required for this project due to the required control parameters.

Figure 2: Example of Wireless Base Station for Overhead Crane

Figure 3: Example of Wireless Remote Control Station for Overhead Crane

The brake system replacement, refurbishment of cab controls and installation of the pendant system can only be performed by qualified crane technicians. This installation must be inspected by a certified crane specialist before it is used by Hydro employees.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	2.0	0.0	2.0
Labour	32.0	48.0	0.0	80.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	10.0	70.0	0.0	80.0
Other Direct Costs	5.0	4.2	0.0	9.2
Interest and Escalation	2.9	12.4	0.0	15.3
Contingency	0.0	34.2	0.0	34.2
TOTAL	**49.9**	**170.8**	**0.0**	**220.7**

Reliability Performance, Outage Statistics, Environmental Performance, Vendor Recommendations, Historical Experience, Forecast Customer Growth and Industry Experience are not relevant to this proposal.

Justification:

As part of Hydro's workplace safety commitment, Hydro determined that the overhead crane should be equipped with a wireless hand held pendant station to resolve issues detailed later in this report. In order for an operator to use the overhead crane, that person must currently have fall arrest training and wear the applicable personal protective equipment to be in the cab area situated under the crane. Due to reduced visibility, a second operator must be stationed on the floor in the vicinity of the load to guide and inform the operator in the cab of required crane movements.

During critical lift situations such as rotor removal and installation, the crane operator is required to be in the cab for several hours and is not able to leave the crane due to ladder access to the crane. This presents potential delays during critical lifts which can be addressed by the provision of a remote control device. A remote pendant will allow one operator to control the crane from a safe location on the floor and facilitate transfer of control to another operator if required. A wireless remote pendant removes the need for hanging cables which can become entangled with moving equipment and enables the operator to move unencumbered about the floor while the load is lifted. The training of a junior operator is also better facilitated through the use of a remote station instead of in the confined area of the cab which is not designed for this purpose.

Providing a remote pendant for the operator resolves or enhances the following issues:

1. The operator would not be required to access the cab and fall arrest training would therefore not be

required. This is a safety enhancement.

2. The operator would not be subjected to long hours in uncomfortable conditions. This is a health and ergonomic enhancement.
3. Only one operator would be required during crane use. This improves labor efficiency.
4. The operator would be able to move freely during lifting to assess crane movements and placement of load. This is a process improvement.
5. Operator training would be better facilitated by using a remote control station in a more comfortable environment. This is a process improvement and ergonomic enhancement.

Existing System:

The main overhead crane in powerhouse 1 at the Bay d'Espoir Hydroelectric Generating Station is a Hepburn, type BDB-T-EC, 180 ton capacity crane with a 30 ton capacity auxiliary hoist. The crane was installed in 1966 and is used for maneuvering large objects such as generator rotors during overhauls.

An operator, having applicable fall arrest training and wearing personal protective equipment, must climb by ladder to a cab situated under the crane in order to control it. A second operator must be situated on the floor to guide the primary operator in moving the crane due to limited visibility from the location of the cab. The cab from which the operator controls the crane is a small area under the crane and is subject to high temperatures. The temperature in the cab has been known to exceed 40^{o} C and is therefore an unsatisfactory work environment for a person to be in for several hours. A fan was installed in 2010 to provide comfort for the operator but was not found to provide sufficient cooling. Figure 4 is a close-up view of the Operator cab showing a fan used to provide air flow for the operator during times when there is excessive heat in the area.


Figure 4: Operator Cab on Overhead Crane

The crane controls are electromechanical in nature consisting of pushbuttons and joysticks. The braking system in the cab is hydraulic and operated by a footswitch. The existing brake, drum and associated mechanical and hydraulic components must be removed and replaced with an electric brake system. Refurbishment of the existing controls and brake replacement is necessary in order to interface to a new wireless base station.

There have been no major upgrades or work done to the controls or braking system of the crane over the past five years.

Operating Experience:

The existing crane and its controls were part of the original generating plant and have been used by operators for moving large pieces of equipment, in particular generator rotors. The crane can be needed for use at any time of the year for moving heavy equipment around the powerhouse. From May through August, the crane can be used weekly and needs two operators for most of each day. For critical work such as generator overhauls, rewinds and generator bearing upgrades, this can increase to operation over an entire day for two operators over several consecutive days. The crane performs its intended function but the working environment for the operator in the cab is not suitable on the basis of requirements and restrictions for working at heights, excessive heat, and that the operator is constrained to the cab once crane maneuvers are underway.

Regular preventative maintenance inspections are performed by Bay d'Espoir mechanical and electrical operations personnel but the crane must also be inspected annually by a certified crane inspector.

Legislative or Regulatory Requirements

The crane must be inspected annually by a certified technician as per Canadian Standards Association B167-96 *Safety Standard for Maintenance and Inspection of Overhead Cranes, Gantry Cranes, Monorails, Hoists, and Trolleys*. This standard is provided in Appendix A. An inspection will be done as part of this project following completion of the proposed work.

Safety Performance

Fall arrest apparatus is required for the operator to climb to and from the crane cab and a second operator is needed on the floor to assist by providing moving instructions. The safety concern is that there are only two access ladders to the crane; one at each end of the powerhouse. When the crane is parked over a unit for a critical lift, the operator has to stay in the crane from the time the load is started to be rigged until it is moved and unhooked. This can take in excess of two hours when moving the generator rotor or the runner.

In July 2012, it was reported by Bay d'Espoir Operations that the temperature at the cab rose above 40^{o} C. This presents an unacceptable work environment.

Maintenance or Support Arrangements

Plant electricians and mechanics have performed preventative and corrective maintenance on the crane but inspections must be performed annually by an external certified crane technician. This service is contracted annually.

Maintenance History

The five-year maintenance history for the overhead crane, including all components of the crane and hoist is shown in Table 2. These costs do not include the required annual inspection by certified crane technician.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2012	1.4	1.8	3.2
2011	0.8	2.6	3.4
2010	5.6	1.4	7.0
2009	1.0	3.4	4.4
2008	2.8	9.3	12.1

Anticipated Useful Life

The remote control pendant and electric brake each has an anticipated useful life of 20 years.

Development of Alternatives:

There are no alternatives other than status quo.

Conclusion:

The overhead crane should be fitted with a remote control system on the basis of safety and health, ergonomics and efficiency. A wireless remote control system is the best choice as it would provide unencumbered movement of the operator. It would allow the operator to check the position of the load during maneuvers without the need for a second person. The status quo operation of the crane is not an acceptable solution.

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Site assessment including crane inspection	August 2014	September 2014
Design	Contract preparation and drawing development	October 2014	February 2015
Procurement	Contract award	November 2014	November 2014
Construction	Contract installation, various site assistance	February 2015	March 2015
Commissioning	Crane operation commissioning and inspection	March 2015	Mach. 2015
Closeout	Closeout documentation	April 2015	April 2015

APPENDIX A

CANADIAN STANDARDS ASSOCIATION

B167-96: SAFETY STANDARD FOR MAINTENANCE AND INSPECTION OF OVERHEAD CRANES, GANTRY CRANES, MONORAILS, HOISTS, AND TROLLEYS.

B167-96

Safety Standard for Maintenance and Inspection of Overhead Cranes, Gantry Cranes, Monorails, Hoists, and Trolleys

Public Safety

B167-96
Safety Standard for Maintenance and Inspection of Overhead Cranes, Gantry Cranes, Monorails, Hoists, and Trolleys

1. Scope

1.1 General

This Standard specifies the minimum requirements for inspection, testing, and maintenance of overhead cranes, monorails, hoists, trolleys, jib cranes, gantry and wall cranes, and other equipment having the same fundamental characteristics.

1.2 Log Book

Equipment covered by this Standard shall have a register in the form of a log book, for recording all findings as a result of inspections, maintenance, repairs, and modifications. The log book shall be available for review during the entire life of the equipment.

2. Definitions

2.1

The following definitions apply in this Standard.

Critical components — those components which may affect the safe load-carrying capacity of the equipment within the scope of the original design and through its full-rated capacity.

Designated — selected or assigned by the employer or the employer's representative as being qualified to perform specific duties.

Overload — any load greater than the rated load.

Qualified — a person who, by possession of a recognized degree or a certificate of professional standing, or who, by extensive knowledge, training, and experience, has successfully demonstrated the ability to solve or resolve problems relating to the subject matter and work.

Rated load (capacity) — the maximum load designated by the manufacturer for which a crane or individual hoist is designed and built.

Special service — that equipment which is not being used in the classification for which it has been designed or is subject to adverse conditions or environment

Out of service — that equipment which has been idle for more than one month but less than one year.

3. Reference Publication

3.1

This Standard refers to the following publication and where such reference is made it shall be to the edition listed below.

CSA Standard
W59-1989,
Welded Steel Construction (Metal Arc Welding).

4. Inspection

4.1 Experience

A crane inspector shall have a minimum 10 000 h of experience relating to the inspection, maintenance, repairs, and modification of equipment described in Clause 1.1, which shall include training in and knowledge of applicable legislation, safety practices, and standards. It is acceptable that crane inspection be performed by a team having combined equivalent qualifications under the supervision of a crane inspector or Professional Engineer.

4.2 Inspection Criteria

Critical components that affect the safe operation of a hoist or crane, as specified (listed) by the manufacturer, shall be inspected in accordance with the inspection criteria or procedures indicated by the manufacturer.

If such a list is not available, or if there is any doubt as to whether a component is safety-related, a Professional Engineer shall make a list of critical components and provide inspection criteria and procedures for each critical component.

4.3 Inspection Records

A dated and signed report shall be kept in the log book on critical components, determining that the hoist or crane is capable of lifting, lowering, supporting, and operating at the maximum rated load.

Verification shall be provided that the supporting structure has been designed and installed to support the maximum rated load.

The log book shall be available to any person involved in the inspection, maintenance, and/or operation of the lifting equipment.

4.4 Inspection Classification

4.4.1 Initial Inspection

4.4.1.1 General

Prior to initial use, all new, reinstalled, modified, or rebuilt equipment (as per Clause 1.1) shall be inspected by (a) crane inspector(s) to ensure compliance with the applicable provisions of this Standard and CSA Standard Z202, as well as to ensure that the supporting structure has been approved by a Professional Engineer to carry the maximum rated load.

Note: *Until the publication of CSA Standard Z202, the applicable requirements of CSA Standard B167-1964 shall be used.*

4.4.1.2 Keeping Records

Records of the initial inspection, outlining the date, inspector's name, and summary of the findings, shall be kept and made available to the operator or crane inspector(s), or both.

4.4.2 Inspections

4.4.2.1 Inspections for Cranes in Regular Use

Inspection procedure for cranes in regular service is divided into two general classifications based upon the intervals at which inspections should be performed. The intervals are dependent upon the nature of the components of the crane, as outlined in Clause 4.2, and the degree of their exposure to wear, deterioration, or malfunction. The two general classifications are designated as operational and periodic, with respective intervals between inspections as defined in more detail by the classification criteria in CSA Standard Z202.

4.4.2.2 Inspections for Cranes Not in Regular Use

Cranes that are not in regular use shall be inspected before being placed into service.

(a) A crane that is used in infrequent service, or is out of service, shall be inspected in accordance with Clause 4.4.4.1.

(b) A crane that has been out of service for more than one year shall be inspected in accordance with Clause 4.4.5.3.

4.4.3 Service Classes

4.4.3.1 Class A (Standby or Infrequent Service)

This service class covers cranes that may be used in installations such as powerhouses, public utilities, turbine rooms, motor rooms, and transformer stations, where precise handling of equipment at slow speeds with long, idle periods between lifts are required. Capacity loads may be handled for initial installation of equipment and for infrequent maintenance.

4.4.3.2 Class B (Light Service)

This service class covers cranes that may be used in repair shops, light assembly operations, service buildings, light warehousing, etc, where service requirements are light and the speed is slow. Loads may vary from no load to occasional full-rated loads, with 2–5 lifts per h, averaging 2.6 m (10 ft) per lift.

4.4.3.3 Class C (Moderate Service)

This service class covers cranes that may be used in machine shops or papermill machine rooms, etc, where service requirements are moderate. In this type of service, the crane will handle loads that average 50% of the rated capacity, with 5–10 lifts per h, averaging 3 m (15 ft), not over 50% of the lift at rated capacity.

4.4.3.4 Class D (Heavy Service)

This service class covers cranes that may be used in heavy machine shops, foundries, fabricating plants, steel warehouses, container yards, lumber mills, etc, and standard duty bucket and magnet operations where heavy-duty production is required. In this type of service, loads approaching 50% of the rated capacity will be handled constantly during the working period. High speeds are desirable for this type of service, with 10–20 lifts per h, averaging 3 m (15 ft), not over 65% of the lifts at rated capacity.

4.4.3.5 Class E (Severe Service)

This service class requires a crane capable of handling loads approaching a rated capacity throughout its life. Applications may include magnet, bucket, ~~and~~ magnet/bucket combination cranes for scrap yards, cement mills, lumber mills, ~~fertilizer plants,~~ container handling, etc, with 20 or more lifts per h at or near the rated capacity.

4.4.3.6 Class F (Continuous Severe Service)

This service class requires a crane capable of handling loads approaching rated capacity continuously under severe service conditions throughout its life. Applications may include custom-designed specialty cranes essential to performing the critical work tasks affecting the total production facility. These cranes must provide the highest reliability, with special attention to ease-of-maintenance features.

4.4.4 Operational Inspection

4.4.4.1 General

Visual examinations shall be recorded in the log book by the operator or a designated person with findings of deficiencies at the following intervals:

(a) light service — Classes A and B monthly;
(b) heavy service — Classes C and D weekly to monthly;
(c) severe service — Classes E and F daily to weekly; and
(d) special service — as recommended by a qualified person.

4.4.4.2 Inspection Targets

Items such as the following shall be examined for defects, malfunctions, and damage at intervals as defined in Clause 4.4.4.1. This includes observations during operation for any defects or damage that might appear between periodic inspections; the resolution of such defects found in this inspection shall be made by a qualified person:

(a) all operational functions;
(b) leakage in lines, tanks, valves, pumps, and other parts of air or hydraulic systems;
(c) deformed, worn, or cracked hooks;
(d) hook latches, if so equipped;
(e) hoist ropes;
(f) limit device(s) for function;
(g) function labels for operator control; and
(h) all brakes.

4.4.5 Periodic Inspection

4.4.5.1 General

Visual examination of equipment, as defined in Clause 1.1, shall be conducted by a crane inspector making a record of apparent conditions, as defined in Clause 4.4.5.2, to provide the basis for a continuing evaluation at intervals defined below:

(a) light service — Classes A and B annually;
(b) heavy service — Classes C and D semi-annually;
(c) severe service — Classes E and F quarterly;
(d) special service — as recommended by a Professional Engineer or crane manufacturer, or both; and
(e) out of service — prior to being put back into service.

4.4.5.2 Verification

Verification shall be provided that the supporting structure has been designed, approved, and installed to carry the maximum load as rated. The verification shall be accomplished by one of the following methods:

(a) a report bearing the seal and signature of a Professional Engineer stating that the supporting structure as installed is capable of handling the maximum load as rated;

(b) the crane inspector has reviewed the applicable drawings bearing the seal and signature of a Professional Engineer that confirms the installed supporting structure has been designed and approved by a Professional Engineer to support the maximum load as rated; or

(c) an affidavit in the log book by the owner or employer that the supporting structure has been designed and approved by a Professional Engineer and installed to carry the maximum load as rated.

4.4.5.3 Inspection Targets

Complete inspections of the crane shall be performed at intervals as defined in Clause 4.4.5.1. Any deficiencies such as those listed below shall be examined and determination made as to whether they will affect the safe operation of the crane:

(a) deformed, cracked, or corroded members;
(b) loose bolts or cracked welds;
(c) sheaves and drum cracks, distortion, and wear;
(d) worn, corroded, cracked, or distorted parts, such as pins, exposed or open bearings, bushings, shafting, couplings, gears, bumpers, and trolley stops;
(e) glazing, scoring, warpage, contamination, or wear of electrical and mechanical brakes;
(f) visible damage to hook, retaining nut, and safety latch;
(g) deformed hook or worn hooks for compliance with manufacturer's recommendations;
(h) evidence of pitting or deterioration of electrical contacts;
(i) interference with the free operation of buttons and controls;
(j) damaged insulation on the electrical wire, cables, and controls;
(k) inadequate performance or reliability of limit switch;
(l) worn and/or damaged trolley and bridge wheel assemblies;
(m) nonperformance of load brake or controlled lowering device;
(n) wear, cracks, or corrosion of wire rope, load chain, end clamps, or rope clips;
(o) missing or loose bolts in the supporting structure; and
(p) rope reeving for noncompliance with crane manufacturer's specifications.

In addition to the deficiencies listed herein, this inspection shall also include the requirements of Clause 4.4.4.2.

4.4.5.4 Overload Conditions

Equipment defined in Clause 1.1 shall always be operated within the rated capacity. However, if at any time during the operation of said equipment it has been accidentally overloaded, the equipment shall be removed from service until an inspection can be performed in accordance with Clauses 4.4.4, 4.4.5.1, 4.4.5.2, and 4.4.5.3.

4.5 Hazardous Conditions

Any hazardous conditions disclosed by the inspection requirements of Clause 4.4 shall be corrected by the owner or employer of the equipment before the equipment is placed in service.

5. Testing

5.1 Operational and Running Tests

Prior to initial use, for all new, reinstalled, ~~modified,~~ or rebuilt equipment (as defined in Clause 1.1), the following functional items and components shall be tested to ensure compliance with CSA Standard Z202:

(a) all motions;
(b) limit switches at full speed;
(c) limiting and indicating devices (if provided);
(d) all circuits, controls, interlocks, and sequence of operation; and
(e) each crane motion, holding brakes, and travel brakes, with the hook carrying
(i) rated capacity – during these tests the specified speeds are to be attained, provided the power supply to the crane is as specified; and
(ii) 125% of the rated capacity – during this test the specified speeds need not be attained but the crane shall show itself capable of dealing with the load without difficulty.

Prior to initial use, the vertical deflection of all new, reinstalled, modified, or rebuilt equipment (as defined in Clause 1.1) shall be measured. The vertical deflection of the girder produced by the weight of the trolley and the rated load shall not exceed the maximum allowed by the applicable design specification.

The rated capacity and 125% of the rated capacity tests must be performed with the crane or hoist installed on its supporting members (runway or monorail).

A test report shall be prepared, including test results and readings. The test report shall be retained in the log book.

6. Maintenance

6.1 Experience

All repairs shall be performed by, or under the supervision of, a person having a minimum of 8 000 h experience related to the repair of equipment defined in Clause 1.1.

6.2 Preventive Maintenance, Repairs, and Adjustments

6.2.1 Maintenance Program

A preventive maintenance program shall be established, based on the specification and operating requirements of the crane. Dated and signed records shall be kept readily available.

6.2.2 Replacement Parts

Replacement parts shall meet or exceed the original manufacturer's specifications.

6.2.3 Welding

All welding shall conform with the requirements of CSA Standard W59.

6.3 Maintenance Procedures

6.3.1 Initial Procedures

Before adjustments and repairs are started on a crane, the following procedures shall be taken:

(a) All motion controllers shall be placed in the off position. Main switch (crane disconnect) shall be operated to the open position, checked, deenergized, locked-out, and tagged.

(b) Before performing maintenance on the crane power-collector system, or any other crane component within the area of the building-power distribution system to the crane, the power source shall be deenergized, locked, and tagged. Where it is not practical to disconnect and lock out the power supply to live electrical installation, equipment, or power lines, the power distributing system shall be guarded to prevent contact, in accordance with the applicable local legislation or regulations, or both.
(c) Consideration shall be given to the power distribution system when mobile lifting equipment is used to access the crane from floor elevation. Mobile cranes, tools, and other equipment, which are capable of conducting electricity and endangering the safety of workers, shall not be used in proximity to any live electrical installation or equipment with which they might make electrical contact.

6.3.2 Safety Barriers

Markings and barriers shall be utilized in instances where maintenance work creates a hazardous area on the floor beneath the crane.

6.3.3 Isolation from Other Cranes

Where other cranes are in operation on the same runway, rail stops or other means shall be provided to prevent interference with the crane being maintained.

6.3.4 Restricting Runways

When work is being carried out on a crane in one of two adjacent crane runways, and the runways are not separated or protected, or if any hazard from the adjacent operations exists, access to the adjacent runway shall be restricted.

6.3.5 Final Procedures

After adjustments and repairs have been made, the crane shall not be restored to service until all guards have been reinstalled, safety devices reactivated, and maintenance equipment removed.

Project Title: Inspect Fuel Storage Tanks

Location: Various Sites

Category: Transmission and Rural Operations - Generation

Type: Other

Classification: Normal

Project Description:

The purpose of this project is to complete detailed inspections of the above ground fuel storage tanks and associated fuel supply systems within Hydro. The inspections will serve to identify corrective and preventive maintenance items. Identifying and completing the necessary work will maximize the service life, ensuring that these assets are in reliable operating condition. The scope of work includes the following:

- Perform tank inspections as outlined in the American Petroleum Institute (API) Standard 653 – Tank Inspection, Repair, Alteration, and Reconstruction, including:
  - API five-year external inspection of tanks on the north coast of Labrador in 2014, the south coast of Labrador and the Northern Peninsula in 2015 and the central and south regions of Newfoundland in 2016. Five-year external inspections to be completed by an authorized inspector and shall include external ultrasonic thickness measurements of the tank shell and the completion of cathodic protection surveys.
  - API ten-year internal tank inspection; the tanks planned to be completed in 2014 include three 501,000 L at Stephenville Gas Turbine and three 22,730 L tanks at St. Anthony Diesel Plant. Future years will see a greater number of internal inspections in an effort to bring all tanks to a ten year internal inspection frequency over the following five years (2015 - 2019).
- Drain and clean the tank;
- Inspect comprehensively all accessible tank components;
- Perform ultrasonic thickness surveys of floor, shell, roof, and nozzles;
- Implement temporary site storage, where required; and
- Complete routine upgrades identified during the inspection.

Separate approval will be sought to complete any additional capital work identified during the inspection. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	66.5	0.0	0.0	66.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	303.6	0.0	0.0	303.6
Other Direct Costs	18.9	0.0	0.0	18.9
Interest and Escalation	28.2	0.0	0.0	28.2
Contingency	77.8	0.0	0.0	77.8
TOTAL	**495.0**	**0.0**	**0.0**	**495.0**

Justification:

In the interest of maximizing the service life of its assets and adhering to Hydro's Environmental Policy and Guiding Principles, Hydro has, in the past, completed routine inspections of its above ground fuel storage tanks. Lacking the guidance of a documented process, the scheduling and implementation of these inspections was often left to the discretion of the area asset managers and site personnel[7]. Consequently, inspections were not completed in a systematic fashion, resulting in variances in: the inspection requirements, frequency of inspection and the documentation of the inspection findings. In order to implement a standardized approach for the completion of all future tank inspections, Hydro has adopted the tank inspection procedures outlined by The American Petroleum Institute[8] (API).

API recommends that above ground fuel storage tanks undergo an external inspection every five years and an internal inspection every ten years after their initial in-service date. The required inspection procedures are outlined in *API Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction*, *section 6* (see Appendix A). The majority of Hydro's fuel storage tanks are due, or soon to be due, for inspection. This project will ensure that the tanks are inspected in accordance with the requirements identified in the API 653 standard.

In order to complete the required inspections and balance financial and human resources an inspection plan has been developed and is outlined in Appendix B. The inspection plan is a listing of tanks, owned by Hydro along with the corresponding dates of the proposed inspections. The basis for this plan is as follows:

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[7] *There is no regulatory driver outlining the requirements for above ground fuel storage tank inspections in NL.*

[8] *The American Petroleum Institute has been the leader in developing equipment and operating standards for the oil and natural gas industry since 1924.*

- These fuel storage tanks have never received a five year external inspection by an authorized[9] inspection agency. In order to bring Hydro's tank inspection philosophy in line with the API standard these inspections will be completed within a three year window. In an effort to minimize inspection costs a phased approach will be implemented with the plan to complete the inspections in the Labrador Region in 2014. Northern and Central regions will be completed in 2015 and 2016 respectively.

- Hydro has completed internal tank inspections in the past, however, these inspections were not carried out in a systematic fashion. With the guidance of the API 653 standard, the inspections will be completed utilizing a formalized approach. The five year plan outlined in Appendix B will place priority for the completion of inspections on those tanks which have not received an initial ten year inspection. Fuel volume, availability of temporary storage, existing work plans, and equipment outages have also been considered. As data is made available on tank corrosion rates through the completion of these inspections, the frequency and timing of future inspections may change.

Hydro must ensure that its fuel storage tanks are maintained in a safe, reliable operating condition. Tank inspections serve to identify maintenance and repair items, enabling the work to be completed in a timely fashion. This proactive maintenance approach will enable the tanks to continue to perform as designed, ensuring that they are structurally sound, suitable for operation, and not at risk of releasing fuel into the environment.

Existing System

Hydro is responsible for the operation and maintenance of transmission and distribution systems, three gas turbines, one frequency converter, one mini-hydro plant and 25 diesel plants. To facilitate these operations, Hydro operates 96 above ground fuel storage tanks comprising 75 horizontal tanks and 21 vertical tanks. Approximately 75 percent of the tanks store diesel fuel, 12 percent store waste oil, ten percent store transformer oil and the remaining three percent store one of Jet A1, lube oil or waste fuel and glycol.

Operating Experience:

Seventy five percent of Hydro's aboveground fuel storage tanks serve as a fuel supply for its isolated diesel

[9] An API 653 authorized inspector certificate will be issued when an applicant has successfully passed the API 653 certification examination, and satisfies the criteria for education and experience. Education and experience criteria is outlined in Annex D of the API 653 Standard. A copy of Annex D is located in Appendix B.

generation units. These tanks are critical to ensuring the continued supply of reliable power to the communities in which they are located. Fuel storage tanks containing diesel fuel are located in isolated communities from Nain on the north coast of Labrador to Ramea on the south coast of Newfoundland. Historically tank inspections have been performed but the frequency of inspection was not in accordance with the API 653 Standard.

Legislative or Regulatory Requirements

This project is not justified on legislative or regulatory requirements.

Safety Performance

Safety performance is not applicable to the justification of this project.

Environmental Performance

Undetected deterioration of fuel storage tanks could potentially result in a loss of fuel oil into the environment. The completion of the proposed inspections will identify potential areas of concern, thus enabling the completion of refurbishments before any loss of fuel oil can occur.

Industry Experience

Industry experience with above ground fuel oil storage tanks indicates the floors and ceilings of the tanks are affected the most by oxidation. Trapped water at the bottom of tank and air voids above the fuel oil result in corrosion of the tank floor and the tank ceiling. Generally, the walls of the steel storage tanks do not experience corrosion from the inside because they are continuously coated with fuel oil through refilling. The main protection against oxidation for the exterior surfaces has been epoxy coating systems.

API Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction, *section 6* is widely accepted as the benchmark for the implementation of tank inspection programs required for the early detection of tank deterioration.

Vendor Recommendations

There are no vendor recommendations applicable to this project.

Maintenance or Support Arrangements

Routine inspection and maintenance of the fuel storage tanks is performed by Hydro personnel, with standardized external and internal inspections performed by a certified inspection agency. All major maintenance, such as the application of epoxy coatings and steel fabrication, is completed by external contractors.

Maintenance History

Hydro performs routine inspections at it diesel plants and gas turbine sites to help identify any equipment deficiency or leak to the environment. These routine inspections are completed on a daily basis by operations personnel and are limited to visual checks of the checks of tanks and associated fuel supply system.

Standardized internal inspections have been completed on various tanks, as indicated in Table 2 below.

Historical Information

Table 2 details the costs associated with tank cleaning and inspection projects within the past five years.

Table 2: Historical Information[10]

Year	Budget ($000)	Actual Expenditures ($000)	Unit(s)	Cost per Unit($)	Comments
2012	80.0	108.5	Two 314,000 L Vertical Tanks	54.3	Clean and Inspect Tanks (Mary's Harbour)
2010	37.0	48.5	One 22,000 L, Horizontal Tank	48.5	Clean and Inspect Tank (Little Bay Islands)
2010	45.8	48.6	Two 45,000 L, Horizontal Tanks	24.3	Clean and Inspect Tanks (Happy Valley-Goose Bay)
2009	30.0	56.6	Three 69,000 L, Horizontal Tanks	18.9	Clean and Inspect Tanks (Mary's Harbour)

Conclusion:

Hydro has moved toward a systematic approach for its fuel storage inspection and the API 653 standard has been adopted as the guide. Inspection of the tanks is imperative to ensuring that the tanks are performing as intended, which will prevent the release of fuel into the environment. Hydro plans to adhere to the API recommended intervals over a five year period.

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[10] [1]*As can be seen in the table, the costs associated with tank cleaning and inspection vary significantly on a per unit basis. This fluctuation is most greatly affected by the size of the tanks, the geographic location of the work area and the number of tanks located at the site. The cleaning and inspection effort associated with the larger vertical tanks is far greater than that of the smaller horizontal tanks and consequently more costly. Remote sites containing a single tank, such as Little Bay Islands, are subject to an increase in cost, generated by the requirement to arrange temporary site fuel storage to facilitate the draining of the existing tank for cleaning and inspection purposes.*

The completion of the upgrades identified during the inspections will extend the useful service life of the tanks, thus, ensuring the continuation of reliable operation for years to come.

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Design transmittal, schedule, work breakdown structure	April 2014	April 2014
Design	Tender package preparation	May 2014	May 2014
Procurement	Contract award	June 2014	June 2014
Construction	Tank cleaning and inspection	June 2014	June 2014
Closeout	Contract closeout	October 2014	October 2014

Future Plans:

Further inspections of fuel storage tanks will be submitted in future capital budget applications.

APPENDIX A

API STANDARD 653 - SECTION 6 INSPECTION

Section 6—Inspection

6.1 General

Periodic in-service inspection of tanks shall be performed as defined herein. The purpose of this inspection is to assure continued tank integrity. Inspections, other than those defined in 6.3 shall be directed by an authorized inspector.

6.2 Inspection Frequency Considerations

6.2.1 Several factors must be considered to determine inspection intervals for storage tanks. These include, but are not limited to, the following:

a) the nature of the product stored;
b) the results of visual maintenance checks;
c) corrosion allowances and corrosion rates;
d) corrosion prevention systems;
e) conditions at previous inspections;
f) the methods and materials of construction and repair;
g) the location of tanks, such as those in isolated or high risk areas;
h) the potential risk of air or water pollution;
i) leak detection systems;
j) change in operating mode (e.g. frequency of fill cycling, frequent grounding of floating roof support legs);
k) jurisdictional requirements;
l) changes in service (including changes in water bottoms);
m)the existence of a double bottom or a release prevention barrier.

6.2.2 The interval between inspections of a tank (both internal and external) should be determined by its service history unless special reasons indicate that an earlier inspection must be made. A history of the service of a given tank or a tank in similar service (preferably at the same site) should be available so that complete inspections can be scheduled with a frequency commensurate with the corrosion rate of the tank. On-stream, non-destructive methods of inspection shall be considered when establishing inspection frequencies.

6.2.3 Jurisdictional regulations, in some cases, control the frequency and interval of the inspections. These regulations may include vapor loss requirements, seal condition, leakage, proper diking, and repair procedures. Knowledge of such regulations is necessary to ensure compliance with scheduling and inspection requirements.

6.3 Inspections from the Outside of the Tank

6.3.1 Routine In-service Inspections

6.3.1.1 The external condition of the tank shall be monitored by close visual inspection from the ground on a routine basis. This inspection may be done by owner/operator personnel, and can be done by other than authorized inspectors as defined in 3.4. Personnel performing this inspection should be knowledgeable of the storage facility operations, the tank, and the characteristics of the product stored.

6.3.1.2 The interval of such inspections shall be consistent with conditions at the particular site, but shall not exceed one month.

6.3.1.3 This routine in-service inspection shall include a visual inspection of the tank's exterior surfaces. Evidence of leaks; shell distortions; signs of settlement; corrosion; and condition of the foundation, paint coatings, insulation systems, and appurtenances should be documented for follow-up action by an authorized inspector.

6.3.2 External Inspection

6.3.2.1 All tanks shall be given a visual external inspection by an authorized inspector. This inspection shall be called the external inspection and must be conducted at least every five years or $RCA/4N$ years (where RCA is the difference between the measured shell thickness and the minimum required thickness in mils, and N is the shell corrosion rate in mils per year) whichever is less. Tanks may be in operation during this inspection.

6.3.2.2 Insulated tanks need to have insulation removed only to the extent necessary to determine the condition of the exterior wall of the tank or the roof.

6.3.2.3 Tank grounding system components such as shunts or mechanical connections of cables shall be visually checked. Recommended practices dealing with the prevention of hydrocarbon ignition are covered by API 2003.

6.3.3 Ultrasonic Thickness Inspection

6.3.3.1 External, ultrasonic thickness measurements of the shell can be a means of determining a rate of uniform general corrosion while the tank is in service, and can provide an indication of the integrity of the shell. The extent of such measurements shall be determined by the owner/operator.

6.3.3.2 When used, the ultrasonic thickness measurements shall be made at intervals not to exceed the following.

a) When the corrosion rate is not known, the maximum interval shall be five years. Corrosion rates may be estimated from tanks in similar service based on thickness measurements taken at an interval not exceeding five years.
b) When the corrosion rate is known, the maximum interval shall be the smaller of $RCA/2N$ years (where RCA is the difference between the measured shell thickness and the minimum required thickness in mils, and N is the shell corrosion rate in mils per year) or 15 years.

6.3.3.3 Internal inspection of the tank shell, when the tank is out of service, can be substituted for a program of external ultrasonic thickness measurement if the internal inspection interval is equal to or less than the interval required in 6.3.3.2 b).

6.3.4 Cathodic Protection Surveys

6.3.4.1 Where exterior tank bottom corrosion is controlled by a cathodic protection system, periodic surveys of the system shall be conducted in accordance with API 651. The owner/operator shall review the survey results.

6.3.4.2 The owner/operator shall assure competency of personnel performing surveys.

6.4 Internal Inspection

6.4.1 General

6.4.1.1 Internal inspection is primarily required to do as follows.

a) Ensure that the bottom is not severely corroded and leaking.
b) Gather the data necessary for the minimum bottom and shell thickness assessments detailed in Section 6. As applicable, these data shall also take into account external ultrasonic thickness measurements made during in-service inspections (see 6.3.3).
c) Identify and evaluate any tank bottom settlement.

6.4.1.2 All tanks shall have a formal internal inspection conducted at the intervals defined by 6.4.2. The authorized inspector who is responsible for evaluation of a tank must conduct a visual inspection and assure the quality and completeness of the non-destructive examination (NDE) results. If the internal inspection is required solely for the purpose of determining the condition and integrity of the tank bottom, the internal inspection may be accomplished with the tank in-service utilizing various ultrasonic robotic thickness measurement and other on-stream inspection methods capable of assessing the thickness of the tank bottom, in combination with methods capable of assessing tank bottom integrity as described in 4.4.1. Electromagnetic methods may be used to supplement the on-stream ultrasonic inspection. If an in-service inspection is selected, the data and information collected shall be sufficient to evaluate the thickness, corrosion rate, and integrity of the tank bottom and establish the internal inspection interval, based on tank bottom thickness, corrosion rate, and integrity, utilizing the methods included in this standard. An individual, knowledgeable and experienced in relevant inspection methodologies, and the authorized inspector who is responsible for evaluation of a tank must assure the quality and completeness of the in-service NDE results.

6.4.2 Inspection Intervals

6.4.2.1 The interval from initial service until the initial internal inspection shall not exceed 10 years. Alternatively, when either a risk-based inspection (RBI) assessment per 6.4.2.4, or a similar service assessment per Annex H is performed, and the tank has one of the following leak prevention, detection, or containment safeguards, the initial internal inspection interval shall not exceed the applicable maximum interval as shown below.

Tank Safeguard	Max. Initial Interval
i) Original nominal bottom thickness 5/16 in. or greater	12 Years
ii) Cathodic protection of the soil-side of the primary tank bottom per Note 1	12 Years
iii) Thin-film lining of the product-side of the tank bottom per Note 2	12 Years
iv) Fiberglass-reinforced lining of the product-side of the tank bottom per Note 2	13 Years
v) Cathodic protection plus thin-film lining	14 Years
vi) Cathodic protection plus fiberglass-reinforced lining	15 Years
vii) Release prevention barrier per Note 3 (when similar service assessment performed)	20 Years
viii) Release prevention barrier per Note 3 (when RBI assessment performed)	25 Years

NOTE 1 For purposes of 6.4.2.1, effective cathodic protection of the soil-side of the primary tank bottom means a system installed and maintained in accordance with API 651.

NOTE 2 For purposes of 6.4.2.1, lining of the product-side of the tank bottom means a lining installed, maintained and inspected in accordance with API 652.

NOTE 3 For purposes of 6.4.2.1, a release prevention barrier means an under-bottom leak detection and containment system designed in accordance with API 650, Appendix I.

6.4.2.2 The interval between subsequent internal inspections shall be determined in accordance with either the corrosion rate procedures of 6.4.2.3 or the RBI procedures as outlined in 6.4.2.4 and shall not exceed the applicable maximum intervals as shown below.

Procedure Used	Max. Interval
i) Corrosion rate procedures in 6.4.2.3	20 Years
ii) RBI assessment per 6.4.2.4	25 Years
iii) RBI assessment per 6.4.2.4 and a release prevention barrier per Note	30 Years

NOTE: For purposes of 6.4.2.2, a release prevention barrier means an under-bottom leak detection and containment system designed in accordance with API 650, Appendix I.

6.4.2.3 An owner/operator who has obtained data on the thickness and condition of the tank bottom during an internal inspection may calculate the interval until the subsequent internal inspection using the measured tank bottom corrosion rate and the minimum remaining thickness in accordance with 4.4.7.

6.4.2.4 As an alternative to the procedures in 6.4.2.3, an owner/operator may establish the internal inspection interval using RBI procedures in accordance with this section.

RBI assessment shall be performed by an individual or team of individuals knowledgeable in the proper application of API 580 principles to aboveground storage tanks, and experienced in tank design, construction details, and reasons for tank deterioration, and shall be reviewed and approved by an authorized inspector and a storage tank engineer. The initial RBI assessment shall be re-assessed at intervals not to exceed 10 years, at the time of a premature failure, and at the time of proposed changes in service or other significant changes in conditions.

RBI assessment shall consist of a systematic evaluation of both the likelihood of failure and the associated consequence of failure, utilizing the principles of API 580. RBI assessment shall be thoroughly documented, clearly defining all factors contributing to both likelihood and consequence of tank leakage or failure.

6.4.2.4.1 Likelihood Factors

Likelihood factors that should be considered in tank RBI assessments include, but are not limited to, the following:
a) original thickness, weld type, and age of bottom plates;
b) analysis methods used to determine the product-side, soil-side and external corrosion rates for both shell and bottom and the accuracy of the methods used;
c) inspection history, including tank failure data;
d) soil resistivity;
e) type and quality of tank pad/cushion;
f) water drainage from berm area;
g) type/effectiveness of cathodic protection system and maintenance history;
h) operating temperatures;
i) effects on internal corrosion rates due to product service;
j) internal coating/lining/liner type, age and condition;
k) use of steam coils and water draw-off details;
l) quality of tank maintenance, including previous repairs and alterations;
m) design codes and standards and the details utilized in the tank construction, repair and alteration (including tank bottoms);
n) materials of construction;
o) effectiveness of inspection methods and quality of data;
p) functional failures, i.e. floating roof seals, roof drain systems, etc.;
q) settlement data.

6.4.2.4.2 Consequence Factors
Consequence factors that should be considered in tank RBI assessments include, but are not limited to, the following:
a) tank bottom with a release prevention barrier (RPB);
b) product type and volume;
c) mode of failure (i.e. slow leak to the environment, tank bottom rupture or tank shell brittle fracture);
d) identification of environmental receptors such as wetlands, surface waters, ground waters, drinking water aquifers, and bedrock;
e) distance to environmental receptors;
f) effectiveness of leak detection systems and time to detection;
g) mobility of the product in the environment, including, releases to soil, product viscosity and soil permeability;
h) sensitivity characteristics of the environmental receptors to the product;
i) cost to remediate potential contamination;
j) cost to clean tank and repair;
k) cost associated with loss of use;
l) impact on public safety and health;
m) dike containment capabilities (volume and leak tightness).

More qualitative approaches may be applicable that do not involve all of the factors listed above. In these cases, conservative assumptions must be used and conservative results should be expected. A case study may be necessary to validate the approach.

The results of the RBI assessment are to be used to establish a tank inspection strategy that defines the most appropriate inspection methods, appropriate frequency for internal, external and on-stream inspections, and prevention and mitigation steps to reduce the likelihood and consequence of tank leakage or failure.

6.4.2.5 Tank owners/operators should review the internal inspection intervals of existing tanks, as they could be modified by the requirements of this section. The following outlines the applicability of the intervals determined in

a) Tanks that have been internally inspected and whose internal inspection intervals were determined solely by corrosion-rate data per 6.4.2.3 need not be included in this review, as their internal inspection intervals remain unaffected.
b) Tanks that have never been internally inspected should be reviewed for compliance with 6.4.2.1.
c) Tanks that have been internally inspected and whose internal schedules were determined by RBI assessment should be reviewed for compliance with 6.4.2.2. If RBI assessment that complies with 6.4.2.4 determined an interval that has already exceeded the applicable maximum interval under 6.4.2.2, or will exceed it within a period of five years from the publication date of this edition of API 653, then the owner/operator may use the RBI assessment to schedule and complete the inspection, independent of the applicable maximum interval, so long as the inspection is completed within the five-year period. After the five-year period, the interval shall not exceed the applicable maximum interval under 6.4.2.2.

6.4.2.6 If RBI assessment or similar service assessment has been performed, the applicable maximum interval under 6.4.2.1 or 6.4.2.2 does not apply to a tank storing highly viscous substances which solidify at temperatures below 110 °F. Some examples of these substances are: asphalt, roofing flux, resid, vacuum bottoms and reduced crude.

6.5 Alternative to Internal Inspection to Determine Bottom Thickness
In cases where construction, size, or other aspects allow external access to the tank bottom to determine bottom thickness, an external inspection in lieu of an internal inspection is allowed to meet the data requirements of Table 4.4. However, in these cases, consideration of other maintenance items may dictate internal inspection intervals. This alternative approach shall be documented and made part of the permanent record of the tank.

6.6 Preparatory Work for Internal Inspection
Specific work procedures shall be prepared and followed when conducting inspections that will assure personnel safety

and health and prevent property damage in the workplace (see 1.4).

6.7 Inspection Checklists

Annex C provides sample checklists of items for consideration when conducting in-service and out-of-service inspections.

6.8 Records

6.8.1 General

Inspection records form the basis of a scheduled inspection/maintenance program. (It is recognized that records may not exist for older tanks, and judgments must be based on experience with tanks in similar services.) The owner/operator shall maintain a complete record file consisting of three types of records, namely: construction records, inspection history, and repair/alteration history.

6.8.2 Construction Records

Construction records may include nameplate information, drawings, specifications, construction completion report, and any results of material tests and analyses.

6.8.3 Inspection History

The inspection history includes all measurements taken, the condition of all parts inspected, and a record of all examinations and tests. A complete description of any unusual conditions with recommendations for correction of details which caused the conditions shall also be included. This file will also contain corrosion rate and inspection interval calculations.

6.8.4 Repair/Alteration History

The repair/alteration history includes all data accumulated on a tank from the time of its construction with regard to repairs, alterations, replacements, and service changes (recorded with service conditions such as stored product temperature and pressure). These records should include the results of any experiences with coatings and linings.

6.9 Reports

6.9.1 General

For each external inspection performed per 6.3.2 and each internal inspection performed per 6.4, the authorized inspector shall prepare a written report. These inspection reports along with inspector recommendations and documentation of disposition shall be maintained by the owner/operator for the life of the tank. Local jurisdictions may have additional reporting and record keeping requirements for tank inspections.

6.9.2 Report Contents

Reports shall include at a minimum the following information:

a) date(s) of inspection;
b) type of inspection (external or internal);
c) scope of inspection, including any areas that were not inspected, with reasons given (e.g. limited scope of inspection, limited physical access;
d) description of the tank (number, size, capacity, year constructed, materials of construction, service history, roof and bottom design, etc.), if available;
e) list of components inspected and conditions found (a general checklist such as found in Annex C may be used to identify the scope of the inspection) and deficiencies found;
f) inspection methods and tests used (visual, MFL, UT, etc.) and results of each inspection method or test;
g) corrosion rates of the bottom and shell;
h) settlement survey measurements and analysis (if performed);
i) recommendations per 6.9.3.1;
j) name, company, API 653 certification number and signature of the authorized inspector responsible for the

inspection;
k) drawings, photographs, NDE reports and other pertinent information shall be appended to the report.

6.9.3 Recommendations

6.9.3.1 Reports shall include recommendations for repairs and monitoring necessary to restore the integrity of the tank per this standard and/or maintain integrity until the next inspection, together with reasons for the recommendations. The recommended maximum inspection interval and basis for calculation that interval shall also be stated. Additionally, reports may include other less critical observations, suggestions and recommendations.

6.9.3.2 It is the responsibility of the owner/operator to review the inspection findings and recommendations, establish a repair scope, if needed, and determine the appropriate timing for repairs, monitoring, and/or maintenance activities. Typical timing considerations and examples of repairs are:
a) *prior to returning the tank to service*—repairs critical to the integrity of the tank (e.g. bottom or shell repairs);
b) *after the tank is returned to service*—minor repairs and maintenance activity (e.g. drainage improvement, painting, gauge repairs, grouting, etc.);
c) *at the next scheduled internal inspection*—predicted or anticipated repairs and maintenance (e.g. coating renewal, planned bottom repairs, etc.);
d) *monitor condition for continued deterioration*—(e.g. roof and/or shell plate corrosion, settlement, etc.). The owner/operator shall ensure that the disposition of all recommended repairs and monitoring is documented in writing and that reasons are given if recommended actions are delayed or deemed unnecessary.

6.10 Nondestructive Examinations (NDEs)

Personnel performing NDEs shall meet the qualifications identified in 12.1.1.2, but need not be certified in accordance with Annex D. The results of any NDE work, however, must be considered in the evaluation of the tank by an authorized inspector.

APPENDIX B

FUEL STORAGE TANK INSPECTION PLAN

LOCATION	Area	YEAR FABRICATED /INSTALLED	CAP (Litres	API 653 (Last 10 yr Initial Internal Inspection Date)	Planned Internal Inpsection Date	Planned External Inspection Date
BISHOP FALLS, Hanger	TROC	10/20/2010	10,000		2020	2016
BISHOP FALLS, M.M.	TROC	1996/96	1,300		2016	2016
BISHOP FALLS, Salvage	TROC	1996/96	4,540		2016	2016
BISHOP FALLS, Salvage	TROC	1996/96	18,000		2017	2016
BISHOP FALLS,Transp.	TROC	1988/88	2,300	1998	2016	2016
BISHOP"S FALLS, Diesel	TROC	2002	960		2016	2016
BISHOPS FALLS,Terminals	TROC	1996/96	4,540		2016	2016
BISHOPS FALLS, Terminals	TROC	1996/96	4,540		2016	2016
BLACK TICKLE	TROL	1992/92	257,000	2007	2019	2014
BLACK TICKLE	TROL	1992/92	257,000	2007	2019	2014
CARTWRIGHT	TROL	2009	46,202		2019	2014
CHARLOTTETOWN	TRON	2001	10,000		2016	2015
CHARLOTTETOWN	TRON	2008	5,005		2019	2015
CHARLOTTETOWN	TRON	1984/84	300,000	2008	2019	2015
FRANCOIS	TROC	2011	5,000		2021	2016
FRANCOIS	TROC	2011	5,000		2021	2016
GOOSE BAY, G T	TROL	1990/1991	54,552	2001	2017	2014
GOOSE BAY, G T	TROL	1990/1991	54,552	2001	2017	2014
GOOSE BAY, G T	TROL	1990/1991	54,552	2001	2017	2014
GOOSE BAY, G T	TROL	1990/1991	37,900	2001	2017	2014
GOOSE BAY, G T	TROL	1990/1991	2,293	2001	2017	2014
GOOSE BAY, NORTH PLANT	TROL	2001/01	264	2011	2015	2014
GOOSE BAY, NORTH PLANT	TROL	1996	45,400		2016	2014
GOOSE BAY, NORTH PLANT	TROL	1996	45,400		2016	2014
GOOSE BAY, NORTH PLANT	TROL	1996	4,540		2016	2014
GOOSE BAY, NORTH PLANT	TROL	2001/01	946	2011	2016	2014
GOOSE BAY, NORTH PLANT	TROL	2001/01	946	2011	2016	2014
GOOSE BAY, NORTH PLANT	TROL	2001/01	946	2011	2016	2014
GOOSE BAY, NORTH PLANT	TROL	2008	30,363		2018	2014
GOOSE BAY, NORTH PLANT	TROL	2001/01	5,000	2011	2018	2014
GREY RIVER	TROC	1990/90	22,730	2009	2019	2016
GREY RIVER	TROC	1990/90	22,730	2009	2019	2016
HARDWOODS GT	TROC	2004	454		2015	2016
HARDWOODS GT	TROC	1976/97	2,273,000	1997	2015	2016
HAWKES BAY	TRON	1974/96	23,730		2016	2015
HAWKES BAY	TRON	1996/96	23,730		2016	2015
HOPEDALE	TROL	2005/05	22,700	2015	2016	2014

LOCATION	Area	YEAR FABRICATED /INSTALLED	CAP (Litres	API 653 (Last 10 yr Initial Internal Inspection Date)	Planned Internal Inpsection Date	Planned External Inspection Date
L'ANSE au LOUP	TRON	1999/05	22,730		2015	2015
L'ANSE au LOUP	TRON	2003/04	22,700		2018	2015
LITTLE BAY ISLANDS	TROC	1990/90	22,730		2015	2016
LITTLE BAY ISLANDS	TROC	1995/95	4,546		2015	2016
MAKKOVIK	TROL	1982/90	68,190	2006	2017	2014
MAKKOVIK	TROL	1982/90	68,190	2006	2017	2014
MAKKOVIK	TROL	1970/90	45,460	2006	2017	2014
MAKKOVIK	TROL	1990/90	314,000	2006	2018	2014
MAKKOVIK	TROL	1990/90	314,000	2006	2018	2014
MAKKOVIK	TROL	1990/90	314,000	2006	2018	2014
MARY'S HARBOUR	TRON	2009	5,011		2019	2015
MARY'S HARBOUR	TRON	1990/90	314,000	2012	2024	2015
MARY'S HARBOUR	TRON	1990/90	314,000	2012	2024	2015
McCALLUM	TROC	1998/98	90,800		2015	2016
MUD LAKE	TROL	1997/98	2,270		2016	2014
MUD LAKE	TROL	1997/99	2,270		2016	2014
NAIN	TROL	2001/01	45,400		2016	2014
NAIN	TROL	1974/74	144,140	2002	2016	2014
NAIN	TROL	1974/74	144,140	2002	2016	2014
NAIN	TROL	1974/74	144,140	2002	2016	2014
NAIN	TROL	1987/87	600,000	2006	2016	2014
NORMAN BAY	TRON	2007	32,400		2017	2015
NORMAN BAY	TRON	2007	32,400		2017	2015
NORMAN BAY	TRON	2011	20,000		2021	2015
PARADISE RIVER	TROL	2005/2005	45,400		2016	2014
PETITES	TROC	1993/97	22,730		2015	2016
PORT HOPE SIMPSON	TRON	1975/75	22,730		2015	2015
PORT HOPE SIMPSON	TRON	1995/95	22,730		2015	2015
PORT HOPE SIMPSON	TRON	2010	5,000		2020	2015
PORT SAUNDERS	TRON	1997/97	4,540		2015	2015
PORT SAUNDERS	TRON	1997/00	2,270		2015	2015
Postville	TROL	2011	319,000		2021	2014
Postville	TROL	2011	319,000		2021	2014
RAMEA	TROC	2006	9,000		2017	2016
RAMEA	TROC	1994/94	45,460		Replaced 2014	2016
RIGOLET	TROL	1997/97	45,400	2007	2018	2014

LOCATION	Area	YEAR FABRICATED /INSTALLED	CAP (Litres	API 653 (Last 10 yr Initial Internal Inspection Date)	Planned Internal Inpsection Date	Planned External Inspection Date
RIGOLET	TROL	1997/97	45,400	2007	2018	2014
RIGOLET	TROL	1998/2000	22,730	2007	2018	2014
RIGOLET	TROL	1995/95	90,920	2008	2018	2014
RIGOLET	TROL	1983/95	90,900	2008	2018	2014
RIGOLET	TROL	1985/85	300,000	2007	2018	2014
ST. ANTHONY	TRON	1973/73	22,730		2014	2015
ST. ANTHONY	TRON	1992/92	22,730		2014	2015
ST. ANTHONY	TRON	1992/92	22,730		2014	2015
ST. ANTHONY	TRON	2007	1,900		2017	2015
ST. BRENDAN'S	TROC	1981/2000	68,190	2000	2017	2016
ST. BRENDAN'S	TROC	2010	1,136		2020	2016
ST. LEWIS	TRON	2011	5,011		2021	2015
ST. LEWIS	TRON	2012	45,000		2022	2015
ST. LEWIS	TRON	2012	45,000		2022	2015
STEPHENVILLE DEPOT	TROC	1997/97	4,540		2015	2016
STEPHENVILLE DEPOT	TROC	1999/99	2,273		2015	2016
STEPHENVILLE GT	TROC	2005	329		2014	2016
STEPHENVILLE GT	TROC	1975/2000	501,000	2000	2014	2016
STEPHENVILLE GT	TROC	1975/2000	501,000	2000	2014	2016
STEPHENVILLE GT	TROC	1975/2000	501,000	2000	2014	2016
WHITBOURNE	TROC	1999/99	4,560		2015	2016
WHITBOURNE	TROC	1999/99	4,560		2015	2016
WILLIAMS HARBOUR	TRON	2007/07	40,391		2017	2015
WILLIAMS HARBOUR	TRON	2007/07	40,391		2017	2015
WILLIAMS HARBOUR	TRON	2007/07	40,391		2017	2015

TROC = Transmission and Rural Operations, Central Region
TRON = Transmission and Rural Operations, Northern Region
TROL = Transmission and Rural Operations, Labrador Region

APPENDIX C

API STANDARD 653 – AUTHORIZED INSPECTOR CERTIFICATE (ANNEX D)

Annex D
Authorized Inspector Certification

D.1 Examination
A written examination to certify an authorized inspector within the scope of API 653 shall be administered by a third party designated by API. The examination shall be based on the current API 653 body of knowledge as published by API.

D.2 Certification
D.2.1 An API 653 authorized inspector certificate will be issued when an applicant has successfully passed the API 653 certification examination, and satisfies the criteria for education and experience. Education and experience, when combined, shall be equal to at least one of the following.

a) A bachelor of science degree in engineering or technology plus one year of experience in supervision or performance of inspection activities as described in API 653.
b) A two-year degree or certificate in engineering or technology, plus two years of experience in the design, construction, repair, inspection, or operation of aboveground storage tanks, of which one year must be in supervision or performance of inspection activities as described in API 653.
c) A high school diploma or equivalent, plus three years of experience in the design, construction, repair, inspection, or operation of aboveground storage tanks, of which one year must be in supervision or performance of inspection activities as described in API 653.
d) A minimum of five years of experience in the design, construction, repair, inspection, or operation of aboveground storage tanks, of which one year must be in supervision or performance of inspection activities as described in API 653.

D.2.2 An API certificate for an authorized inspector is valid for three years from its date of issuance.

D.2.3 An API 653 authorized inspector certificate is valid in all jurisdictions and any other location that accepts or other wise does not prohibit the use of API 653.

D.3 Certification Agency
API shall be the certifying agency.

D.4 Retroactivity
The certification requirements of API 653 shall not be retroactive or interpreted as applying before 12 months after the date of publication of this edition or addendum of API 653. The recertification requirements of D.5 shall not be retroactive or interpreted as applying before three years after the date of publication of this edition or addendum of API 653.

D.5 Recertification
D.5.1 Recertification is required three years from the date of issuance of the API 653 authorized inspector certificate. Recertification by written examination will be required for authorized inspectors who have not been actively engaged as authorized inspectors within the most recent three-year certification period. Recertification exams will be in accordance with all of the provisions contained in API 653.

D.5.2 Actively engaged as an authorized inspector shall be defined as one of the following provisions:
a) a minimum of 20 % of the time spent performing inspection activities, or supervision of inspection activities, or engineering support of inspection activities as described in API 653 over the most recent three-year certification period;
b) performance of inspection activities or supervision of inspection activities or engineering support of inspection

activities on 75 aboveground storage tanks as described in API 653 over the most recent three-year certification period

NOTE: Inspection activities common to other API inspection documents (NDE, record keeping, review of welding documents, etc.) may be considered here.

D.5.3 Once every other recertification period (every six years), inspectors actively engaged as an authorized inspector shall demonstrate knowledge of revisions to API 653 that were instituted during the previous six years. This requirement shall be effective six years from the inspector's initial certification date. Inspectors who have not been actively engaged as an authorized inspector within the most recent three-year period shall recertify as required in D.5.1.

Project Title: Upgrade Ventilation System

Location: Ramea

Category: Transmission and Rural Operations - Generation

Type: Other

Classification: Normal

Project Description:

This project involves upgrading the ventilation system in the diesel plant located in Ramea. The scope of the project includes:

- Installation of two new corrosion resistant direct-drive roof exhausters;
- Replacement of the existing louvers on the south and west walls;
- Replacement of the window on the west wall of the engine hall with a supply louver;
- Closure of one supply louver on the east/back wall relative to the generator sets and one supply louver on the second story of the south wall to improve ventilation airflow routing;
- Addition of a window air conditioning unit in the kitchen;
- Removal of the existing exhaust and supply fans and seal the roof and wall openings;
- Installation of insulation blankets on the exhaust piping and mufflers; and
- Installation of generator mounted crankcase breather filters to remove oil from the building atmosphere.

The budget estimate for the project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	47.3	0.0	0.0	47.3
Labour	62.0	0.0	0.0	62.0
Consultant	33.8	0.0	0.0	33.8
Contract Work	54.0	0.0	0.0	54.0
Other Direct Costs	11.9	0.0	0.0	11.9
Interest and Escalation	14.0	0.0	0.0	14.0
Contingency	40.0	0.0	0.0	40.0
TOTAL	**263.0**	**0.0**	**0.0**	**263.0**

The budget estimate is higher than the capital cost estimate provided in the Hatch report (see Appendix A, Table 7-2). The Hatch report is a high level estimate that allows small margins for design costs and labor estimates that are based on a conservative percentage of materials cost (25%). Considering Hydro's experience in recent years in receiving higher than expected tender submissions, and the isolated location of the work site, the estimate provided in Table 1 is more accurate.

Justification:

In 2012, Hatch, an engineering consulting company, was engaged to develop remediation options and class five estimates for deficiencies at various remote diesel locations owned by Hydro. Ramea was identified by Hydro as having ventilation concerns because the diesel plant was too warm. On April 12, 2013 Hatch issued their final report, *Diesel Plant Remediation Phase 2* (see *Appendix A* for the report section outlining the recommendations for Ramea).

The modifications recommended by Hatch will decrease the heat rejected back into the building by adding insulation to the exhaust piping on the diesel generator. The current exhaust fans are proposed to be replaced by higher capacity fans along with a reconfiguration of the intake and exhaust louvers in the facility. The result of these changes will be adequate ventilation and improved air flow to ensure no more than a 10°C temperature rise in the building, which meets the diesel generator's manufacturers suggested temperature rise of between 8.5°C and 12.5°C. The final recommendation to reduce the buildup of heat in the diesel plant is to install a window air conditioner unit in the second level kitchen to allow for cooling on this level during the warmest periods of the year regardless of the operation of the diesel generators.

Another recommendation from Hatch is to add generator mounted crankcase breather filters to improve the air quality in the generator hall. These filters will capture any blow-by, which occurs when some of the gasses from the combustion process leak past the piston ring and end up in the crankcase.

This project is required to ensure reliable operation of the diesel generators in Ramea. Leaving the system as it is will increase the risk of damaging the diesel generators, potentially leading to a generator shutdown or a forced de-rating of the diesel generator's output to control the high temperatures in the facility.

Existing System:

The diesel plant in Ramea is located on the Northwest Island off the southwest coast of Newfoundland. The facility's engine hall contains three 925 kW diesel generators that serve the community of Ramea. The engine hall ventilation system consists of two roof-mounted exhaust fans, EF1 and EF2, two wall-mounted fan-forced supply louvers, LV1 and LV2, and three passive-ventilation wall louvers, LV3 – LV5, as illustrated in Figure 1.

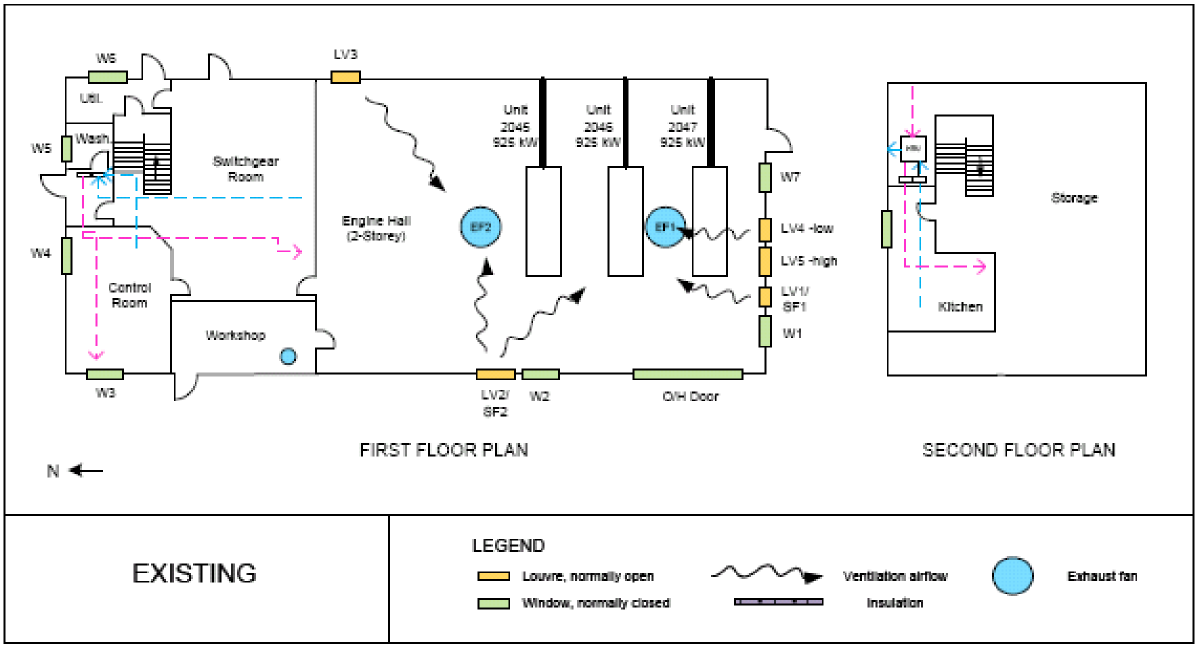

Figure 1: Ramea – Existing Ventilation System

The existing system was designed to utilize the supply fans and supply louvers to provide ventilation and combustion air to the diesel generators. The heat rejected from the diesel generators and auxiliary equipment would then be removed from the diesel building through the roof exhaust fans. In 2011 the system was identified as not working properly and when assessed, it was determined that it needed replacement. Currently, the system is not in service and Hydro is relying on the passive systems and the use of windows and the overhead door while staff is on site.

There has been no major work and/or upgrade to this system.

Operating Experience:

There is no relevant data to provide regarding: Outage Statistics, Legislative or Regulatory Requirements, Safety Performance, Environmental Performance, Maintenance History, and Historical Information.

The current ventilation system is not in operation which is putting the facility at risk for a decreased in performance and possibly a de-rating on the units in Ramea. The status quo in this situation is not acceptable as the system is required for normal operation of the diesel plant.

A properly functioning diesel generator building ventilation system ensures there are sufficient amounts of cooling air and combustion air. Cooling air is necessary to remove the heat rejected from the generator, engine, and auxiliary components. The combustion air is required for the engine to burn the diesel fuel. A malfunctioning ventilation system can result in the following problems:

- High temperatures around the generator can lead to poor performance, overheating and subsequent shutdown, as well as a decrease in service life;
- There can be issues with other equipment in the building that may be sensitive to high or low temperatures; and
- It produces an uncomfortable work environment for personnel to work in.

Reliability Performance

There are no outage statistics concerning the ventilation system in Ramea as the diesel generators continue to operate at the present time. However the reliability of the system is part of the justification as the system is not operational.

Vendor Recommendations

The recommendation from Caterpillar in terms of the ventilation is to limit engine room enclosure temperature rise when the diesel generators are in operation to be not more than 8.5°C – 12.5°C. This is noted in the *Caterpillar Application and Installation Guide: Engine Room Ventilation* on page 4 (see Appendix B for the applicable section).

Maintenance or Support Arrangements

All equipment associated with this project is maintained by plant personnel and contractors.

Anticipated Useful Life

The anticipated useful life of a new ventilation system would be approximately 15 years.

Development of Alternatives

When Hatch was engaged to develop remediation options with order of magnitude estimates for deficiencies at various remote diesel locations owned by Hydro they were asked to assess the ventilation system at Ramea. Hatch looked at three options:

- Do nothing - keep the status quo;
- Perform basic improvements to get the system back on-line; and
- A complete redesign and modification of the ventilation system.

Option 1 was immediately rejected as the status quo of not acceptable. Option 3 was not feasible as there would be a need to do significant modifications to the diesel building to incorporate the redesign and modifications to the ventilation system. Therefore option 2 was the option pursued for this estimate. Option 2 will ensure a temperature rise of approximately 10°C which is within the manufacturer's recommendations. The scope of the work is contained in the project description section of this proposal and the reworked layout is below in Figure 2.

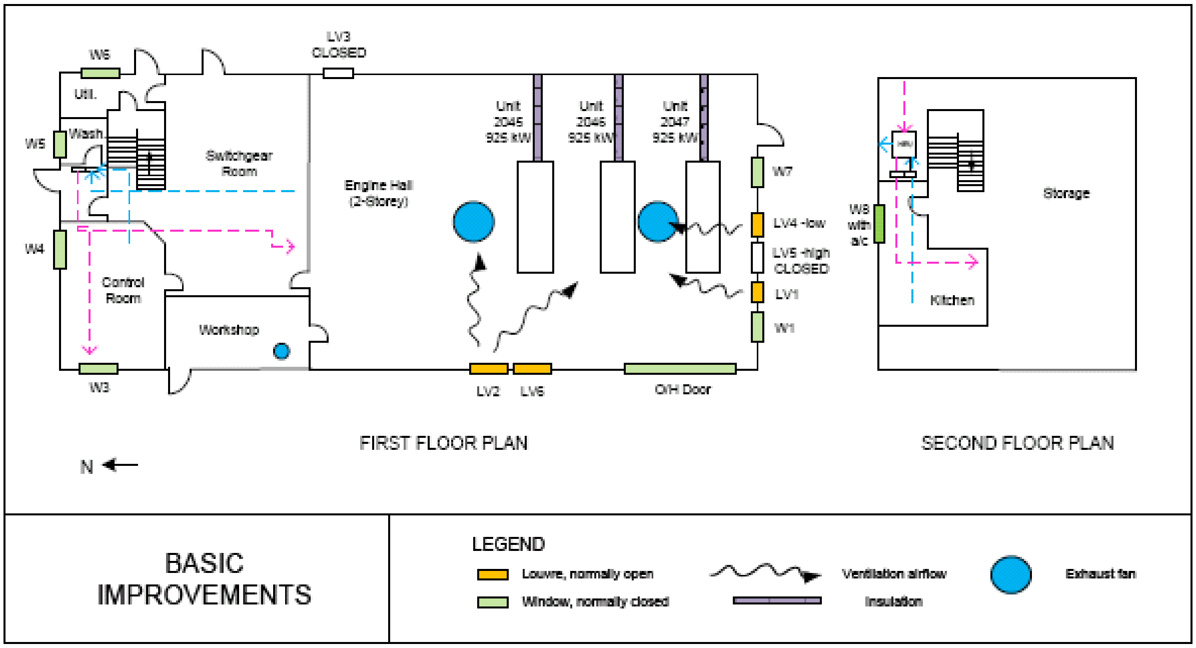

Figure 2: Proposed Basic Improvements to the Ventilation System - Ramea

Conclusion:

This project is justified to ensure reliable operation of the diesel generators in Ramea. Leaving the system as is will increase the risk of damaging the diesel generators and potentially leading to a generator shutdown or a forced de-rating of the diesel generator to control the temperature in the facility. The option chosen to mitigate the high temperatures at Ramea considered all areas of the facility. There is a proposed change to the ventilation system that will ensure the system is properly sized, to provide additional insulation and filters to add to the diesels to minimize heat rejected and fumes that leak back into the diesel building, and finally, to add an air conditioner in the kitchen so employees can have a cool area for relief during the warmest periods of the year. Since the forced de-rating or shutdown of these diesel units could cause a loss of power to the community, this project is required.

Project Schedule:

The anticipated project schedule is shown in table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Open project, review schedule Consultant contracts and purchase order required	March 2014	March 2014
Design	Site visit with consultant Design package	April 2014	May 2014
Procurement	Order equipment	May 2014	May 2014
Construction	Remove old ventilation equipment Install new ventilation equipment Install filters and insulation on diesels Install ladder	August 2014	September 2014
Commissioning	Commission ventilation system	September 2014	September 2014
Closeout	Project close-out	October 2014	October 2014

APPENDIX A

HATCH REPORT

DIESEL PLANT REMEDIATION PHASE 2 - RAMEA

7. Ramea

The Ramea plant is located in and serves the community of Ramea, on the Northwest Island off the south east coast of Newfoundland. Similar to Charlottetown, the ventilation system at the plant was selected for remediation by NL Hydro because the plant is too warm.

7.1 Existing Conditions

Ramea's generator building consists of a 2-storey engine hall containing three gensets which is adjacent to a downstairs workshop, switchgear room, washroom and control room with a kitchen and storage area above. There is a heat recovery unit (HRU) with supply and return air ducting serving these two levels of rooms adjacent to the engine hall. The exhaust and supply louvre for the HRU has motorized dampers. There is also an exhaust fan dedicated to the workshop.

There is no insulation on the genset turbochargers, engine exhaust manifolds or exhaust ducting and mufflers. The engine hall ventilation system consists of 2 roof-mounted exhaust fans, 2 wall-mounted fan-forced supply louvres and 3 additional passive-ventilation wall louvres. The ventilation equipment is summarized in Table 7-1 below. Equipment locations are shown in the building drawings in Appendix A.

Table 7-1: Ramea Equipment

Diesel Gensets						
Unit #	Model #	Gen. (kW)	Exh. Dia. (m)	Exh. Mat.	Exh. Ht. (m)	
2045	Cat. 3512	925	0.254	S.S.	12.00	
2046	Cat. 3512	925	0.254	S.S.	12.00	
2047	Cat. 3512	925	0.254	S.S.	12.00	
Exhaust Fans						
ID	Make	Model	Cat #	Power (hp)	SP (" w.g.)	Q (Am^3/hr)
EF1	unknown -assumed capacity of intake fans and louvres				0.125	43,435
EF2	unknown -assumed capacity of intake fans and louvres				0.125	43,435
Supply Fans						
ID	Make	Model	Cat #	Power (hp)	SP (" w.g.)	Q (Am^3/hr)
SF1	Penn Ventilator	Breezeway	BF30	1	0.125	16,143
SF2	Penn Ventilator	Breezeway	BF30	1	0.125	16,143
Louvres						
ID	Location	Length (m)	Width (m)	Free (%)	Free (m^2)	
LV1	South side -for supply fan 1	1.22	1.22	60	0.9	
LV2	West side -for supply fan 2	1.22	1.22	60	0.9	
LV3	East side	0.91	0.91	60	0.5	
LV4	South side -low	1.22	1.22	60	0.9	
LV5	South side -high	0.91	0.91	60	0.5	

Historical weather data most representative of the Ramea location was obtained from Environment Canada's Port aux Basques station. The mean daily maximum temperature in August is 18°C (considered to be summer maximum) while the mean daily minimum temperature in February is -10°C (considered to be winter minimum). Winds are most frequently from the east at an average speed of 24.4 km/h. Exposure to the harsh climate and high levels of salt in the air has been the main cause of ventilation system equipment failure at this plant.

There was no Phase I site visit conducted at Ramea due to its remote location. An assessment of the ventilation system was completed using data from NL Hydro. A schematic of the current ventilation system is shown below.

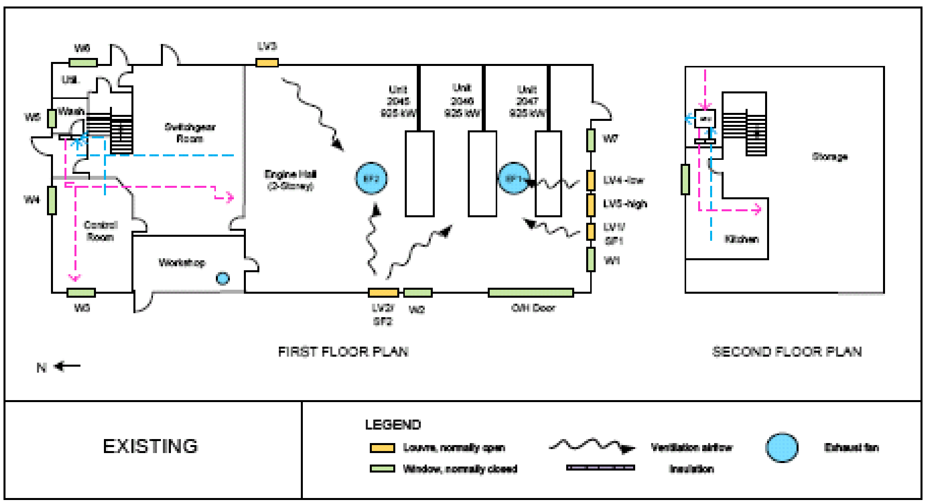

Figure 7-1: Ramea – Existing Ventilation System

Heat rejection from all 3 generator sets running on full load is 718 kW without insulating the exhaust piping/mufflers. This equates to a maximum ventilation requirement of 237,864 Am^3/h (224,742 Am^3/h cooling airflow and 13,122 Am^3/h combustion airflow) to achieve a temperature rise of no more than 10°C.

The capacity of the existing roof exhausters, at 86,869 Am^3/hr, is significantly below the current ventilation requirement. When all gensets are at full load and both roof exhausters are operating at design, the resulting maximum temperature rise would be 26°C, which is intolerable.

Additionally, air flow in the engine hall is routed from all around the generators, not in a "sweeping" motion across the units which results in unnecessary movement of air through areas where heat is not generated and inadequate movement of air across the gensets where it is needed.

7.2 Generator Building Ventilation Considerations

Refer to Section 3.2.

7.3 Remediation Options

Three tiers of options have been investigated with varying degrees of performance and cost impacts. They range from the minimum requirements to basic improvements to complete redesign and system modifications. Details of each option are presented below.

7.3.1 Minimum Requirements

The minimum requirements for the Ramea plant would include:

- decommissioning of the supply fans;
- repairing the remaining existing system components; and
- restricting generator operation during warm ambient periods.

A schematic of this option is as per the existing system depicted in Figure 7-1.

Even with repairs to make the existing ventilation system operable, it would not meet the airflow requirements for the installed generators. Therefore, this option would only be feasible if generator operation was reduced.

Heat rejection from two generator sets running on full load is 493 kW without insulating the exhaust piping. This equates to a maximum ventilation requirement of 158,576 Am^3/h (149,828 Am^3/h cooling airflow and 8,748 Am^3/h combustion airflow) to achieve a temperature rise of no more than 10°C.

Reducing operation further to one generator set running on full load decreases heat rejection to 239 kW which corresponds to 79,288 Am^3/h (74,914 Am^3/h cooling airflow and 4,374 Am^3/h combustion airflow).

The capacity of the existing roof exhausters would meet the current ventilation requirement only if generator operation was restricted to one unit on.

It is not viable to restrict generator operation to meet ventilation requirements. Therefore improvements to the system, rather than repairs are necessary at Ramea.

7.3.2 Basic Improvements

Basic improvements for the Ramea plant would include:

- installation of 2 new 'corrosion resistant', direct-drive roof exhausters;
- closure of 1 supply louvre on the east/back wall relative to the generator sets (LV3) and 1 supply louvre on the second storey of the south wall (LV5) to improve ventilation airflow routing;
- replacement in-kind of the remaining existing louvres on the south and west walls (LV1, LV2 and LV4), assuming they are beyond repair;

- replacement of the window on the west wall of the engine hall (W2) with a supply louvre (LV6);
- installation of insulation blankets on the exhaust piping and mufflers;
- installation of generator mounted crankcase breather filters to remove oil from the building atmosphere;
- addition of a window air conditioning unit in the kitchen; and
- decommission the existing exhaust and supply fans and seal the roof and wall openings.

A schematic of this option is shown below:

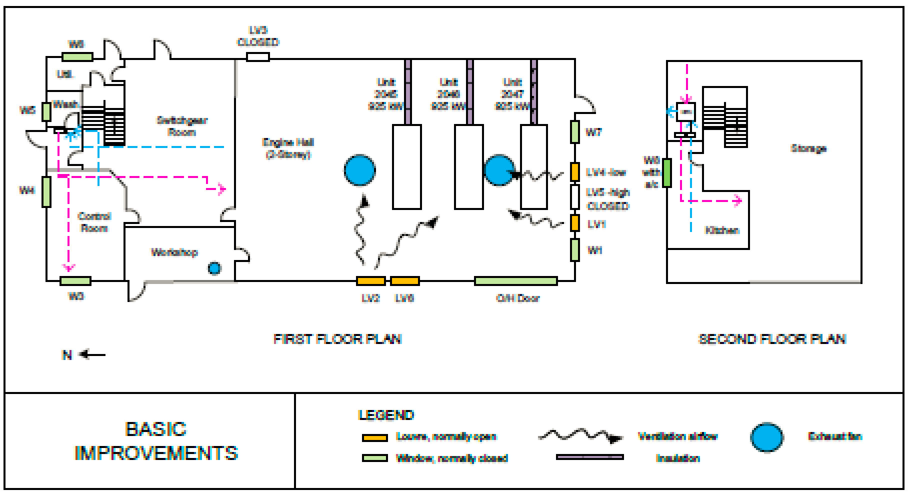

Figure 7-2: Ramea – Basic Improvements Schematic

In this scenario, heat rejection from all 3 generator sets running on full load is 355 kW with insulation on exhaust piping and mufflers, which is a 51% reduction of the heat rejection rate to the building from the existing scenario. This equates to a maximum ventilation requirement of 124,255 Am^3/h (111,133 Am^3/h cooling airflow and 13,122 Am^3/h combustion airflow).

The reduced ventilation rate could be achieved with 2 new direct-drive exhaust fans, each rated for 65,000 Am^3/h installed in the locations of the current roof exhausters. Fans suitable for the harsh climate will be constructed from either stainless steel or FRP. It is also recommended that the fans be direct-driven than belt-driven to decrease maintenance requirements. A ladder added to the exterior of the plant (similar to that at Charlottetown) would allow access to the fans for regular inspection and maintenance.

This solution would provide adequate ventilation to ensure no more than a 10°C temperature rise in the generator building. Air flow will improve as it will generally "sweep" from the front to rear of the generator sets, although replacement of the west side window (W2) with a supply louvre is required to allow sufficient inlet velocities and building static pressure. Supply velocity to the building will be approximately 8 m/s which correspond to a static pressure of 0.25" w.g.

This option includes generator-mounted crankcase ventilation filters to improve air quality in the generator hall. It is important that these filters are replaced as required to maintain the benefits of their use.

An additional window air conditioner unit installed in the second level kitchen will allow for spot cooling on this level for relief in the warmest periods, regardless of operation of the generators and ventilation system.

No changes will be made to HRU and associated ducting.

The total capital cost for basic improvements is estimated at $120,000, as detailed below:

Table 7-2: Ramea – Order of Magnitude (+/- 30%) Capital Cost Estimate – Basic Improvements

DESCRIPTION	QTY.	UNIT	MATERIAL (CAD/UNIT)	MATERIAL COST (CAD)	LABOUR (25% of Estimate) COST (CAD)	TOTAL (CAD)
Mechanical Equipment						
65,000 Am^3/h direct drive fan	2	unit	10,920	21,840	5,460	27,300
Exhuast piping insulating blanket	3	unit	1,821	5,464	1,366	6,831
Louvre	3.57	m^2	400	1,427	357	1,784
Intake Hood	4	unit	500	2,000	500	2,500
Intake Screen	4	unit	500	2,000	500	2,500
Damper	2	unit	1,000	2,000	500	2,500
Actuator	2	unit	1,000	2,000	500	2,500
Crankcase ventilation generator-mounted filter	3	unit	500	1,500	375	1,875
Exterior roof access ladder	1	unit	500	500	125	625
Air conditioner for kitchen	1	unit	1,200	1,200	300	1,500
Mechanical Total						**49,915**
Based on 35% of Mechanical Total for Civil/Structural						17,470
Civil/Structural Total						**17,470**
Based on 10% of Mechanical Total for Electrical Equipment						4,991
Electrical Total						**4,991**
Based on 10% of Mechanical Total for Instrumentation						4,991
Instrumentation Total						**4,991**
DIRECT COST TOTAL						**77,368**
INDIRECT COST						
Based on 20% of Direct Cost for Engineering, Procurement and Construction Management						15,000
Based on 5% of Direct Cost for other Indirects including spares and freight						4,000
INDIRECT COST TOTAL						**19,000**
			ESTIMATED TOTAL			**100,000**
			Contingency (20% of Estimate)			**20,000**
			TOTAL CAPITAL COST (+/- 30%)			**120,000**

7.3.3 *Redesign and System Modifications*

A complete redesign and modification of the ventilation system to optimize performance would include the following:

- installation of 3 new 'corrosion resistant', direct-drive roof exhausters in new locations in the engine hall;
- closure of 1 supply louvre on the east/back wall relative to the generator sets (LV3) and 2 supply louvres on the south wall (LV1 and LV5) to improve ventilation airflow routing;
- replacement of 1 existing louvre on the south wall (LV4) and 1 existing louvre on the west wall (LV2) with larger ones (equivalent to 1.2m x 2.4m each);
- installation of insulation blankets on the exhaust piping and mufflers;
- installation of insulation on the engine exhaust manifolds;
- installation of insulation on the wall between the engine hall and the 2nd-storey kitchen and storage rooms;
- installation of a 3 (1 for each generator) wall-mounted crankcase mist eliminators to remove oil from the building atmosphere;
- addition of a window air conditioning unit in the kitchen; and
- sealing of the existing exhaust and supply fan and 2 window roof and wall opening.

A schematic of this option is shown below:

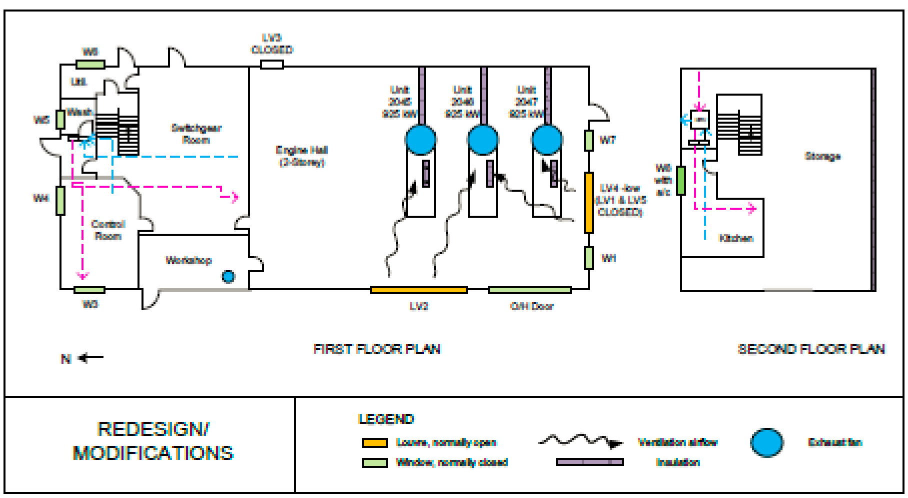

Figure 7-3: Ramea – Redesign/Modification Schematic

Heat rejection from all 3 generator sets running on full load, is 341 kW with insulation on exhaust piping/mufflers and manifolds which is a 53% reduction of the heat rejection rate from the existing scenario. This equates to a maximum ventilation requirement of 119,845 Am^3/h (106,723 Am^3/h cooling airflow and 13,122 Am^3/h combustion airflow).

The reduced ventilation rate could be achieved with 3 new direct-drive exhaust fans, each rated for 40,000 Am^3/h installed in new locations dedicated to and directly above the back end of each generator set. Fans suitable for the harsh climate will be constructed from either stainless steel or FRP. It is also recommended that the fans be direct-driven rather than belt-driven to decrease maintenance requirements. A ladder added to the exterior of the plant (similar to that at Charlottetown) would allow access to the fans for regular inspection and maintenance.

This solution would provide adequate ventilation to ensure no more than a 10°C temperature rise in the generator building. Air flow will improve as it will better flow in a "sweeping" motion from the front to rear of the generator sets where there is a dedicated outlet point for each generator. A dedicated inlet louvre cannot be supplied for the southernmost generator (unit #2047) as it is directly in front of an overhead door and a louvre above this would be too high to be effective. Increasing the size of the inlet louvres on either side of the main doors however, allows the airflow path to cross this unit while maintaining reasonable inlet velocities and building static pressure. Supply velocity to the building will be approximately 8 m/s which correspond to a static pressure of 0.23" w.g.

This option includes wall-mounted crankcase mist eliminators for each generator. These units require less maintenance than generator-mounted filters but are more costly.

An additional window air conditioner unit installed in the second level kitchen will allow for spot cooling on this level for relief in the warmest periods, regardless of operation of the generators and ventilation system.

No changes will be made to HRU and associated ducting. However, insulating the 2nd storey interior wall shields this area from the warm, rising air in the engine hall allowing it to cool more effectively during warm periods.

The total capital cost for redesign/modifications is estimated at $170,000, as detailed below:

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Table 7-3: Ramea – Order of Magnitude (+/- 30%) Capital Cost Estimate – Redesign/Modifications

DESCRIPTION	QTY.	UNIT	MATERIAL (CAD/UNIT)	MATERIAL COST (CAD)	LABOUR (25% of Estimate) COST (CAD)	TOTAL (CAD)
Mechanical Equipment						
40,000 Am3/h direct drive fan	3	unit	6,720	20,160	5,040	25,200
Exhuast piping insulating blanket	3	unit	1,822	5,465	1,366	6,831
Exhaust manifold insulating blanket	3	unit	300	900	225	1,125
Louvre	3.57	m^2	400	1,428	357	1,785
Intake Hood	2	unit	1,000	2,000	500	2,500
Intake Screen	2	unit	1,000	2,000	500	2,500
Damper	3	unit	1,000	3,000	750	3,750
Actuator	3	unit	1,000	3,000	750	3,750
Wall Insulation	40	m^2	10	400	100	500
Crankcase ventilation wall-mounted filter	3	unit	6,000	18,000	4,500	22,500
Exterior roof access ladder	1	unit	500	500	125	625
Air conditioner for kitchen	1	unit	1,200	1,200	300	1,500
Mechanical Total						72,566
Based on 35% of Mechanical Total for Civil/Structural						25,398
Civil/Structural Total						25,398
Based on 10% of Mechanical Total for Electrical Equipment						7,257
Electrical Total						7,257
Based on 10% of Mechanical Total for Instrumentation						7,257
Instrumentation Total						7,257
DIRECT COST TOTAL						112,477
INDIRECT COST						
Based on 20% of Direct Cost for Engineering, Procurement and Construction Management						22,000
Based on 5% of Direct Cost for other Indirects including spares and freight						6,000
INDIRECT COST TOTAL						28,000
			ESTIMATED TOTAL			140,000
			Contingency (20% of Estimate)			30,000
			TOTAL CAPITAL COST (+/- 30%)			170,000

APPENDIX B

CATERPILLAR APPLICATION AND INSTALLATION GUIDE: ENGINE ROOM VENTILATION

Engine Room Enclosure Temperature
The primary reason for maintaining engine room temperature at an appropriate level is to protect various components from excessive temperatures. Items that require cool air are:

- Electrical and electronic components.
- Cool air to the air cleaner inlet.
- Cool air to the torsional vibration damper.
- Habitable temperatures for the engine operator or service personnel.
- Cooling air for the generator or other driven equipment.

For electrical and electronic components, the surface temperature should not exceed 90° C (194° F) unless otherwise specified in the component EDS sheet. This is especially important, since many electronic components are placed in high temperature areas of the engine and can be shielded from the direct airflow provided by the engine room ventilation system.

A properly designed engine room ventilation system will maintain engine room air temperatures within 8.5 to 12.5°C (15 to 22.5°F) above the ambient air temperature. For example, if the engine room temperature is 24°C (75°F) without the engine running, the ventilation system should maintain the room temperature between 32.5°C (90°F) and 36.5°C (97.5°F) while the engine is in operation.

Caterpillar recommends a ventilation design that ensures engine room temperature should not exceed 50°C (122°F). If the engine room temperature cannot be maintained below 50°C (122°F), outside air should be ducted directly to the engine air cleaners.

Temperature limits of the driven equipment must also be considered. If the engine room temperature exceeds 40°C (104°F), the generator must be derated per the generator derate schedule and cool outside air must be ducted directly to the generator air intake. Alternatively, custom generators can be sized to handle specific ambient conditions.

In larger multiple engine sites, the normal 8.5 to 12.5°C (15 to 22.5°F) temperature rise guidelines for engine rooms may require unobtainable or uncomfortable air velocities. For these larger sites, a ventilation system needs to give priority to the five items listed above and provides a bottom to top airflow similar to that shown in **Figure 8** and **Figure 9.** In all cases, engine room/enclosure design must ensure that air temperature around the engine will not exceed 50° C (122° F). Critical locations include the engine torsional damper and generator coupling. Air temperature reading should be taken no more than 6 inches away from these components. Note that in these extreme situations, it may be necessary to duct cool air directly to these critical components.

Project Title: Replace Fuel Storage Tank

Location: Ramea

Category: Transmission and Rural Operations - Generation

Type: Other

Classification: Mandatory

Project Description:

This project involves the purchase and installation of two new 30,000 litre, double wall, vacuum sealed, horizontal fuel storage tanks, to replace the existing 45,460 litre, self-dyked, horizontal fuel tank. Work will include the supply and installation of the new fuel tanks and modifications to the fuel header system to accommodate the new tanks. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	74.7	0.0	0.0	74.7
Labour	60.5	0.0	0.0	60.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	35.1	0.0	0.0	35.1
Other Direct Costs	13.5	0.0	0.0	13.5
Interest and Escalation	13.6	0.0	0.0	13.6
Contingency	36.8	0.0	0.0	36.8
TOTAL	**234.2**	**0.0**	**0.0**	**234.2**

Justification:

The existing fuel storage tank was installed in 1994. The tank has deteriorated with age due, in large part, to its proximity to a corrosive marine environment. During the completion of a daily tank inspection on October 28, 2011, it was noted that the tank's dyke drain and drain valve had completely rusted through (see Figures 1 and 2).


Figure 1: Corroded Dyke Drain Valve


Figure 2: Water Leaking from Dyke Drain Valve Piping During Leak Test

While it has since been fitted with a makeshift wooden plug, the current condition of the dyke drain has compromised the ability of the dyke to adequately contain fuel, essentially rendering it useless in the event of a leak. This is a violation of the *Storage and Handling of Gasoline and Associated Products Regulation 2003, section 27 (8)(a)* states that "Aboveground storage tanks shall be surrounded by a dyke which shall be designed and constructed as follows: (a) where a dyked area contains only one storage tank, the dyked area shall retain not less than 110 percent of the capacity of the tank; and (c) the base and walls of the dyke shall have an impermeable lining of clay, concrete, solid masonry or other material designed, constructed and maintained to be liquid tight to a permeability of 25 litres/metre^2 /day."

As there is only one fuel storage tank located at the Ramea diesel plant, logistical issues arise when attempting to conduct tank maintenance. Presently, the completion of maintenance work and internal tank inspections require the tank to be drained, and temporary site storage arranged to ensure continuity of fuel supply to the generation units; this process is both costly and can be difficult to schedule from a logistical perspective. Consequently, the completion of annual tank maintenance and internal tank inspections[11] is often delayed. Due to existing constraints, presented by the single fuel storage tank, the tank in Ramea has never undergone an internal inspection.

Aside from the operational benefits achieved through the addition of a second tank, there is the added bonus of additional fuel storage capacity. While there have been no fuel supply issues to date, should the ferry experience extensive delays as a result of inclement weather, ice or operational issues, there is a possibility that the fuel supply could be exhausted. The two 30,000 litre tanks will provide an additional 14,450 litres of storage capacity – enabling the plant to produce electricity for an additional four to five days under peak load.

While the majority of Hydro's 25 diesel generation sites contain multiple fuel storage tanks, eight facilities, located in Little Bay Islands, McCallum, Petites, Ramea, St. Brendan's, Cartwright, Hopedale, and Paradise River, only contain a single tank. To help to ensure the continued provision of reliable power to these remote communities, Hydro is presently drafting a corporate standard to ensure that a minimum of two fuel storage tanks are available at these sites.

Replacement of the existing tank is justified based on the need to conform to the provincial regulatory requirements. Replacement of the tank with two new double wall, vacuum sealed, horizontal fuel storage tanks will satisfy the applicable regulatory requirements, provide added fuel storage contingency, ensure continuity of fuel supply, and simplify the completion of routine tank maintenance by enabling a tank undergoing maintenance to be drained while satisfying fuel supply requirements via the second tank.

[11] *Hydro has adopted the guidelines outlined in the American Petroleum Institute (API) Standard 653 for the completion of tank inspections. The API 653 standard recommends that internal tank inspections be completed every ten years.*

Existing System:

The existing diesel fuel site storage in Ramea, consists of a single 45,460 litre, self-dyked, horizontal fuel tank (see figure 3).

Figure 3: Ramea Fuel Storage Tank

The plant contains three diesel generating units, each with an installed capacity of 925 kW. The tank satisfies Hydro's site fuel storage requirements and is required to ensure the continued provision of safe, reliable power to the community of Ramea.

Fuel is delivered to the Ramea diesel plant by way of truck delivery. Fuel trucks are loaded in Stephenville, before travelling to Burgeo where they utilize the provincial ferry service to travel to Ramea. Fuel crossings are completed on a weekly basis, during the designated dangerous goods crossing.

Operating Experience:

The Ramea diesel plant is the community's primary source of electrical power and, thus, is in continuous operation. The fuel storage tanks in Ramea provide the fuel supply for the plant.
As there is only one fuel storage tank located at the Ramea diesel plant, this creates logistical issues when attempting to conduct routine tank maintenance. Presently, the completion of any maintenance work requires the tank to be drained and temporary site storage arranged to ensure continuity of fuel supply to the generation units. This process often impedes the completion of routine maintenance work and

scheduled fuel deliveries, thus, extending the time periods between scheduled maintenance items beyond the acceptable limit.

Legislative or Regulatory Requirements

This project is necessary to meet the requirements of the *Storage and Handling of Gasoline and Associated Products Regulation 2003*. Section 27 (8) (a) of the regulations states that “Aboveground storage tanks shall be surrounded by a dyke which shall be designed and constructed as follows: (a) where a dyked area contains only one storage tank, the dyked area shall retain not less than 110% of the capacity of the tank; and (c) the base and walls of the dyke shall have an impermeable lining of clay, concrete, solid masonry or other material designed, constructed and maintained to be liquid tight to a permeability of 25 litres/metre^2 /day.”

Environmental Performance

There are no environmental performance issues, outside of the regulatory non-compliance indicated in the previous section.

Maintenance or Support Arrangements

Maintenance of the fuel storage system in Ramea is performed by Hydro personnel. Regular tank inspections are contracted out to local companies through the Public Tendering process.

Maintenance History

The tank in Ramea is subject to a daily inspection by the plant operator. Weekly reconciliation measures also include fuel dips to ensure that there is no fuel being released into the environment. Given the routine nature of these tasks, they are not tracked under separate work orders. Consequently, a detailed breakdown of the five-year maintenance history is unavailable.

Historical Information

Historical information for recent fuel tank replacement projects is contained in Table 2.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per Unit ($000)	Comments
2011	131.3	139.3	1	139.3	Replace Fuel Tank Francois
2010	149.1	166.9	1	166.9	Upgrade Fuel Storage Hinds Lake
2009	139.1	141.9	1	141.9	Upgrade Fuel Storage Cartwright

<u>Anticipated Useful Life</u>

The anticipated useful life of the new tanks and fuel header system is 20 years.

Evaluation of Alternatives:

A cost benefit analysis was completed for two tank replacement alternatives. The study period for the cost benefit analysis was 20 years, as this is the service life achieved by the existing tank.

Alternative 1: Direct replacement of the single 45,460 litre, self-dyked, horizontal fuel tank with a new 45,460 litre, double wall, vacuum sealed, horizontal fuel storage tank.

While the material and installation costs for this alternative were lower than that of Alternative 2, the maintenance costs associated with this option proved to be higher. With a single tank, the completion of interior inspection and cleaning requires the establishment of a temporary fuel storage system. This temporary storage system serves to fuel the generation units, enabling the permanent tank to be drained, cleaned and inspected. The arrangement, set-up and dismantling of a temporary system which complies with applicable regulatory requirements, while required infrequently, is a costly endeavor.

Alternative 2: Replacement of the single 45, 460 litre, self-dyked, horizontal fuel tank with two new 30,000 litre, double wall, vacuum sealed, horizontal fuel storage tanks.

The addition of a second tank eliminates the requirement to establish a temporary site storage system for the completion of interior tank maintenance and cleaning while ensuring continuity of supply to Hydro's customers.

Although the cumulative Present Worth (CPW) difference between the two alternatives is marginal, Alternative 2 is the least cost option and is the recommended alternative. The results of the cost benefit analysis are illustrated in Table 3.

Table 3: Cost Benefit Analysis Summary Table

RAM - Replace Fuel Tank		
Alternative Comparison ***Cumulative Net Present Value*** ***To The Year*** **2033**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Alt. #1 Replace Fuel Tank In-Kind	306,137	2,472
Alt. #2 Replace w/ Two 30,000 Litre Tanks	303,665	0

Conclusion:

To ensure compliance with the provincial *Storage and Handling of Gasoline and Associated Products Regulations, 2003* the existing fuel storage tank in Ramea must be replaced.

The existing tank is approximately 20 years old and, given its close proximity to a corrosive marine environment, the tank is severely corroded. The dyke's drain and drain valve have completely rusted away, requiring them to be fitted with a makeshift wooden plug. The current condition of the dyke drain has compromised the ability of the dyke to adequately contain fuel, essentially rendering it useless in the event of a leak.

Replacement of the existing 45,460 litre tank with two new 30,000 litre tanks will satisfy the applicable regulatory requirements, provide added fuel storage contingency, ensure continuity of fuel supply, and simplify the completion of routine tank maintenance by enabling a tank undergoing maintenance to be drained while satisfying fuel supply requirements via the second tank.

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Budget review, develop schedule, site visit	April 2014	April 2014
Design	Develop tender package	May 2014	June 2014
Procurement	Purchase of fuel storage tanks	June 2014	July 2014
Construction	Installation of new fuel storage tanks	August 2014	August 2014
Commissioning	Final inspection	-	August 2014
Closeout	Project closeout	-	October 2014

Project Title: Install Additional Washrooms

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Type: Other

Classification: Normal

Project Description:

This project is the second year of a multi-year program to install additional washrooms in various Hydro site facilities to accommodate employees of both genders required to work at these sites. This budget proposal is requesting $251,000 for 2014 and is the second year of a 15 year program. There are approximately sixty Hydro facilities which require an additional washroom under this program. The sites include all of Hydro's remote sites and encompass terminal station control buildings, diesel generation plants, and hydroelectric generation plants. A listing of the sites, in priority order, is included as Appendix A. The intention is to complete the required upgrades at all Hydro remote site facilities. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	2014	2015	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	90.8	0.0	0.0	90.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	114.9	0.0	0.0	114.9
Other Direct Costs	28.5	0.0	0.0	28.5
Interest and Escalation	16.8	0.0	0.0	16.8
Contingency	0.0	0.0	0.0	0.0
TOTAL	**251.0**	**0.0**	**0.0**	**251.0**

Justification:

This project is required to provide additional washrooms in all of Hydro's remote site facilities which currently contain a single washroom. Since Hydro employs without regard to gender, there is a requirement to provide separate washroom facilities for each gender to support workplace inclusion and diversity.

The provision of separate, washroom facilities for male and female employees is a requirement of the Occupational Health and Safety Regulations, as outlined in the legislative requirements section below. This project is justified on the need to provide a workplace which meets current industry standards and complies with the provincial legislative requirements.

Existing System:

Hydro's site facilities include diesel plants, hydroelectric plants, and terminal station control buildings. Based on occupancy requirements these buildings typically contain a single washroom. For the most part, this has satisfied Hydro's requirements as the vast majority of the staff members utilizing these facilities have typically been male. In recent years, there has been a greater deployment of female workers at these sites and, as a result, there is a requirement for the addition of separate washroom facilities.

This work will form the second year of a multi-year program to complete the installation of additional washroom facilities. This project is driven by workplace diversity and a requirement under the Occupational Health and Safety Regulations. As a result, the following items are not relevant to this project:

- Operating Experience;
- Reliability Performance;
- Outage Statistics;
- Environmental Performance;
- Vendor Recommendations;
- Industry Experience;
- Maintenance or Support Arrangements;
- Maintenance History;
- Anticipated Useful Life;
- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Economic Analysis.

<u>Process for Selecting Site Facilities to Receive Additional Washrooms</u>

The prioritization list, located in Appendix A, was derived through an internal assessment of the various sites within Hydro's system. The prioritized ranking of these sites was based on the frequency in which female employees have been required to visit these locations. While is Hydro's intent to complete the work in accordance with the prioritized ranking scheme, changes in site conditions and facility usage may result in slight deviations from this plan. Site priority will be reviewed on an annual basis and, if warranted, the list may be modified to reflect the revised priorities.

The number of sites completed in a given year will vary as the costs to complete this work will fluctuate on a site by site basis. Factors such as geographic location, condition of existing facilities, and spatial constraints will all have a substantial impact on the cost to complete the work.

Legislative or Regulatory Requirements

Section 61.(2)(c) of the *Provincial Occupational Health and Safety Regulations, 2012,* states that, "where both male and females are employed, separate toilets shall be provided and suitably identified for workers of each sex". A copy of the applicable section of the regulations is attached as Appendix B.

Hydro's remote site facilities are frequently visited by both male and female employees for the completion of routine maintenance tasks. Hydro's standard includes two gender specific washrooms in all new construction; the existing facilities contain a single washroom.

The *Provincial Occupational Health and Safety Regulations, 2012* stipulate that where both male and female workers are employed, a separate toilet shall be provided and suitably identified for workers of each sex. Hydro's remote facilities presently contain a single washroom and fail to comply with the current regulatory requirements. This creates health and sanitation concerns for employees who are uncomfortable with sharing the washrooms with employees of the opposite sex.

To comply with the requirements of the Newfoundland and Labrador Occupational Health and Safety Regulations, and provide a workplace that is fair and equitable to all of its employees, the installation of separate washroom facilities is required.

Historical Information

As this is a new initiative there is limited, relevant historical information pertaining to this work. Details of the facility upgrades completed in 2013 will be incorporated in the 2015 capital proposal document.

Development of Alternatives

Given that the existing facilities contain single washrooms, the alternative of installing privacy locksets and affixing unisex signage on the washroom doorways was considered. Consultations with the provincial occupational health and safety enforcement officers have deemed this to be an unacceptable solution. The regulations state that separate facilities are required - the provision of additional washroom space is required.

The alternative of arranging for portable toilet facilities during the completion of any work at these remote facilities was also considered. This is not a viable alternative given the remote location of many of these sites. It would require weeks of notice to make the necessary arrangements. As visits to these sites are conducted on a frequent basis and often driven by unscheduled maintenance requirements, it would not be feasible to arrange for the periodic transport of such units to Hydro's sites on an as-needed basis.

The third and final alternative, which proved to be the only viable option, consisted of the construction of an additional washroom at Hydro's site facilities within a prioritized approach.

Conclusion:

The implementation of this multi-year program will ensure that separate toilets are available for male and female employees at all of Hydro's remote site facilities. The inclusion of separate washroom facilities for each gender will ensure that Hydro meets the current industry standard and satisfy any requirements of the Provincial Occupational Health and Safety Regulations.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Design transmittal, project set-up, work breakdown structure, and scheduling	February 2014	March 2014
Design	Tender preparation	March 2014	April 2014
Procurement	Tender awarded	April 2014	May 2014
Construction	Install additional washrooms	June 2014	August 2014
Commissioning	Final inspection	-	August 2014
Closeout	Contract closeout	-	October 2014

APPENDIX A

PRIORITIZED SITE LISTING OF FACILITIES REQUIRING ADDITIONAL WASHROOM

No.	Location	Description	Area
1	Hardwoods	Gas Turbine/Terminal Station	CENTRAL
2	Happy Valley	Gas Turbine/Terminal Station	LABRADOR
3	Oxen Pond	Terminal Station	CENTRAL
4	Western Avalon	Terminal Station	CENTRAL
5	Come By Chance	Terminal Station	CENTRAL
6	Sunnyside	Terminal Station	CENTRAL
7	Vale (Long Harbour)	Terminal Station	CENTRAL
8	Stoney Brook	Terminal Station	CENTRAL
9	Buchans	Terminal Station	CENTRAL
10	Harbour Breton	Line Depot	CENTRAL
11	Springdale	Terminal Station	CENTRAL
12	Bottom Waters	Terminal Station	CENTRAL
13	Fogo Central	Line Depot	CENTRAL
14	Farewell Head	Terminal Station	CENTRAL
15	La Scie	Line Depot	CENTRAL
16	Bay Verte	Line Depot	CENTRAL
17	Sops Arm	Line Depot	CENTRAL
18	Howley	Terminal Station	CENTRAL
19	Deer Lake	Terminal Station	CENTRAL
20	Massey Drive	Terminal Station	CENTRAL
21	Bottom Brook	Terminal Station	CENTRAL
22	Stephenville	Gas Turbine/Terminal Station	CENTRAL
23	Doyle’s	Terminal Station	CENTRAL
24	Burgeo	Line Depot	CENTRAL
25	St. Anthony	Maintenance Shop	NORTHERN
26	Rocky Harbour	Line Depot	NORTHERN
27	Berry Hill	Terminal Station	NORTHERN
28	Woody Point	Line Depot	NORTHERN
29	Flowers Cove	Line Depot	NORTHERN
30	Cow Head	Line Depot	NORTHERN
31	Hawke’s Bay	Terminal Station	NORTHERN
32	Peters Barren	Terminal Station	NORTHERN
33	Plum Point	Terminal Station	NORTHERN

No.	Location	Description	Area
34	Bear Cove	Terminal Station	NORTHERN
35	Roddickton	Line Depot	NORTHERN
36	St. Anthony Airport	Terminal Station	NORTHERN
37	Happy Valley	Gas Turbine/Terminal Station	LABRADOR
38	St. Anthony	Diesel Plant	NORTHERN
39	Wabush	Line Depot	LABRADOR
40	Hopedale	Diesel Plant	LABRADOR
41	Wabush	Terminal Station	LABRADOR
42	Postville	Diesel Plant	LABRADOR
43	Makkovik	Diesel Plant	LABRADOR
44	Cartwright	Diesel Plant	LABRADOR
45	Nain	Diesel Plant	LABRADOR
46	Rigolet	Diesel Plant	LABRADOR
47	Black Tickle	Diesel Plant	LABRADOR
48	St. Lewis	Diesel Plant	LABRADOR
49	Charlottetown	Diesel Plant	LABRADOR
50	Mary’s Harbour	Diesel Plant	LABRADOR
51	Port Hope Simpson	Diesel Plant	CENTRAL
52	McCallum	Diesel Plant	CENTRAL
53	St. Brendan’s	Diesel Plant	CENTRAL
54	Ramea	Diesel Plant	CENTRAL
55	Grey River	Diesel Plant	CENTRAL
56	Happy Valley	Diesel Plant	LABRADOR
57	Little Bay Islands	Diesel Plant	CENTRAL
58	Norman Bay	Diesel Plant	LABRADOR
59	William’s Harbour	Diesel Plant	LABRADOR
60	Francois	Diesel Plant	CENTRAL
61	Bay d’Espoir	Terminal Station	CENTRAL
62	Holyrood	Terminal Station	CENTRAL

APPENDIX B

NLR 5/12 – SECTION 61 “TOILET FACILITIES”

Toilet facilities
61.

(1) An employer shall provide, maintain and keep clean sufficient and suitable toilet facilities for workers and shall make effective provision for lighting and heating the toilet facilities.

(2) Sufficient and suitable toilet facilities referred to in subsection (1) include the following:
- (a) one suitable toilet to be provided for up to 10 workers and one additional toilet for every 20 workers or fraction of those likely to be present;
- (b) additional toilets to be provided where toilet facilities are likely to be used by persons in addition to workers;
- (c) where both males and females are employed, separate toilets shall be provided and suitably identified for workers of each sex;
- (d) where a toilet is designated for males, the employer may replace not more than two thirds of the toilets with urinals;
- (e) where more than 100 males work or are likely to work on a shift and sufficient urinal accommodations are provided, the requirements of paragraph (a) may be reduced at the discretion of an officer;
- (f) a toilet that is under cover and positioned and partitioned off to secure privacy shall have a proper door and fastenings;
- (g) doors and partitions shall extend at all parts from not more than 30.48 centimetres and not less than 1.83 metres above floor level;
- (h) a supply of toilet tissue shall be maintained in a toilet stall at all times and easily cleanable covered receptacles shall be provided for waste materials; and
- (i) the toilets shall be conveniently accessible to the workers at all times during work.

Project Title: Replace Personal Computers

Location: Various Sites

Category: General Properties - Information Systems

Type: Other

Classification: Normal

Project Description:

The Personal Computer (PC) Replacement program is an on-going program required to enhance the efficiency of Hydro's employees by replacing the PCs used for their day to day requirements.

This project will enable Hydro to replace 237 Desktop, Notebook, and Workstation computers that were deployed in 2009 and 2010. There are 109 Laptops, 121 Desktops, and seven Workstations to be replaced. A workstation is a more powerful desktop that is used for specialized applications that require more power and resources, such as AutoCad for drafting.

The assignment of a particular device is determined by the employee's manager or supervisor. Generally, if an employee is expected to use their computer while away from the office, a laptop is assigned.

The projected costs of the units are as follows:

- Laptop - $1,900;
- Desktop - $1,050; and
- Workstation - $2,300.

In 2009, Hydro released a tender for supply of PC equipment. This tender was awarded to Bell/Xwave. Bell/Xwave supplies Lenovo desktops, laptops, and Wyse Thin Clients. This order is for a three year period, 2010, 2011 and 2012, with extensions to 2013 and 2014. Previously, in 2009, Bell/Xwave supplied Lenovo PC equipment.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	350.3	0.0	0.0	350.3
Labour	12.0	0.0	0.0	12.0
Consultant	50.0	0.0	0.0	50.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	15.7	0.0	0.0	15.7
Contingency	61.8	0.0	0.0	61.8
TOTAL	**489.8**	**0.0**	**0.0**	**489.8**

Justification:

Hydro must keep computers current in order to adequately support and protect the Information Technology applications and information required to operate its business. The replacement and addition of PC components to achieve this goal requires investment over the life cycle of the computers.

The refresh program makes it possible for computers to be replaced in a planned and consistent manner. This allows for even distribution of budgets and ensures that the computers are available and reliable to support user applications. Continued review of the computer life cycle allows Hydro to adjust plans based on performance, technology changes and new business requirements.

In addition, the computers to be replaced under this project are approaching the end of their useful lives and failures can be expected. The maintenance agreements for these computers will have expired and replacement parts can no longer be guaranteed.

Existing System:

Hydro has approximately 1,000 end-user personal computers in service. It is important to refresh this equipment on a regular cycle to keep the technology current to maintain a reliable, efficient and productive workforce. Refreshing is the replacement of end user equipment, such as desktops, laptops and thin clients, on a life cycle depending on the type of device.

Minimum specifications for replacement of personal computers are reviewed on an annual basis to ensure that the PCs in service continue to remain effective. Industry best practices, technology and application trends are taken into consideration when specifications for computer devices are decided for the current year. The annual review continues the replacement life cycle for laptops of every four years and desktops every five years.

As this budget proposal is for the routine replacement of computing hardware based on a corporate standard consistent with industry practice, the following items under the existing system section are not relevant to the proposal:

- Major Work and/or Upgrades;
- Operating Regime.

Age of Equipment or System

The existing PCs that are to be replaced under this project will have been in service between four and five years depending on the hardware platform used.

Availability of Replacement Parts

Replacement parts are readily available for the duration of the maintenance agreements. Once the maintenance agreement has expired there is no guarantee that replacement parts can be obtained.

Operating Experience:

Status Quo

If the end user infrastructure is not kept current the following scenarios could potentially occur:

- New applications may not run on the old hardware platform;
- Decreased speed may result in lost production;
- Failure rates will exceed 50 percent;
- Maintenance agreements will not be offered by vendor; and
- Operating systems may be unsupported.

Alternatives

The only alternative is to consider leasing the equipment. However, this has been done in the past and has proven to be more expensive and difficult to manage.

As this budget proposal is for the routine replacement of computing hardware based on a corporate standard consistent with industry practice, the following items are not relevant to the justification of this proposal:

- Reliability Performance;
- Outage Statistics;

- Legislative or Regulatory Requirements;
- Safety Performance;
- Environmental Performance;
- Vendor Recommendation;
- Maintenance History;
- Forecast Customer Growth; and
- Energy Efficiency Benefits.

<u>Industry Experience</u>

Hydro has a similar life cycle plan for computer equipment as other companies in the utility industry, including Newfoundland Power.

<u>Maintenance or Support Arrangements</u>

Hydro has purchased maintenance agreements with Lenovo Corporation, the manufacturer, that cover laptops for four years and desktops for five years.

<u>Historical Information</u>

Historical information on computer replacement over the last five years as well as those budgeted for 2014 is presented in Table 2.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per Unit ($000)	Comments
2013B	463.9		229		
2012	490.6	499.0	183	2.73	
2011	403.5	422.2	142	2.97	Laptops only replaced
2010	406.6	403.6	215	1.87	
2009	491.4	489.7	230	2.13	
2008	451.4	456.7	215	2.12	

Anticipated Useful Life

According to Gartner[12], the useful life for a laptop is three years while for a desktop is four to five years. The North American industry standard life cycle for end-user devices is three years for laptops and five years for desktops. Hydro has adopted a four to five year life cycle and utilizes extended warranties to ensure reliable operation.

Economic Analysis

This project is subject to a lease or purchase cost benefit analysis to determine the lowest cost alternative. The cost benefit analysis is done in the year of replacement to ensure consideration of incentives or other benefits that may be offered by the providers.

Conclusion:

The PC Replacement Program as proposed in this project is the preferred solution for the following reasons:

- It enables the end user equipment to remain current;
- It improves workforce efficiency by providing reliable hardware; and
- It allows for a predictable annual budget.

Project Schedule:

The project is scheduled to start in March 2014 and be completed before December 31, 2014.

[12] *Gartner Inc. provides research and analysis on the global Information Technology industry. They assist companies in making informed technology and business decisions by providing in-depth analysis and advice on virtually all aspects of technology.*

Project Title: Replace Peripheral Infrastructure

Location: Various Sites

Category: General Properties - Information Systems

Type: Other

Classification: Normal

Project Description:

The Peripheral Infrastructure Replacement Project is an ongoing program to replace the printers, copiers, fax machines and video conference equipment used in the day to day operation of the business. For the year 2014, this project will consist of the replacement of 13 Multi-Function Devices (MFDs) used for printing, copying, faxing and scanning, as well as ten laser printers and smaller multi-purpose units. Ten units are to be replaced at St. John’s, two at Bishops Falls, one at Deer Lake, three at Bay d’Espoir, three at Happy Valley, two at Port Saunders, one at Stephenville, and one at Wabush. In addition, this budget includes funds for replacement of 12 projectors, one digital video recording unit, six wide screen display units, and one wireless sound system. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	138.4	0.0	0.0	138.4
Labour	20.0	0.0	0.0	20.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	10.6	0.0	0.0	10.6
Contingency	31.7	0.0	0.0	31.7
TOTAL	**200.7**	**0.0**	**0.0**	**200.7**

Justification:

This is the continuation of the Peripheral Infrastructure Replacement Project to replace peripheral devices as they reach the end of their useful lives. The units scheduled for replacement in 2014 have all been in service for five years or more and maintenance contracts and warranties have expired. While the manufacturer will provide extended maintenance (at an increased cost) they will not guarantee the performance of these devices after five years. In this case Hydro would have to incur an unbudgeted capital expense in order to replace the device and could take several weeks before the unit is replaced. Smaller area offices have a single MFD and would have no services during this time.

Hydro must keep its peripheral infrastructure current in order to adequately support the needs of its business. This project makes it possible for such equipment to be replaced in a planned and consistent manner. This allows for even distribution of expenditures and ensures that these peripherals are available and reliable to support the user's needs. Continued review of the products' lifecycles allows Hydro to adjust plans based on performance, technology changes and new business requirements.

Existing System:

Table 2: Peripheral Devices in Service

Office Location	Number of Printers	Number of Employees	Buildings Per Location
Hydro Place	84	350	1
Bay d'Espoir	22	90	4
Happy Valley/Goose Bay	7	34	2
St. Anthony	6	21	2
Stephenville	4	22	2
Deer Lake	2	6	1
Wabush	3	12	2
Whitbourne	2	25	2
Bishop's Falls	18	80	3
Holyrood	24	102	4
Port Saunders	4	22	1

There is no relevant information for:

- Safety Performance;
- Environmental Performance;
- Operating Regime;
- Outage Statistics; and
- Major Work/Upgrades;

<u>Age of Equipment or System</u>

The units scheduled for replacement have been in service for over five years.

The decision to replace a printer or MFD is based on many criteria, including:

- Vendor's product roadmap (new features like secure print and scanning will not be supported on older equipment);
- Users' printing requirements (color need, print volumes and speed);
- Number of users supported by the equipment;

- Availability of alternate printing;
- Available support for the equipment; and
- Age of equipment.

Availability of Replacement Parts

Replacement parts are readily available for the duration of the maintenance agreements and warranties. Once these agreements and warranties have expired, replacement parts may or may not be available.

Operating Experience:

Status Quo

If the peripheral infrastructure is not kept current, there is a risk of increase in failure rates and lack of maintenance agreements offered by vendor.

Alternatives

The only alternative is to consider leasing the equipment. The lease versus buy decision will be evaluated during the tendering process.

As this budget proposal is for the routine replacement of computing hardware based on a corporate standard consistent with industry practice the following items are not relevant to the justification of this proposal:

- Reliability Performance;
- Outage Statistics;
- Legislative or Regulatory Requirements;
- Safety Performance;
- Environmental Performance;
- Maintenance History;
- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Economic Analysis;

Industry Experience

Industry best practices indicate that the typical service life for a peripheral device is four to five years. Hydro has a life cycle plan for peripheral devices similar to that of other companies in the utility industry.

Maintenance or Support Arrangements

Hydro has purchased a maintenance agreement with a supplier (Xerox) that covers the larger multi-function devices for five years. Smaller laser printers have a manufacturer's warranty of one to three years duration.

Vendor Recommendations

The vendor (Xerox) recommends a maximum lifespan of five years for these devices. Other major vendors have not stated their recommended lifespan.

Historical Information

Table 3 contains a five-year history as well as 2013 budget for the Peripheral Infrastructure Replacement Project.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per Unit[13] ($000)
2013B	309.9			
2012	327.5	328.5	45	7.3
2011	258.2	276.2	36	7.7
2010	222.0	227.0	34	6.7
2009	161.1	160.9	34	4.7
2008	159.0	158.8	32	5.0

Anticipated Useful Life

According to Gartner[14], the useful life for a color printer is three years while a black and white printer is between three and five years. The average age of Hydro's printers is around seven years.

Evaluation of Alternatives:

Net Present Value

A net present value calculation was not performed in this instance as there is no viable alternative to the

[13] *The variability in unit costs are due to specifications of the printers being replaced such as pages per minute, memory, fax and scanning capability.*

[14] *Gartner Inc. provides research and analysis on the global Information Technology industry. They assist companies in making informed technology and business decisions by providing in-depth analysis and advice on virtually all aspects of technology.*

planned replacement of peripheral infrastructure.

Cost Benefit Analysis

A cost benefit analysis was not performed as there are no quantifiable benefits.

Conclusion:

The ongoing program involves a coordinated effort to keep Hydro's peripheral infrastructure in good working order and use current technologies while delivering a cost effective solution to the end-user.

Project Schedule:

The project is scheduled to start in March 2014 and be completed before December 31, 2014.

Project Title: Upgrade Server Technology Program

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

This project involves the replacement, addition and upgrade of hardware components and software related to Hydro's shared server infrastructure and replacement of systems in the Energy Management Systems (EMS) infrastructure pertaining to data acquisition and water management.

Based on the age of existing servers, each year an appropriate number of servers will be refreshed. This ensures that Hydro has a reliable, secure infrastructure environment required to support efficient operations.

The scope of this project includes the replacement of one network appliance in the Hydro system and 14 physical servers within the EMS by eight servers including a mix of virtual and physical servers. Eight servers in EMS Energy Systems will be replaced with virtual machines, and six will have physical machine replacements. One new virtual host will be added to the Hydro system to support further reduction of physical hosts by replacing them with virtual machines [15] as they reach end of life.

- Within EMS, four servers are used in the Water Management System and were all acquired at the same time, therefore all expire at the same time and require physical replacements;
- Within EMS, two IBM AIX based systems will be replaced by physical Intel based servers running RedHat Enterprise Linux. Two new VMware virtual machine host servers and licensing will be added to provide physical capacity to host six RedHat Enterprise Linux and two Windows virtual machines to replace current IBM AIX and Windows based physical systems;
- The systems being replaced have been in service for eight years;
- Within the Hydro System, one new VMware virtual machine host server and licensing will be added to increase capacity to handle new server virtualizations hosting corporate applications; and

[15] *A Virtual machine (VM) is a software implementation of a machine (i.e. a computer) that executes programs like a physical machine.*

- Within the Hydro System, a Cisco ACS authentication appliance which provides network authentication services will be replaced. The device will be seven years old at the time of replacement.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	133.0	0.0	0.0	133.0
Labour	34.0	0.0	0.0	34.0
Consultant	14.0	0.0	0.0	14.0
Contract Work	84.0	0.0	0.0	84.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	10.0	0.0	0.0	10.0
Contingency	53.0	0.0	0.0	53.0
Sub-Total	328.0	0.0	0.0	328.0
Cost Recoveries[16]	(42.0)[17]	0.0	0.0	(42.0)
TOTAL	**286.0**	**0.0**	**0.0**	**286.0**

Justification:

The factors that are driving Hydro's proposal to upgrade servers in its environment include:

- Addressing obsolescence/maintaining vendor support;
- Providing security/managing the infrastructure; and
- Supporting current versions of applications.

All the servers being replaced have reached the age that the availability of vendor parts is driving the upgrade.

Addressing obsolescence and maintaining vendor support – Without vendor support, the functions and services reliant on the server infrastructure are at risk as security and support patches for the operating system will no longer be available. As a result, Hydro's ability to support and ensure continuation of these functions and services is impeded. At this time, the vendor support and inventory of spare parts are

[16] *The Information Systems shared services methodology for calculating appropriate chargebacks to non-regulated components of Nalcor is based on a ratio considering the average of the number of full time equivalents and Lower Churchill contractors, email users, personal computers and JD Edwards users across each line of business.*
[17] *The ratio for cost recoveries is less than 37 percent as the Energy Management System Servers are exclusive to Hydro.*

discontinued. As the servers are used by Hydro employees to provide support in running the business on a daily basis, loss of availability of these servers would have a negative effect on employee productivity by not allowing access to software applications.

As technology advances, there are built-in architectures and devices that improve the security of the servers and allow for better management of them. As applications are upgraded and new applications implemented throughout the organization, many are built to take advantage of technologies only present in the newer servers. An example would be an application built to take advantage of Virtualization or Hyper-threading Technology.

Existing System:

There are both physical and virtual servers which support and are used to run various applications for the organization. The applications that run on these servers include the Energy Management System, Enterprise Resource Planning, File-Print, Database and Email systems in addition to numerous other applications which comprise the operating environment. These applications are used by staff in running the business on a day to day basis and fall into one of four classification levels (0 to III) for the purpose of assigning a hardware replacement age.

The standard classifications used for server replacement are shown below in Table 2.

Table 2: Server Replacement Classifications

Classification	Criteria	Maximum Age
Level 0	Critically important to business operations; hardware is known to have a longer general life expectancy; This classification requires additional measures for redundant components, application fault tolerance architectures, and signoff by system owners to extend the standard lifecycle timeframes accepting all associated risks in doing so.	8+ years
Level I	Critically important to business operations; access required on daily basis; outage/failure will have immediate negative impact on business and requires expedited problem resolution within 1 day or less.	5 years
Level II	Standard operating importance; used/accessed daily to weekly; outage would have less impact to business and requires immediate attention/resolution within 1 – 3 days.	6 years
Level III	Non-critical to business operations; accessed occasionally or performs automated procedures on a scheduled basis; outage would not impact business significantly unless not recovered after 3 days or more.	7 years

Summary of the 15 devices:

Level 0

- Eight IBM AIX based servers in the Energy Management system which are eight years old;
- Two Windows based servers in the Energy Management system which are eight years old;

Level I

- None

Level II

- Four AutoVista servers in the Energy Management system which are six years old;

Level III

- One Network Authentication appliance which are seven years old.

Operating Experience

As this budget proposal is for routine replacement of hardware and software related to the corporations shared server infrastructure, the following items are not relevant to this proposal:

- Major Work and/or Upgrades;
- Maintenance History;
- Outage Statistics;
- Safety Performance; and
- Environmental Performance.

Reliability Performance

Hydro's servers are used on a continuous basis. The servers are active for the life of the unit once placed in service. Hydro standardizes on enterprise grade hardware for both corporate and energy management applications and has had very satisfactory performance and reliability levels from this hardware as a result.

Industry Experience

Hydro must keep its servers current in order to adequately support and protect the information technology infrastructure required to operate its business. Failure to keep this infrastructure current will put Hydro at risk of unplanned outages, possible data loss, and data corruption. The replacement, addition and upgrading of hardware components to achieve this goal requires investment over the lifecycle of the infrastructure.

Vendor Recommendations

General industry practice is that servers be replaced in a five year lifecycle. Parts may not be available after five years for the servers to be replaced depending on the component that fails.

Maintenance or Support Arrangements

IBM Software Support Lifecycle Policy applies to the software which powers systems including the enterprise server subsystems, drivers, firmware and management tools. A minimum of five full years of standard support from the date the product release was made generally available by IBM, with the option to get support extensions for at least an additional three years following a product's end-of-service date for an extra charge set by IBM.

IBM warranty support for the servers is discontinued. Hydro has determined that the standard three year manufacturer warranty is insufficient for its Intel Server Infrastructure and increases this warranty to five years at time of purchase.

After the initial five year warranty, the server is placed on a maintenance program with IBM that is renewed yearly until the server is replaced.

Historical Information

Table 2 shows the five-year historical costs of the Server and Operating System Evergreen Program as well as the budgeted amount for 2013.

Table 2: Five-Year Historical Information

Year	Budget ($000)	Actual ($000)	Servers
2013B	367.6		45
2012	171.7	171.3	19
2011	209.3	213.5	18
2010	196.6	197.9	14
2009	272.6	268.9	14
2008	241.0	238.2	21

Anticipated Useful Life

Industry standards indicate that server hardware has a useful life of five years. Beyond this timeframe reliability and support may become problematic. The age of the equipment being replaced ranges from seven to eight years.

Development of Alternatives:

The alternative to a server refresh program is to replace servers as they fail. This would put the infrastructure at risk of unplanned outages, possible data loss, and data corruption. This alternative would also cause a significant increase in maintenance costs as repairs are undertaken and spare equipment is kept on hand. This is not a viable alternative.

Evaluation of Alternatives:

As this budget proposal is for routine replacement of hardware and software related to the corporations shared server infrastructure, the following items are not relevant to the justification of this proposal:

- Levelized Cost of Energy;
- Legislative and Regulatory Requirements;
- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Loss during Construction.

Economic Analysis:

As this budget proposal is for the routine replacement of hardware and software related to the Corporations shared server infrastructure, Economic Analysis is not relevant to the justification of this proposal.

Conclusion:

This is an ongoing program to maintain server performance. Hydro continues to seek efficiencies in systems management tools and reducing energy, space and cooling usage by virtualizing eligible systems upon the end of the physical servers service life. Future replacements and upgrades will be proposed in future budget applications.

Project Schedule:

The project is scheduled to start in February 2014 and be completed by the end of November 2014.

Project Title: Replace Radomes

Location: Various Sites

Category: General Properties - Telecontrol

Type: Pooled

Classification: Normal

Project Description:

To reduce the probability of system outages resulting from radome failure, Hydro has a radome replacement program for the microwave antennas of the corporate network. This is an ongoing program to replace microwave antenna radomes, the protective covers that enclose the delicate components of the microwave antennas in Hydro's microwave radio system. The radome replacement program proposed by Hydro is based on operational experience and the manufacturers' recommendations. Due to financial and operational risks associated with the failure of corporate microwave equipment, this project is a proactive approach to ensuring that the likelihood of failure of microwave antenna radomes is minimal.

Radomes are replaced at different sites throughout the network each year, depending on age and condition. The radome replacement schedule for 2014-2018 is provided in Appendix A. Fourteen radomes are scheduled to be replaced in 2014. Historically, this project has been performed through the joint effort of an external contractor who performs the actual work and internal forces that perform project management and provide technical support. This joint effort will be continued in 2014. The budget estimate for this project is shown in Table 1.

Cost estimates have increased from previous budgets due to increased installation costs by external contractors through the public tendering process. The replacement schedule for 2014 has been changed as a result some radome replacements that were not completed in 2012 because of high wind conditions. This resulted in a general re-scheduling of radomes from 2012 to 2013, and from 2013 to 2014 based on priority and balancing the totals for each year. Some corrections to the ages were also made.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	60.1	0.0	0.0	60.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	181.8	0.0	0.0	181.8
Other Direct Costs	13.5	0.0	0.0	13.5
Interest and Escalation	18.4	0.0	0.0	18.4
Contingency	51.1	0.0	0.0	51.1
TOTAL	**324.9**	**0.0**	**0.0**	**324.9**

Justification:

One of the challenges associated with the development of the radome replacement schedule is that many of Hydro's microwave sites were installed in the same year. For example, during the installation of the East Coast Microwave System in 2001, approximately 20 antennas were installed. To avoid the financial and logistical challenges that would be created by replacing each of these radomes in the same year, Hydro decided that the replacement program should be distributed as much as practical on the basis of risk and condition. The planned replacement schedule for the next five years is included in Appendix A.

The decision to distribute the replacement of radomes across years requires that some radomes will be left in service for periods longer than recommended. To manage this issue, Hydro has initiated an inspection program that allows for the identification of radomes which are torn or otherwise damaged, as illustrated in Figure 2. These radomes must be replaced as soon as the damage is identified to ensure that the integrity of the microwave system is maintained.

The impact of a microwave failure today could have a greater effect compared to the incident of 1996 due to the fact that teleprotection signals, which protect transmission lines in the event of a system disturbance, are now transmitted using the microwave network. Today, protection signals for 17 of Hydro's 24 critical 230 kV transmission lines are carried on the microwave network. Because of this, a microwave failure would cause the Energy Control Centre to lose control of the system stations and likely cause and/or extend customer outages.

Existing System:

Hydro has a network of microwave radio, by which corporate communications and system data are transmitted. The microwave radio system provides the backbone for all corporate voice and data communications. Traffic carried over the microwave system includes:

- Teleprotection signals for the provincial transmission system;
- Data pertaining to the provincial Supervisory Control and Data Acquisition (SCADA) system;
- Data pertaining to the corporate administrative system; and
- Operational and administrative voice systems.

Microwave radio signals are transmitted from one location to the next using parabolic antennas attached to towers. These antennas are mounted up to heights of 120 meters and range in diameter from two meters to five meters. At such extreme heights, the antennas are subjected to high wind and ice loading when storms occur, and must be protected. To provide this protection, the feed horn of the antennas responsible for sending and receiving microwave radio signals are covered using a flexible covering, stretched over the antenna shroud, known as a radome. These covers are made of advanced plastics known as Hypalon and Teglar that prevent the accumulation of ice and snow which could bend or break the feed horn, and does not interfere with the microwave radio signals. The white cover illustrated in Figure 1 is an example of a radome on an uninstalled antenna.

Figure 1: Microwave Antenna with Radome

Damage to radomes can occur in several ways. Exposure to wind, sun, rain, and ice causes the radomes to deteriorate over time. When the radome weakens, tears form in the fabric, as shown in Figure 2. Left unchecked, the tears quickly grow in size (Figure 3) and the material can be torn free by wind. Such tears may result in severe damage to the delicate antenna components.

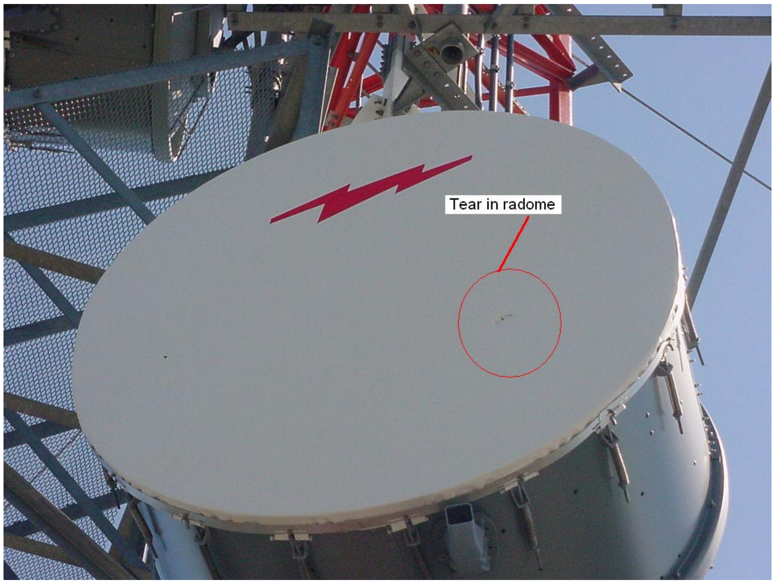


Figure 2: Tear in Radome

Figure 3: Heavily Damaged Radome

Other modes of failure are less common. Ice falling from the tower can damage radome components, such as the hardware that hold the radome in place, as shown in Figure 4. Vandalism by the use of shotguns, rocks, or other projectiles has also occurred at sites that are accessible by road. Each of these occurrences has the potential to damage the radome and make it prone to complete failure.

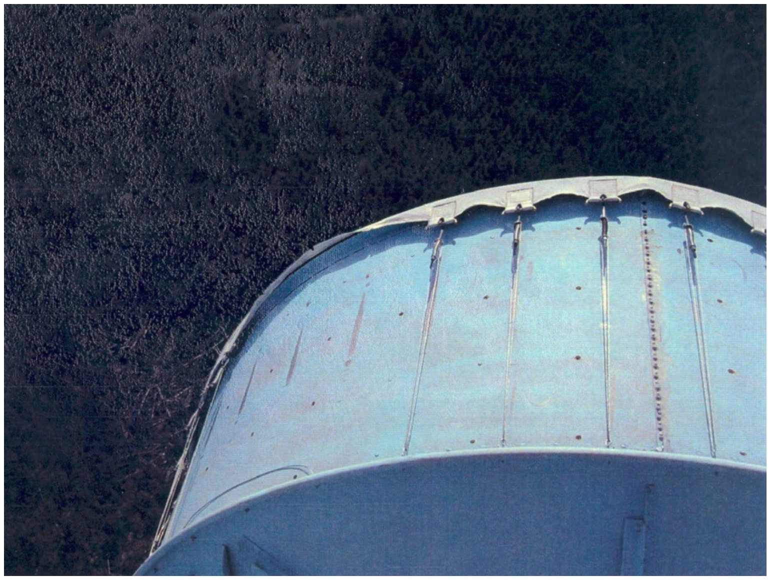


Figure 4: Missing Radome Mounts

There are 80 radomes throughout Hydro's system. They are installed on towers from St. John's to Deer Lake, and south to Bay D'Espoir. Figure 5 shows Hydro's Telecommunication Network.

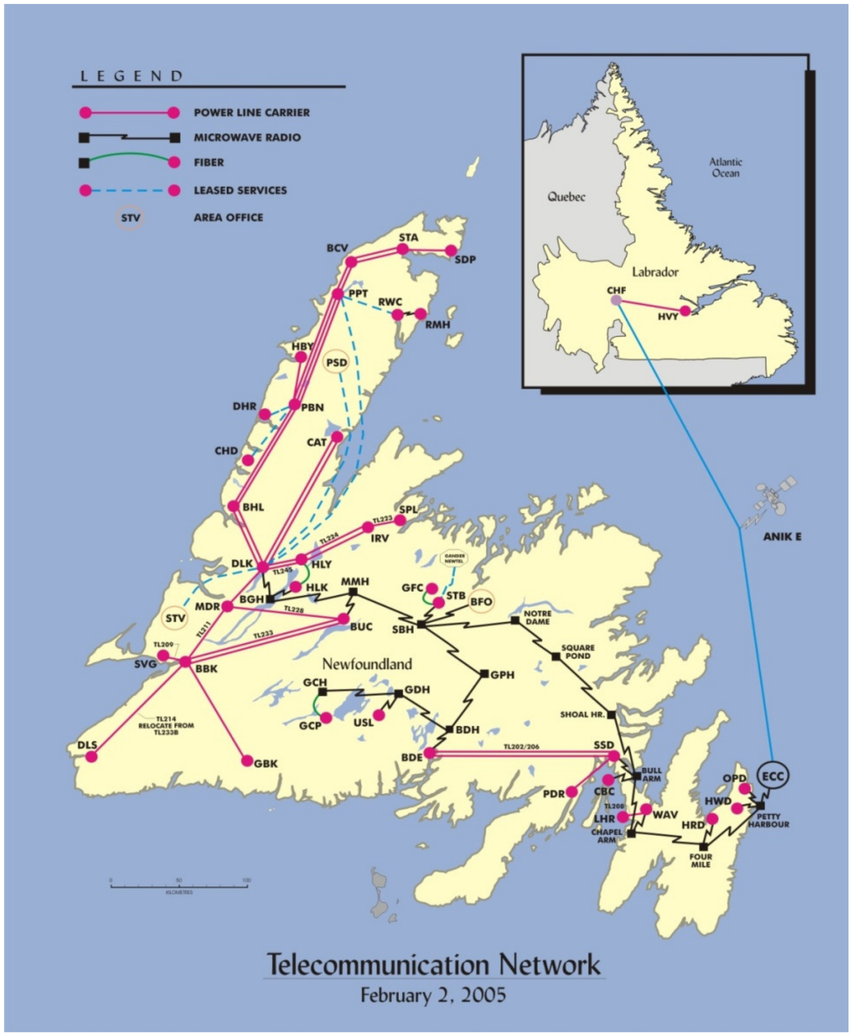


Figure 5: Location of Towers

Major Work and/or Upgrades

There are no upgrades available for a radome. It must be replaced based upon the estimated useful life or upon observed damage during inspection.

Operating Experience:

Outage Statistics

In the winter of 1996, a wind storm caused a significant and sustained outage to a part of Hydro's communications network as a result of the failure of two separate radomes at the Sandy Brook Hill and Mary March Hill Microwave Sites. Despite routine inspections, the radomes were torn and the material of the shells became entangled in the antenna feed horns. As a result, critical components at both sites were irreparably damaged and the antennas required replacement. Once the storm cleared and the cause of the outage was identified, antennas could not be replaced until three weeks later, due to lead times associated with material procurement and weather related delays.

In total, the microwave radio system was out of service for approximately six weeks. During that time, temporary leased services were procured and installed, resulting in unanticipated labour and materials costs.

There has been no other communication outages caused by radome failures since the 1996 storm.

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements associated with radome replacement.

Safety Performance

There is no known safety performance issues associated with the radomes.

Environmental Performance

There are no environmental performance concerns or environmental code violations associated with the operation of microwave radomes.

Industry Experience

Industry experience information is not available.

Vendor Recommendations

As a result of the costs and outage time associated with the 1996 storm, personnel from Hydro consulted with manufacturers to develop a proactive radome replacement plan. Based on discussions with representatives from radome manufacturers Andrew Solutions and CableWave, the following conclusions were met:

- CableWave radomes (made of Hypalon material) should be replaced on a seven-year cycle;
- Andrew Solutions radomes (made of Teglar material) should be replaced on an eight-year cycle.
- Andrew Solutions radomes, with a slightly longer life, cannot be substituted for CableWave radomes on CableWave antennas on account of the structural differences associated with each type of antenna.

Maintenance or Support Arrangements

There are no maintenance or support arrangements associated specifically with radomes. Radome inspection is included as part of an overall periodic tower inspection which occurs annually.

Maintenance History

Radomes are visually inspected each year when the tower is inspected, or as soon as practical after any extremely severe storm that might have affected a particular site. A visual inspection may also be required as part of any corrective maintenance investigation into any loss or degradation of signal that may have been caused by a radome tear damaging the feed horn assembly. The radomes are inspected for any tears in the radome and any failure of the mounting hardware. Radomes cannot be repaired and must be replaced when a tear of any size is visually detected. Even a small tear is unacceptable as it will become much larger due to the high stresses caused by wind and other environmental factors including icing.

Historical Information

Table 2 shows the historical information for the Radome Replacement Program.

Table 2: Capital Budget and Expenditures

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per Unit ($000)	Comments
2013B	336.0		18		
2012	172.0	148.8	14	10.6	Incomplete due to weather restrictions.
2011	195.9	101.7	11	9.2	
2010	195.9	110.4	13	8.5	No travel expenses; all sites close to St. John's.
2009	129.7	110.5	9	12.3	
2008	123.8	111.0	9	12.2	

Anticipated Useful Life

Hydro's microwave antennas are supplied primarily by two manufacturers, Andrew Solutions and CableWave. Each manufacturer uses a different radome. Radomes used on antennas manufactured by CableWave have a useful life of seven years, and the radomes used on Andrew antennas have a useful life of eight years.

Alternatives:

No viable alternatives exist to radome replacement.

Conclusion:

Hydro's Radome Replacement Program is necessary in order to prevent outages caused by radome damage.

The radome replacement program proposed by Hydro is based on operational experience and manufacturer's recommendations. Historically, this project has been executed by external contractors and supported by internal resources and this joint effort will continue in 2014.

Due to financial and operational risks associated with the failure of corporate microwave equipment, this project is a proactive approach to ensuring that the likelihood of failure of microwave antenna radomes is minimal.

Future Plans:

Future plans will be proposed in future capital budget applications. Radome replacements are planned for three of the next five years as listed in Appendix A of this report and shown in the five-year capital plan (2014 Capital Plan Tab, Appendix A).

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Prepare project Plan and site visits	January 2014	February 2014
Design	Complete tender package	February 2014	March 2014
Procurement	Purchase radomes	April 2014	April 2014
Installation	Install radomes	May 2014	September 2014
Commissioning	Site inspections	October 2014	October 2014
Closeout	Project closeout	November 2014	December 2014

APPENDIX A

RADOME REPLACEMENT SCHEDULE

2014 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
BDE	BDH	1.8m(6')	CW	DA6-71hp	2006
BDH	GPH	2.4m(8')	Andrew	HP8-71D	2006
BDH	GPH	1.8m(6')	CW	DA6-71hp	2006
BDH	BDE	1.8m(6')	CW	DA6-71hp	2006
BDH	GDH	3.0m(10')	CW	DA10-71hp	2006
BUC	MMH	1.8m(6')	CW	DA6-71hp	2008
SHH	BAH (main)	2.4m(8')	Andrew	HP8-71GE	2003
SHH	BAH (div)	2.4m(8')	Andrew	HP8-71GE	2003
SHH	SPH (main)	3.6m(12')	Andrew	HP12-71E	2003
SHH	SPH (div)	3.6m(12')	Andrew	HP12-71E	2003
SPH	SHH (main)	3.6m(12')	Andrew	HP12-71E	2003
SPH	SHH (div)	3.6m(12')	Andrew	HP12-71E	2003
SPH	NDH (main)	3.6m(12')	Andrew	HP12-71E	2003
SPH	NDH (div)	3.6m(12')	Andrew	HP12-71E	2003

2015 Radome Replacements

None Required

2016 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
BAH	CAH	2.4m(8')	Andrew	HP8-71D	2009
BAH	CBC	1.8m(6')	Andrew	HP6-71E	2009
BAH	SSD	1.8m(6')	Andrew	HP6-71E	2009
GPH	SBH (main)	3.6m(12')	Andrew	HP12-71E	2009
GPH	SBH (div)	3.6m(12')	CW	DA12-71hp	2009
GPH	BDH	2.4m(8')	Andrew	HP8-71D	2008
GPH	BDH	1.8m(6')	CW	DA6-71hp	2008
SBH	GPH	3.6m(12')	CW	DA12-71hp	2009
SBH	GPH	3.6m(12')	Andrew	HP12-71E	2009
SBH	MMH	3.0m(10')	Andrew	HP10-71D	2009
SBH	STB	1.8m(6')	CW	DA6-71hp	2009

2017 Radome Replacements

None Required

2018 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
CAH	FMH (main)	3.0m(10')	Andrew	HP10-71D	2010
CAH	FMH (div)	2.4m(8')	Andrew	HP8-71D	2010
CAH	BAH (main)	3.0m(10')	Andrew	HP10-71D	2010
CAH	BAH (div)	2.4m(8')	Andrew	HP8-71D	2010
CAH	WAP	2.4m(8')	Andrew	HP8-71D	2010
FMH	PHH (main)	3.0m(10')	Andrew	HP10-71D	2010
FMH	CAH (main)	3.0m(10')	Andrew	HP10-71D	2010
FMH	CAH (div)	2.4m(8')	Andrew	HP8-71D	2010
FMH	HRP	2.4m(8')	Andrew	HP8-71D	2010
MMH	BUC	1.8m(6')	CW	DA6-71hp	2011
OPD	PHH	1.8m(6')	Andrew	HP6-71E	2010
PHH	FMH (main)	3.0m(10')	Andrew	HP10-71D	2010
PHH	FMH (div)	1.8m(6')	Andrew	HP6-71E	2010
STB	SBH	1.8m(6')	CW	DA6-71hp	2011
WAP	CAH	2.4m(8')	Andrew	HP8-71D	2010
WAP	WAV	2.4m(8')	Andrew	HP8-71D	2010
WAV	WAP	1.8m(6')	Andrew	HP6-71E	2010

List of Abreviations

Abv	Site Name
BAH	Bull Arm Hill Microwave/Repeater
BDE	Bay d'Espoir Terminal Station
BDH	Bay d'Espoir Hill Microwave/Repeater
BFI	Bishop Falls Office
BGH	Blue Grass Hill Microwave/Repeater
BUC	Buchans Terminal Station
CAH	Chapel Arm Hill Microwave/Repeater
CBC	Come By Chance Terminal Station
DLK	Deer Lake Terminal Station
DLP	Deer Lake Passive Repeater
ECC	Energy Control Center
FMH	Four Mile Hill Microwave/Repeater
GCH	Granite Canal Hill Microwave
GDH	Godaleich Hill Microwave/Repeater
GPH	Gull Pond Hill Microwave
HRP	Holyrood Plant
HWD	Hardwoods Terminal Station
MMH	Mary March Hill Microwave
NDH	Notre Dame Hill
OPD	Oxen Pond Terminal Station
PHH	Petty Harbour Hill Microwave/Repeater
SBH	Sandy Brook Hill Microwave
SHH	Shoal Harbour Hill
SPH	Square Pond Hill
SSD	Sunnyside Terminal Station
STB	Stony Brook Terminal Station
USL	Upper Salmon Plant
WAP	Western Avalon Passive Repeater
WAV	Western Avalon Terminal Station

Project Title: Upgrade IP SCADA Network

Location: Various Sites

Category: General Properties - Telecontrol

Type: Other

Classification: Normal

Project Description:

This is a two year project in which twenty routers in the Supervisory Control and Data Acquisition (SCADA) network will be replaced and upgraded with the current router technology including compliance to IEEE 1613-2003 (Standard Environmental and Testing Requirements for Communications Networking Devices in Electric Power Substations) and additional security features. Design and procurement will take place in the first year followed by installation and commissioning in the second year. Table 1 provides a list of the routers to be replaced and their locations.

Table 1: SCADA Routers to be Replaced

SCADA Routers		
#	**Router**	**Location**
1	BDP	Bay d'Espoir Hydro Plant
2	BUC	Buchans Terminal Station
3	CBC	Come By Chance Terminal Station
4	DLK1	Deer Lake Terminal Station
5	DLK2	Deer Lake Terminal Station
6	ECC1	Hydro Place
7	ECC2	Hydro Place
8	ECC3	Hydro Place
9	GCL	Granite Canal Plant
10	GDH	Godaleich Hill Microwave Repeater
11	GPH	Gull Pond Hill Microwave Site
12	HLK	Hinds Lake Hydro Plant
13	HRP	Holyrood Thermal Plant
14	HWD	Hardwoods Terminal Station
15	OPD	Oxen Pond Terminal Station
16	PPT	Plum Point Terminal Station
17	SSD	Sunnyside Terminal Station
18	STB	Stony Brook Terminal Station
19	USL	Upper Salmon Terminal Station
20	WAV	Western Avalon Terminal Station

The budget estimate for this project is shown in Table 2.

Table 2: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	150.0	3.8	0.0	153.8
Labour	39.0	110.7	0.0	149.7
Consultant	49.0	0.0	0.0	49.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	10.9	0.0	10.9
Interest and Escalation	16.2	40.6	0.0	56.8
Contingency	0.0	72.7	0.0	72.7
TOTAL	**254.2**	**238.7**	**0.0**	**492.9**

Justification:

This project is justified on the need to replace obsolete equipment. The reliable performance of the SCADA router network is critical to the remote monitoring and control of the Island Interconnected power grid. The Energy Control Center (ECC) in St. John's relies on this network for all manual operations and must have availability at all times. ECC uses the network to remotely control the power system including terminal stations and power generating sites using remote terminal units (RTUs) located at each site. The existing routers are obsolete with an end-of-sale date of March 27, 2007 and a last date of support of March 25, 2012. It is expected that reliable performance will be affected by the depletion of spares beyond the proposed completion schedule.

Existing System:

ECC uses the SCADA network to remotely monitor and control the Island Interconnected power grid, including terminal stations and power generating sites using RTUs (Remote Terminal Units) located at each site as detailed in Table 1. The primary communications between ECC and each router in the SCADA network is provided on Hydro’s microwave communications network. Secondary communications systems are also used to for communications of RTUs to these routers from other sites using power line carrier, fiber optic cables, UHF radio and some leased circuits.

The existing SCADA network has been in service since 2005. It consists of a ring of twenty Cisco 2620 XM routers installed with RS-232 serial interfaces to RTUs located at terminal stations and power plants. The routers connect 52 RTUs to ECC. Some of these RTUs act as data concentrators and poll an additional 17 RTUs. The routers are configured in a ring for reliability. If any router fails, affected SCADA circuits from other locations using the router will be automatically re-routed around the ring in the opposite direction. The failure will then be limited to the RTUs connected directly or indirectly to the failed router. In addition, a backup circuit is in place between ECC and the Deer Lake Terminal Station in case there is a failure on the microwave system.

There have been no major work or upgrades to this system since it was installed.

Figure 1 provides an overview of both the SCADA network and the communications network.

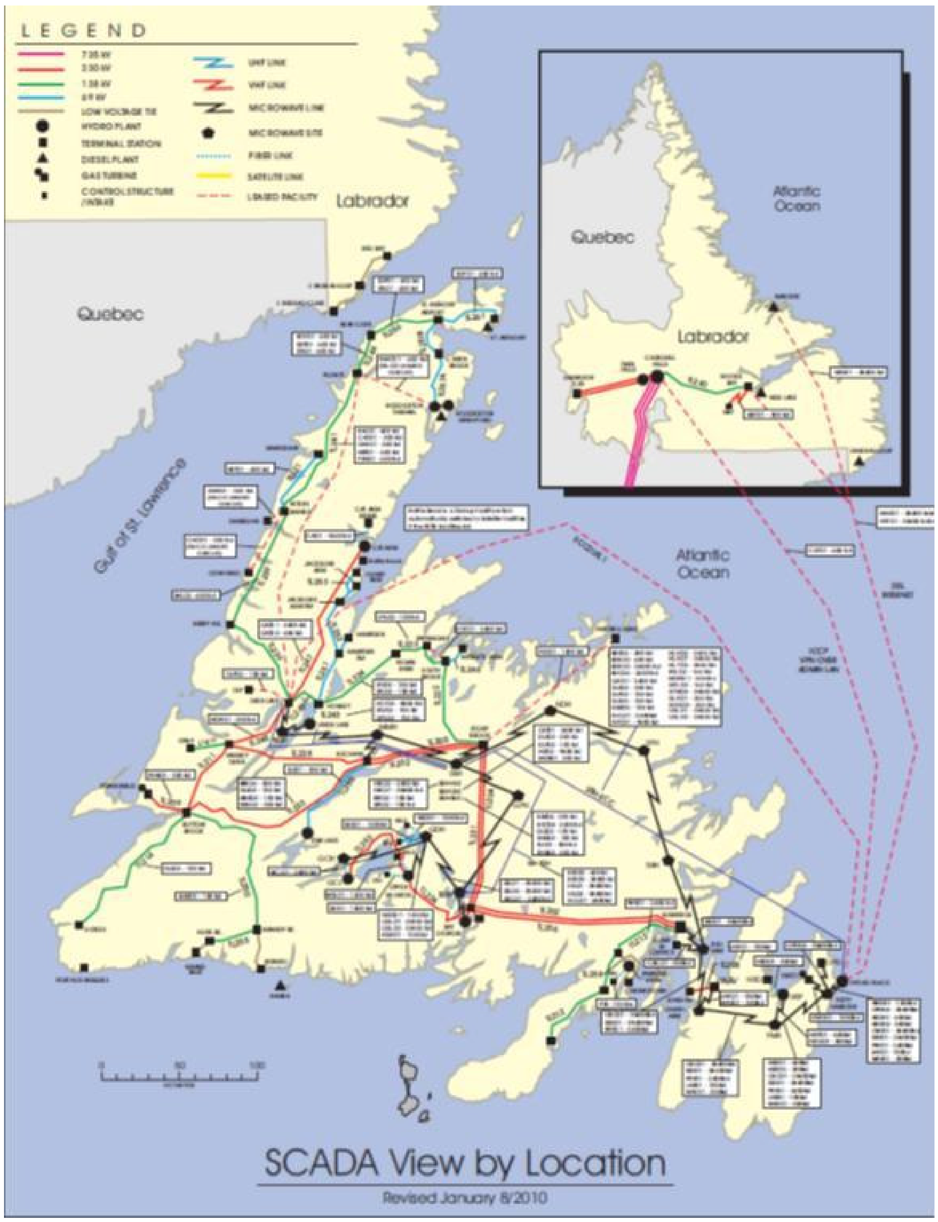


Figure 1: SCADA Network and Communications

Operating Experience:

The existing system has performed without problems or failures but the equipment has become obsolete and is no longer supported by the vendor, Cisco Systems (Cisco). That is, hardware and software support will no longer be provided; this includes security updates. Given the criticality of the SCADA network in terms of remote operation and control of Hydro's generation plants, and the increasing potential of attacks on SCADA networks, access to security updates is essential.

Reliability Performance

This project is justified on the basis of avoiding failures before they affect reliability by replacing equipment that has become obsolete.

Outage Statistics

There have been no power outages related to the performance of the SCADA network.

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements applicable to the justification of the project.

Safety Performance

There are no safety performance concerns applicable to the project.

Environmental Performance

There are no environmental performance concerns applicable to the project.

Industry Experience

Power utilities require remote monitoring and control of remote sites and use a variety of communications and networking to achieve this from their control centers. Due to the prevalence of Internet Protocol (IP) networks and broad catalogue of IP capable field devices, most utilities now use, or are planning to migrate to an Internet Protocol (IP) network of routers to provide efficient and reliable connections to RTUs using either RS-232 serial communications (serial tunneling) or direct Ethernet connections. The basic router network is the same for both types of connection. Hydro is aware of the trends in the industry through informal discussions with other utilities and through contact at technical conferences.

Vendor Recommendations

The existing Cisco 2620 XM routers are obsolete with an end-of-sale date of March 27, 2007 and a last date of support of March 25, 2012. Cisco recommends their new connected grid router (CRG) 2010 router as the direct replacement. The CGR 2010 is designed for substation networks to meet the harsh environments, including variations in temperature, dust and electromagnetic interference, common in transmission and distribution stations, as specified by IEEE 1613-2003. It also offers additional security features and other functions not found in the existing routers. The CGR 2010 is specifically designed for this type of application.

<u>Maintenance or Support Arrangements</u>

Hydro has a comprehensive Cisco maintenance and support agreement for all Cisco equipment including the SCADA network. When commissioned, the new routers will be entered into the Cisco database replacing the coverage of the existing routers. Each year the Cisco billing is revised to reflect changes and additions as part of a consolidated contract for all Cisco equipment.

<u>Maintenance History</u>

The SCADA network required no preventative maintenance since Hydro maintained vendor hardware support as well as a stock of spare routers on hand in case of failure. Furthermore, the SCADA network has had minimal corrective maintenance since its installation. Remote network management continuously monitors each device in the system and provides alarms when there is a failure or abnormal condition. In addition, since the ECC is continuously polling RTUs through the routers any failure will be reported immediately. To date, one router has been replaced due to failure; there have also been two instances where the router software had to be reloaded due to errors.

<u>Historical Information</u>

There have been no projects similar to this project.

<u>Anticipated Useful Life</u>

The estimated service life of the new routers is based on the standard Hydro depreciable life of five years.

Development of Alternatives:

There are no viable alternatives to the replacement of the routers.

Conclusion:

The timely replacement of the SCADA network routers will reduce the probability of failures resulting in an unacceptable level of communications loss. Such a loss has the potential to cause or extend power outages.

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Revise and refine a WBS with regard to planned outages and resources	January 2014	March 2014
Design	Complete all configuration work with work requests and drawings	April 2014	April 2015
Procurement	Purchase equipment	September 2014	November 2014
Installation and Commissioning	Install and commission routers one site at a time during the same trip to site	April 2015	October 2015
Closeout	Complete all drawings and project management closeout procedures	November 2015	December 2015

Project Title: Remove Safety Hazards

Location: Various Sites

Category: General Properties - Administrative

Type: Other

Classification: Mandatory

Project Description:

This project is required to ensure adequate capital funding is available to quickly address safety hazards as they are identified through Hydro's Safe Work Observation Program (SWOP). A component of this program involves identifying and reporting conditions that can potentially lead to an incident or an accident. The budget estimate for the project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	80.0	0.0	0.0	80.0
Labour	103.0	0.0	0.0	103.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	35.0	0.0	0.0	35.0
Other Direct Costs	21.0	0.0	0.0	21.0
Interest and Escalation	18.8	0.1	0.0	18.8
Contingency	0.0	0.0	0.0	0.0
TOTAL	**257.8**	**0.0**	**0.0**	**257.8**

Justification:

This project is justified on Hydro's requirement to provide a safe work environment for its employees in compliance with the Occupational Health and Safety Regulations (OH&S), Section 14 which states:

> *"14. (1) An employer shall ensure, so far as is reasonably practicable, that all buildings, structures, whether permanent or temporary, excavation, machinery, workstations, places of employment and equipment are capable of withstanding the stresses likely to be imposed upon them and of safely performing the functions for which they are used or intended.*
>
> *(2) An employer shall ensure that necessary protective clothing and devices are used for the health and safety of his or her workers.*
>
> *(3) The employer shall ensure that safe work procedures are followed at all workplaces.*

(4) An employer shall ensure, so far as is reasonably practicable, that work procedures promote the safe interaction of workers and their work environment to minimize the potential for injury."

In an effort to avoid injury and/or fatality, Hydro has initiated a Safe Work Observation Program (SWOP). The SWOP involves workers actively looking for safety hazards and problems that may otherwise go unnoticed, which could lead to serious health and/or safety issues for Hydro customers, employees, contractors, and the general public. This project provides Hydro with the budget to address unsafe situations where capital work is identified as the solution, and enables Hydro to respond quickly to address unsafe conditions rather than waiting for the normal capital budget process. These deficiencies, as reported under the SWOP, need to be immediately corrected to provide a safe work environment. Criteria for the selection of acceptable projects includes, but is not necessarily limited to, the remediation of safety deficiencies identified in the SWOP.

Existing System:

In Hydro's 2012 Capital Budget Application, the Board of Commissioners of Public Utilities approved a budget of $249,100 to address safety hazards in the workplace. Several potential safety hazards were identified through the SWOP. Table 2 lists the projects completed in 2012, which total $141,400.

Table 2: Projects Completed

Location	Project Description	Cost ($000)
Bay d'Espoir	Replacement of 60A, 600V plugs with 100A, 600V plugs and correction of grounding deficiencies	$19.0
Bay d'Espoir	Purchased new master log which meets the requirements of OH&S regulations	$35.7
Bay d'Espoir	Repaired Victoria control structure access road bridges	$19.7
Salmon River Spillway	Installed three 100A, 600V disconnect switches at the Salmon River spillway gates	$12.0
Holyrood	Installed retractable barricades, erected signage, and replaced mechanical safety edges on overhead service doors #17 and #20	$25.0
Stephenville	Relocated existing fence to increase space in the yard for increased maneuverability. Repositioned main gate at an angle to eliminate pinching point when large vehicles are entering the yard	$30.0
TOTAL		**$141.4**

As this is an on-going program, safety hazards will be identified as they arise in 2014 and reviewed and approved on a project by project basis. Hydro plans to continue to identify and remove safety hazards in this manner on an annual basis.

Process for Selecting Eligible Projects:

These safety hazards are typically identified through Hydro's SWOP by employees, contractors and others who access Hydro facilities. Often mitigation of the safety concern can be accomplished through an operating or procedural change, or as a communication or an operating budget item. When it is concluded that a mitigation measure is a capital item, a cost estimate is completed for the mitigation work which is submitted to Hydro's Project Execution and Technical Services (PETS) department for consideration under the Remove Safety Hazards category. These requests are reviewed, and if warranted, the funding is approved by the Vice President of Hydro and Vice President of PETS.

As this project involves removing safety hazards as they are identified at various sites through the SWOP system, there is no relevant data related to:

- Age of Equipment or System;
- Major Work and/or Upgrades;
- Anticipated Useful Life;
- Maintenance History;
- Outage Statistics;
- Industry Experience;
- Maintenance or Support Arrangements;
- Vendor Recommendations;
- Availability of Replacement Parts;
- Operating Regime;
- Environmental Performance;
- Industry Experience;
- Net Present Value; and
- Levelized Cost of Energy.

Legislative or Regulatory Requirements

Hydro must comply with the Newfoundland and Labrador Occupational Health and Safety Regulations. Each unsafe situation identified as a safety hazard that requires immediate attention must be corrected to comply with current legislative and regulatory requirements.

Safety Performance

Hydro must comply with the Newfoundland and Labrador Occupational Health and Safety Regulations.

When safety issues are identified that require immediate action, Hydro strives to make those improvements as expeditiously as possible, thus reducing exposure to unsafe conditions. Hydro aims to create a safe work environment so that nobody gets hurt.

Historical Information

Table 3 shows the budget and actual expenditures for years 2010-2013.

Table 3: Capital Expenditure History

Year	Capital Budget ($000)	Actual Expenditures ($000)
2013B	257.8	-
2012	249.1	141.4
2011	252.1	239.4
2010	252.4	207.8

Forecast Customer Growth

Customer load growth does not affect this project.

Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to removing safety hazards.

Losses during Construction

This project will have no effect on normal plant operations and will not cause any interruptions or system outages. Therefore, there will be no losses during construction.

Status Quo

The status quo is not acceptable since there are safety hazards to be identified and corrected for the safety of Hydro employees, customers, contractors and the general public.

Alternatives

This project is a general proposal to correct various identified safety hazards in the workplace.

Conclusion:

Unsafe conditions identified by employees, contractors and the public are recorded through the SWOP implemented by Hydro. This budget provides Hydro with the funds to address unsafe situations where capital work is identified as the solution, and enables Hydro to respond quickly to address unsafe conditions rather than waiting for the normal capital budget process. Unsafe conditions requiring immediate attention need to be mitigated to provide a safe environment for workers and the public.

Project Schedule

As this budget relates to unanticipated safety issues, no schedule is available.

Future Plans:

Future Safety Hazards Removal projects will be proposed in future capital budget applications. Also see five-year capital plan (2014 Capital Plan Tab).

PROJECT DESCRIPTION	Expended to 2013	2014	Future Years	Total	Page Ref
			($000)		
GENERATION					
Replace Generator Bearing Coolers Units 4 and 5 - Bay d'Espoir		199.0		199.0	E - 2
Install Automated Fuel Monitoring System at West Salmon Spillway - Bay d'Espoir		193.2		193.2	E - 5
Replace Spherical By Pass Valve Assemblies Units 1 and 2 - Bay d'Espoir		57.5	96.3	153.8	E - 17
Replace Fall Arrest on Surge Tank 1 - Bay d'Espoir		142.8		142.8	E - 22
Replace Turbine/Generator Cooling Water Flow Meters - Upper Salmon		139.7		139.7	E - 33
Raise Height of Earth Dam - Paradise River		98.7		98.7	E - 37
Replace Engine on Emergency Lift System - West Salmon Spillway		67.1		67.1	E - 50
Overhaul Boiler Feed Pump East Unit 3 - Holyrood		194.9		194.9	E - 53
Replace DC Distribution Panels and Breakers - Holyrood		174.2		174.2	E - 66
Upgrade Waste Water Basin Building - Holyrood		136.7		136.7	E - 69
Upgrade Underground Plant Drainage System - Holyrood		112.6		112.6	E - 73
Overhaul Cooling Water Pump East Unit 1 - Holyrood		98.4		98.4	E - 76
Overhaul Extraction Pump South Unit 1 - Holyrood		96.8		96.8	E - 88
TOTAL GENERATION		1,711.6	96.3	1,807.9	
TRANSMISSION AND RURAL OPERATIONS					
Upgrade Terminal Station Foundations - Various Sites		197.9		197.9	E - 100
Replace Optimho Relays on TL203 - Western Avalon to Sunnyside		89.1	96.9	186.0	E - 104
Replace Surge Arresters - Various Sites		181.9		181.9	E - 116
Replace Recloser Control Panels - Various Sites		111.3	84.4	195.7	E - 123
Construct Storage Facility - Postville		183.8		183.8	E - 139
Install Fall Protection Equipment - Various Sites		199.2		199.2	E - 196
Legal Survey of Primary Distribution Line Right of Ways - Various Sites (2014-2015)		156.8	40.3	197.1	E - 207
Legal Survey of Primary Distribution Line Right of Ways - Various Sites (2013-2014)	156.2	40.0		196.2	
Purchase Meters, Equipment and Metering Tanks - Various Sites		199.0		199.0	E - 212
Purchase Track Mounted Backyard Radial Boom Derrick - Bishop Falls		158.7		158.7	E - 231
Replace Excavator Unit 7833 - St. Anthony		110.0		110.0	E - 233
Purchase Portable Vibration Testing Equipment - Various Sites		60.6		60.6	E - 235
TOTAL TRANSMISSION AND RURAL OPERATIONS	156.2	1,688.3	221.6	2,066.1	
GENERAL PROPERTIES					
Perform Minor Application Enhancements - Hydro Place		87.3		87.3	E - 237
Upgrade Energy Management System - Hydro Place		187.9		187.9	E - 239
Replace Network Communications Equipment - Various Sites		91.0		91.0	E - 241
Replace Telephone System - Stephenville		139.9		139.9	E - 243
Replace Wescom Scanner - Corner Brook		81.7		81.7	E - 245
TOTAL GENERAL PROPERTIES		587.8		587.8	
TOTAL PROJECTS OVER $50,000 AND UNDER $200,000	156.2	3,987.7	317.9	4,461.8	

Project Title: Replace Generator Bearing Coolers Units 4 and 5

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Pooled

Classification: Normal

Project Description:

This project is the first year of a three year program to replace the generator bearing coolers (see Figures 1 and 2) on Units 1 to 6 at Bay d'Espoir generating station. In 2014, the scope of work involves the replacement of three deteriorated coolers in each of Units 4 and 5. A design review of the existing coolers will be completed in 2013 by Andritz Hydro who has purchased GE Hydro, the original equipment manufacturer (OEM). They have suggested some modifications, including changing the cooling tube material from copper nickel to stainless steel, that can be made to extend the service life of new coolers beyond what has been experienced with the existing coolers. The new coolers will be procured and replacement of the coolers will be completed by internal labor forces. The estimated budget for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	95.0	0.0	0.0	95.0
Labour	54.8	0.0	0.0	54.8
Consultant	7.0	0.0	0.0	7.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	10.8	0.0	0.0	10.8
Contingency	31.4	0.0	0.0	31.4
TOTAL	**199.0**	**0.0**	**0.0**	**199.0**

Operating Experience:

In the last three years there have been four incidents where generator bearing cooler failures have been experienced, resulting in water leaks. Typical failures are associated with pin holes and wear at the elbows and headers of the coolers. These water leaks result in forced outages of the generating units and contamination of the generator bearing's lubricating oil. Replacement or repairing a damaged cooler normally requires approximately 40 hours of forced outage time.

Project Justification:

All generator bearing coolers were replaced in Units 1 to 6 from 1999 to 2001 due to failures of coolers on a number of units that resulted in forced outages. Any time a cooler fails, and especially during the winter months, the result is a forced outage which negatively affects both a unit's and the Island's Interconnected System availability and reliability. If the water leak is significant, it can also require total replacement of the bearing oil if the leak is not detected on a timely basis. The bearing coolers that were originally supplied with the generators and were commissioned from 1967 to 1970 were replaced after approximately 30 years of service due to increasing frequency of leaks. The existing coolers, which have now been in operation for 15 years, have developed leaks much earlier in their anticipated service life of 25 years, and experience gained from the original coolers has shown that once leaks start to be incurred, the frequency increases as time goes on. The recent failures have been caused by pinholes in the elbows and headers and failure of the braised joints which suggests poor quality workmanship and materials when they were manufactured. To ensure the availability and reliability of Units 1 to 6 at Bay d'Espoir a program to replace the coolers is required.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Open work order, plan and develop detailed schedules	January 2014	February 2014
Design	Design review was completed in 2013		
Procurement	Procure new coolers for two units	March 2014	July 2014
Construction	Install new coolers in two units	August 2014	October 2014
Commissioning	Pressure test coolers and commission	August 2014	October 2014
Closeout	Close work order and review lessons learned	November 2014	November 2014

Future Plans:

Future replacements of bearing coolers will be proposed in 2015 on Units 2 and 6 and in 2016 on Units 1 and 3 as part of the 2015 and 2016 Capital Budget Application.

Figure 1: Bay d'Espoir Units 1- 6 – Generator Bearing Coolers

Figure 2: Bay d'Espoir Units 1- 6 – Generator Bearing Coolers

Project Title: Install Automated Fuel Monitoring System at West Salmon Spillway

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Justifiable

Project Description:

West Salmon Spillway is a remote spillway structure for the Upper Salmon development. It is used for the emergency release of water to preserve dam and dyke integrity. Primary power to the site is normally supplied by a 25 kV distribution line five kilometers in length from the Upper Salmon Terminal Station. A diesel unit at site provides back-up power in the event of a distribution line outage. Fuel storage facilities consist of one 8,073 liter bulk double wall tank and one 905 liter day tank. The tanks were installed in 2005.

This project involves the installation of an automated fuel monitoring system at the West Salmon Spillway structure. This system will be a programmable logic controller (PLC) based fuel delivery system for the two diesel storage tanks located at the site. It will provide the necessary controls for the transfer of fuel between the bulk storage tank and the day tank and will allow for remote monitoring from Hydro's Energy Control Center (ECC). This project involves the installation of devices on the bulk fuel tank to monitor fuel level, temperature and volume of fuel transferred to the day tank and a cabinet containing a programmable logic controller. Similar systems have been installed at the Cat Arm Generating Station in 2007 as part of the replacement of an underground fuel tank at a cost of $148,884, at the Ebbegunbaeg Control Structure in 2010 at a cost of $159,689, and at the North Salmon Spillway Structure in 2013 at an estimated cost of $192,700. Automated fuel monitoring systems serve as alternatives to the standard fuel reconciliation process.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	30.0	0.0	0.0	30.0
Labour	92.0	0.0	0.0	92.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	15.0	0.0	0.0	15.0
Other Direct Costs	14.4	0.0	0.0	14.4
Interest and Escalation	11.5	0.0	0.0	11.5
Contingency	30.3	0.0	0.0	30.3
TOTAL	**193.2**	**0.0**	**0.0**	**193.2**

Operating Experience:

The diesel fuel tanks at West Salmon Spillway have been dipped and visually inspected for leaks on a monthly basis since May 2009. Prior to that, inspections were performed on a biweekly basis. Dipping is the process whereby an operator lowers a graduated measuring stick into a tank to physically measure the level of the fuel in the tank. An Operator must travel one and half hours each day that fuel dips are required by truck for approximately eight months and by snowmobile for the remaining four months. As the site is only inspected monthly, there is a potential for fuel spills that can go unnoticed for that period of time. A total of 12 site visits were made in 2012 to inspect the fuel system at West Salmon Spillway. The present staffing complement is only able to support monthly inspections. Thus, weekly site visits are not able to be performed. Section 18 of the Storage and Handling of Gasoline and Associated Products Regulations, 2003 (GAP) regulations require weekly inspections. Hydro has attempted to modify staff inspection schedules but is still unable to meet the weekly requirements due to an insufficient number of operators to accommodate a weekly inspection schedule. This project offers a technology solution to address Hydro’s current lack of compliance.

There is presently only a low fuel alarm in place for remote monitoring of this site. The systems installed at Cat Arm and Ebbegunbaeg have several alarms as well as fuel level and temperature signals. The following is an example of the information transmitted to the ECC from Ebbegunbaeg:

Alarms:

- EBBE Bulk Tank Low Fuel Level;
- EBBE Bulk Tank Leak Detection;
- EBBE Day Tank Low Fuel Level;
- EBBE Day Tank High Fuel Level;
- EBBE Day Tank Leak Detection;
- EBBE Fuel Line Leak Detection;
- EBBE Fuel Transfer; and
- EBBE Diesel Monitoring System.

Telemetry:

- EBBE Bulk Tank Fuel Level;
- EBBE Bulk Tank Corrected Fuel Volume;
- EBBE Bulk Tank Fuel Volume; and
- EBBE Bulk Tank Fuel Temp.

Project Justification:

This project is justified on cost savings from installing the new system and on the need for compliance with the *Environmental Protection Act, 2003.* A Cost Benefit Analysis indicates that the proposed automated system is cost effective. The installation of an automatic fuel monitoring and PLC-based enhanced delivery system will ensure continuous monitoring of the levels of the fuel in the tanks including alarms to alert ECC personnel of possible problems with either the transfer system or the fuel tanks. This will shorten response time in the event of an actual loss of fuel, and reduce the likelihood of a diesel fuel loss. As a result, Hydro will be able to file a written request with the provincial government that the operator duties be varied from the regulatory requirements so that weekly tank dipping is not required. Cat Arm has received a variance and Ebbegunbaeg is awaiting mechanical modifications to the fuel system that are unrelated to the automated fuel monitoring system but are presently delaying the process of applying for a variance. Fuel reconciliation is a reporting requirement of Section 18 of the *Storage and Handling of Gasoline and Associated Products Regulations, 2003* (GAP) under the *Environmental Protection Act, 2003,* which states:

> "The operator of an above-ground tank system shall:
>
> *18 (2) (a)*
>
> *ensure that the tank or tanks are gauged or dipped, including a water dip, at least weekly or at such less frequent interval as the minister may approve in writing to accommodate remote installations.*
>
> *18 (2) (b)*
>
> *reconcile gauge or dip readings with receipt and withdrawal records at least weekly."*

As Hydro is presently completing these dips on a monthly basis at this site, Hydro is not compliant with Section 18 of the GAP regulations. Over the past nine years, compliance audit findings have identified issues with Hydro Generation fuel reconciliation processes. The Internal Environmental Compliance Audit Report, a web based reporting tool used by Hydro to address environmental compliance, stated in 2006 that water and fuel dips were not consistently performed and in 2012 that Hydro submitted a variance to the weekly dipping and reconciliation requirements for seven sites, of which includes West Salmon Spillway, under provincial legislation and this was rejected by government. Reports are included in Appendix A. Therefore in order to satisfy the requirements, Hydro plans on implementing automated fuel monitoring systems at remote fuel sites. Under GAP Section 18, Hydro is required to report apparent losses on a weekly basis but this is not able to be done due to the current complement of staff.

A potential environmental impact with the existing system is that a spill or leak could continue for up to three weeks before Hydro becomes aware of it. Adjacency of the site to a water body increases the potential environmental impact. The implementation of the proposed system would alert the ECC as soon as a spill or leak is detected, allowing for an immediate response. Installing an automated monitoring system supports Hydro's environmental policy and guiding principles of prevention of pollution, improve continually and comply with legislation. Weekly dipping would no longer be required if a variance is granted by government following the installation of the automated fuel monitoring system. The application for a variance to operator duties is to be made to government by Hydro, based on the fuel monitoring system installed at Ebbegunbaeg but an unrelated mechanical issue has delayed the process. This matter is in the process of being resolved and the application for variance will be submitted, once completed.

Photos 1 and 2 taken during the project work at Ebbegunbaeg show the before and after installation of fuel monitoring devices mounted on the main tank and Photos 3 and 4 show the automation system components in a cabinet inside the diesel building.

Photo 1: Ebbegunbaeg Main Fuel Tank before Monitoring Devices

Photo 2: Ebbegunbaeg Main Fuel Tank with New Monitoring Devices

Photo 3: Ebbegunbaeg Automated Fuel Monitoring System Cabinet (door closed)

Photo 4: Ebbegunbaeg Automated Fuel Monitoring System Cabinet (door open)

A cost benefit analysis was prepared over a 25 year period to compare weekly dipping to an automated system. Weekly dipping was used in the analysis in accordance with government regulations for fuel reconciliation. The analysis considered monthly site visits for regular maintenance and overall site checks at which time fuel dipping could be performed. Hence, 40 days annually were used in the analysis for Alternative 2: Manual Site Check.

The Operation and Maintenance costs of each alternative are as follows:

Alternative 1: Automated Fuel Monitoring System
The cost benefit analysis was done with consideration given to replacing sensors in the automated system every five years and PLC replacement every 15 years.

Alternative 2: Manual Site Check
The cost benefit analysis was based on one operator and one truck for eight months and two operators travel by snowmobile during the four winter months. The fuel costs were conservatively estimated to be $15 per day for round trip travel to West Salmon Spillway regardless of mode of transportation.

Also, the enhanced monitoring function of an automated fuel monitoring system will provide Operations with a means to remotely monitor the bulk tank for alarms related to low fuel levels and more reliable data. This will enable Operations to expediently address a fuel loss situation to minimize environmental impacts.

Utilizing a 25 year study period for these two alternatives, the cumulative net present value for each alternative is as follows:

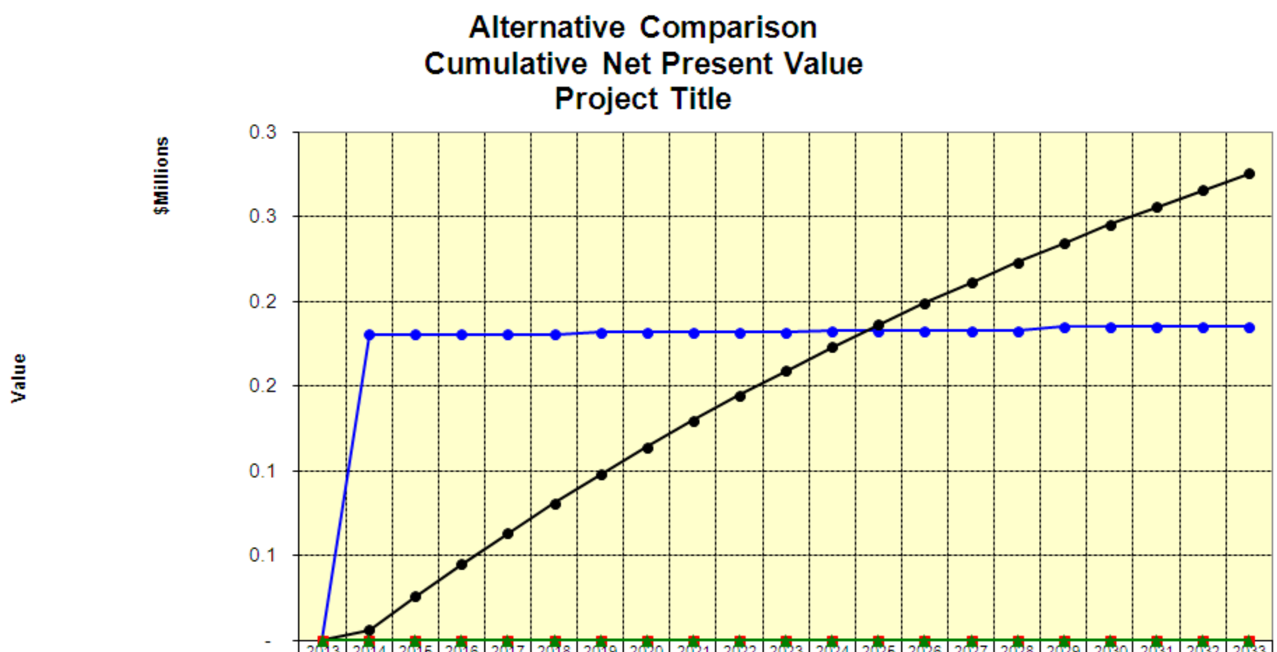
Alternative 1: $185,808
Alternative 2: $318,111

A savings of $132,303 would result if Alternative 1, the automatic fuel monitoring system, is chosen. Based on this analysis, Alternative 1 is the preferred alternative. The results of the cost benefit analysis are shown in Table 2 and Graph 1.

Table 2: Alternative Comparison

USL - Install Automated Fuel Monitoring System at West Salmon Spillway		
Alternative Comparison ***Cumulative Net Present Value*** ***To The Year*** **2038**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Alt. 1 Fuel Monitor	185,808	0
Alt. 2 Manual Site Check	318,111	132,303

Graph 1: Alternative Comparison



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Alt. #1 Fuel Monitor - Graph	-	180,4	180,4	180,4	180,4	180,4	181,6	181,6	181,6	181,6	181,6	182,5	182,5	182,5	182,5	182,5	185,0	185,0	185,0	185,0	185,0
Alt. #2 Manual Site Check - Graph	-	6,169	25,99	45,04	63,35	80,93	97,82	114,0	129,6	144,6	159,0	172,8	186,1	198,9	211,1	222,9	234,2	245,1	255,5	265,6	275,2
Alt. #3 Description - Graph	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Alt. #4 Description - Graph	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Year

Project Schedule:

The anticipated project schedule is shown in Table 3. Engineering development will be done by Hydro staff. Installation is intended to be done by a Contractor under supervision of Hydro Plant Operations and Commissioning is to be done by Hydro Operations.

Table 3: Project Schedule

Activity		**Start Date**	**End Date**
Planning	Prepare project design transmittal Site visit to evaluate work	Feb. 2014	March 2014
Design	Prepare protection and control drawings Program Programmable Logic Controller (PLC)	March 2014	May 2014
Procurement	Order materials Order construction trailer rental	March 2014	March 2014
Construction	Install conduit and cables Install tank monitoring apparatus Install PLC cabinet	May 2014	June 2014
Commissioning	Commission new monitoring system	July 2014	July 2014
Closeout	Drafting and review of as-built drawings Prepare project closeout documentation	July 2014	August 2014

Future Plans:

Similar systems will be proposed for other remote diesel sites as needs are identified.

APPENDIX A

ENVIRONMENTAL AUDIT ISSUE REPORT

Environmental Audit Issue Report

Audit Number:	E1621F3		
Created By:	Rod Healey/NLHydro	**Date Created:**	01/24/2006 08:16 AM
Status:	Complete	**Issue Number:**	E1N37D4
		Review Cycle Created:	Yes

Followup Update Required | Area Update Required

Issue Title:	Dipping and Reconciliation of Storage Tank Systems		
Person Responsible:	Rob Bartlett/NLHydro		
Company Responsible:	Newfoundland & Labrador Hydro	**Division Responsible:**	Regulated Operations
Department Responsible:	Hydro Generation	**Section Responsible:**	No Section Assigned
Risk Level:	Medium Risk		
Class:	Spill Prevention and Emergency Response	**Sub Class:**	
Causal Factor:	Lack of Compliance	**Working Paper Number:**	

Effect:

Issue:

Sections 18(1) and (2) of the *Storage and Handling of Gasoline and Associated Products Regulations, Newfoundland and Labrador Regulation 58/03,* requires storage tanks be gauged or dipped and water dipped, and the gauge or dip readings be reconciled with meter readings on a weekly basis for aboveground tanks, and daily for underground tanks. These records must be maintained for two years. The Department of Government Services must also be notified immediately of losses above normal as indicated by two consecutive reconciliations. Normal is defined as losses greater than one percent of the capacity of the storage tank or one percent of the throughput, whichever is greater. Since the 2002 Environmental Compliance Audit, Hydro Generation has been making some significant progress in the area of fuel dipping and reconciliation, however there were several items identified that are in non-compliance with the regulations. These are as follows:

- fuel and water dips and reconciliations were not being performed on the 9,092 litre dual compartment storage tank next to the carpentry shop in Bay d'Espoir,
- the 11,000 litre diesel storage tank at the Granite Canal Powerhouse was not dipped or reconciled weekly as required;
- the 960 litre diesel storage tank and the 10,000 litre jet fuel tank at the main Bay d'Espoir Powerhouse, and the diesel storage tank at the Paradise River Powerhouse were not dipped consistently on a weekly basis. There were several weeks that the systems were not dipped as required;

- water dips were not being performed and recorded for the diesel storage tank at the Paradise River Powerhouse;
- water and fuel dips were not consistently being performed bi-weekly on the diesel storage tanks at the Ebbegunbaeg Control Structure and North Salmon and West Salmon Spillways. There were several periods where the systems were not dipped as required and the Bulk Fuel Storage Inventory Form does not have a column properly labelled to record water dips.
-
-
- determination of two consecutive reconciliations on the 10,000 litre jet fuel storage tank indicated a loss during November 12 to November 26, 2004, greater than normal. There was no indication that the loss was reported to the Department of Government Services; and,
- review of the reconciliations performed on the 10,000 litre jet fuel storage tank indicated that the improper numerical sign was recorded for the volume discrepancy (column 14) of the Bulk Fuel Storage Inventory Form.

Recommendation:

To comply with Section 18 of the Storage and Handling of Gasoline and Associated Products Regulations, Newfoundland and Labrador Regulation 58/03, all storage tanks should be gauged or dipped and water dipped, the readings reconciled, and determination of apparent losses made, and reported to the Department of Government Services, if required. Alternatively, a written proposal outlining alternate methods and procedures for the dipping and reconciliation of fuel storage systems should be filed with the Department of Government Services.

Formal Management Response:

Agree that we are not in compliance with the GAP regulations. Although not all sites can be done on a weekly basis we will ensure that the regulations are followed as per our schedule. For any variances we will will apply to the Department of Government Services.

Finalized Email Sent To:

Trevor Arbuckle/NLHydro

Monthly Update:

Follow-up:

All actions have been completed. Follow-up will be completed during the 2011 Compliance Audit of Hydro Generation

Project Title: Replace Spherical By-Pass Valve Assemblies Units 1 and 2

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the spherical valve by-pass assemblies on Units 1 and 2 located in Powerhouse 1 at Bay d'Espoir Hydroelectric Generation Station (Bay d'Espoir). The spherical valve is a large valve, approximately seven feet in diameter, used to isolate the flow of water to the turbine generator when it is taken out of service. The by-pass assembly allows water to flow around the spherical valve and includes an eight inch remotely activated motorized valve, manual valve and piping. It routes penstock water to the scroll case, located on the discharge side of the spherical valve. The scroll case is a spiral area surrounding the turbine. The scroll case has to be flooded and pressurized, close to that of the penstock pressure feeding the supply side of the spherical valve, before the spherical valve is opened.

Removal of the old by-pass assembly and installation of new will be performed by Hydro personnel. This project will be completed over a two year period due to the estimated 24 week lead time required to procure the valves. The budget estimate for this project is provided in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	40.0	0.0	0.0	40.0
Labour	13.6	55.2	0.0	68.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	5.5	0.0	5.5
Interest and Escalation	3.9	12.6	0.0	16.5
Contingency	0.0	22.9	0.0	22.9
TOTAL	**57.5**	**96.3**	**0.0**	**153.8**

Operating Experience:

The spherical valve by-pass valves and associated components (see Figure 1) are original plant equipment installed in 1967. This assembly provides pressurized water to allow safe operation of the spherical valve by priming the scroll case before the spherical valve is opened, minimizing the pressure shock experienced by the scroll case when the spherical valve is activated. Operation of the spherical valve is fully automatic and remotely activated from the control room with a set of logic controls in place. The control system requires several conditions to be met before the unit is allowed to start up. Priming of the scroll case is a critical step in the operation of the unit and is the first condition that must be met for safe operation of the spherical valve. The set value of scroll case pressure, by engineering design, is 100 pounds per square inch (psi), while the penstock pressure is 250 psi. In recent years it has been difficult to attain the proper pressure of 100 psi in the scroll cases due to by-pass valve malfunctions (see Figure 2). If the operation of the by-pass assembly does not meet the designed activation pressure, technicians have to manually manipulate the valves in order to open or close them, as internal components may have become jammed or seized. If the technicians are unable to open the valves this could lead to a forced generating unit outage until the issue is resolved. However, if a jammed by-pass valve occurred during a critical time of the year, it is possible to circumvent the priming pressure requirement and operate the spherical valve. By circumventing the priming pressure requirement the spherical valve would be at a higher risk of damage, and it is not standard practice to operate this way.

Figure 1: Spherical Valve By-Pass Assembly

Figure 2: By-Pass Valve with Disk Jammed in Half Open Position

The by-pass assembly on Unit 2 is in worse condition than Unit 1 because Unit 1 is a station service unit and is not cycled on and off as often as Unit 2. The motorized valve on Unit 2 is in a degraded condition, as the presence of water inside the housing indicates that the internal components of the valve are damaged. Along with the valves, the piping in these assemblies also has signs of wear. Over the years the passing of high pressure water around the spherical valve has caused erosion in the by-pass pipe lines such that they need to be replaced.

In the past five years there have been 24 corrective maintenance work orders on Unit 2 spherical valve and 15 on Unit 1 spherical valve. The associated annual maintenance costs are provided in Table 2. The majority of the corrective maintenance work on Unit 2 spherical valves was required to address scroll case pressure or problems with the remotely activated motorized valve in the by-pass assembly. In general, the maintenance work orders for Unit 1 were required to address scroll case pressure. The larger cost incurred in 2011 was associated with replacing a seal on the spherical valve. In addition to corrective maintenance, regular preventative maintenance is performed on the spherical valve by-pass valves, and is similar for all assemblies.

Table 2: Five Year Spherical Valve Maintenance Costs

Year	Unit 1 Spherical Valve ($000)	Unit 2 Spherical Valve ($000)
2012	5.5	7.0
2011	19.1	1.1
2010	1.6	1.7
2009	0.0	0.8
2008	0.7	0.5
Total	26.9	11.1

A project titled “Replace By-Pass Valves Units 3 and 4 – Bay d’Espoir” for $141,900 was approved by Order No. P.U. 4(2013) as part of the 2013 Capital Budget. This project is not yet complete.

Project Justification:

Increased maintenance has been required on the spherical valve by-pass assemblies as they have aged. In the past five years, there have been times when the spherical valve by-pass assemblies have been operating in an abnormal condition that is not in compliance with the basis of design for the system. In the current state, Hydro personnel are required to manually manipulate malfunctioning valves that were designed for remote activation. The by-pass valves are being greased and manually manipulated in order for the spherical valves to operate. This method of operation is not acceptable and there is concern that the by-pass valves are close to failure and inhibit the proper function of the spherical valve. There have been ongoing problems with the by-pass assemblies and in order to maintain reliability and ensure proper operation of the generating units, they must be replaced.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Review scope; Confirm schedule; review budget	March 2014	March 2014
Design	Submit design transmittal; risk workshop	March 2014	March 2014
Procurement	Confirm schedule; tender materials/review tenders; award tender for supply	April 2014	October 2014
Construction	Safety meetings; schedule meetings; risk/ change management; site safety tour	June 2015	July 2015
Commissioning	Safety meeting; training	July 2015	July 2015
Closeout	Financial close out; post implementation review	August 2015	August 2015

Future Plans:

Hydro plans to submit a proposal to upgrade the by-pass system on the two remaining generating units, Units 5 and 6, under a two year project as part of the 2015 Capital Budget Application.

Project Title: Replace Fall Arrest on Surge Tank 1

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project involves procurement and installation of a new fall arrest rigid rail (Glideloc) system on Surge Tank 1. This is the last of the three surge tanks to have a new fall arrest system installed. The budget estimate for the project is shown in Table 1.

Figure 1: Surge Tank

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	35.9	0.0	0.0	35.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	70.0	0.0	0.0	70.0
Other Direct Costs	5.5	0.0	0.0	5.5
Interest and Escalation	9.1	0.0	0.0	9.1
Contingency	22.3	0.0	0.0	22.3
TOTAL	**142.8**	**0.0**	**0.0**	**142.8**

Operating Experience:

The surge tank was constructed in the mid 1960's and has the original rigid rail fall protection equipment installed on the tank ladder at the time of construction. The rail system is used for fall arrest when workers are ascending and descending the tank. This system is a North Saf-T-Climb rigid rail system.

There are a minimum of four inspections of the surge tank per year. During these inspections, workers are required to climb up and down the 368 foot structure to complete inspections and maintenance while being secured to the structure for safety and fall protection. The existing rigid rail system performs well when a worker falls vertically but has been proven to fail when a worker falls backward and away from the rigid rail system. The attached Canadian Standards Association Safety Alert in Appendix A references one reported incident where a worker was injured when this type of fall arrest system did not arrest the person's fall.

A Canadian Standards Association Safety Alert has been issued pertaining to fall arrest systems that are not in compliance (see Appendix A attached). Additionally, the manufacturer has issued a "Safety Alert", (see Appendix B attached).

Workers preparing to climb the ladder on the surge tank are required to use a Y lanyard system for fall protection. See Figure 2 below.

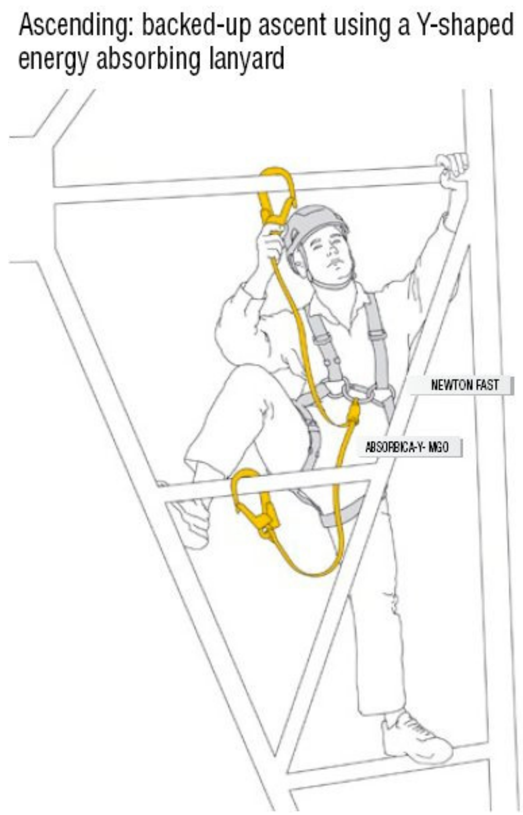


Figure 2: Y Lanyard System

This system requires a climber to wear a Y lanyard harness that has two connection or tie-off points. While climbing, the user is required to have at least one connection secured to the ladder at all times. The climber attaches one connection of the Y lanyard to the ladder between rungs. As the climber ascends to the next ladder rung, he attaches the second connection of the Y on an upper ladder rung (with the first connection of the Y still attached on a lower rung). As he continues to climb, at every one or two rungs, he must remove the lower connection point of the Y and attach it above the upper connection point. This method ensures that there is one connection secured at all times. For a ladder height of 368 feet, removing and reconnecting one connection of the Y lanyard with every one or two ladder rungs can be exhausting for a climber which can increase the risk of slipping.

Project Justification:

This project will restore the surge tank fall arrest system to operate as originally designed by using upgraded equipment to address a known hazard with the original design. The Canadian Standards Association (CSA) issued a product safety alert (see Appendix A) relating to Class FRL (Frontal-fixed Rail Ladder) fall protection systems. A list of affected rigid rail fall arrest systems, also found in Appendix A, was issued with this CSA product safety alert in which the existing rigid rail system installed on the surge tank, North Safety Products Ltd., Saf-T- Climb Ladder Prevention system, is named in the alert list. North Safety Products has issued a safety alert in response, instructing users of the Saf-T climb system to use a Y lanyard system as their fall protection system on ladders equipped with their Saf-T climb system. A copy of the North Safety Products Ltd., safety alert is contained in Appendix B. As a result of this safety alert, the use of the existing North rigid rail system as fall protection while climbing the surge tank has been discontinued by Hydro.

The current method for climbing the surge tank is the Y lanyard method as outlined in the Operating Experience section above. Once a climber has climbed the 368 foot ladder using the Y lanyard method, he/she is too exhausted to complete the work that necessitated the climb. As a result of this, any work required on the surge tanks is currently being carried out by a contractor with experience in rope access methods. Condition assessments of the tank indicate that it requires increased maintenance, with more frequent climbing of the tank. To improve the effectiveness of climbing this structure so that maintenance and inspections can be performed in a safe manner, by workers that are not physically taxed, Hydro plans to replace the existing rigid rail system with a certified rigid rail system. The system, SOLL Glideloc, to be installed is currently certified by CSA as a safe Class Frontal-Fixed Rail Ladder (FRL) fall protection system.

During the most recent inspection in 2011, the contractor hired to undertake the work chose not to use the existing system. During a previous inspection the contractor experienced operational issues with the fall arrest system, pertaining to the inability of the fall arrester to slide freely up the vertical rail, and during the inspection in 2011, a visual inspection from the ground revealed that the vertical rail used for the slider system was bent and twisted. As a result the contractor decided to rig their own fall arrest line.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Planning	February 2014	March 2014
Design	Specification development tender	March 2014 April 2014	April 2014 May 2014
Construction	Contract completion	June 2014	July 2014
Commissioning	Commissioning	August 2014	August 2014
Closeout	Closeout	September 2014	September 2014

Future Plans:

None.

APPENDIX A

CSA PRODUCT SAFETY ALERT

CSA Group

Product Alerts & Recalls

Frequently Asked Questions

CSA International Announces a Product Safety Alert for Class FRL Fall Protection Systems - Frequently Asked Questions (FAQs)

Download the FRL Certification Notice

Q: **Does this affect all types of fall protection systems that are permanently installed on communication towers, buildings, chimneys, water towers, etc.?**

A: No. This Product Safety Alert only applies to Class FRL Fall Protection Systems which are Frontal-Fixed Rail Ladder Systems. This does not apply to cable systems as a similar type of fall back scenario has not been able to be reproduced where the cable grab has not functioned. It must also be noted that older fixed rail ladder fall protection systems were previously designated as Class AS Fall Protection Systems prior to the August 2002 update of CSA Standard Z259.2.1-98. Products certified to the updated version of the standard were subsequently designated as Class FRL Fall Protection Systems. As such, there may be some Fall Protection Systems incorporating fixed rails that may have trolleys that bear the designation "Class AS" instead of "Class FRL" that are still in use. These systems may no longer be found on CSA's Certified Products Directory and may no longer be produced by the manufacturer. These units would have to have their compliance to the new Fall Back requirements confirmed through other means as agreed upon with the local regulatory authority having jurisdiction.

Q: **Why has this not been addressed in the standard already?**

A: CSA standards are developed through a consensus process whereby the Technical Committee identifies risks associated with hazardous activities. They then devise requirements that would allow for the testing of products to determine if they would address the identified risks. In some situations, incidents may identify a rare and isolated risk that is not addressed adequately by the existing requirements within the current product standards. It is the responsibility of the Technical Committee of volunteer experts for the product type (or industry sector) to review the adequacy of the standard's current requirements to determine if they need to be updated. One such incident came to CSA's attention and has initiated a review and update to the standard./td>

Q: **How do I know if the Class FRL Fall Protection System that I work with meets the new Fall Back Performance requirements?**

A: Currently, a set of requirements have been developed through input from CSA International, some of the product manufacturers and the Ontario Ministry of Labour. These requirements have been reviewed by the Technical Committee on Fall Protection to determine their adequacy to address the concerns identified through the investigation of the accident in question and all pertinent comments were taken into account. To expeditiously implement the Fall Back Performance requirements within the marketplace, the vetted requirements were announced through a CSA International Certification Notice (i.e. Occupational Health and Safety Products No. 61) and all affected CSA certified products will be retested and compliance confirmed. After the effective date of May 1, 2011 of the Certification Notice, only compliant Class FRL Fall Protection Systems will be viewed on the CSA Certified Products Directory. All compliant Class FRL Fall Protection Systems' descriptions within the Certified Products Directory will follow the phrase, "The following products comply with the requirements of CSA Standard CAN/CSA Z259.2.1-98 (Reaffirmed 2004) & TIL No. S-02.". In addition, Class FRL Fall Protection Systems certified by CSA International and installed in the marketplace that comply with these Fall Back requirements will bear the following markings (in addition to the CSA Mark) on their trolleys: - T.I.L. S-02 Fall-Back.

Q: **How many people have been injured so far in a fall back situation while using a Class FRL Fall Protection System?**

A: In the approximately 15 years of certifying Class FRL Fall Protection Systems, CSA has been notified of only 1 incident in which a worker was injured from a fall back situation in which the fall arresting device did not arrest the worker's fall.

Q: **How do I find out if I am using my device correctly?**

A: All fall protection devices should be used in accordance with the manufacturer's instructions. The user is advised to contact the manufacturer of each of their devices to obtain the instructions on how to use their protective devices. For Class FRL Fall Protection Systems, links to the manufacturer's instructions are provided within the Table on "Compliance Status of Class FRL Fall Protection Systems to Fall Back Performance Requirements" provided within the Product Alert Section of CSA's website.

Q: **What is CSA doing to rectify the problem?**

A: A set of requirements have been developed through input from CSA International, some of the product manufacturers and the Ontario Ministry of Labour. These requirements have been reviewed by the Technical Committee on Fall Protection to determine their adequacy to address the concerns identified through the investigation of the accident in question and all pertinent comments were taken into account. To expeditiously implement the Fall Back Performance requirements within the marketplace, the vetted requirements were announced through a CSA International Certification Notice (i.e. Occupational Health and Safety Products No. 61) and all affected products will be retested and compliance confirmed. After the effective date of May 1, 2011 of the Certification Notice, only compliant Class FRL Fall Protection Systems will be viewed on the CSA Certified Products Directory.

Q: **Why aren't you doing a full product recall?**

A: The products currently certified to CSA Standard Z259.2.1-98 (Reaffirmed 2004) meet the standard that has been referenced and implemented within legislation. With the Fall Back Performance test requirement in place and the need (if any) of alterations to the current devices to achieve compliance is identified, it can then be determined what actions are necessary to address the issue. It will be left to the manufacturers to determine how they wish to deal with the devices currently available and in use today.

Q: **Who do we report any suspected fall back incidents where a Class FRL Fall Protection System has not worked properly to?**

A: If an incident occurs where a Class FRL Fall Protection System bearing the CSA Mark is suspected of failing to arrest a workers fall within a 150 mm drop distance, the employer or worker can contact CSA's Global Mark Integrity Team at mark.integrity@csagroup.org.

Q: **How can requirements that are not in the CSA standard be utilized for testing and certifying products?**

A: Certification Bodies that have been accredited by the Standards Council of Canada (SCC) may introduce interim requirements that are known as Other Recognized Documents (ORDs) to address issues that were not originally addressed by the requirements within a published standard. These requirements remain in effect for a period of two years or until requirements that address the issue in question are included within the applicable standard. Should it take longer than two years to update the standard, the ORD requirements would be vetted once again by the Technical Committee responsible for the standard or the ORD would be withdrawn. CSA International's ORDs are called Technical Information Letters (TILs).

Compliance Status of Class FRL Fall Protection Systems to Fall Back Performance Requirements

The following is a list of all CSA certified Class FRL Fall Protection Systems that are affected by the Product Safety Alert with details as to the status of their compliance to new requirements for Fall Back Performance. In addition, a link to each manufacturer's website with specific instructions on interim measures to take until compliance to the new requirements for Fall Back Performance have been confirmed has been provided.

Manufacturer	Class FRL Fall Protection System Product Identification	Compliance Status of FRL Fall Protection System to Fall Back Performance Requirements	General Instructions for Utilization of Existing Systems	Link to Manufacturer's Website for Specific Instructions and Contact Details
Capital Safety Group USA Ltd	**Class FRL Fall Arresters - RAILOK 90 Fall Arrest System** Model 6000377 with utilizing Rigid Rails, SR (Standard Rail) with Part # 6000030, 6000031, 6000033 & 6000035, and LR (Ladder Rail) & LRR (Ladder Rail with Rungs) with Part # 6000301, 6000302, 6000303, 6000304, 6000305, 6000306 & 6000307.	Compliance to CAN/CSA-Z259.2.1-98 (R2004) & TIL # S-02 has been confirmed.	Use only in accordance with the manufacturer's instructions.	www.capitalsafety.ca Phone: 905.795.9333 Toll-Free: 800.387.7484 Fax: 888.387.7484 info.ca@capitalsafety.com
MSA, Mine Safety Appliances Company	**Class AS Ladder Climbing Protection System, Series DYNA-GLIDE.** Model 415752 is CSA Certified for use only with MSA Ladder/Rail Assembly Part Number 506390 (Galvanized Ladder/Rail Assembly) or 506513 (Stainless Steel Ladder/Rail Assembly)	Compliance of existing product to new requirements has not yet been confirmed. Compliance of existing product to new requirements has not yet been confirmed.	Use only in accordance with the manufacturer's instructions and until compliance to new Fall Back Performance is confirmed, utilize additional fall protection in the form of a double tie-off procedure.	www.MSANet.com Phone - 1-800-MSA-2222 (ie. 1-800-672-2222)
North Safety Products Ltd.	**Saf -T- Climb Ladder Fall Prevention System, Class FRL, Model 602-100-003** Approved for use with the following Metal Rails, (Stainless Steel) Part Number 526-103-001, (Stainless Steel, Self Locking Screw) Part Number 526-203-001, (Stainless Steel) Part Number 526-105-001, (Stainless Steel, Self Locking Screw) Part Number 526-205-001, (Aluminum) Part Number 526-102-001, (Aluminum Self Locking Screw) Part Number 526-202-001, (Galvanized) Part Number 526-101-001R	Compliance of existing product to new requirements has not yet been confirmed. Compliance of existing product to new requirements has not yet been confirmed.	Use only in accordance with the manufacturer's instructions and until compliance to new Fall Back Performance is confirmed, utilize additional fall protection in the form of a double tie-off procedure.	www.saf-t-climb.com Phone - 1-800-836-8006
Prestige Telecom Formerly Known As: Radian Communication Services Corporation	**Class "AS" Fall Arrester, Rail System, Model RAM. Class "FRL" Rail Fall Arrester, Rail System, Model RAM, Part No. 160372. Class "FRL" Rail Fall Arrester, Rail System, Model RAM, Part No. 160389.** Note: The Rail System Fall Arresters are only certified to operate with the following Radian Rails, Part Number 160362 and or 160363.	Compliance of existing product to new requirements has not yet been confirmed.	Use only in accordance with the manufacturer's instructions and until compliance to new Fall Back Performance is confirmed, utilize additional fall protection in the form of a double tie-off procedure.	www.prestigetel.com Phone - 1-866-472-3426
Sperian Fall Protection Inc.	**"Soll GlideLoc" Fall Arrest Systems: Class 'FRL' - Fall Arrester "COMFORT #22697"** with utilizing Guide Rails "FS-SAL" (Anodised Aluminium), " FS-SST" (Hot Dip Galvanized Steel), "FS-SA4" (Pickled Stainless Steel), "PivotLoc" (Aluminium), "TwinLadder - ZAL" (Aluminium) or "Y-Spar Ladder-YAL" (Aluminium). **Class 'FRL' - Fall Arrester "UNIVERSAL II #23531"** with utilizing Guide Rails "FS-SAL" (Anodised Aluminium), " FS-SST" (Hot Dip Galvanized Steel), "FS-SA4" (Pickled Stainless Steel), "PivotLoc" (Aluminium), "TwinLadder - ZAL" (Aluminium) or "Y-Spar Ladder-YAL" (Aluminium). **Class 'FRL' - Fall Arrester "UNIVERSAL II #25805"** with utilizing Guide Rails "FS-SAL" (Anodised Aluminium), "FS-SST" (Hot Dip Galvanized Steel), "FS-SA4" (Pickled Stainless Steel),	Compliance to CAN/CSA-Z259.2.1-98 (R2004) & TIL # S-02 has been confirmed.	Use only in accordance with the manufacturer's instructions.	www.millerfallprotection.com Phone - 1-800-645-5373

	"PivotLoc" (Aluminium), "TwinLadder - ZAL" (Aluminium) or "Y-Spar Ladder-YAL" (Aluminium). Note: The above "Soll GlideLoc" Fall Arrest Systems are supplied with the Safety System Kits incorporating the applicable rails above and attachment hardware with Part # "GGxxxx" (Glavanized), "GAxxxx" (Aluminum) and "GSxxxx" (Stainless Steel) - Where "xxxx" denotes the system length in the range of 20 to 300 ft.			
Trylon TSF Inc.	**Trylon "Cougar" Safety Rail System, Class "FRL" - "AS" Fall Arrester Part No 4.97.0102.000 & 4.97.102.001** utilize "Cougar" Rail - Part #4.97.0300.xxx (last three numeric characters denote the length of the rail).	Compliance of existing product to new requirements has not yet been confirmed.	Use only in accordance with the manufacturer's instructions and until compliance to new Fall Back Performance is confirmed, utilize additional fall protection in the form of a double tie-off procedure.	www.trylon.com/safetyclimb/cougar_safetyrail.asp Phone - 1-877-834-8912

APPENDIX B

NORTH SAFETY PRODUCTS SAFETY ALERT

⚠ Important Safety Notice

All Climbers on Saf-T-Climb Systems Must Tie-off With Shock Absorbing Y-Type Lanyards

As a part of North Safety Products' on-going efforts to ensure our fall protection systems are the safest in the industry, we have identified certain conditions where Saf-T-Lok Sleeves or Rail may not perform properly during a fall. Under these conditions, a climber may fall farther than intended, resulting in serious injuries or death. If you have received this notice, you may have an affected Saf-T-Climb Fall Prevention System.

To reduce the risk of serious injuries or death:

⚠ **North Safety is instructing all climbers to tie-off with a Shock Absorbing Y-lanyard (no longer than 6'), that is ANSI Z359.1 compliant, in addition to using the Saf-T-Climb Fall Prevention System as directed in your Saf-T-Climb Instruction Manual.**

⚠ **For ALUMINUM rail Saf-T-Climb systems, ONLY use the Shock-Absorbing Y-lanyard. Do not use the Saf-T-Lok Sleeve.**

⚠ **For GALVANIZED STEEL rail and STAINLESS STEEL rail Saf-T-Climb systems, use BOTH the Shock-Absorbing Y-lanyard and the Saf-T-Climb system, including the sleeve and harness, as directed in the Saf-T-Climb Instruction Manual.**

If you are unsure what type of rail (i.e., aluminum or steel) your Saf-T-Climb system has, contact North Safety for help in identifying the material.

North Safety is continuing to investigate this issue and is currently designing an appropriate remedy. Once testing and production has been completed, North Safety will provide this remedy at no cost to existing customers of the Saf-T-Climb system who register their Saf-T-Climb systems or Saf-T-Lok sleeves with North Safety in response to this notice. In the meantime, all climbers MUST use a Shock Absorbing Y-lanyard (no longer than 6'). To ensure you are notified about the remedy, please register your Saf-T-Climb Fall Prevention system with North Safety at http://www.saf-t-climb.com or by faxing the enclosed registration form to (800) 585-2354.

If you have questions about this notice, selecting a Shock-Absorbing Y-lanyard, or proper climbing techniques, contact North Safety at (800) 836-8006, Option 4, between 8:30 a.m. and 4:30 p.m. ET Monday through Friday or visit http://www.saf-t-climb.com

Product Registration

Saf-T-Climb Fall Prevention Systems Safety Notice

Please complete the following form and fax to (800) 585-2354.

Download Form

Project Title: Replace Turbine/Generator Cooling Water Flow Meters

Location: Upper Salmon

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project involves the replacement of two orifice plate flow meters with electromagnetic flow meters at the Upper Salmon Generating Station (Upper Salmon). The flow meters are used for monitoring the cooling water flow to the unit's generator bearing and turbine shaft seal (see Figure 1). All work will be completed by Hydro's internal engineering and labor forces including design, procurement and installation. The budget estimate for this project is shown in Table 1.

Figure 1: Existing Orifice Plate Flow Meters at Upper Salmon

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	17.5	0.0	0.0	17.5
Labour	84.8	0.0	0.0	84.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	8.1	0.0	0.0	8.1
Interest and Escalation	7.2	0.0	0.0	7.2
Contingency	22.1	0.0	0.0	22.1
TOTAL	**139.7**	**0.0**	**0.0**	**139.7**

Operating Experience:

The existing flow meters in the Upper Salmon Generating Station are original to the station and are the Barton orifice plate type. The orifice plate flow meter has a thin plate placed in the pipe in which fluid flows, as seen in Figure 2. Then based on Bernoulli's principle, which states that there is a relationship between the pressure of the fluid and the velocity of the fluid, when the velocity increases, the pressure decreases and vice versa.

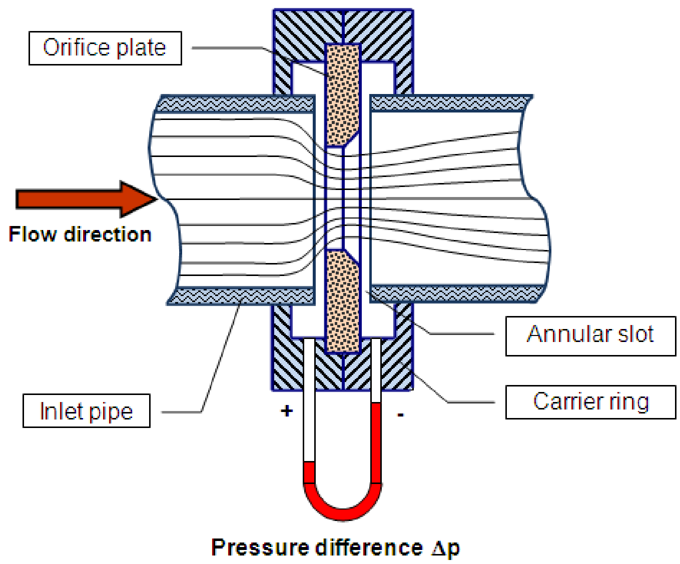


Figure 2: Barton Orifice Plate Flow Meter

The current flow meters have caused six forced outages over the last five years due to low flow alarms. As the plant is normally unmanned and remotely located, a low flow alarm is grouped and classified as a "unit major anomaly" alarm at the Energy Control Center in St. John's and necessitates unit shut down upon annunciation. As the orifice plate type flow meters are intrusive to the flow and are equipped with small diameter sensing lines, fouling is usually the cause of an alarm especially during high reservoir levels when eroded bog from the shorelines often ends up entering the cooling water system. Another problem with this type of flow meter includes wear of the orifice plate. Over time the hole in the plate will start to erode and the hole will grow bigger.

Electromagnetic flow meters are non-intrusive and do not require any sensing lines. These electromagnetic type flow meters replaced the orifice plate flow meters used for the generator surface air coolers at Upper Salmon in 2007 and replaced all six orifice plate type flow meters on the two units at Cat Arm Generating Station in 2011. A program is also in place to replace all of the orifice plate flow meters on the generating units at the Churchill Falls (Labrador) Corporation's generating station with electromagnetic flow meters.

Project Justification:

Upper Salmon is a remote unmanned plant and low flow alarms resulting from problems with the existing orifice plate flow meters have caused six forced outages in the last five years. Replacing the orifice plate flow meters with more reliable and less intrusive electromagnetic flow meters will reduce the number of forced outages and increase Upper Salmon availability. The electromagnetic flow meters, which are not susceptible to fouling, have been effective in reducing false alarms at Upper Salmon related to the surface air coolers, and at Cat Arm (see Figures 3 and 4) on Units 1 and 2 where they replaced all the cooling water system orifice plate flow meters in 2011. These electromagnetic flow meters require less maintenance because there are no orifice sensing lines that require cleaning. Reliability and accuracy of flow monitoring is critical to the operation of the generating unit. Loss of cooling water flow could result in high bearing temperatures, damage to the turbine shaft seal, and an extended forced outage. Also a low alarm causing a forced outage during peak loading in winter months or during a spill situation could result in significant costs.

Figure 3: New Electromagnetic Flow meters at Cat Arm

Figure 4: New Electromagnetic Flow Meters at Cat Arm

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Prepare design transmittal and open job	February 2014	February 2014
Design	Equipment selection and prepare installation drawing	March 2014	April 2014
Procurement	Order and receive equipment and materials	May 2014	August 2014
Construction and Commissioning	Installation, commissioning, and close out documentation	September 2014	October 2014

Future Plans:

Replacement of the orifice plate flow meters in Hinds Lake, for the turbine and generator cooling water system is planned in 2019.

Project Title: Raise Height of Earth Dam

Location: Paradise River

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

The Paradise River Hydroelectric Generating Station (Paradise River) is located on the Burin Peninsula. The reservoir at the Paradise River is contained by a concrete arch dam and an earth fill embankment dyke (See Figure 1). The earth fill embankment dyke is six metres high. This project involves raising the overall height of the earth fill embankment dyke by 0.60 m as well as raising the height of the impervious core by 0.45 m as shown in Figure 2.

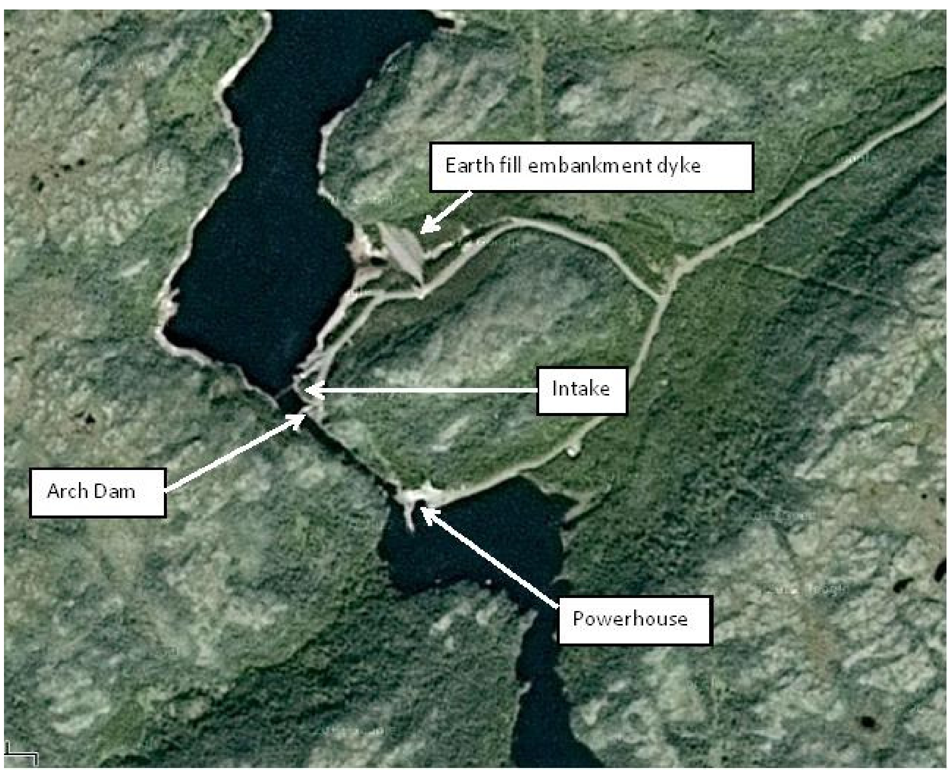


Figure 1: Project Layout

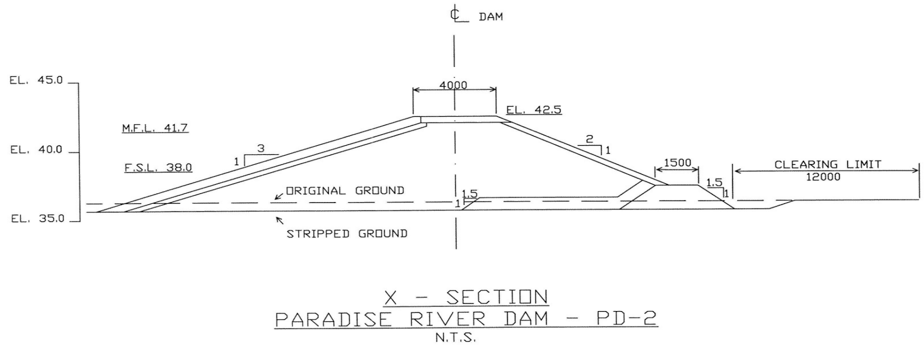


Figure 2: Earth Fill Embankment Section

The budget estimate for the project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	32.5	0.0	0.0	32.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	41.5	0.0	0.0	41.5
Other Direct Costs	4.7	0.0	0.0	4.7
Interest and Escalation	4.3	0.0	0.0	4.3
Contingency	15.7	0.0	0.0	15.7
TOTAL	**98.7**	**0.0**	**0.0**	**98.7**

Operating Experience:

The reservoir system at Paradise River has operated successfully since commissioning in 1988. A significant storm event occurred in September 2010 when Hurricane Igor passed through the Province that caused damage at Paradise River and prompted Hydro to undertake a review of the Inflow Design Flood (IDF) for Paradise River.

During the storm, the reservoir level increased to an estimated elevation of 42.1 m, which is above the IDF for Paradise River and overtopped the crest of the concrete arch dam by 0.40 m. Figure 3 shows the reservoir one day after the peak of the storm had passed. This is not a problem for a concrete structure but would likely cause erosion and failure of an earth embankment dyke. This reservoir level came within 0.40 m of the top of the earth embankment dyke. As a result, Hydro contracted a hydro technical consultant, Hatch, to undertake an IDF review. This review was completed in 2010 and the results are outlined below and attached in Appendix A.

Figure 3: Concrete Arch Dam and Powerhouse

Project Justification:

Following Hurricane Igor in September 2010, there was flooding and damage experienced in certain parts of Newfoundland, including the Burin Peninsula. Flood damage occurred at Paradise River as a result of this storm. Flooding damage was experienced at the Intake structure, in the gorge area below the concrete dam and further downstream, in the switchyard and adjacent to the accommodations building on site. After the storm subsided and road repairs were completed by Works Services and Transportation, Hydro personnel were able to gain access to the site. It became apparent during the site visit that the concrete arch dam had been overtopped, as water from the reservoir spilled over the top of the concrete arch dam by as much as .40 m. The concrete arch dam did not sustain any damage but it was estimated that the earth fill embankment dyke had come within .40 m of being overtopped. As a result of this event, Hydro retained a consultant to review the Inflow Design Flood (IDF) for the project. This review determined that the original IDF for the project had been exceeded. The original IDF was

388m^3/s and the new IDF was determined to be 618m^3/s. This new IDF was derived from more than 20 years of additional hydrologic data, since the original design, plus the Hurricane Igor event. As a result of this new IDF, the consultant recommended that the earth fill dyke at Paradise River be raised by 0.59 m to a new crest elevation of 43.09 m and additionally, the impervious core, which is the water retaining material of an earth fill embankment dyke, should be raised to the new maximum flood level of 42.73 m.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Project Planning	April 2014	April 2014
Design	Complete field reconnaissance and complete design	May 2014	May 2014
Procurement	Tender, evaluate and award	June 2014	July 2014
Construction	Undertake construction	August 2014	August 2014
Closeout	Closeout	September 2014	September 2014

Future Plans:

None.

APPENDIX A

PARADISE RIVER IDF STUDY

HATCH™

Suite E200, Bally Rou Place, 280 Torbay Rd.
St. John's, Newfoundland, Canada A1A 3W8
Tel. (709) 754 6933 ◆ Fax: (709) 754 2717 ◆ www.hatch.ca

February 7, 2011

Mr. Garry Poole, P.Eng.
Nalcor Energy - Newfoundland and Labrador Hydro
500 Columbus Drive
P.O. Box 12400
St. John's, NL A1B 4K7

Dear Sir:

Subject: Paradise River IDF Study - Final Letter Report

1. Introduction

Hatch Ltd. was retained by Nalcor Energy – Newfoundland and Labrador Hydro in November 2010 to perform a study of the Paradise River Hydroelectric System. The scope of work of this study is outlined and discussed below.

- Dam classification
- Inflow Design Flood (IDF) selection
- IDF handling assessment
- Freeboard assessment

2. Dam Classification

The concrete arch dam and embankment dam at Paradise River were classified in 1986 according to the Institute of Civil Engineers (ICE) "Floods & Reservoir Safety" guidelines (1978). Current dam classification is based on the 2007 Canadian Dam Association (CDA) Guidelines. A dam break study was performed by Generation Engineering for the concrete arch dam at Paradise River in March, 1999. The hydrological portion of this study was updated in April 2001 and the DAMBRK simulation was re-run. The results of the updated analysis are presented in an Inter-Office Memorandum, entitled "Paradise River Arch Dam (PD-1) DAMBRK Analysis", dated April 30, 2001 and form the basis of the current dam classification exercise.

The dam break study concluded that a breach of PD-1 will have little impact on the downstream community of Monkstown as only minor flooding along the shoreline is anticipated. The downstream model boundary condition was set at 0.5 m (high tide) and the resultant maximum water surface elevation at Monkstown due to simulated dam breach was 1.0 m. It was noted that the greatest economic impact downstream would be at

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February 7, 2011

Nalcor's powerhouse on Paradise River, where water levels were expected to reach an elevation of 17.1 m (3.7 m above the powerhouse roof elevation).

Dam classification was carried out according to 2007 CDA Guidelines which is based on three loss categories:

- Loss of Life
- Environmental and Cultural Loss
- Infrastructure and Economic Loss

2.1.1 Loss of Life

The community of Monkstown is the only permanently inhabited area downstream that could be affected in a dam breach scenario. It is important to determine the extent of expected flooding at Monkstown before selecting a dam classification. A decision to classify the dam as **SIGNIFICANT** or **HIGH** would hinge on whether the population at risk is temporarily or permanently in the dam breach inundation zone, as follows:

1. **SIGNIFICANT**: Population at risk is considered temporary only, i.e., people are only temporarily in the dam breach inundation zone (e.g., seasonal cottage use, passing through on transportation routes, participating in recreational activities).
2. **HIGH**: Population at risk is considered permanent, i.e., the population at risk is ordinarily located in the dam breach inundation zone (e.g., as permanent residents).

Based on a field investigation carried out on January 20, 2011, there appeared to be no permanently inhabited structures in Monkstown situated below the simulated dam breach flood elevation (1.0 m above mean sea level). Consequently, a dam classification of **SIGNIFICANT** is applied for loss of life.

2.1.2 Environmental and Cultural Loss

No environmental or cultural losses were identified in the dam break study. For this reason, a dam classification of **LOW** is applied for environmental and cultural loss.

2.1.3 Infrastructure and Economics

Economic losses that may be incurred by the dam owner are typically not included in this assessment except in cases where the owners' losses have a great impact on society. Potential economic loss sustained at Paradise River Powerhouse have therefore not been considered in the classification exercise. Since economic losses at Monkstown are considered to be low, a dam classification of **LOW** is applied for infrastructure and economic loss.

Of the three loss categories, the governing classification is **SIGNIFICANT** based on potential loss of life. For the perimeter embankment dam, it can be assumed that the consequences of failure will be less than that of PD-1 based on the relatively smaller structure. In the absence of any dam break analysis for this structure, it can easily be assumed that this structures classification would either be **LOW** or **SIGNIFICANT**. For this exercise it is assumed to have the same classification as the concrete arch dam at Paradise River based on their close proximity and the fact the arch dam will likely have a more critical consequence of failure and govern IDF selection.

Freeboard and flood routing analyses were carried out for this dam classification.

3. Inflow Design Flood Selection

The IDF of PD-1 is the 1/1,000 annual exceedance probability (AEP) flood. In the "Paradise River Small Hydro Development Pre-Feasibility Study" (May, 1986), the flood peak magnitude was determined from a regional hydrology chart prepared by ShawMont Newfoundland Limited, showing mean annual instantaneous flood (Q_{MAF}) as a function of drainage area and providing a list of multipliers to obtain various AEP flood estimates (Q_T) from the value of Q_{MAF}. (The reader is referred to Chart #1, Appendix II of the feasibility study report.) Using the chart, a Q_{MAF} of 155 m^3/s was estimated for Paradise River, and the multiplier for the 1/1,000 AEP flood was 2.50, yielding an estimate of 388 m^3/s for $Q_{1,000}$.

A calculation check of the main dam spillway discharge capacity as constructed suggests a flow capacity of 390 m^3/s at dam crest level, which is consistent with the 1/1,000 AEP flood estimate above.

For the current study, the perimeter embankment dam is assumed to have the same hazard classification, and thus the same IDF, as the concrete arch dam. The IDF for a **SIGNIFICANT** classification, as specified by the 2007 CDA Guidelines, is the 1/1,000 AEP flood.

The above flood estimates were prepared in 1986 based on data available at that time. As there are now more years of data available, new flood estimates are recommended. The records of two nearby Water Survey of Canada (WSC) gauges were reviewed for use in this analysis:

Table 3-1: WSC Hydrometric Gauges

Gauge Name & Number	Period of Record	Drainage Area (km^2)
Piper's Hole River (02ZH001)	1953 – 2009	764
Rattle Brook near Boat Harbour (02ZG004)	1981 – 2009	42.7

A flood frequency analysis was carried out on historical instantaneous annual maximums from the gauge at Piper's Hole River. The gauge has a period of record of annual maximums from 1953 to 2009 and a drainage area of 764 km^2. Piper's Hole River gauge was selected for this analysis based on its length of record, which makes it a suitable candidate for frequency analysis, and its proximity and similarity in drainage area and physiography which are expected to make its runoff characteristics similar to those of Paradise River. The Paradise River Hydroelectric System has a total drainage area of 477 km^2.

Flood frequency estimates (Q_T) for various AEPs for Piper's Hole River were determined by fitting a Three-Parameter Lognormal (3PLN) distribution curve to the Piper's Hole data. The estimates were then transposed to Paradise River using the Index Flood Method. The assumption is that the ratio of various AEP floods to the 1/2 AEP flood (Q_T/Q_2) for Paradise River is the same as for Piper's Hole River. Knowing the ratios of Q_T/Q_2 from the Piper's Hole data, the ratios can be multiplied by the estimated Q_2 at Paradise River to produce corresponding AEP flood estimates Q_T at Paradise River.

To use this method, an independent estimate of Q_2 at Paradise River is required. Within a homogeneous hydrologic region, Q_2 can be estimated from known values at other sites on the basis of drainage area. Thus Q_2 for Paradise River was estimated by linearly interpolating (by drainage area) between the Q_2 for Piper's Hole River and Rattle Brook, to arrive at a value of 156 m^3/s. (As a check, an alternative Q_2 estimate of

158 m^3/s was determined using a regional regression equation developed by the provincial Water Resources Management Division; the estimates were considered to be consistent.)

Using the flood data up to 2009, the resulting 1/1,000 AEP flood estimate for Paradise River was 384 m^3/s, very similar to the 388 m^3/s estimated in 1986. However, the available flood data at Piper's Hole River did not include data from Hurricane Igor. According to WSC staff, the hydrometric gauge was lost in the hurricane. The occurrence of extreme historical events should always be taken into consideration, as they can greatly alter the estimates of flood frequency. Further investigation was carried out to determine the sensitivity of the flood frequency estimates to the inclusion of Hurricane Igor in the historical data set.

In the absence of data from the hydrometric gauge, it was necessary to devise an alternative estimate of peak flow during Hurricane Igor that could be added to the data set. Nalcor personnel advised that, during Hurricane Igor, debris was deposited up to an elevation of 42.1 m along the face of the perimeter embankment dam. This elevation is assumed to be the maximum water surface elevation for this event, although it should be noted that this may underestimate the water surface elevation as debris may have been deposited as the reservoir level was receding. The peak flow for Hurricane Igor was estimated to be 472 m^3/s by extending the discharge rating curve at Paradise River (spillway and dam overtopping) to elevation 42.1 m. (The discharge rating curve is discussed in Section 4 below.) This estimate was transposed to Piper's Hole River on the basis of drainage area, and the 3PLN curve was re-fit to the extended data set. The Index Flood method was repeated to develop a second set of flood estimates at Paradise River that includes the effect of Hurricane Igor on the frequency distribution.

Table 3-2 below presents both sets of flood estimates for Paradise River. As can be seen by the results, prior to 2010, an event such as Hurricane Igor would have been considered to be more extreme than a 1/10,000 AEP event. However, statistical frequency estimates are based on knowledge of what has happened in the past; when an event much larger than any on record occurs, the effect is to increase the predicted frequency of extreme events. The updated results suggest that the AEP of the Hurricane Igor flood at Paradise River (472 m^3/s) is between 1/100 and 1/1,000, and that the 1/1,000 AEP flow is higher than previously estimated in 1986. The recommended peak flood value for the 1/1,000 AEP event (IDF for **SIGNIFICANT** classification) is 618 m^3/s.

Table 3-2: Updated Flood Frequency Analysis Results (Paradise River)

AEP	Q_T based on 1953-2009 data (m^3/s)	Q_T based on 1953-2010 data (m^3/s)
1/10,000	441	820
1/1,000	384	**618**
1/100	320	438
1/50	298	387
1/10	241	274
1/5	210	225
1/2	156	156

4. Inflow Design Flood Handling Assessment

A reservoir routing exercise was carried out on Paradise River headpond using Acres Reservoir Simulation Package (ARSP). Reservoir storage and spillway rating curves were obtained from previous studies, extrapolated to an elevation of 43.0 m and are presented below.

Table 4-1: Paradise River Headpond Storage Curve

Elevation (m)	Volume (10^6 m^3)
35	0
36	0.25
37	0.77
38	1.29
39	1.83
40	2.38
41	2.93
42	3.49
43*	4.05*

* value extrapolated for current study

Table 4-2: Paradise River Discharge Rating Curve

Elevation (m)	Spillway Discharge (m^3/s)	Concrete Crest Overflow Discharge (m^3/s)	Total Discharge (m^3/s)
38.0	0	0	0
38.5	17	0	17
39.0	51	0	51
39.5	97	0	97
40.0	156	0	156
40.5	218	0	218
41.0	286	0	286
41.5	360	0	360
41.7	390	0	390
42.0*	438*	11*	449*
42.1*	455*	17*	472*
42.5*	523*	47*	570*
43.0*	613*	97*	710*

* values extrapolated for current study

The rating curve of the spillway (crest elevation 38.0 m) extended only up to the elevation of the concrete dam crest (elevation 41.7 m). The design flow at this elevation is 390 m^3/s which corresponds closely to the previous 1/1,000 AEP flood estimate. Given the revised 1/1,000 AEP inflow estimate (618 m^3/s), it was necessary to extrapolate the rating curve to higher elevations, and to include overflow of the concrete crest.

The extrapolated discharges were calculated using the weir equation.

Weir Equation: $Q = C_w L H^{1.5}$

where Q is flow (m^3/s)

C_w is the weir discharge coefficient

L is the length of the structure (m)

H is the height of water above the structure crest (m)

The length of the spillway is 26.7 m, and the calculated weir coefficient of the spillway is 2.05 (based on the design flow of 390 m^3/s) which is consistent with an ogee spillway. The overtopping length of the concrete crest is 45 m, and the assumed weir coefficient of the crest is 1.46 which is typical for a broad-crested weir.

Historical flow records for Piper's Hole River were reviewed, and a flow hydrograph from 1988 was selected as a representative inflow hydrograph shape for modeling purposes, on the basis of maximizing flood peak and volume.

The simulated maximum flood level for the 1/1,000 AEP flood was 42.73 m, which is 0.23 m over the crest of the perimeter embankment dam (crest elevation 42.5 m), and 1.03 m over the crest of the concrete dam.

5. Freeboard Assessment

The scope of the freeboard assessment included the following.

- Conduct wind frequency analysis.
- Estimate required freeboard (wave run-up and wind setup) for the perimeter embankment dam.

The industry accepted guideline related to determining allowable freeboard for structures in Canada is the 2007 CDA Guidelines. These guidelines state that for an earth embankment structure, the crest level should be set so that the structure is protected against the most critical of the following conditions.

- Condition 1: No overtopping by 95 percent of the waves caused by the most critical wind with an AEP of 1/1,000 when the reservoir is at its maximum normal elevation.
- Condition 2: No overtopping by 95 percent of the waves caused by the most critical wind when the reservoir is at its maximum extreme level during passage of the IDF. For **SIGNIFICANT** consequence dams, CDA recommends using the 1/10 AEP wind speed during the IDF condition.

Environment Canada maintains a network of wind measurement stations in Canada and a search was conducted for representative long term wind stations that could be used to approximate wind conditions for Paradise River. The wind station for the St. John's Airport (available data 1953-2009) was the closest available station with a suitable record. Hourly wind data by direction was provided by Environment Canada for the period of record noted above. Wind frequency analyses were completed for the annual series of peak hourly wind speeds (by direction). The wind frequency estimates are summarized in Table 5-1.

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Nalcor Energy - Newfoundland and Labrador Hydro
February 7, 2011

Table 5-1: Wind Frequency Estimates

Direction	Peak Hourly Wind Speed (km/h)	
	1/1,000 AEP	1/10 AEP
North	159	89
Northeast	103	76
East	108	76
Southeast	95	75
South	106	85
Southwest	145	91
West	126	94
Northwest	149	88

A freeboard assessment was carried out, in accordance with U.S. Army Corps of Engineers Coastal Engineering Manual (CEM) methodology to determine the freeboard requirement under normal and IDF conditions. The following steps were carried out to determine the run-up and setup on the dam for each cardinal wind direction.

- Calculation of effective and maximum fetch for each direction.
- Correction of wind speeds from over land to over water.
- Calculation of wave parameters (wave period, time to form under fetch-limited conditions, wave height, wave length, wave steepness).
- Wave type check (deep water).
- Correction of wave height for angle of incidence.
- Calculation of run-up.
- Calculation of setup (wind tide).

The results of the freeboard assessment are summarized in Table 5-2. The critical wind direction is the direction of the wind that produces the largest freeboard requirement (combination of wave run-up and wind setup) of all winds for the given AEP.

Table 5-2: Freeboard Estimates

	Condition #1: Normal Freeboard	Condition #2: Minimum Freeboard
Condition	1/1,000 AEP Wind + FSL	1/10 AEP Wind + IDF Maximum Flood Level
Critical Wind Direction	SW	SW
Wind Speed	145 km/h	91 km/h
Effective Fetch	0.72 km	0.72 km
Run-up	0.45 m	0.35 m
Setup	0.02 m	0.01 m
Required Freeboard (Run-up + Setup)	0.47 m	0.36 m
Still Water Level	38.00 m	42.73 m
Available Freeboard (Embankment Crest el. 42.5 m – Still Water Level)	4.5 m	None (overtopped by flood)
Freeboard Adequate?	YES	NO
Required Embankment Crest el.	n/a	(42.73 + 0.36) = 43.09 m

As shown in Table 5-2 the normal freeboard is adequate but the minimum freeboard requirement is not met. In the IDF, as already noted in Section 4, the maximum flood level is 42.73 m, overtopping the embankment dam by 0.23 m. Therefore the embankment dam crest has to be raised to 42.73 m plus an additional 0.36 m to allow for freeboard, to elevation 43.09 m (i.e., total crest raising required 0.59 m).

6. Conclusions and Recommendations

A dam classification is the first step in determining the extent of any remediation requirements at Paradise River perimeter embankment dam. It is recommended that the main dam and perimeter embankment dam be classified as **SIGNIFICANT** under the 2007 CDA Guidelines and that an IDF be adopted with an AEP of 1/1,000 and peak inflow 618 m^3/s.

It is recommended that the perimeter embankment dam at Paradise River be raised by 0.59 m to crest elevation 43.09 m. It should be noted that the impervious core should, at a minimum, be at the elevation of the maximum flood level, 42.73 m, in accordance with the 2007 CDA Guidelines. For PD-1, review of dam stability should be conducted taking into consideration the higher level of overtopping than previously assumed for design.

Yours truly,

R.D. Woolgar, P.Eng.
Manager, Newfoundland and Labrador Renewable Power
WMc:cdh

cc: Carissa Sparkes (Nalcor Energy - Newfoundland and Labrador Hydro)

Project Title: Replace Engine on Emergency Lift System

Location: West Salmon Spillway

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project involves the replacement of the Lombardini 3LD510 diesel engine for the portable emergency lift system which is used to operate the two gates at West Salmon Spillway. Work will include engineering, procurement and adapting the new engine to the existing emergency drive. All work will be completed by Hydro's internal engineering and labor personnel.

The budget estimate for the project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	6.5	0.0	0.0	6.5
Labour	43.4	0.0	0.0	43.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	3.3	0.0	0.0	3.3
Interest and Escalation	3.3	0.0	0.0	3.3
Contingency	10.6	0.0	0.0	10.6
TOTAL	**67.1**	**0.0**	**0.0**	**67.1**

Operating Experience:

The existing emergency system as seen in Figure 1 is located in the hoist house of the West Salmon Spillway structure. It is a portable unit which can be relocated to operate either of the two spillway gates. It was part of the original design to be used in an emergency when the normal power supply from the incoming power line or the emergency backup diesel generator is lost and the spillway gates have to be opened to spill water during a flood situation. The emergency lift system is tested on an annual basis to confirm its readiness. It was installed in 1988 when the spillway structure was constructed and by the year 2014 it will be over 25 years old. The Lombardini diesel engine which drives the emergency lift system has had a total of four starting and fuel supply issues in the last five years and since the Lombardini engine is no longer manufactured, spare parts are unavailable.

Project Justification:

Emergency lift systems for reservoir spillway gates are critical design features and must be reliable when needed. Where they are the last source, a failure of these systems when required during flood situations could result in a dam breech and flooding with potential for major loss to property, loss of life, and damage to the environment. The engine is no longer manufactured and spare parts are no longer available. It has reached the end of its service life and needs to be replaced to ensure reliable operation of the emergency lift system.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Open work order, refine schedule, site visit	March 2014	April 2014
Design	Design necessary modifications, drawings, procedures	April 2014	June 2014
Procurement	Procure engine and other components	April 2014	July 2014
Construction	Modify base and install engine	September 2014	September 2014
Commissioning	Test engine by lifting gate	September 2014	September 2014
Closeout	Close work order, lesson learned	October 2014	October 2014

Figure 1: Diesel Engine for Emergency Drive at West Salmon Spillway

Future Plans:

None.

Project Title: Overhaul Boiler Feed Pump East Unit 3

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project will involve overhauling the Unit 3 boiler feed pump requiring a full disassembly of the pump. The boiler feed water pump supplies water at high pressure to the boiler for producing steam. Unit 3 boiler has two boiler feed water pumps. Each pump is capable of supplying feed water for 50 percent capacity of the boiler. The boiler feed water pump draws water from the deaerator feed water tank located at the eighth floor. The pump is driven by a 3,000 horse power motor and is capable of pumping 1,088 gallons per minute at a pressure of 2,700 pounds per square inch. It draws feed water at a temperature of 300 degrees Fahrenheit before pumping to the high pressure heaters.

The refurbishing of the Unit 3 boiler feed pump will include:

- Removing the pump;
- Dismantling the pump;
- Examining components;
- Replacing the volute;
- Repairing wear damage to barrel; and
- Reassembling the pump.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	5.0	0.0	0.0	5.0
Labour	40.0	0.0	0.0	40.0
Consultant	20.0	0.0	0.0	20.0
Contract Work	90.0	0.0	0.0	90.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	8.9	0.0	0.0	8.9
Contingency	31.0	0.0	0.0	31.0
TOTAL	**194.9**	**0.0**	**0.0**	**194.9**

Operating Experience:

Typically one boiler water feed pump is in service until the unit is producing 80 MW, at which point a second boiler water feed pump is necessary to provide sufficient feed water if the generation is to be increased above 80 MW.

Project Justification:

Two boiler feed pumps are required to produce 100 percent power; a loss of one pump will restrict the unit production. Moreover, with only one operating pump running, there is the increased risk of the unit being out of service completely if the operating pump breaks down. Recognized pump specialists Flowserve, were consulted for optimization of the overhaul schedule for boiler feed pumps at Holyrood and they established that "Based on operating experience at Holyrood the (BFP) volutes cannot be left in service for more than seven years without the risk of barrel damage", outlined in Appendix A page 2. The boiler feed pump east on Unit 3 was last overhauled in 2008.

During the last operating season, December 2012 to April 2013, both east and west operating pumps had deteriorated to the point where a second pump was required for operation at 70 MW. From operating experience, this is an indication of poor pump health prior to failure. With the west boiler feed pump overhaul being completed in 2013, the earliest the east pump can be overhauled is 2014.

Future Plans:

Other boiler feed pump overhaul projects will be proposed in future capital budget applications.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Project initialization, refine schedule	January 2014	January 2014
Design	Project design	February 2014	February 2014
Procurement	Equipment/part procurement	March 2014	March 2014
Construction	Remove and dismantle pump, replace volute and repair barrel. Reassemble pump	April 2014	June 2014
Commissioning	Commissioning and testing of pump	June 2014	July 2014
Closeout	Project completion and closeout, lessons learned	August 2014	September 2014

APPENDIX A

FLOWSERVE REVIEW (MAY 24, 2011)

FLOWSERVE

ServiceRepair Division

LONG TERM ASSET PLANNING

Customer: Newfoundland Labrador Hydro Holyrood G.S.

References: Holyrood Meeting Minutes – May 9, 2011
Holyrood Forecast Repair Chart
Flowserve Site Visit By Arnold Padgett

Date: May 24, 2011

Meeting Minutes – Item 11 Discussion Items

1 - The 3 remaining LP Drains Pumps – one in each unit require repair and conversion to mechanical seal.

2 – Refer to marked up "Repair Chart". Flowserve estimate of dollars vary a little from Holyrood's but there are unknowns in each repair. The overall costs are approximately the same. Holyrood's repair schedule on the pumps and timing is acceptable. Flowserve recommend that the repairs for 2019 and 2020 be deleted. The cost increased in Units 1 and 2 extraction pumps from the 1st pump in 2012 is because of probable new 1st stage impeller. Holyrood has one impeller in stock.

3 – The existing pumps are repairable at a much lower cost than replacement pumps and in a much shorter time interval. All of Holyrood's 4000 volt pumps have an acceptable mean time between repair.

4 – Baseline Test. Any additional baseline testing is not relevant at this time in the remaining life of the station. Each pump groups have internal weaknesses that will be presented that baseline testing would not pick up.

5 – Nash Vacuum Pumps. These pumps have not been a high maintenance pump but are of cast iron construction. It may be worth purchasing one new pump for inventory in case it is needed.

6 – Smaller verticals would be a better option for synchronous condenser cooling.

Additional Pumps

Add the LP Drain Pumps to the list as these pumps help to unload the extraction pumps minimizing cavitation damage on the 1st stage impeller and allowing Units 1 and 2 to basically run on one pump up to 150 MW range.

Page 1 of 3

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FLOWSERVE

ServiceRepair Division

Pump History And Weaknesses

Boiler Feed Pumps – Unit 1, 2 and 3

The weakness in the pump design is the sealing gasket surface of volute to barrel. The two volute haves split surface is a lapped surface relying on external discharge pressure to seal across the split surface. Over running time leakage occurs across the split surface around the volute to barrel gasket. Wire drawing takes place cutting through the gasket and into the barrel. If left unattended major repair of the barrel is required involving field welding and machining which has a significant repair cost. Based on operating experience at Holyrood the volute cannot be left in service for more than 7 years without the risk of barrel damage. The unit 3 pumps have a new volute to barrel design gasket that would appear may give a longer time between volute change out.

Extraction Pumps

Units 1 and 2
These pumps had a history of expensive repair due to pump thrust bearing failures, 1st stage impeller cavitation and stuffing box deterioration letting air into the system. Starting in 1999 thru to 2001 each pump was repaired, converted to mechanical seal and a new high thrust efficiency motor capable of carrying the pump thrust load. The inlet vanes of the 1st stage double suction impeller were cut back approximately 1.25" to remove the cavitational damage and to save the impeller.

Unit 3
Prior to Flowserve repair in 2003 and 2005 there was no history of these pumps having been repaired. The cavitated cast iron suction bells were replaced in 304ss.

C.W. Pumps

Unit 1 and 2
These pumps have been modified starting in 1998 with a spider in each outer column, 316ss suction liner and a mechanical seal. The unit 1 west pump repaired in 2010 has a large piping strain which will affect the life of the pump.

Unit 3
These pumps were repaired in 1997 and 2001. Inadvertently the bearing sleeves were hard chrome plated for longer life but chrome plating does not stand up in sea water. All pumps have been repaired since with standard 316ss bearing sleeves.

Vacuum Pumps

All pumps have been repaired once by Flowserve.

Page 2 of 3

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L.P. Drain Pumps

These pumps never worked and were added to Flowserve list of pumps.

A piping change was required on all three units. In addition the Units 1 and 2 pumps required re-bowling to a smaller size pump. Since the changes the pumps have operated satisfactory for a 11 year period.

Arnold Padgett May 24, 2011

Page 3 of 3

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Long Term Asset Planning Department

Meeting Minutes – Pump Overhauls / Replacement / Optimization

May 9, 2011
Present: Jeff Vincent, Paul Woodford, Bob Garland
Next meeting: May 17, 2011, 09:00, Conference Room

I. Arnold Padgett

Arnold has been scheduled to come to site for May 17 – 18 to assist us with developing our long term pump maintenance strategy. The following is a list of items that we would like him to address while he is here.

II. Discussion Items

- Based on Paul's Historical document – What's next and when? Mechanical seals on balance of pumps?
- Based on Jeff's overhaul schedule, assign budget dollars to items.
- Should we replace any pumps due to obsolescence, efficiency gains or deteriorated condition (not maintainable)
- Do we have sufficient Instrumentation/Monitoring Software in place to predict what pumps to overhaul next year, allowing us to budget for, plan and execute, any required maintenance.
- Define any baseline tests that may be required such as vibration, bearing temperature, discharge pressure, flow etc.
- Specifically, Nash Vacuum pumps, what is the recommended strategy? Maintain / Replace?
- Recommend options to provide cooling water for Stage I synchronous condenser operation mode.

III. Timeline for Steam @ HRD

- Official timeline

2011 – 2016	Status Quo	- Load Increasing, GWA ≥ 95%
2017 – 2019	Standby	- One Unit Hot
2020 – ∞	All Three Units as Synchronous Condenser	

- Likely timeline

2011 – 2018	Status Quo	- Load Increasing, GWA ≥ 95%
2019 – 2021	Standby	- One Unit Hot
2022 – ∞	All Three Units as Synchronous Condenser	

IV. Supporting Documents

- FlowServe Pump Binder, formerly Jeff' Vincent's, now kept in Paul Woodfords office.
- Flowserve document – N&L Hydro Holyrood G.S. Repair History

Pumps	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
1 CW Pump East			X												76,762.00					1 CW Pump East
1 CW Pump West											75,000.00									1 CW Pump West
2 CW Pump East	X				X												84,438.00			2 CW Pump East
2 CW Pump West												66,750.00								2 CW Pump West
3 CW Pump East		X									75,000.00									3 CW Pump East
3 CW Pump West						75,000.00												105,500.00		3 CW Pump West
1 Ext Pump North	X												79,000.00							1 Ext Pump North
1 Ext Pump South			X												91,500.00					1 Ext Pump South
2 Ext Pump North					10,000.00												100,500.00			2 Ext Pump North
2 Ext Pump South		X												80,500.00						2 Ext Pump South
3 Ext Pump North						60,000.00												75,000.00		3 Ext Pump North
3 Ext Pump South				X												68,000.00				3 Ext Pump South
1 Vac Pump North											25,000.00									1 Vac Pump North
1 Vac Pump South			X												28,000.00					1 Vac Pump South
2 Vac Pump North				X												29,000.00				2 Vac Pump North
2 Vac Pump South							15,000.00												32,000.00	2 Vac Pump South
3 Vac Pump North				X												29,000.00				3 Vac Pump North
3 Vac Pump South			X												28,000.00					3 Vac Pump South
1 BF Pump East		X								100,000.00						140,000.00				1 BF Pump East
1 BF Pump West				X							160,000.00							154,500.00		1 BF Pump West
2 BF Pump East					70,000.00								160,000.00						162,000.00	2 BF Pump East
2 BF Pump West			X									179,500.00					147,000.00			2 BF Pump West
3 BF Pump East	X								100,000.00						145,000.00					3 BF Pump East
3 BF Pump West	X					10,000.00								138,000.00						3 BF Pump West
Total					80,000.00	145,000.00	15,000.00		100,000.00	100,000.00	335,000.00	246,250.00	239,000.00	218,500.00	369,262.00	266,000.00	331,938.00	335,000.00	194,000.00	

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Newfoundland & Labrador Hydro Holyrood G.S. Repair History

Units 1 & 2 B.F. Pump History – Byron Jackson

1994 – Units 1 & 2 East B.F. Pump	: field welded barrel and field machined. repaired cartridge installed.
1995 – Units 1 & 2 West B.F. Pump	: field welded barrel and field machined. repaired cartridge installed.
1996 – Unit 2 East	: Pump self destruct. Replaced cartridge.
1997 -	: Identified the system problem failing the East B.F. Pumps.
1998 – Units 1 & 2	: Increased the system resistance for the East B.F. Pumps by installing a 3 stage orifice in the discharge line from inside the barrel. Repaired the discharge cover of Unit 2 East ie a minor failure.
2001 – Unit 1 East	: changed out the cartridge – planned repair after 7 years of service.
2002 – Unit 2 West	: changed out cartridge – planned repair after 7 years of service.
2003 – Unit 1 West	: changed out cartridge – planned repair after 8 years of service.
2004 – Unit 2 East	: changed out cartridge – planned repair after 7 years of service.
2009 – Unit 1 East	: changed out cartridge after 8 years – barrel washed requiring welding & machining. Close clearance stufbx bushings installed. Larger drain holes in bearing support brkt.
2010 – Unit 1 West	: changed out cartridge after 7 years – barrel repair and hand dressing. Close clearance stufbx bushings installed. Larger drain holes in bearing support brkt.

Units 1 & 2 Extraction Pump History – Mather + Platt

1997 -	: reviewed maintenance history and made upgrade recommendations. - delete the pump thrust bearing. - new motors with high thrust bearing. - change from packing to mechanical seal.
1999 – Units 1 South and 2 North	: repaired and upgraded per recommendations.

Page 1 of 4

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2000 – Unit 1 North	: repaired and upgraded per recommendations.
2001 – Unit 2 South	: repaired and upgraded per recommendations.
2004 – Unit 2 North	: inspected 1st stage impeller for cavitation damage – no damage.

Units 1 & 2 C.W. Pump History – Ingersol Rand

1997	: reviewed maintenance history and made recommendations. -each outer column to have a spider and bearing. -replace the bowl marine bearings with a small fluted Thordon bearing. -change from packing to mechanical seal.
1998 – Unit 2 West	: repaired and upgraded per recommendations.
1999 – Unit 1 west	: repaired and upgraded per recommendations.
2000 – Unit 2 East	: repaired and upgraded per recommendations.
2002 – Unit 1 East	: repaired and upgraded per recommendations.
2004 – Unit 2 East	: bolting from column to bowl came off breaking pump shaft. Pump repaired
2010 – Unit 1 West	: new bearings, line shafts, pump shaft head shaft and mechanical seal.. Considerable pipe strain from valve

Units 1 & 2 Vacuum Pumps History - Nash

1997	: reviewed maintenance history and Inspected one pump.
2002 – Units 1 & 2	: repaired 2 pumps
2003	: repaired 1 pump.
2010 – Unit 1 South	: repaired pump.

Units 1 & 2 LP Drain Pumps – Bingham/Willamette

1997	: added to the list of pumps
1998	: piping modification.
1999	: re-bowl – 4 pumps.

Page 2 of 4.

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2010	: repaired one pump from each unit c/w mechanical seal

Unit 3 B.F. Pump History – Bigham/Willamette

1995	: East & West pump repaired by Bingham/Willamette.
1996 – East Pump	: repaired washout on discharge cover – BW/IP
1998 – West Pump	: repaired washout on discharge cover – BW/IP
1999 – East Pump	: repaired washout on discharge cover – BW/IP - design change on balance bushing to prevent cover washout. - temporary repair of barrel washout. - designed new cartridge to barrel gaskets. - installed repaired cartridge.
2000 – East Pump	: weld repair and field machine barrel. Installed the same cartridge c/w new design cartridge to barrel gasket.
2000 – West Pump	: weld repair and field machine barrel. - installed repaired sag bore cartridge c/w new design cartridge to barrel gasket.
2002 – West Pump	: replace leaking discharge cover gasket. - requested an order for high pressure cover gaskets.
2003 – East And West Pump	: replaced inboard glands.
2005 – West Pump	; discharge cover gasket leaking. - removed cartridge – barrel washed at high pressure gasket. - field welded and machined. - repaired sag bored cartridge installed c/w new discharge cover gasket. - discharge cover gasket surface machined.
2008 – East Pump	: planned change out of cartridge - 9 years of service. - no barrel wash. - replace outboard gland.

Page 3 of 4.

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2008 – West Pump	: replaced outboard gland.

Unit 3 Extraction Pump History – Bingham/Willamette

2003 – South Pump	: repaired pump
2005 – North Pump	: repaired pump

Unit 3 C.W. Pump History – Ebara

1997 – West Pump	: repaired pump.
2001 – East Pump	: repaired pump
2005 – West Pump	: repaired pump - changed from threaded line shaft couplings to sleeve type. - no hard chrome plating on bearing sleeves.
2010 – East Pump	:new bearings and bearing sleeves

Unit 3 Vacuum Pump History - Siemens

1997 – South Pump	: inspected – no repair. 304ss rotor.
1999 – North Pump	: repaired using devcon repaired parts. New 304ss rotor re-versed engineered.
2003 – North Pump	: repaired with new 304ss rotor.

Unit 3 LP Drain Pump History

1998	: requested piping change.
2010 – West Pump	: repaired pump c/w mech. seal.

Page 4 of 4.

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Project Title: Replace DC Distribution Panels and Breakers

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project includes the replacement of 129 V and 258 V DC distribution panels and breakers and the purchase of critical spares for the Stage 1 (Units 1 and 2) DC electrical system at the Holyrood Thermal Generating Station (Holyrood). The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	36.5	0.0	0.0	36.5
Labour	98.7	0.0	0.0	98.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	1.0	0.0	0.0	1.0
Other Direct Costs	0.6	0.0	0.0	0.6
Interest and Escalation	10.0	0.0	0.0	10.0
Contingency	27.4	0.0	0.0	27.4
TOTAL	**174.2**	**0.0**	**0.0**	**174.2**

The Stage 1 DC panels and breakers included for replacement in the 2014 project are:

- Unit 1 258 volt DC panel and breakers;
- Unit 2 258 volt DC panel and breakers;
- 129 volt DC main distribution panel and breakers;
- Unit 1 129 volt DC panel and breakers;
- Unit 2 129 volt DC panel and breakers; and
- Common 129 volt DC panel and breakers.

Operating Experience:

The Stage 1 129 volt and 258 volt DC panels and breakers supply power to critical protection and control equipment. The purpose of the panels and breakers is to distribute DC power from the battery banks to various DC equipment, and protect the electrical cables and DC equipment in the event of a fault. The DC panel breakers are frequently operated by electricians in order to isolate the DC equipment for maintenance. The frequency of operation can vary depending on the maintenance schedule, but typically the breakers are locked out and tagged out on a monthly basis. See Figure 1.

Figure 1: Unit 1 129 V and 258 V DC panels locked out and tagged

Project Justification:

The recent failure of Unit 1 at the Holyrood Thermal Generation Station on January 11, 2013 has highlighted the criticality of the DC system and its function for reliable operation of various plant processes. The failure was a result of a lack of lubricating oil to Unit 1. The lubricating oil pump is driven by a DC motor. The DC system supplies power to lubricating oil pumps for each unit, as well as other critical auxiliary systems for the units and plant processes. The DC system is comprised of batteries, chargers, power cables, distribution panels and breakers, and motors. This project proposal is for the replacement of the DC distribution panels and circuit breakers.

This project is justified on the basis of reliability. The 129 volt and 258 volt DC distribution panels are original to the plant, circa 1969, with the exception of Unit 2's 258 V DC panel which was replaced in

1991. The anticipated service life of distribution panels is 30 years. Consequently, all of the stage 1 panels have exceeded their useful service life, with the exception of Unit 2's 258 Vdc panel. Additionally, the Unit 1 129 V and 258 Vdc panel breakers are no longer available from the manufacturer and no replacement breaker exists for this type of panel. In consideration of the age and critical application of the DC system, it is necessary to replace the distribution panels with modern versions. Replacement of the DC panels will ensure reliability of the system and make available an adequate supply of critical spares.

This project is planned to occur during the scheduled Stage 1 outage and supports a pro-active approach for replacement. Alternatively, should a distribution panel fail during regular plant operation, replacement of the panel and breakers at that time could result in an unscheduled outage of upwards of six weeks, including purchase, delivery and replacement time. This would be especially problematic during the winter peak season.

Project Schedule:

The anticipated project schedule is shown in Table 2

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Project initiating, design transmittal, schedule and cost baseline and project plan	January 2014	January 2014
Design	Detailed engineering and drafting of new 129 V and 258 V DC panels and breakers, including construction work package	February 2014	March 2014
Procurement	Material procurement for new, 129 V and 258 V DC panels. Coordinate material delivery *(five week lead time)*	April 2014	May 2014
Construction	Remove existing panels. Mount, install and terminate cable to new distribution panels *(To be scheduled during total plant outage)*	August 2014	August 2014
Commissioning	Energize, inspect and test proper operation of new distribution panels and breakers	August 2014	August 2014
Closeout	Post implementation review, complete asset assignment form, close out meeting/lessons learned	September 2014	September 2014

Future Plans:

Replacement of Stage 2, 129 volt and 258 volt DC panels and breakers is planned in 2015.

Project Title: Upgrade Waste Water Basin Building - Inspection and Phase 1 Engineering

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

The waste water basin building (WWBB) provides the essential housing for the Holyrood Thermal Generating Station's (Holyrood) continuous and periodic equalization basins[1]. The building's structural steel is corroded and mold growth is present throughout (see Figures 1 and 2).

Figure 1: Mold Growth on Interior Face of Roof Insulation

[1] *The periodic and continuous basins handle the effluent released from Holyrood prior to its discharge into the wastewater treatment plant and Indian Pond respectively. The periodic basin holds the wastewater streams generated during periodic events such as the cleaning of boiler fireside equipment. The continuous basin serves as a holding pond for the effluent generated during daily operations such as boiler blow down water and drainage from floor drains in the plant.*

Figure 2: Corrosion on Bolted Connection

This deterioration is primarily due to the warm moist air emitted from the effluent and the ensuing condensation in the building. Work under this project includes the engagement of an external consultant to complete an inspection of the WWBB and the phase 1 engineering for the recommended refurbishments. Deliverables include the development of technical specifications and drawings to ensure the building is safe and usable until no longer needed to support generation at Holyrood.

Funding for the completion of the building upgrade will be sought during Hydro's 2015 capital budget submission. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	30.4	0.0	0.0	30.4
Consultant	76.9	0.0	0.0	76.9
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.2	0.0	0.0	0.2
Interest and Escalation	7.8	0.0	0.0	7.8
Contingency	21.5	0.0	0.0	21.5
TOTAL	**136.7**	**0.0**	**0.0**	**136.7**

Operating Experience:

Constructed in 1992, the periodic and continuous waste water basins are vital to the operation of Holyrood. These structures serve as temporary holding ponds for the effluent generated during plant operations, prior to discharge - each basin has a total volume of 900 m^3. While contained in the holding basins, the effluent is subject to a monitoring program whereby it is tested regularly to ensure compliance with provincial environmental discharge criteria prior to release. The Waste Water Basin Building serves to house the basins, sheltering them from the infiltration of precipitation, which can alter the monitoring program test results.

Holyrood is in operation 24 hours a day, year round although Holyrood generation is required only seasonally. Hydro has identified that the Holyrood plant has the following maximum acceptable down times:

- Either Holyrood Unit 1, 2 or 3: 336 days maximum
- Holyrood Stage 1 (both Unit 1 and 2): Less than 1 day
- Entire Holyrood Generating Plant: Less than 1 day

These requirements were based on average winter peak loads and assume that all other hydro units are available for full rated generation.

The basins are in operation whenever any of the boilers at Holyrood are producing steam. The system is in service 24 hours a day, year round but is usually shut down once a year during the total plant outage.

Project Justification:

The refurbishment of the waste water basin building is required to address the health and safety risks associated with the current condition of the building. Currently, personnel who enter the building are exposed to poor quality air as a result of mold/mildew growth on the underside of the building insulation. The mold is a result of condensation build-up inside the enclosure.

The moisture, combined with the close proximity of the structure to a marine environment has also resulted in corrosion to the building steel. The corrosion has progressed to the point at which safety concerns have been raised. These concerns include the integrity of the building structure, the condition of electrical and mechanical components, and the condition of safety railing around the perimeter of the basins.

The completion of the proposed inspection and phase 1 engineering is required to establish the proper scope of work for the completion of the necessary building upgrades. Implementing the required modifications will allow the building to continue serving its purpose until the facility is repurposed, while ensuring the health and safety of plant personnel.

Future Plans:

Completion of required upgrades to the waste water basin building is planned in 2015.

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Project start-up, design transmittal, and scheduling	April 2014	April 2014
Procurement	Develop request for proposals and engage consultant	May 2014	June 2014
FEED	Site inspection, technical specification and tender drawings	June 2014	October 2014
Closeout	Final billing, interest cut-off, contract closeout	-	October 2014

Project Title: Upgrade Underground Plant Drainage System

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project involves the engagement of an external consultant to complete an inspection of the underground plant drainage system at the Holyrood Thermal Generating Station (Holyrood). Based on the inspection findings the phase 1 engineering, for the completion of the recommended upgrades, will be completed. Work includes assessment of the piping, manholes and valves associated with the underground powerhouse drainage system and the development of a technical specification and tender drawings to complete the required upgrades. Approximately 220 meters of existing piping, three manholes, two oil - water separators and two grease traps will be cleaned, videotaped and/or tested. The inspection findings will determine the parts of the piping system requiring an upgrade.

Funding for the completion of the drainage system upgrades will be sought during Hydro's 2015 capital budget submission. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	32.5	0.0	0.0	32.5
Consultant	55.9	0.0	0.0	55.9
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.2	0.0	0.0	0.2
Interest and Escalation	6.3	0.0	0.0	6.3
Contingency	17.7	0.0	0.0	17.7
TOTAL	**112.6**	**0.0**	**0.0**	**112.6**

Operating Experience:

The underground plant drainage system consists of a network of pipes, valves and manholes which direct the effluent produced during the powerhouse operations, to a series of grease traps, oil-water separators and equalization basins. The effluent consists of wastewater streams generated during periodic events such as the cleaning of boiler fireside equipment and continuous waste water flows, generated during daily operations such as boiler blow down runoff and drainage from floor drains in the plant.

Holyrood is in operation 24 hours a day, year round although Holyrood generation is required only seasonally. Hydro has identified that the Holyrood Plant has the following maximum acceptable down times:

Either Holyrood Unit 1, 2 or 3: 336 days maximum
Holyrood Stage 1 (both Unit 1 and 2): Less than 1 day
Entire Holyrood Generating Plant: Less than 1 day

These requirements were based on average winter peak loads and assume that all other hydroelectric units are available for full rated generation.

The piping system is in operation whenever any of the boilers at Holyrood are producing steam. The system is in service 24 hours a day, year round but is usually shut down once a year during the total plant outage.

Project Justification:

Waste water control and treatment is a mandatory component of the thermal generation process. Any interruption to, or loss of flow throughout, the underground piping in the waste water treatment system could result in negative environmental impacts. Effluent moving through this piping network often contains trace amounts of contaminant and/or hydrocarbons. Consequently, this waste water requires treatment prior to being released into the environment. To provide this treatment the wastewater is conveyed to concrete settling basins where it is retained and tested for compliance prior to its release into the environment.

The effluent treatment and disposal process is monitored and regulated by the Provincial Department of Environment and Conservation (DOEC) to ensure compliance with the Environmental Protection Act SNL 2002 c E-14.2. Should a leak in the system enable the discharge of effluent, prior to its treatment, this could result in contamination of the environment and a violation of the Act.

Preliminary testing of the drainage system by Hydro personnel has confirmed that there is leakage in the system, although the exact location is unknown. This has resulted in an environmental non-compliance. Failure to address this non-compliance could result in penalties, fines or an order to cease plant operations pending remediation of the non-compliance.

The refurbishment of the underground drainage system are justified to address this non-compliance. The inspection and phase 1 engineering proposed under this project is required to enable Hydro to clearly pinpoint the problem areas within the drainage system and to accurately define the scope for the refurbishment work. The development of a defined scope and repair methodology will result in minimal disruption to plant operations and ensure that the least cost alternative is pursued.

Project Schedule:

The anticipated project schedule is contained in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Project start-up, design transmittal, and scheduling	March 2014	April 2014
Procurement	Develop request for proposals and engage consultant	May 2014	June 2014
Inspection and Phase 1 Engineering	Site inspection, technical specification and tender drawings	June 2014	October 2014
Closeout	Final billing, interest cut-off, contract closeout	-	October 2014

Future Plans:

Future plans will see the completion of upgrades to the underground plant drainage system in 2015.

Project Title: Overhaul Cooling Water Pump East Unit 1

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

The unit cooling water (CW) pumps provide circulating water to the turbine condenser, which is required for unit operation. Each pump, east and west, provides approximately 50 percent of the required circulating water necessary for full operation of the unit. The CW pumps, located in pump house 1, draw sea water from Conception Bay to the turbine condenser located on the first floor of the power house. The pumps are single stage vertical turbine pumps, each providing 28,000 US GPM at 31 feet of head, driven by a 300 HP motor.

The following is the scope of work for the overhaul:

- Remove and disassemble pump;
- Investigate any deterioration to shaft, bearings and internal components;
- Ship pump, shaft and other parts offsite for:
    - Detailed inspection;
    - Cleaning; and
    - Overhaul and refurbishment;
- Install and reassemble pump.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	4.0	0.0	0.0	4.0
Labour	18.0	0.0	0.0	18.0
Consultant	15.0	0.0	0.0	15.0
Contract Work	40.0	0.0	0.0	40.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	6.0	0.0	0.0	6.0
Contingency	15.4	0.0	0.0	15.4
TOTAL	**98.4**	**0.0**	**0.0**	**98.4**

Operating Experience:

One CW pump is in service until Unit 1, a 175 MW unit, reaches approximately 50 percent of its operating capacity at which point the second pump is needed to provide sufficient volume of circulating water to generate above 90 MW. With two pumps available, they also provide some protection against a forced outage should a single CW pump fail, when the unit is operating below 90 MW.

Project Justification:

Unit 1 and 2 CW pumps are overhauled on a twelve year schedule with Unit 1 CW pump east being last overhauled in 2002 making 2014 the scheduled overhaul window. This is outlined in the overhaul schedule in Appendix A. Two CW pumps are required to maintain vacuum in the turbine condenser and enable the unit to produce 100 percent power. The loss of a CW pump would restrict the unit power production by 50 percent. The operation of a unit in service with one CW pump cannot be guaranteed as a breakdown of the single running pump would cause unrecoverable loss of vacuum in the turbine condenser and shut down the unit.

Future Plans:

Additional condensate extraction pump overhaul projects will be proposed in future capital budget applications.

APPENDIX A

FLOWSERVE REVIEW (MAY 24, 2011)

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ServiceRepair Division

LONG TERM ASSET PLANNING

Customer: Newfoundland Labrador Hydro Holyrood G.S.

References: Holyrood Meeting Minutes – May 9, 2011
Holyrood Forecast Repair Chart
Flowserve Site Visit By Arnold Padgett

Date: May 24, 2011

Meeting Minutes – Item 11 Discussion Items

1 - The 3 remaining LP Drains Pumps – one in each unit require repair and conversion to mechanical seal.
2 – Refer to marked up "Repair Chart". Flowserve estimate of dollars vary a little from Holyrood's but there are unknowns in each repair. The overall costs are approximately the same. Holyrood's repair schedule on the pumps and timing is acceptable. Flowserve recommend that the repairs for 2019 and 2020 be deleted. The cost increased in Units 1 and 2 extraction pumps from the 1st pump in 2012 is because of probable new 1st stage impeller. Holyrood has one impeller in stock.
3 – The existing pumps are repairable at a much lower cost than replacement pumps and in a much shorter time interval. All of Holyrood's 4000 volt pumps have an acceptable mean time between repair.
4 – Baseline Test. Any additional baseline testing is not relevant at this time in the remaining life of the station. Each pump groups have internal weaknesses that will be presented that baseline testing would not pick up.
5 – Nash Vacuum Pumps. These pumps have not been a high maintenance pump but are of cast iron construction. It may be worth purchasing one new pump for inventory in case it is needed.
6 – Smaller verticals would be a better option for synchronous condenser cooling.

Additional Pumps

Add the LP Drain Pumps to the list as these pumps help to unload the extraction pumps minimizing cavitation damage on the 1st stage impeller and allowing Units 1 and 2 to basically run on one pump up to 150 MW range.

Page 1 of 3

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Pump History And Weaknesses

Boiler Feed Pumps – Unit 1, 2 and 3

The weakness in the pump design is the sealing gasket surface of volute to barrel. The two volute haves split surface is a lapped surface relying on external discharge pressure to seal across the split surface. Over running time leakage occurs across the split surface around the volute to barrel gasket. Wire drawing takes place cutting through the gasket and into the barrel. If left unattended major repair of the barrel is required involving field welding and machining which has a significant repair cost. Based on operating experience at Holyrood the volute cannot be left in service for more than 7 years without the risk of barrel damage. The unit 3 pumps have a new volute to barrel design gasket that would appear may give a longer time between volute change out.

Extraction Pumps

Units 1 and 2
These pumps had a history of expensive repair due to pump thrust bearing failures, 1st stage impeller cavitation and stuffing box deterioration letting air into the system. Starting in 1999 thru to 2001 each pump was repaired, converted to mechanical seal and a new high thrust efficiency motor capable of carrying the pump thrust load. The inlet vanes of the 1st stage double suction impeller were cut back approximately 1.25" to remove the cavitational damage and to save the impeller.

Unit 3
Prior to Flowserve repair in 2003 and 2005 there was no history of these pumps having been repaired. The cavitated cast iron suction bells were replaced in 304ss.

C.W. Pumps

Unit 1 and 2
These pumps have been modified starting in 1998 with a spider in each outer column, 316ss suction liner and a mechanical seal. The unit 1 west pump repaired in 2010 has a large piping strain which will affect the life of the pump.

Unit 3
These pumps were repaired in 1997 and 2001. Inadvertently the bearing sleeves were hard chrome plated for longer life but chrome plating does not stand up in sea water. All pumps have been repaired since with standard 316ss bearing sleeves.

Vacuum Pumps

All pumps have been repaired once by Flowserve.

Page 2 of 3

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L.P. Drain Pumps

These pumps never worked and were added to Flowserve list of pumps.

A piping change was required on all three units. In addition the Units 1 and 2 pumps required re-bowling to a smaller size pump. Since the changes the pumps have operated satisfactory for a 11 year period.

Arnold Padgett May 24, 2011

Page 3 of 3

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Long Term Asset Planning Department

Meeting Minutes – Pump Overhauls / Replacement / Optimization

May 9, 2011
Present: Jeff Vincent, Paul Woodford, Bob Garland
Next meeting: May 17, 2011, 09:00, Conference Room

I. Arnold Padgett

Arnold has been scheduled to come to site for May 17 – 18 to assist us with developing our long term pump maintenance strategy. The following is a list of items that we would like him to address while he is here.

II. Discussion Items

- Based on Paul's Historical document – What's next and when? Mechanical seals on balance of pumps?
- Based on Jeff's overhaul schedule, assign budget dollars to items.
- Should we replace any pumps due to obsolescence, efficiency gains or deteriorated condition (not maintainable)
- Do we have sufficient Instrumentation/Monitoring Software in place to predict what pumps to overhaul next year, allowing us to budget for, plan and execute, any required maintenance.
- Define any baseline tests that may be required such as vibration, bearing temperature, discharge pressure, flow etc.
- Specifically, Nash Vacuum pumps, what is the recommended strategy? Maintain / Replace?
- Recommend options to provide cooling water for Stage I synchronous condenser operation mode.

III. Timeline for Steam @ HRD

- Official timeline

2011 – 2016	Status Quo	- Load Increasing, GWA ≥ 95%
2017 – 2019	Standby	- One Unit Hot
2020 – ∞	All Three Units as Synchronous Condenser	

- Likely timeline

2011 – 2018	Status Quo	- Load Increasing, GWA ≥ 95%
2019 – 2021	Standby	- One Unit Hot
2022 – ∞	All Three Units as Synchronous Condenser	

IV. Supporting Documents

- FlowServe Pump Binder, formerly Jeff' Vincent's, now kept in Paul Woodfords office.
- Flowserve document – N&L Hydro Holyrood G.S. Repair History

Pumps	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
1 CW Pump East			X												76,762.00					1 CW Pump East
1 CW Pump West											75,000.00									1 CW Pump West
2 CW Pump East	X				X												84,438.00			2 CW Pump East
2 CW Pump West												66,750.00								2 CW Pump West
3 CW Pump East		X									75,000.00									3 CW Pump East
3 CW Pump West						75,000.00												105,500.00		3 CW Pump West
1 Ext Pump North	X												79,000.00							1 Ext Pump North
1 Ext Pump South			X												91,500.00					1 Ext Pump South
2 Ext Pump North					10,000.00												100,500.00			2 Ext Pump North
2 Ext Pump South		X												80,500.00						2 Ext Pump South
3 Ext Pump North						60,000.00												75,000.00		3 Ext Pump North
3 Ext Pump South				X												68,000.00				3 Ext Pump South
1 Vac Pump North											25,000.00									1 Vac Pump North
1 Vac Pump South			X												28,000.00					1 Vac Pump South
2 Vac Pump North				X												29,000.00				2 Vac Pump North
2 Vac Pump South							15,000.00												32,000.00	2 Vac Pump South
3 Vac Pump North				X												29,000.00				3 Vac Pump North
3 Vac Pump South			X												28,000.00					3 Vac Pump South
1 BF Pump East		X								100,000.00						140,000.00				1 BF Pump East
1 BF Pump West				X							160,000.00							154,500.00		1 BF Pump West
2 BF Pump East					70,000.00								160,000.00						162,000.00	2 BF Pump East
2 BF Pump West			X									179,500.00					147,000.00			2 BF Pump West
3 BF Pump East	X								100,000.00						145,000.00					3 BF Pump East
3 BF Pump West	X					10,000.00								138,000.00						3 BF Pump West
Total					80,000.00	145,000.00	15,000.00		100,000.00	100,000.00	335,000.00	246,250.00	239,000.00	218,500.00	369,262.00	266,000.00	331,938.00	335,000.00	194,000.00	

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ServiceRepair Division

Newfoundland & Labrador Hydro Holyrood G.S. Repair History

Units 1 & 2 B.F. Pump History – Byron Jackson

1994 – Units 1 & 2 East B.F. Pump	: field welded barrel and field machined. repaired cartridge installed.
1995 – Units 1 & 2 West B.F. Pump	: field welded barrel and field machined. repaired cartridge installed.
1996 – Unit 2 East	: Pump self destruct. Replaced cartridge.
1997 -	: Identified the system problem failing the East B.F. Pumps.
1998 – Units 1 & 2	: Increased the system resistance for the East B.F. Pumps by installing a 3 stage orifice in the discharge line from inside the barrel. Repaired the discharge cover of Unit 2 East ie a minor failure.
2001 – Unit 1 East	: changed out the cartridge – planned repair after 7 years of service.
2002 – Unit 2 West	: changed out cartridge – planned repair after 7 years of service.
2003 – Unit 1 West	: changed out cartridge – planned repair after 8 years of service.
2004 – Unit 2 East	: changed out cartridge – planned repair after 7 years of service.
2009 – Unit 1 East	: changed out cartridge after 8 years – barrel washed requiring welding & machining. Close clearance stufbx bushings installed. Larger drain holes in bearing support brkt.
2010 – Unit 1 West	: changed out cartridge after 7 years – barrel repair and hand dressing. Close clearance stufbx bushings installed. Larger drain holes in bearing support brkt.

Units 1 & 2 Extraction Pump History – Mather + Platt

1997 -	: reviewed maintenance history and made upgrade recommendations. - delete the pump thrust bearing. - new motors with high thrust bearing. - change from packing to mechanical seal.
1999 – Units 1 South and 2 North	: repaired and upgraded per recommendations.

Page 1 of 4

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2000 – Unit 1 North	: repaired and upgraded per recommendations.
2001 – Unit 2 South	: repaired and upgraded per recommendations.
2004 – Unit 2 North	: inspected 1st stage impeller for cavitation damage – no damage.

Units 1 & 2 C.W. Pump History – Ingersol Rand

1997	: reviewed maintenance history and made recommendations. -each outer column to have a spider and bearing. -replace the bowl marine bearings with a small fluted Thordon bearing. -change from packing to mechanical seal.
1998 – Unit 2 West	: repaired and upgraded per recommendations.
1999 – Unit 1 west	: repaired and upgraded per recommendations.
2000 – Unit 2 East	: repaired and upgraded per recommendations.
2002 – Unit 1 East	: repaired and upgraded per recommendations.
2004 – Unit 2 East	: bolting from column to bowl came off breaking pump shaft. Pump repaired
2010 – Unit 1 West	: new bearings, line shafts, pump shaft head shaft and mechanical seal.. Considerable pipe strain from valve

Units 1 & 2 Vacuum Pumps History - Nash

1997	: reviewed maintenance history and Inspected one pump.
2002 – Units 1 & 2	: repaired 2 pumps
2003	: repaired 1 pump.
2010 – Unit 1 South	: repaired pump.

Units 1 & 2 LP Drain Pumps – Bingham/Willamette

1997	: added to the list of pumps
1998	: piping modification.
1999	: re-bowl – 4 pumps.

Page 2 of 4.

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2010	: repaired one pump from each unit c/w mechanical seal

Unit 3 B.F. Pump History – Bigham/Willamette

1995	: East & West pump repaired by Bingham/Willamette.
1996 – East Pump	: repaired washout on discharge cover – BW/IP
1998 – West Pump	: repaired washout on discharge cover – BW/IP
1999 – East Pump	: repaired washout on discharge cover – BW/IP - design change on balance bushing to prevent cover washout. - temporary repair of barrel washout. - designed new cartridge to barrel gaskets. - installed repaired cartridge.
2000 – East Pump	: weld repair and field machine barrel. Installed the same cartridge c/w new design cartridge to barrel gasket.
2000 – West Pump	: weld repair and field machine barrel. - installed repaired sag bore cartridge c/w new design cartridge to barrel gasket.
2002 – West Pump	: replace leaking discharge cover gasket. - requested an order for high pressure cover gaskets.
2003 – East And West Pump	: replaced inboard glands.
2005 – West Pump	; discharge cover gasket leaking. - removed cartridge – barrel washed at high pressure gasket. - field welded and machined. - repaired sag bored cartridge installed c/w new discharge cover gasket. - discharge cover gasket surface machined.
2008 – East Pump	: planned change out of cartridge - 9 years of service. - no barrel wash. - replace outboard gland.

Page 3 of 4.

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2008 – West Pump	: replaced outboard gland.

Unit 3 Extraction Pump History – Bingham/Willamette

2003 – South Pump	: repaired pump
2005 – North Pump	: repaired pump

Unit 3 C.W. Pump History – Ebara

1997 – West Pump	: repaired pump.
2001 – East Pump	: repaired pump
2005 – West Pump	: repaired pump - changed from threaded line shaft couplings to sleeve type. - no hard chrome plating on bearing sleeves.
2010 – East Pump	:new bearings and bearing sleeves

Unit 3 Vacuum Pump History - Siemens

1997 – South Pump	: inspected – no repair. 304ss rotor.
1999 – North Pump	: repaired using devcon repaired parts. New 304ss rotor re-versed engineered.
2003 – North Pump	: repaired with new 304ss rotor.

Unit 3 LP Drain Pump History

1998	: requested piping change.
2010 – West Pump	: repaired pump c/w mech. seal.

Page 4 of 4.

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Project Title: Overhaul Extraction Pump South Unit 1

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

The scope of the overhaul of Unit 1 condensate extraction pump South consists of:

- Removing the pump;
- Dismantling the pump;
- Inspecting the pump for damage to shaft, bearings and internal components;
- Shipping parts offsite for detailed inspection, cleaning , overhaul and refurbishment; and
- Re-assembling the pump.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	4.0	0.0	0.0	4.0
Labour	18.0	0.0	0.0	18.0
Consultant	15.0	0.0	0.0	15.0
Contract Work	40.0	0.0	0.0	40.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	4.4	0.0	0.0	4.4
Contingency	15.4	0.0	0.0	15.4
TOTAL	**96.8**	**0.0**	**0.0**	**96.8**

Operating Experience:

Each Holyrood generating unit has two condensate extraction pumps. There is only one pump in service during operation of the unit. The other pump is a standby pump which is taken into service when the normal operating pump fails or is out of service for maintenance.

Project Justification:

Two condensate extraction pumps are required to maintain condensate flow from the turbine condenser and enable the unit to produce rated power. The reliability of a unit in service with one extraction pump cannot be guaranteed as a breakdown of the single running pump would cause the eventual shut down of the unit. Recognized pump experts, Flowserve, were consulted for optimization of the overhaul schedule for the extraction pumps at Holyrood and it was established that the extraction pump south on generating Unit 1 is due for an overhaul in 2014. This can be found in Appendix A with a chart outlining the overhaul schedule on page E-95.

Future Plans:

Other condensate extraction pump overhaul projects will be proposed in future capital budget applications.

APPENDIX A

FLOWSERVE REVIEW (MAY 24, 2011)

FLOWSERVE

ServiceRepair Division

LONG TERM ASSET PLANNING

Customer: Newfoundland Labrador Hydro Holyrood G.S.

References: Holyrood Meeting Minutes – May 9, 2011
Holyrood Forecast Repair Chart
Flowserve Site Visit By Arnold Padgett

Date: May 24, 2011

Meeting Minutes – Item 11 Discussion Items

1 - The 3 remaining LP Drains Pumps – one in each unit require repair and conversion to mechanical seal.

2 – Refer to marked up "Repair Chart". Flowserve estimate of dollars vary a little from Holyrood's but there are unknowns in each repair. The overall costs are approximately the same. Holyrood's repair schedule on the pumps and timing is acceptable. Flowserve recommend that the repairs for 2019 and 2020 be deleted. The cost increased in Units 1 and 2 extraction pumps from the 1st pump in 2012 is because of probable new 1st stage impeller. Holyrood has one impeller in stock.

3 – The existing pumps are repairable at a much lower cost than replacement pumps and in a much shorter time interval. All of Holyrood's 4000 volt pumps have an acceptable mean time between repair.

4 – Baseline Test. Any additional baseline testing is not relevant at this time in the remaining life of the station. Each pump groups have internal weaknesses that will be presented that baseline testing would not pick up.

5 – Nash Vacuum Pumps. These pumps have not been a high maintenance pump but are of cast iron construction. It may be worth purchasing one new pump for inventory in case it is needed.

6 – Smaller verticals would be a better option for synchronous condenser cooling.

Additional Pumps

Add the LP Drain Pumps to the list as these pumps help to unload the extraction pumps minimizing cavitation damage on the 1st stage impeller and allowing Units 1 and 2 to basically run on one pump up to 150 MW range.

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Pump History And Weaknesses

Boiler Feed Pumps – Unit 1, 2 and 3

The weakness in the pump design is the sealing gasket surface of volute to barrel. The two volute haves split surface is a lapped surface relying on external discharge pressure to seal across the split surface. Over running time leakage occurs across the split surface around the volute to barrel gasket. Wire drawing takes place cutting through the gasket and into the barrel. If left unattended major repair of the barrel is required involving field welding and machining which has a significant repair cost. Based on operating experience at Holyrood the volute cannot be left in service for more than 7 years without the risk of barrel damage. The unit 3 pumps have a new volute to barrel design gasket that would appear may give a longer time between volute change out.

Extraction Pumps

Units 1 and 2
These pumps had a history of expensive repair due to pump thrust bearing failures, 1st stage impeller cavitation and stuffing box deterioration letting air into the system. Starting in 1999 thru to 2001 each pump was repaired, converted to mechanical seal and a new high thrust efficiency motor capable of carrying the pump thrust load. The inlet vanes of the 1st stage double suction impeller were cut back approximately 1.25" to remove the cavitational damage and to save the impeller.

Unit 3
Prior to Flowserve repair in 2003 and 2005 there was no history of these pumps having been repaired. The cavitated cast iron suction bells were replaced in 304ss.

C.W. Pumps

Unit 1 and 2
These pumps have been modified starting in 1998 with a spider in each outer column, 316ss suction liner and a mechanical seal. The unit 1 west pump repaired in 2010 has a large piping strain which will affect the life of the pump.

Unit 3
These pumps were repaired in 1997 and 2001. Inadvertently the bearing sleeves were hard chrome plated for longer life but chrome plating does not stand up in sea water. All pumps have been repaired since with standard 316ss bearing sleeves.

Vacuum Pumps

All pumps have been repaired once by Flowserve.

Page 2 of 3

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L.P. Drain Pumps

These pumps never worked and were added to Flowserve list of pumps.

A piping change was required on all three units. In addition the Units 1 and 2 pumps required re-bowling to a smaller size pump. Since the changes the pumps have operated satisfactory for a 11 year period.

Arnold Padgett May 24, 2011

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Long Term Asset Planning Department

Meeting Minutes – Pump Overhauls / Replacement / Optimization

May 9, 2011
Present: Jeff Vincent, Paul Woodford, Bob Garland
Next meeting: May 17, 2011, 09:00, Conference Room

I. Arnold Padgett

Arnold has been scheduled to come to site for May 17 – 18 to assist us with developing our long term pump maintenance strategy. The following is a list of items that we would like him to address while he is here.

II. Discussion Items

- Based on Paul's Historical document – What's next and when? Mechanical seals on balance of pumps?
- Based on Jeff's overhaul schedule, assign budget dollars to items.
- Should we replace any pumps due to obsolescence, efficiency gains or deteriorated condition (not maintainable)
- Do we have sufficient Instrumentation/Monitoring Software in place to predict what pumps to overhaul next year, allowing us to budget for, plan and execute, any required maintenance.
- Define any baseline tests that may be required such as vibration, bearing temperature, discharge pressure, flow etc.
- Specifically, Nash Vacuum pumps, what is the recommended strategy? Maintain / Replace?
- Recommend options to provide cooling water for Stage I synchronous condenser operation mode.

III. Timeline for Steam @ HRD

- Official timeline

2011 – 2016	Status Quo	- Load Increasing, GWA ≥ 95%
2017 – 2019	Standby	- One Unit Hot
2020 – ∞	All Three Units as Synchronous Condenser	

- Likely timeline

2011 – 2018	Status Quo	- Load Increasing, GWA ≥ 95%
2019 – 2021	Standby	- One Unit Hot
2022 – ∞	All Three Units as Synchronous Condenser	

IV. Supporting Documents

- FlowServe Pump Binder, formerly Jeff' Vincent's, now kept in Paul Woodfords office.
- Flowserve document – N&L Hydro Holyrood G.S. Repair History

Pumps	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
1 CW Pump East			X												76,762.00					1 CW Pump East
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2 CW Pump West												66,750.00								2 CW Pump West
3 CW Pump East		X									75,000.00									3 CW Pump East
3 CW Pump West						75,000.00												105,500.00		3 CW Pump West
1 Ext Pump North	X												79,000.00							1 Ext Pump North
1 Ext Pump South			X												91,500.00					1 Ext Pump South
2 Ext Pump North					10,000.00												100,500.00			2 Ext Pump North
2 Ext Pump South		X												80,500.00						2 Ext Pump South
3 Ext Pump North						60,000.00												75,000.00		3 Ext Pump North
3 Ext Pump South				X												68,000.00				3 Ext Pump South
1 Vac Pump North											25,000.00									1 Vac Pump North
1 Vac Pump South			X												28,000.00					1 Vac Pump South
2 Vac Pump North				X												29,000.00				2 Vac Pump North
2 Vac Pump South							15,000.00												32,000.00	2 Vac Pump South
3 Vac Pump North				X												29,000.00				3 Vac Pump North
3 Vac Pump South			X												28,000.00					3 Vac Pump South
1 BF Pump East		X								100,000.00						140,000.00				1 BF Pump East
1 BF Pump West				X							160,000.00							154,500.00		1 BF Pump West
2 BF Pump East					70,000.00								160,000.00						162,000.00	2 BF Pump East
2 BF Pump West			X									179,500.00					147,000.00			2 BF Pump West
3 BF Pump East	X								100,000.00						145,000.00					3 BF Pump East
3 BF Pump West	X					10,000.00								138,000.00						3 BF Pump West
Total					80,000.00	145,000.00	15,000.00		100,000.00	100,000.00	335,000.00	246,250.00	239,000.00	218,500.00	369,262.00	266,000.00	331,938.00	335,000.00	194,000.00	

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Newfoundland & Labrador Hydro Holyrood G.S. Repair History

Units 1 & 2 B.F. Pump History – Byron Jackson

1994 – Units 1 & 2 East B.F. Pump	: field welded barrel and field machined. repaired cartridge installed.
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2003 – Unit 1 West	: changed out cartridge – planned repair after 8 years of service.
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2010 – Unit 1 West	: changed out cartridge after 7 years – barrel repair and hand dressing. Close clearance stufbx bushings installed. Larger drain holes in bearing support brkt.

Units 1 & 2 Extraction Pump History – Mather + Platt

1997 -	: reviewed maintenance history and made upgrade recommendations. - delete the pump thrust bearing. - new motors with high thrust bearing. - change from packing to mechanical seal.
1999 – Units 1 South and 2 North	: repaired and upgraded per recommendations.

Page 1 of 4

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2000 – Unit 1 North	: repaired and upgraded per recommendations.
2001 – Unit 2 South	: repaired and upgraded per recommendations.
2004 – Unit 2 North	: inspected 1st stage impeller for cavitation damage – no damage.

Units 1 & 2 C.W. Pump History – Ingersol Rand

1997	: reviewed maintenance history and made recommendations. -each outer column to have a spider and bearing. -replace the bowl marine bearings with a small fluted Thordon bearing. -change from packing to mechanical seal.
1998 – Unit 2 West	: repaired and upgraded per recommendations.
1999 – Unit 1 west	: repaired and upgraded per recommendations.
2000 – Unit 2 East	: repaired and upgraded per recommendations.
2002 – Unit 1 East	: repaired and upgraded per recommendations.
2004 – Unit 2 East	: bolting from column to bowl came off breaking pump shaft. Pump repaired
2010 – Unit 1 West	: new bearings, line shafts, pump shaft head shaft and mechanical seal.. Considerable pipe strain from valve

Units 1 & 2 Vacuum Pumps History - Nash

1997	: reviewed maintenance history and Inspected one pump.
2002 – Units 1 & 2	: repaired 2 pumps
2003	: repaired 1 pump.
2010 – Unit 1 South	: repaired pump.

Units 1 & 2 LP Drain Pumps – Bingham/Willamette

1997	: added to the list of pumps
1998	: piping modification.
1999	: re-bowl – 4 pumps.

Page 2 of 4.

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2010	: repaired one pump from each unit c/w mechanical seal

Unit 3 B.F. Pump History – Bigham/Willamette

1995	: East & West pump repaired by Bingham/Willamette.
1996 – East Pump	: repaired washout on discharge cover – BW/IP
1998 – West Pump	: repaired washout on discharge cover – BW/IP
1999 – East Pump	: repaired washout on discharge cover – BW/IP - design change on balance bushing to prevent cover washout. - temporary repair of barrel washout. - designed new cartridge to barrel gaskets. - installed repaired cartridge.
2000 – East Pump	: weld repair and field machine barrel. Installed the same cartridge c/w new design cartridge to barrel gasket.
2000 – West Pump	: weld repair and field machine barrel. - installed repaired sag bore cartridge c/w new design cartridge to barrel gasket.
2002 – West Pump	: replace leaking discharge cover gasket. - requested an order for high pressure cover gaskets.
2003 – East And West Pump	: replaced inboard glands.
2005 – West Pump	; discharge cover gasket leaking. - removed cartridge – barrel washed at high pressure gasket. - field welded and machined. - repaired sag bored cartridge installed c/w new discharge cover gasket. - discharge cover gasket surface machined.
2008 – East Pump	: planned change out of cartridge - 9 years of service. - no barrel wash. - replace outboard gland.

Page 3 of 4.

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2008 – West Pump	: replaced outboard gland.

Unit 3 Extraction Pump History – Bingham/Willamette

2003 – South Pump	: repaired pump
2005 – North Pump	: repaired pump

Unit 3 C.W. Pump History – Ebara

1997 – West Pump	: repaired pump.
2001 – East Pump	: repaired pump
2005 – West Pump	: repaired pump - changed from threaded line shaft couplings to sleeve type. - no hard chrome plating on bearing sleeves.
2010 – East Pump	:new bearings and bearing sleeves

Unit 3 Vacuum Pump History - Siemens

1997 – South Pump	: inspected – no repair. 304ss rotor.
1999 – North Pump	: repaired using devcon repaired parts. New 304ss rotor re-versed engineered.
2003 – North Pump	: repaired with new 304ss rotor.

Unit 3 LP Drain Pump History

1998	: requested piping change.
2010 – West Pump	: repaired pump c/w mech. seal.

Page 4 of 4.

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Project Title: Upgrade Terminal Station Foundations

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

Work under this project consists of the completion of upgrades to reinforced concrete pier foundations at Hydro's Bottom Brook, Sunnyside and Western Avalon Terminal Stations. Work includes: the installation of bracing, required to temporarily support existing electrical equipment to facilitate the foundation repairs; removal and stockpile, for reuse, of existing yard gravel; hand excavation around concrete foundation to facilitate the completion of concrete repairs; repair of concrete pier, backfilling of structure, and the reinstatement of yard gravel.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	65.4	0.0	0.0	65.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	78.1	0.0	0.0	78.1
Other Direct Costs	11.7	0.0	0.0	11.7
Interest and Escalation	11.7	0.0	0.0	11.7
Contingency	31.0	0.0	0.0	31.0
TOTAL	**197.9**	**0.0**	**0.0**	**197.9**

Operating Experience:

The reinforced concrete foundations, utilized to support high voltage equipment in Hydro's terminal station yards, range in age from one to 45 years. The majority of these structures formed part of the original station construction and are in excess of thirty-five years of age.

A number of the structures have deteriorated as a result of repeated exposure to the forces generated during the freeze/thaw cycle. Three structures, in particular, have deteriorated to the point in which there are concerns over their integrity. These structures include: structure B1T1 at the Bottom Brook terminal station, structure L01L37 at the Western Avalon Terminal Station, and structure l03L06 at the Sunnyside terminal station (see Figures 1, 2 and 3).

Figure 1: Structure B1T1 at Bottom Brook Terminal Station

Figure 2: Structure L03L06-2 at Sunnyside Terminal Station

Figure 3: Structure L01L37-1 at Western Avalon Terminal Station

These foundations support high voltage equipment such as circuit breakers, disconnect switches, instrument transformers and post insulators. The continuous operation of this equipment is required to maintain power supply to the Island Interconnected System.

Project Justification:

The deteriorated structures in Bottom Brook, Sunnyside and Western Avalon support high voltage equipment. This equipment is critical to Island Interconnected System and its continued operation is required to ensure the delivery of safe, reliable power to Hydro's customers.

Inspections of these reinforced concrete foundations, completed by internal forces, have found them to be severely deteriorated leading to concerns over their structural integrity. To ensure their ability to perform as per the original design intent upgrades to the structures must be completed. Failure to complete the necessary upgrades could result in a catastrophic failure causing outages, personal injury or death.

Future Plans:

With the noted deterioration of the concrete foundations in Bottom Brook, Sunnyside and Western Avalon, Hydro has a recognized the need to conduct a complete assessment of all its concrete foundations. Future plans will see the completion of a foundation condition assessment in 2013. Funding will be sought, as required, to rectify any issues arising from the assessment.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Design transmittal, site visit, outage schedules	February 2014	February 2014
Design	Prepare tender package	March 2014	April 2014
Tender/Award	Issue tender; award contract	April 2014	May 2014
Construction	Complete foundation repairs	July 2014	July 2014
Commissioning	Final inspection	-	July 2014
Closeout	Contract closeout	-	September 2014

Project Title: Replace Optimho Relays on TL203

Location: Western Avalon to Sunnyside

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This is the second year of a program to replace the existing Optimho relays on the 230 kV system east of Bay d'Espoir with modern microprocessor relays. TL242 is scheduled to be done in 2013. Two Optimho relays used on TL203 between Sunnyside and Western Avalon terminal stations are planned to be replaced in 2014 and 2015. The replacement schedule for TL203 is based on the line outage availability. In 2013 the Lower Churchill Project design team will be identifying the transmission line relays for the 230 kV transmission lines that will be connected to the Soldiers Pond Terminal Station. These relays will be reviewed and approved by Hydro for use on the Island Interconnected Transmission System. These relays will also be reviewed for application on TL203 as noted in the Henville Consulting Inc. report recommendations (see Appendix A and B). The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	44.0	0.0	0.0	44.0
Labour	38.5	56.5	0.0	95.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.5	2.5	0.0	3.0
Interest and Escalation	6.1	9.5	0.0	15.6
Contingency	0.0	28.4	0.0	28.4
TOTAL	**89.1**	**96.9**	**0.0**	**186.0**

Operating Experience:

Optimho relays have been used to protect Hydro's 230 kV transmission lines since the 1980s. They are used in one of the two primary line protection schemes for Hydro's 230 kV transmission lines. The relays used in the other protection scheme are Schweitzer SEL-321. Line protective relays such as the Optimho relays, detect fault conditions on the line such as line contact between conductors or conductor to ground or lightning strikes to conductor(s). These are dangerous and/or intolerable conditions with high current flowing to ground or between conductors. The fault current is sufficiently high to cause damage to the transmission line or the electrical equipment in the terminal station. When a fault occurs on a transmission line, a protective relay will initiate a trip and the circuit breakers at each end of the transmission line will react by tripping or switching off the transmission line so that no damage occurs.

Project Justification:

The manufacturer of the Optimho relays (Alstom, now Schneider Electric) ceased production of the Optimho relays in 2002. A protection consultant, Henville Consultant Inc., reviewed the protection on the ten 230 kV lines east of Bay d'Espoir Hydroelectric Generating Station; five lines were reviewed in 2010 and five lines reviewed in 2011. Historical performance of the protection on the lines was reviewed and actual faults that had occurred in the past were analyzed. Detailed review of the settings for each line was also completed. The final report by Henville Consultant Inc. recommends "*Replacing some or all of the existing Optimho protection systems to improve flexibility of settings and monitoring facilities for disturbance analysis. Maintenance issues due to lack of availability of spare parts for these systems are now becoming a concern as well.*" Also recommendations V and VI regarding the enhancement of the monitoring and record retrieving functions in the new relay are applicable to the replacement of the Optimho relays with modern relays (see Appendix A, page 3 of the final 2010 review report titled "Circuits TL202, TL203, TL206, TL207 and TL237 Transmission Line Protection Performance and Settings Review"). Justifications for the above recommendations can be found in the recommended protection upgrade report in Appendix B.

Future Plans:

This is a four year program. Two transmission lines will be done in each subsequent year and will include the following lines: TL202, TL206, TL207, TL237, TL218, and TL236 TL201, TL217 and TL242 will be completed under a separate Capital Budget Proposal.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Planning initiation	Jan 2014	Jan 2014
Design	Consultant report review	Feb 2014	Mar 2014
	Training - cost not included in this budget	Apr 2014	May 2014
	Circuit design	Jun 2014	Aug 2014
	Relay settings	Aug 2014	Sept 2014
Procurement	Relay confirmation	Feb 2014	Mar 2014
	Relay ordering	Mar 2014	Jun 2014
Construction	Installation	Mar 2015	Apr 2015
Commissioning	Commissioning	Apr 2015	Apr 2015
Closeout	Closeout activity	May 2015	May 2015

APPENDIX A

RECOMMENDATIONS ON PAGE 3 OF CONSULTANT FINAL REVIEW REPORT

TITLED “CIRCUITS TL202, TL203, TL206, TL207 AND TL237 TRANSMISSION LINE PROTECTION PERFORMANCE AND SETTINGS REVIEW”

COMPLETED IN 2010 FOR NEWFOUNDLAND & LABRADOR HYDRO

BY HENVILLE CONSULTING INC.

<u>Protection review for 5 230 kV transmission lines Final Report</u>

i) Replacing some or all of the existing optimho distance protection systems to improve flexibility of settings and monitoring facilities for disturbance analysis. Maintenance issues due to lack of availability of spare parts for these systems are now becoming a concern.
ii) Removal of the electromechanical ground time overcurrent relays in the P2 protection systems since they add little value to the ground time overcurrent function built into the SEL 321 relays. A more independent ground time overcurrent function would be available in the new P1 protection systems if they were replaced.
iii) Modification of the dead line check function of the existing automatic reclosing system to increase the security of the 230 kV supply
iv) Replacing all pneumatic timers used for automatic reclosing or transfer trip auxiliaries with modern digital timers and configurable logic systems.
v) Use of the monitoring functions available in the new relays for steady state current and voltage balance checks. These functions could provide an alarm of steady state unbalances that could indicate a problem in the current or voltage sensing to the relays.
vi) Retrieving event records from relays and teleprotection systems in the highest possible resolution, to supplement the sequence of events records, particularly in the case of questionable operations.

3

APPENDIX B

RECOMMENDED PROTECTION UPGRADE REPORT

BY HENVILLE CONSULTING INC.

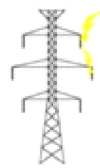
Newfoundland and Labrador Hydro

Recommended Protection Upgrades for Five Transmission Circuits
TL202, TL203, TL206, TL207 and TL237

Prepared by

Charles F. Henville

Henville Consulting Inc



Prepared for

newfoundland labrador hydro

a nalcor energy company

17th December 2010

Recommended Protection Upgrades for Five Transmission Circuits
TL202, TL203, TL206, TL207 and TL237

Table of Contents

Recommended Protection Upgrades for Five Transmission Circuits TL202, TL203, TL206, TL207 and TL237

1. Summary and recommendations

Summary

This report identifies the reasons for upgrading the protection and teleprotection systems on five 230 kV transmission circuits. The intent of the upgrades is to improve the performance of the existing protection systems to meet Newfoundland and Labrador Hydro speed, sensitivity and reliability requirements.

Recommendations

The following recommendations for upgrades are made:

a) Provide separate and independent communications facilities for each of the "P1" and "P2" protection systems for two reasons
   I. To avoid common mode failure
   II. To allow the independent protection systems at each end of the line to independently communicate with their counterparts at the opposite end.

b) Replace the existing optimho distance protection systems to improve flexibility of settings and monitoring facilities for disturbance analysis. Maintenance issues due to lack of availability of spare parts for these systems are now becoming a concern.

c) Remove the electromechanical ground time overcurrent relays in the P2 protection systems since they add little value to the ground time overcurrent function built into the SEL 321 relays.

d) Modify the dead line check function of the existing automatic reclosing system to increase the security of the 230 kV supply

e) Replace all pneumatic timers used for automatic reclosing or transfer trip auxiliaries with modern digital timers and configurable logic systems.

Protection upgrades for five 230 kV transmission lines

2. Introduction and Scope

This report specifies the scope of modifications and upgrades to five 230 kV transmission line protection systems and the reasons for this work. The report is prepared further to a review of the transmission line protection systems for five 230 kV transmission lines [Reference 1]. The transmission circuits involved are TL202, TL203, TL206, TL207, and TL237.

The review discovered some deficiencies in the performance of the existing protection systems and recommended that they be improved by a combination of settings adjustments and physical modifications and upgrades to the hardware. The settings adjustments are defined in the review report and these adjustments may be implemented as part of normal corrective maintenance activities. The physical modifications will require capital investment that is justified in this report.

3. Teleprotection

Additional Facilities

The review noted that the existing teleprotection systems are shared by the P1 and P2 protections. This sharing prohibits the application of weak source echo functions that are required to meet Newfoundland and Labrador Hydro protection sensitivity requirements, especially in the case of long lines TL202, TL203, TL206, TL207.

The sharing also means that failure of one teleprotection channel can result in failure of both P1 and P2 protections. This common mode failure concern is addressed in the case of TL202 and TL206 by the use of a second shared teleprotection channel. However, there is no second teleprotection channel in the case of the protection for TL203, TL207 and TL237. Thus there is a lack of teleprotection redundancy for protections for three of the transmission lines that violates Newfoundland and Labrador Hydro requirements for protection redundancy for the backbone transmission system.

It is recommended that a second independent teleprotection channel be added for each of circuits TL203, TL207 and TL237. In the case of Circuit TL207, this channel should have a bandwidth of at least 64 kbps for line current differential protection application. If it is possible to use power line carrier for the existing P2 protection systems, this would be preferred to provide total independence of the P2 protection from the P1. The P1 system would then use the digital microwave facilities.

Modifications to Existing Facilities

The review noted that the existing facilities are faster than necessary and recommended that in addition to the addition of short security delays, contact outputs should be used instead of solid state outputs for improved security.

Page 2

Protection upgrades for five 230 kV transmission lines

4. Protection Upgrades

Breaker auxiliary switches

The review noted that the existing breaker status inputs to the SEL321 relays used for the P2 protection systems were not phase segregated. However it is probable that the internal logic in the SEL321 relay will be able to compensate for this lack of segregated phase status. Existing 230 kV airblast circuit breakers do not have the ability to deliver phase segregated status to external devices. Newer SF6 circuit breakers do have the individual phase status available. For future projects where newer SF6 breakers are used, it is recommended that phase segregated status be made available to the relays.

Replacing P1 protections.

The review noted that the existing P1 protection systems consisting of optimho relays include several limitations in performance. The key limitations are:

1. There is no built-in event recording facility. Thus unexpected operations cannot be analyzed conclusively to determine the cause of the problem. This lack of recording ability has already prevented determination of the root cause of the 2nd December 2007 disturbance that resulted in a loss of supply to the complete Avalon Peninsula. Considering that these transmission lines are the backbone of the Newfoundland and Labrador transmission system it is critical that facilities to enable thorough disturbance analysis be available.

2. The resistive reach cannot be independently set for each zone. In the case of the short line TL207, this means that the zone 1 function cannot be connected to trip. For all other lines, it means that the desired sensitivity of 100 ohms of fault resistance coverage cannot be achieved for 100% of each line.

3. The reaches of the phase distance functions cannot be set independently from the reaches of the ground distance functions. This means that the zone 1 phase distance function has to be set to reach shorter than the optimum 85% of each line (except TL207 for which the zone 1 element does not trip). It also means on some lines that the zone 2 timers have to be set slower than necessary in order to accommodate the needs of the ground distance functions. Thus zone 2 time delayed tripping is sometimes delayed unnecessarily for multiphase faults (which have a severe impact on system performance.

In addition to performance limitations, the optimho relays are no longer in production with little opportunity to purchase spare parts or support from the manufacturer. In most cases spare parts will have to be cannibalized from other relays that have been removed from service.

In order to overcome the above mentioned limitations, the protection systems should be replaced with modern systems. In addition, in some locations pneumatic auxiliary timers are used. These timers are susceptible to error due to aging and dust. Replacement of the P1 protection systems will also eliminate these sources of unreliability.

Page 3

Protection upgrades for five 230 kV transmission lines

Electromechanical ground time overcurrent relays

The existing P2 protection systems include electromechanical ground time overcurrent relays. However the built-in ground time overcurrent relays provide the same function with improved accuracy and reliability. Removing the electromechanical relays from service will reduce maintenance costs and simplify the existing P2 system.

The electromechanical relays should be removed from service at the same time as the breaker auxiliary contact modifications are done to the P2 protection systems.

Automatic Reclosing upgrades

The review noted that there have been failures of automatic reclosing facilities on some transmission lines in the past. Automatic reclosing improves the performance of the transmission system by restoring circuits quickly and automatically after a fault. More than 90% of faults on transmission circuits are temporary, meaning that automatic reclosing will be almost always successful. Reliable automatic reclosing contributes significantly to reliability of transmission circuits.

A variety of existing automatic reclosing facilities are provided. In the case of TL202 and TL206 breakers, the reclosing facilities use part of the P2 protection functionalities and use up otherwise spare input points on the P2 relay. This makes insufficient inputs available for segregated pole breaker status.

At the same time as the P1 protections on circuits TL202 and TL206 are replaced, the reclosing schemes for these two circuits should be modified to remove or reduce the dependency on the P2 protection systems to free up inputs on the P2 systems for breaker auxiliary switch inputs.

In the case of TL203, TL207 and TL237, the synchronism check supervision of automatic reclosing should be modified to check the status of all three phase voltages are dead before allowing the synchronism check function to be bypassed. This can also be done at the same time as the P1 protections for these circuits are replaced.

Reference

1 Report "Circuits TL202, TL203, TL206, TL207 and TL237 Transmission line protection performance and settings Review" Prepared for Newfoundland and Labrador Hydro, by Henville Consulting Inc., December 2010

Page 4

Project Title: Replace Surge Arresters

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project consists of the purchase and installation of surge arresters at various Hydro terminal stations on the Island Interconnected System. These units are in the 25, 69, 138 and 230 kV classifications. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	55.6	0.0	0.0	55.6
Labour	73.3	0.0	0.0	73.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	12.5	0.0	0.0	12.5
Interest and Escalation	12.2	0.0	0.0	12.2
Contingency	28.3	0.0	0.0	28.3
TOTAL	**181.9**	**0.0**	**0.0**	**181.9**

The surge arresters targeted for replacement in 2014 are:

- Three 230 kV rated surge arresters for transformer T1 in Grand Falls Frequency Converter Terminal Station[2];
- Three 66 kV and three 25 kV rated surge arresters for transformer T2 in Hawke's Bay Terminal Station;
- Three 230 kV and three 66 kV rated surge arresters for transformer T3 in Massey Drive Terminal Station, and;
- Three 230 kV and three 66 kV rated surge arresters for transformer T1 in Western Avalon Terminal Station.

Operating Experience:

Surge arresters are used on major terminal station equipment to protect that equipment from voltage surges due to lightning and switching effects. Surge arresters fail because of the cumulative effects of

[2] *The frequency converter system in the Grand Falls Frequency Converter (GFC) Terminal Station was decommissioned in May 2002. The Terminal Station still maintains the name of GFC.*

lightning strikes and switching surges. The wide variety of operating environments across the system makes it difficult to predict surge arrester failures. The older arrester designs have a higher incidence of failure than the newer designs. Hydro has approximately 440 surge arresters in service in all three voltage classes ranging in age from one year to approximately 47 years.

Project Justification:

Surge arresters provide critical overvoltage protection of power system equipment from lightning and switching surges. Surge arresters are regularly inspected and replacements are made based on these maintenance assessments as well as in-service failures.

Hydro has developed a Long Term Asset Management Plan (LTAMP) for surge arresters. The LTAMP is a prioritized list of surge arresters scheduled for replacement. The LTAMP replacement schedule is based primarily on the age of the surge arrester, but in some instances the replacement is based on known defects. The LTAMP is revised annually based on the above criteria. The surge arresters targeted for replacement in 2014 are considered most susceptible to failure of all surge arresters contained in Hydro's systems.

When a surge arrester fails, it is not repairable and must be replaced immediately; otherwise the major equipment is exposed to serious damage from lightning surges. Failure of any major equipment could result in major system disturbances, which may cause system outages and interruption of service to customers.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Project initiation and planning	January 2014	February 2014
Design	Design transmittal, project work package and commissioning procedures	March 2014	April 2014
Procurement	Material requisition, specification and procurement. Coordinate material delivery. *(four month lead time)*	March 2014	August 2014
Construction	Deliver surge arresters to designated terminal station, perform outage including required permits, install surge arresters	September 2014	November 2014
Commissioning	Initial surge arrester commissioning procedures	September 2014	November 2014
Closeout	Project close-out	December 2014	December 2014

Future Plans:

Surge arrester replacements will be proposed in future capital budget applications. Hydro's five-year plan for surge arrester replacements is presented in Appendix A.

APPENDIX A

FIVE-YEAR PLAN FOR

SURGE ARRESTER REPLACEMENTS

TABLE A1 – 2014 SURGE ARRESTER REPLACEMENT PLAN

Target Year	Terminal Station Location	Asset Description
2014	Grand Falls Frequency Converter	GFC – T1 H1
2014	Grand Falls Frequency Converter	GFC – T1 H2
2014	Grand Falls Frequency Converter	GFC – T1 H3
2014	Hawke's Bay	HBY – T2 H1
2014	Hawke's Bay	HBY – T2 H2
2014	Hawke's Bay	HBY - T2 H3
2014	Hawke's Bay	HBY - T2 X1
2014	Hawke's Bay	HBY - T2 X2
2014	Hawke's Bay	HBY - T2 X3
2014	Massey Drive	MDRTS – T3 H1
2014	Massey Drive	MDRTS – T3 H2
2014	Massey Drive	MDRTS – T3 H3
2014	Massey Drive	MDRTS – T3 X1
2014	Massey Drive	MDRTS – T3 X2
2014	Massey Drive	MDRTS – T3 X3
2014	Western Avalon	WAV – T1 H1
2014	Western Avalon	WAV – T1 H2
2014	Western Avalon	WAV – T1 H3
2014	Western Avalon	WAV – T1 X1 TOP
2014	Western Avalon	WAV – T1 X2 TOP
2014	Western Avalon	WAV – T1 X3

TABLE A2 – 2015 SURGE ARRESTER REPLACEMENT PLAN

Target Year	Terminal Station Location	Asset Description
2015	Grand Falls Frequency Converter	GFC – T2 H1
2015	Grand Falls Frequency Converter	GFC – T2 H2
2015	Grand Falls Frequency Converter	GFC – T2 H3
2015	Western Avalon	WAV – T3 H1
2015	Western Avalon	WAV – T3 H2
2015	Western Avalon	WAV – T3 H3
2015	Western Avalon	WAV – T3 X1
2015	Western Avalon	WAV – T3 X2
2015	Western Avalon	WAV – T3 X3
2015	Western Avalon	WAV – T4 H1
2015	Western Avalon	WAV – T4 H2
2015	Western Avalon	WAV – T4 H3
2015	Western Avalon	WAV – T4 X1
2015	Western Avalon	WAV – T4 X2
2015	Western Avalon	WAV – T4 X3

TABLE A3 – 2016 SURGE ARRESTER REPLACEMENT PLAN

Target Year	Terminal Station Location	Asset Description
2016	Hampden	HDN – T1 H1
2016	Hampden	HDN – T1 H2
2016	Hampden	HDN – T1 H3
2016	Hampden	HDN – T1 X1
2016	Hampden	HDN – T1 X2
2016	Hampden	HDN – T1 X3
2016	Hardwoods	HWD – T5 H1
2016	Hardwoods	HWD – T5 H2
2016	Hardwoods	HWD – T5 H3
2016	Hardwoods	HWD – GT1 H1
2016	Hardwoods	HWD – GT1 H2
2016	Hardwoods	HWD – GT1 H3
2016	Hawke's Bay	HBY – T3 H1
2016	Hawke's Bay	HBY – T3 H2
2016	Hawke's Bay	HBY - T3 H3
2016	Hinds Lake	HLK - T1 H1
2016	Hinds Lake	HLK - T1 H2
2016	Hinds Lake	HLK - T1 H3
2016	Hinds Lake	HLK - T2 H1
2016	Hinds Lake	HLK - T2 H2
2016	Hinds Lake	HLK – T2 H3
2016	Oxen Pond	OPD – GT1 H1
2016	Oxen Pond	OPD – GT1 H2
2016	Oxen Pond	OPD – GT1 H3
2016	Rocky Harbour	RHR – T1 H1
2016	Rocky Harbour	RHR – T1 H2
2016	Rocky Harbour	RHR – T1 H3
2016	Rocky Harbour	RHR – T1 X1
2016	Rocky Harbour	RHR – T1 X2
2016	Rocky Harbour	RHR – T1 X3

TABLE A4 – 2017 SURGE ARRESTER REPLACEMENT PLAN

Target Year	Terminal Station Location	Asset Description
2017	Roddickton Woodchip	RWC GT1 - H1
2017	Roddickton Woodchip	RWC GT1 H2
2017	Roddickton Woodchip	RWC GT1 H3
2017	Western Avalon	WAV – GT1 H1
2017	Western Avalon	WAV – GT1 H2
2017	Western Avalon	WAV – GT1 H3
2017	Sunnyside	SSD – T1 H1
2017	Sunnyside	SSD – T1 H2
2017	Sunnyside	SSD – T1 H3
2017	Sunnyside	SSD – T1 X1
2017	Sunnyside	SSD – T1 X2
2017	Sunnyside	SSD –T1 X3
2017	Stony Brook	STB – T2 H1 OVERALL
2017	Stony Brook	STB – T2 H2 OVERALL
2017	Stony Brook	STB – T2 H3 OVERALL
2017	Stony Brook	STB – T2- X1
2017	Stony Brook	STB – T2- X2
2017	Stony Brook	STB – T2- X3

TABLE A5 – 2018 SURGE ARRESTER REPLACEMENT PLAN

Target Year	Terminal Station Location	Asset Description
2018	Corner Brook Frequency Converter	CBFTS – T1 H1
2018	Corner Brook Frequency Converter	CBFTS – T1 H2
2018	Corner Brook Frequency Converter	CBFTS – T1 H3
2018	Corner Brook Frequency Converter	CBFTS – T2 H1
2018	Corner Brook Frequency Converter	CBFTS – T2 H2
2018	Corner Brook Frequency Converter	CBFTS – T2 H3
2018	Holyrood	HRD – T8 H1
2018	Holyrood	HRD – T8 H2
2018	Holyrood	HRD – T8 H3
2018	Holyrood	HRD – T8 X1
2018	Holyrood	HRD – T8 X2
2018	Holyrood	HRD – T8 X3
2018	Holyrood	HRD – T10 H1
2018	Holyrood	HRD – T10 H2
2018	Holyrood	HRD – T10 H3
2018	Holyrood	HRD – T10 X1
2018	Holyrood	HRD – T10 X2
2018	Holyrood	HRD – T10 X3
2018	Holyrood	HRD SST-1-2 H1
2018	Holyrood	HRD SST-1-2 H2
2018	Holyrood	HRD SST-1-2 H3

Project Title: Replace Recloser Control Panels

Location: Various Sites

Category: Transmission and Rural Operations - Distribution

Definition: Pooled

Classification: Normal

Project Description:

The Recloser Control Panel Replacement Project is required to replace 50 aging recloser control panels. This is the final two years of a seven-year program. Four recloser control panels will be replaced in this project. The existing control panels are housed in steel enclosures which have deteriorated due to the environment. To prevent future deterioration of the new panels due to weather, the Recloser Control Panel Replacement Project uses rack mounted control panels inside control buildings where applicable and control panels located inside stainless steel enclosures where no building exists. The new recloser control panels will also have remote control capability to support integration with future telecommunications network and system control upgrades. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	45.0	0.0	0.0	45.0
Labour	45.0	36.5	0.0	81.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	14.0	9.0	0.0	23.0
Interest and Escalation	7.3	9.0	0.0	16.3
Contingency	0.0	29.9	0.0	29.9
TOTAL	**111.3**	**84.4**	**0.0**	**195.7**

In 2014, four rack mounted control panels will be installed as shown in Table 2. For a complete list of the recloser control panels to be replaced under this program see Appendix A.

Table 2: 2014 Recloser Control Panel Replacements

Location	Type	Recloser ID	Installation Year
Mary’s Harbour	Rack Mounted	MH1-R1	1970
Port Hope- Simpson	Platform Mounted	PH1-R1	1970
Wiltondale	Rack Mounted	WD1-R1	1981
Hawke's Bay	Rack Mounted	HB3-R2	1982

These recloser control panels have been identified for replacement based on condition and age. The rack mounted unit listed in Table 2 will be mounted inside the available control building and need no further enclosure. This measure will reduce the effect of salt corrosion which is a known factor in these areas.

Operating Experience:

Hydro operates distribution systems throughout Newfoundland and Labrador and supplies power to approximately 36,000 metered customers. A key component of the distribution systems is the distribution automatic recloser. It is the primary fault protective device on distribution feeders. A distribution recloser is set to detect faults on the feeders and to open if a fault occurs. The feeder is put back in service automatically by the recloser and if the fault has been cleared, the feeder will stay in service, minimizing the outage to customers.

Justification:

The distribution recloser is a key protective device for detection of various types of system faults and the automatic restoration of power when these line faults are only temporary in nature. It also enables isolation of the faulted line section should the system fault be permanent. Therefore, the operating integrity of this key protective device must not be compromised by the failure of an internal electronic component due to rusting of the recloser control panel.

This project is to replace aging and weathered distribution recloser control panels on distribution feeders to ensure fault protection reliability is not compromised. Photo of a recloser control panel is shown in Figure 1.

Figure 1: Hawke's Bay HB3-R2 Recloser Control Cabinet

The existing recloser control panels, manufactured by Cooper Power Systems, are housed in a painted steel compartment which has been exposed to a corrosive coastal environment for many of the recloser locations.

Operating Regime

All distribution reclosers listed for upgrade are in continuous operating mode.

Age of Equipment or System

Refer to Appendix A for a listing of the age of the assets being replaced.

Major Work/ or Upgrades

Refer to Appendix B for a list of major work and upgrades on various reclosers.

Outage Statistics

Hydro tracks all distribution system outages using industry standard indexes, SAIFI and SAIDI which are explained as follows:

SAIDI- indicates the System Average Interruption Duration for customers served per year, or the average length of time a customer is without power in the respective distribution system per year.

SAIFI - Indicates the average of sustained interruptions per customer served per year or the average number of power outages a customer has experienced in the respective distribution system per year.

Table 3 lists the 2008 to 2012 average SAIFI and SAIDI data by feeder and distribution system where the upgrades are proposed. The table also lists the 2008 to 2012 corporate value and the latest Canadian Electrical Association (CEA) five year average (2006 to 2010) for comparison.

Table 3: Outage Statistics

Five Year averages (2008 to 2012)					
	All Causes			Defective Equipment	
SYSTEM	SAIFI	SAIDI		SAIFI	SAIDI
Mary's Harbour	11.72	7.37		0.29	0.54
Port Hope Simpson	6.17	3.50		0.20	0.03
Willian's Harbour	6.85	8.60		0.02	2.68
Hawke's Bay Feeder L3	6.49	9.19		0.67	1.22
Northern Interconnected	11.54	15.80		0.37	1.06
Northern Isolated	6.37	6.03		0.43	0.56
Hydro Corporate	4.88	10.57		0.38	1.00
CEA Region 2 (2007-2011)	2.70	7.19		0.45	1.14

Hydro’s present system for collecting outage information does not record equipment failures by distribution equipment components such as recloser panels. Outages due to recloser control panels along with other defective equipment would be included in the general defective equipment category. The data provided in the table lists the outage statistics for all causes and defective equipment.

Defective equipment is defined by the CEA, Service Continuity Reliability Committee as:
Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.

The CEA statistics do not include planned outages to repair defective equipment.

Safety Performance

During a fault, electrical energy enters the earth. These electronic reclosers sense the fault condition and break the electrical path feeding the fault. This quickly limits the electrical energy entering the earth greatly reducing the electrocution hazard.

Environmental Performance

This multi-year project does not have any environmental impact. All of the reclosers listed have been tested and are below 1 part per million (PPM) polychlorinated biphenyl (PCB) content.

Industry Experience

The stainless steel enclosure for the control panel or the rack mounted control panel is recommended for installations subject to severe weather or salt contamination.

Vendor Recommendations

Peter Dennis from R L Dennis Associates Ltd, the representative for Cooper Power Systems verbally advised Hydro, in 2009, that the solution to the severe rust contamination on the recloser control panels is replacement with the latest digital control which is available in a stainless steel panel enclosure, as well as in rack mount configuration. The vendor has also confirmed that the existing recloser itself does not require change out and that only its sensing current transformers (CT) require replacement in order to be compatible with the accuracy of the new digital control.

Availability of Replacement Parts

Hydro has been advised by Cooper Power Systems that circuit boards and plug-in cards have delivery times of 3-6 months, as can be seen below in an excerpt from their email dated May 10th, 2012:

> “ Lead times on replacement control boards has now reached three to six months, as the stock-pile has been depleted. While some pre-existing sub-suppliers for these components are still in business, others have left the business all together.

Roughly 90% of the original F3 users have now moved on to more feature-rich controls like the F6 which supports smart grid technologies to be used today, or very shortly in their future"

Notes: F3 is the existing recloser panel and F6 is the new replacing recloser panel.

Maintenance or Support Arrangements

There are no maintenance or support agreements with the manufacturers. Maintenance and support are provided by Hydro in-house resources.

Maintenance History

Table 4 shows the five-year maintenance history for the reclosers being replaced in 2014. Refer to Appendix C for the five-year maintenance history for all reclosers to be replaced under the program.

Table 4: Five Year Maintenance History

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2012	Hawke's Bay Recloser HB3-R2	1.5	0.0	1.5
2011	Wiltondale Recloser WD1-R1	0.7	0.0	0.7
2010	Port Hope-Simpson PH1-R1	2.7	0.0	2.7
2010	Mary's Harbour Recloser MH1-R1	0.4	0.0	0.4
2009	Mary's Harbour Recloser MH1-R1	0.0	1.2	1.2
2008	Hawke's Bay Recloser HB3-R2	0.0	0.9	0.9
2008	Wiltondale Recloser WD1-R1	0.6	0.0	0.6
2008	Mary's Harbour Recloser MH1-R1	0.7	0.0	0.7

Historical Information

Eight recloser control panel replacements were completed in 2008. These consisted of reclosers at the Change Islands Substation (CH2-R1 and CH3-R1), Fogo Island Substation (FO4-R1, FO5-R1 and FO6-R1), and the Bottom Waters Terminal Station (BW1-R1, BW2-R1 and BW3-R1).

Five recloser control panel replacements were completed in 2009. These consisted of reclosers at the Burgeo Substation (BU2-R1, BU3-R1 and BU4-R1) and at the Bottom Waters Terminal Station (BW2-R3 and BW4-R1).

Of the sixteen recloser control panels that were budgeted replaced in 2010, eleven recloser control panels were completed in 2010. These were located at South Brook (SB7-R2), English Hr. West (EH1-R1 and EH1-R2), Jackson's Arm (JA1-R1 and JA2-R1), Hampden (HA1-R1), Happy Valley-Goose Bay (HV1-R1, HV7-R1, HV8-R1, HV10-R1 and HV16-R1). Five were completed in 2011. These were Bear Cove (BC6-R2, BC4-R1 and BC6-R1), and Plum Point (PP1-R1 and PP2-R1).

Of the seven recloser control panels that were budgeted to be replaced in 2011, two recloser control panels were completed in 2011. These were located at Barachoix (BA1-R1 and BA4-R1). The remaining five Roddickton (RO1-R2, RO1-R3, RO3-R2, RO4-R1) and Main Brook (MB1-R2) were purchased and will be installed and commissioned in 2013 .

Five recloser control panels were completed in 2012. These consisted of in Parson's Pond Terminal Station (PP1-R1), Cow Head Terminal Station (CH1-R1), Daniel's Harbor Terminal Station (DH1-R1), Hawkes Bay Terminal Station (HB3-R1) and Cook’s Harbour (CH7-R1). The Cook's Harbour recloser was replaced due to a failure just prior to the start of the 2012 project.

The project work includes the installation of CTs (current transformers) inside the reclosers. These CTs are required for the operation of the new control panels. These installations were scheduled and completed with the use a spare recloser. The approach to installing the recloser panels was that the spare was installed at the first site which allowed the old recloser to be removed and shipped to the maintenance shop in Bishop Falls where it was fitted with the new CTs and then shipped to the second site. This approach was used for all the sites which decreased the amount of time that reclosers were bypassed on the electrical system, and reduced field time which also resulted in some savings in travel expenses.

Table 5 contains the historical information for these replacements.

Table 5: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2013B	209.7		5		
2012	202.3	113.9	5	$28.48 for 4 units (see notes in Comments)	Four units were done under this program and the 5th unit Cook's Harbour CH7-R1 was replaced due to a failure and the costs were not charged on the 2012 project.
2011	231.9	178.4	7	25.14	Two completed and five recloser panels have been pushed into 2013 for installation and commissioning due to resource issues.
2010	603.1	370.24	16	23.14	See Footnote[3].
2009	132.4	107.3	5	21.46	
2008	222.5	133.9	8	16.74	See Footnote[4]

Anticipated Useful life

The recloser control panel has an anticipated useful life of 20 years.

Alternatives

There is no viable alternative to replacement of the control panels for the distribution reclosers listed in Appendix A. Many of the original electronic components for these control panels have long lead times as per the availability of parts section of this document and the enclosures are in a deteriorating condition.

Losses during Construction

There may be planned power outages involving the reclosers that require current transformer (CT) replacements. The reclosers will have to be temporarily removed from service.

[3] *The 2010 budget was revised as the amount of field work by operations crew was less than originally estimated. The total reduction to the project was was $218,411. Resource issues in Rural Operations had pushed the schedule of five recloser panels into 2011*

[4] *The 2008 budget was revised as the cost for the recloser controls was less than originally estimated and several of the recloser structure modifications were not required as originally anticipated. The amount of field work by operations crews was also significantly reduced by retrofitting each recloser and pre-commissioning it with its new electronic controls in the Hydro terminals maintenance repair facility at Bishop's Falls, thereby reducing operations crews overtime and travel time. The total reduction on the change order was $88,961.*

Status Quo

Maintaining the status quo will result in prolonged outages and by-passed protective devices due to the availability of replacement parts for the existing recloser controls. This could also cause unnecessary outages. If a recloser did not operate because it was in bypass mode or simply didn't operate due to age, an upstream protective device would operate and by doing so, increase the number of customers affected.

Conclusion:

Replacing each panel with a more modern digital control panel with rack mounted panels located in a control building is the only option.

Project Schedule:

The anticipated project schedule is shown in Table 6.

Table 6: Project Schedule

Activity		Start Date	End Date
Planning	Project initiation	January 2014	January 2014
Design	Project design	February 2014	April 2014
Procurement	Equipment ordering	February 2014	April 2014
Construction	Field construction and installations	July 2014	April 2015
Commissioning	Commissioning after installation	August 2014	May 2015
Closeout	Project completion and closeout	June 2015	June 2015

Future Plans:

None.

APPENDIX A

AGE OF ASSETS

Replacement History

Location	Recloser ID	Asset #	Year Installed	Year Scheduled/Replaced
Hawke’s Bay	HB3-R1	58178	1971	2012
Cow Head	CH1-R1	58187	1981	2012
Cook’s Harbour	CH7-R1	80051	1975	2012
Daniels Harbour	DH1-R1	58184	1981	2012
Parsons Pond	PP1-R1	159132	1999	2012
St. Anthony	SA2-R1	107289	1980	2013
St. Anthony	SA3-R1	99273	1985	2013
St. Anthony	SA1-R1	97367	1986	2013
L’Anse au Loup	LL2-R1	95688	1968	2013
L’Anse au Loup	LL1-R1	99933	1975	2013
Mary’s Harbour	MH1-R1	80037	1970	2014
Port Hope- Simpson	PH1-R1	80031	1970	2014
Wiltondale	WD1-R1	257156	1981	2014
Hawke's Bay	HB3-R2	158910	1982	2014

APPENDIX B

MAJOR WORK/UPGRADES

Major Work/Upgrades

Date	Recloser	Major Work/Upgrade	Cost
September 2009	Parson's Pond Recloser PP1-R1	Replace power cable	$463
March 2006	Hawke's Bay Recloser HB3-R1	Recloser Control Panel Repaired	$2,086
March 2006	St. Anthony Recloser SA3-R1	Recloser Control Panel Repaired	$2,086
December 2005	St. Anthony Recloser SA3-R1	Recloser Control Panel Failure To Trip	$806
May 2005	Glenburnie Recloser GL2-R1	Replace CT	$407
August 2004	L'Anse au Loup Recloser LL2-R1	Install Sequence Coordination Accessory	$904
July 2004	Roddickton Recloser RO4-R1	Install Sequence Coordination Accessory	$830

APPENDIX C

MAINTENANCE HISTORY

Maintenance History

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2012	Hawke's Bay Recloser HB3-R2	1.5	0.0	1.5
Total 2012		**1.5**	**0.0**	**1.5**
2011	Wiltondale Recloser WD1-R1	0.7	0.0	0.7
2011	St Anthony Recloser SA1-R1	0.0	0.4	0.4
Total 2011		**0.7**	**0.4**	**1.3**
2010	Port Hope-Simpson PH1-R1	2.7	0.0	2.7
2010	Mary's Harbour Recloser MH1-R1	0.4	0.0	0.4
2010	L'Anse au Loup Recloser LL2-R1	2.0	0.0	2.0
2010	L'Anse au Loup Recloser LL1-R1	2.0	0.0	2.0
2010	St Anthony Recloser SA2-R1	0.7	0.0	0.7
2010	Hawke's Bay Recloser HB3-R1	3.0	0.0	3.0
2010	Parson 's Pond PP1-R1	0.9	0.0	0.9
2010	Recloser Battery	0.7	0.0	0.7
Total 2010		**12.4**	**0.0**	**12.4**
2009	Mary's Harbour Recloser MH1-R1	0.0	1.2	1.2
2009	Barachoix Recloser BA4-R1	1.3	0.0	1.3
2009	Glenburnie Recloser GL2-R1	0.0	0.1	0.1
Total 2009		**1.3**	**1.3**	**2.6**
2008	Mary's Harbour Recloser MH1-R1	0.7	0.0	0.7
2008	Hawke's Bay Recloser HB3-R2	0.0	0.9	0.9
2008	Wiltondale Recloser WD1-R1	0.6	0.0	0.6
2008	Barachoix Recloser BA1-R1	0.6	0.0	0.6
2008	Cow Head Recloser CH1-R1	0.3	0.0	0.3
2008	Daniels Harbour Recloser DH1-R1	0.0	0.4	0.4
2008	Roddickton Recloser RO4-R1	0.0	0.1	0.1
2008	St Anthony Recloser SA1-R1	0.0	0.4	0.4
2008	St. Anthony Recloser SA3-R1	0.5	1.2	1.7
2008	Parson's Pond Recloser PP1-R1	0.0	0.8	0.8
Total 2008		**2.7**	**3.8**	**6.5**
2007	L'Anse au Loup Recloser LL2-R1	0.9	0.0	0.9
2007	Port Hope Simpson Recloser PH1-R1	0.4	0.3	0.7
2007	Hawke's Bay Recloser HB3-R1	0.0	1.2	1.2
2007	L'Anse au Loup Recloser LL2-R1	0.9	0.0	0.9
2007	L'Anse au Loup Recloser LL1-R1	0.7	0.0	0.7
2007	Cooks Harbour Recloser CH7-R1	0.0	0.2	0.2
2007	Daniels Harbour Recloser DH1-R1	0.4	0.0	0.4
2007	Glenburnie Recloser GL2-R1	0.4	1.1	1.5
2007	St Anthony Recloser SA2-R1	0.0	0.7	0.7
2007	St. Anthony Recloser SA3-R1	0.0	1.4	1.4
Total 2007		**3.7**	**4.9**	**8.6**
2006	Port Hope Simpson Recloser PH1-R1	0.4	0.0	0.4
2006	Hawke's Bay Recloser HB3-R1	0.0	2.0	2.0
2006	St. Anthony Recloser SA1-R3	0.0	0.1	0.1
2006	Barachoix Recloser BA1-R1	0.0	0.8	0.8

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2006	Glenburnie Recloser GL2-R1	0.0	0.6	0.6
2006	Roddickton Recloser RO1-R2	0.3	0.0	0.3
2006	Roddickton Recloser RO4-R1	0.3	0.8	1.1
2006	Roddickton Recloser RO1-R3	0.0	0.2	0.2
2006	St. Anthony Recloser SA1-R1	0.0	5.1	5.1
Total 2006		**1.0**	**9.6**	**10.6**

Project Title: Construct Storage Facility

Location: Postville

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Normal

Project Description:

Work under this project consists of the construction of a new, detached 7.30 m x 9.14 m wood frame storage facility at Hydro's Postville diesel generation facility. The new storage facility will be finished with metal cladding. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.5	0.0	0.0	0.5
Labour	53.2	0.0	0.0	53.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	83.9	0.0	0.0	83.9
Other Direct Costs	9.0	0.0	0.0	9.0
Interest and Escalation	7.9	0.0	0.0	7.9
Contingency	29.3	0.0	0.0	29.3
TOTAL	**183.8**	**0.0**	**0.0**	**183.8**

Operating Experience:

The Postville diesel generation facility was constructed in 1975. Measuring 6.09 m wide by 15.25 m long, the structure consists of a porch, a washroom, a small office area and an engine hall, which houses four diesel generating units. There is presently no work space or dedicated storage areas in the plant. Site storage is restricted to a 5.0 m x 6.0 m waste oil storage facility and two small 3.0 m x 3.0 m general storage sheds, located at the rear of the plant (see Figure 1).

Figure 3: Postville Diesel Generation Facility General and Waste Oil Storage Buildings

The absence of a proper workspace impedes the ability of the plant operators to conduct day-to-day maintenance work at the facility. This work is presently confined to a corner of the engine hall which restricts the ability of the employees to maneuver and complete the task at hand.

Furthermore, the general storage facilities are unable to adequately meet the storage needs of the Postville generation facility, resulting in excess items having to be stored in the engine hall. This creates numerous safety and operational concerns as the material impedes walkways, increases the risk of fire within the facility and reduces the available clearance required for the completion of routine maintenance on the generation units.

Project Justification:

This project is justified on the requirement to provide additional work and storage space at the Postville diesel generation facility. The existing spatial constraints were identified in the “Diesel Plant

Remediation - Phase II" report, completed by Hatch Engineering Ltd. in 2012 (see Appendix A). The report recommendations form the basis of this proposal.

Presently, there is inadequate space available to meet Hydro's requirements. This creates both maintenance and safety concerns for personnel utilizing the facility. The requirement to store materials and equipment within the engine hall has resulted in inadequate clearances around the perimeter of the generation equipment. This hinders maintenance personnel's ability to follow proper work procedures when working on the equipment and results in a cluttered work space, with an increased potential for injury as a results of trips and falls. The construction of a new, detached structure is required to provide the required space and resolve these concerns.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Project start-up, design transmittal and schedule review	March 2014	March 2014
Design	Preparation of tender package	April 2014	May 2014
Tender Award	Tender, review and contract award	May 2014	June 2014
Construction	Construct new workspace/storage facility	July 2014	July 2014
Commissioning	Final inspection	-	July 2014
Closeout	Final billing, interest cut-off, and project completion	-	September 2014

Future Plans:

None.

APPENDIX A

DIESEL PLANT REMEDIATION PHASE II – FINAL REPORT

HATCH™

Newfoundland and Labrador Hydro

Diesel Plant Remediation

Phase II - Final Report

H342925-0000-00-124-0002
Rev. 0
April 12, 2013

Newfoundland and Labrador Hydro

Diesel Plant Remediation

Phase II - Final Report

H342925-0000-00-124-0002
Rev. 0
April 12, 2013

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Newfoundland and Labrador Hydro - Diesel Plant Remediation
Phase II - Final Report - April 12, 2013

Newfoundland and Labrador Hydro
Diesel Plant Remediation

Phase II - Final Report

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Date	**Rev.**	**Status**	**Prepared By**	**Checked By**	**Approved By**	**Approved By**
HATCH						**Client**

H342925-0000-00-124-0002, Rev. 0
Page i

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Table of Contents

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List of Tables

List of Figures

Executive Summary

Site	Deficiency	Remediation Options	Capital Cost
Charlottetown	Inadequate ventilation	Minimum Requirements – minimal cost fixes that will bring the ventilation system into reasonable working order, typically via repair and rearrangement of existing equipment. If existing equipment is repairable, this option will restore ventilation airflow and comfort in the building. If existing equipment is beyond repair, this option is not feasible.	$60k
		Basic Improvements – alternate/additional improvements that can be implemented to decrease heat rejection rate from the generator sets into the building and improve ventilation airflow more than the minimum requirements. The costs associated with the new equipment required in this option can be weighed against the expected benefits.	$110k
		Redesign/System Modifications – more extensive changes to the system that will bring the facility into compliance with 'best practice'. These modifications go beyond the Basic Improvements and will further decrease the heat rejection rate from the generator sets, improve ventilation airflow overall as well as in localized areas. The costs associated with these upgrades are generally higher due to the new equipment required.	$160k
Makkovik	Over the years, the siding has become damaged and weathered. There are many patches around the perimeter due to repairing the damaged areas and covering unused equipment penetrations.	Replace siding and door on north facing wall only.	$45k
		Replace siding, door and windows on half of building only.	$111k
		Replace siding, door and windows in entire building.	$195k
Paradise River	The concrete foundation supporting the wall closest to the ocean has moved outward and the wall is bowed out so it is no longer vertical. A section of the	Replace only the 9.5 m long section of exterior wall that appears to have moved and the shallow concrete footing that has cracked as well as the section of the interior concrete slab that has settled and cracked. This option provides immediate repairs to the wall and concrete footing that are in distress but does not address investigating the source of the structural problems or carrying out additional work to prevent similar problems from occurring in the future.	$325k

Site	Deficiency	Remediation Options	Capital Cost
	concrete floor slab in this area also appears to have settled and cracked. The building envelope develops open gaps during winter primarily along the connection between the original building and the extension	Carry out more extensive repairs to the existing building including, a geotechnical investigation to determine the location and characteristics of the soil and bedrock in the vicinity of the building, replacement of the existing shallow concrete foundations with deeper concrete foundations more suitable for the Labrador climate, and replacement of the original structure with new materials in the original building footprint with the extension demolished and removed.	$595k
	Inadequate floor area. There is no washroom in plant, the existing office is small, the workshop is inadequate and there is inadequate storage. No potable water and septic services.	Construction of a new building consisting of an office, workshop, washroom and storage. Provision of potable water and septic services.	$115k (New building) $216k (water and septic services)
	Inadequate ventilation	Install ventilation.	$50k
	All of above	Construct new powerhouse	$5,321k
Postville	Inadequate storage. Currently relies on small detached sheds for storage. No workshop.	Construction of a new building consisting of a workshop and storage area.	$83k
Ramea	Inadequate ventilation	Minimum Requirements – minimal cost fixes that will bring the ventilation system into reasonable working order, typically via repair and rearrangement of existing equipment. If existing equipment is repairable, this option will restore ventilation airflow and comfort in the building. If existing equipment is beyond repair, this option is not feasible.	Not Feasible
		Basic Improvements – alternate/additional improvements that can be implemented	$120k

Site	Deficiency	Remediation Options	Capital Cost
		to decrease heat rejection rate from the generator sets into the building and improve ventilation airflow more than the minimum requirements. The costs associated with the new equipment required in this option can be weighed against the expected benefits.	
		Redesign/System Modifications – more extensive changes to the system that will bring the facility into compliance with 'best practice'. These modifications go beyond the Basic Improvements and will further decrease the heat rejection rate from the generator sets, improve ventilation airflow overall as well as in localized areas. The costs associated with these upgrades are generally higher due to the new equipment required.	$170k

2. Deficiencies

2.1 Charlottetown

The following was noted in Hatch's 2009 Condition Assessment Final Report.

- Ventilation – Temperature in plant was fairly high and uncomfortable. This plant has a two-story layout; the upstairs office, lunchroom and storage areas were all too warm [1].

This deficiency has been chosen by NL Hydro for remediation.

2.2 Makkovik

The following was noted in Hatch's 2009 Condition Assessment Final Report.

- Building envelope - Bad to fair condition [1].

This deficiency has been chosen by NL Hydro for remediation.

2.3 Paradise River

The following was noted in Hatch's 2009 Condition Assessment Final Report.

- Building envelope - Wooded structure, asbestos sheeting, cracked foundation. Ice damming is a problem due to open trusses (bad to fair condition). Recommend further structural analysis to determine adequacy of building envelope [1].
- Availability/condition of office – Office was small but generally adequate [1].
- Availability/condition of lunchroom – No lunch room at plant [1].
- Availability/condition of washroom facilities – No washroom in plant. During winter months, the nearest washroom is in the operator's house approximately ½ km away [1].
- Plant has no mechanical ventilation. Plant relies on two turbine ventilators in the roof, eave soffit venting and windows. Plant was very warm at time of visit. Office has small A/C unit installed keeping temperature at an acceptable level [1].

These deficiencies have been chosen by NL Hydro for remediation.

2.4 Postville

The following was noted in Hatch's 2009 Condition Assessment Final Report.

- Storage – Storage area in plant was extremely small. Relies on small detached sheds for most storage requirements. Storage space generally inadequate [1].

This deficiency has been chosen by NL Hydro for remediation.

2.5 Ramea

The deficiency selected by NL Hydro for remediation at Ramea is inadequate ventilation.

Ramea was not a part of the assessment completed by Hatch in 2009.

3. Charlottetown

The Charlottetown plant is located in and serves the community of Charlottetown, on the Atlantic coast of Southern Labrador. The ventilation system at the plant was selected for remediation by NL Hydro because the plant is too warm.

3.1 Existing Conditions

Charlottetown's generator building consists of a 2-storey engine hall containing three gensets, a downstairs office and control room with a lunchroom, washroom and storage areas above. There is no insulation on the genset turbochargers, engine exhaust manifolds or exhaust ducting.

The ventilation system consists of 4 roof-mounted exhaust fans (2 old and 2 new) 2 wall-mounted fan-forced supply louvres and 2 additional passive-ventilation wall louvres. The ventilation equipment is summarized in Table 3-1, below.

Table 3-1 Charlottetown Equipment

Diesel Gensets						
Unit #	**Model #**	**Gen. (kW)**	**Exh. Dia. (m)**	**Exh. Mat.**	**Exh. Ht. (m)**	
2079	Cat. 3412	725	0.254	S.S.	10.67	
2087	Cat. 3406	545	0.152	S.S.	10.67	
2034	Cat. 3412	330	0.203	S.S.	10.67	
Exhaust Fans						
ID	**Make**	**Model**	**Cat #**	**Power (hp)**	**SP (" w.g.)**	**Q (Am^3/hr)**
EF1	Penn Ventilator	Domex	QB36	2	0.125	23,446
EF2	Penn Ventilator	Domex	QB36	2	0.125	23,446
EF3	Penn Ventilator	Domex	DX36B	3	0.125	27,135
EF4	Penn Ventilator	Domex	DX36B	3	0.125	27,135
Supply Fans						
ID	**Make**	**Model**	**Cat #**	**Power (hp)**	**SP (" w.g.)**	**Q (Am^3/hr)**
SF1	Penn Ventilator	Breezeway	BC36QS	7.5	0.125	43,212
SF2	Penn Ventilator	Breezeway	BC36QS	7.5	0.125	43,212
Louvres						
ID	**Location**	**Length (m)**	**Width (m)**	**Free (%)**	**Free (m^2)**	
LV1	South side - for supply fan	1.07	1.07	60	0.7	
LV2	South side - for supply fan	0.91	0.91	60	0.5	
LV3	West side	0.91	1.52	60	0.8	
LV4	North side	0.91	1.52	60	0.8	

Historical weather data most representative of the Charlottetown location was obtained from Environment Canada's Cartwright station. The mean daily maximum temperature in July is 18°C (considered to be summer maximum) while the mean daily minimum temperature in January is -20°C (considered to be winter minimum). Winds are most frequently from the south at an average speed of 20.2 km/h. Exposure to the harsh climate and high levels of salt in the air has been the main cause of ventilation system equipment failure at this plant.

Charlottetown's Phase I site visit was conducted on November 13, 2012. On this day, the ambient temperature was 5°C, while inside the plant, it was 30°C. It was noted that most ventilation equipment was not operable. Only one genset (Unit #2034) was running, only one exhaust fan was operating and all louvres, windows and doors were open.

A schematic of the ventilation system operation on the day of the site visit is shown below.

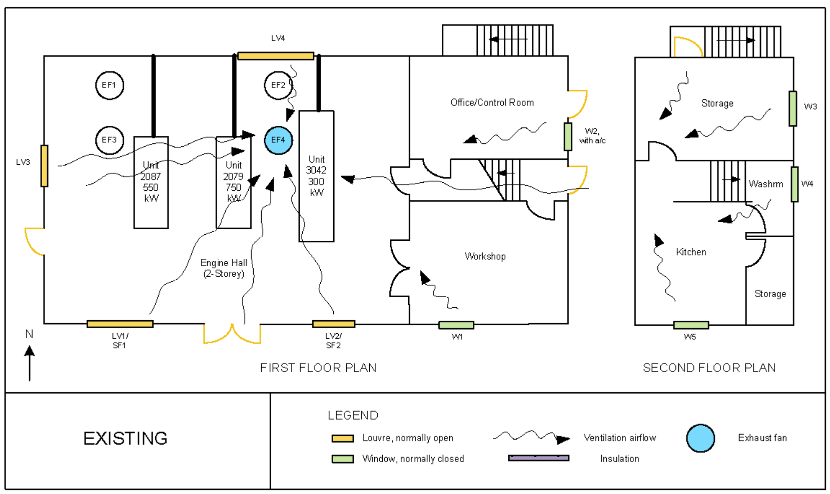

Figure 3-1: Charlottetown – Existing Ventilation System (Nov 13, 2012)

Ventilation systems must be designed to operate with all doors and windows closed in case of bad weather. When plant personnel resort to opening all doors and windows for cooling relief, the system is not functioning properly. At the time of the site visit, ventilation air flow was not adequate. If the one operating exhaust fan was running at its design flow capacity, the temperature rise would theoretically only have been 10°C and inside temperature would have been comfortable. It is likely that the exhaust fan was running below capacity. Additionally, with only this fan running, the path of fresh supply air from the open louvres, windows and doors to the exhaust point was not "sweeping" over the warmest part of the operating generator. Although some air was being exchanged in the building, the warm air was not being removed at an adequate active rate.

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Operators have seen the plant reach 50°C in the summer which is unacceptable from both an equipment and personnel standpoint.

Typically, with effective exhaust ventilation via the roof exhausters, air at the inlet to the generators will be sufficiently cool, making fan-forced supply redundant and unnecessary. It is suspected that the supply fans were added to the louvres on the front of the building in an attempt to provide spot cooling at the inlet of the generator sets because the roof exhausters were not operating correctly.

Another indication that the ventilation system is not effective is the presence of a separate air conditioning unit in the main floor office/control room. This small unit can be left as-is in any of the ventilation remediation options to provide additional spot-cooling in this area as desired.

3.2 Generator Building Ventilation Considerations

The primary aspects of a properly designed diesel generator building ventilation system are cooling air and combustion air. Cooling air is necessary to remove the heat rejected from the engine, generator and auxiliary components. Combustion air is required for the engine to burn the diesel fuel.

Poorly sized or malfunctioning ventilation systems can result in the following problems.

- High temperatures around the generator set that can lead to poor performance, overheating and subsequent shutdown as well as a decrease in service life.
- Issues with other equipment in the building that may be sensitive to high or low temperatures.
- An uncomfortable environment for personnel to perform maintenance and work in.

3.2.1 Determining Airflow Requirements

Required generator building ventilation airflow depends on the cooling air and combustion air requirements as well as the desired building temperature. Proper ventilation is also dependent on the path of the ventilation air.

3.2.1.1 Cooling Air

Cooling air is the exhaust required to convey heat out of the building and maintain the desired indoor workplace temperature rise, per the following equation.

$$V_{cool} = \frac{Q_{Total}}{C_p \Delta Td}$$

where:

V_{cool} = cooling air flowrate at STP (Nm^3/h);

Q_{Total} = total heat rejected from genset to building (kW);

C_p = specific heat of air at STP (1.006 kJ/kg/°C);

ΔT = generator building maximum permissible temperature rise (°C);

d = density of air at STP (1.269 kg/m^3).

Q_{Total}, total heat emitted to a generator building comes from the generator and engine carcases Q_{GS}, as well as from the exhaust piping system and muffler $Q_P + Q_M$, as depicted in Figures 3-2 and 3-3 below.

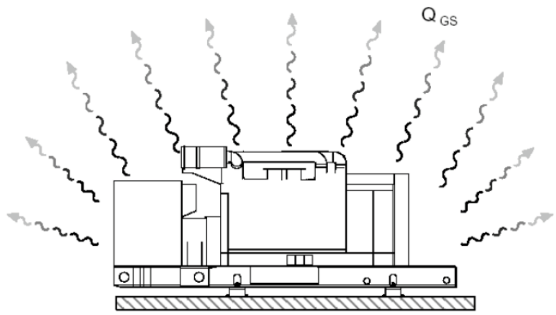

Figure 3-2: Heat Rejected from Generator Set[5]

A conservative approximation of Q_{GS} is ~14% of engine output power rating.

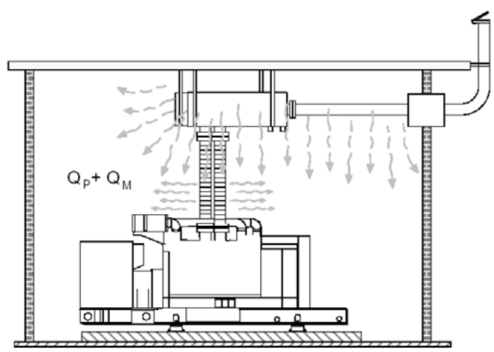

Figure 3-3: Heat Rejected from Exhaust Piping and Muffler[5]

Approximations of Q_{GS} and Q_{GS} vary based on piping diameter. For this assessment, estimates were made using standard Cummins values.[5]

The maximum permissible temperature rise is the difference between the maximum ambient temperature and the maximum temperature inside the generator plant. Typically, ΔT is set to no more than 10°C (lower values are better) when the engines are running. Engine de-rating can be considered when indoor temperatures reach 25°C[6]. Building temperatures must be kept below 40°C to avoid having to de-rate the engines. It is also recommended that air temperature around engines not exceed 50°C[2]. If this happens, engines are susceptible to shut down.

3.2.1.2 Combustion Air

Combustion air at the selected NL Hydro diesel plants is drawn directly from the engine room and is therefore included in ventilation system design. Approximate consumption of air for a diesel engine, V_{comb}, is:

$V_{comb} =$ 0.1 Am^3 air/min/bkW produced[2].

3.2.1.3 Total Ventilation Requirement

The total ventilation air flow required, V_{total}, is the sum of cooling and combustion air.

$$V_{total} = V_{cool} + V_{comb}$$

3.2.2 Ventilation Systems

Ventilation air exhaust systems are designed to maintain a slight positive or slight negative pressure in the generator building, depending on application. In the case of NL Hydro's selected plants, a slight positive should be maintained. Positive pressure within the generator building creates an out draft to expel heat and odour from the building. It also prevents the ingress of dust and dirt which is preferred for engines that draw their combustion air from the engine room. The positive pressure should not normally exceed 0.2" w.g.

Natural or passive draft ventilation is not practical in generator building ventilation due to the low building height. Adequate quantities of fresh air are best supplied by fan-assisted ventilation systems. Fans are most effective when they withdraw ventilation air from the generator building and exhaust the hot air to the atmosphere. A multiple fan system allows the most amount of control of ventilation air distribution and modulation. Fan motors should be mounted outside of the direct flow of hot air for the longest life.

3.2.2.1 In-Leakage of Air

Some air will naturally enter the generator building due to porosity. Opening louvres are required to achieve recommended ventilation rates and inlet velocities. Static pressure inside the generator building is obtained from the following equation:

$$SP = 1.5\left(\frac{v}{4005}\right)^2$$

where:

$v =$ velocity in feet per minute (fpm);

$SP =$ static pressure in inches of water gauge (" w.g.)

3.2.2.2 *Routing Considerations*

Maintaining the desired maximum temperature inside the generator building is not possible without correct routing of the ventilation air. The following are recommended principles to be followed in the system design[2]:

- Inlets and outlets shall be located such that air will flow across the entire generator set from alternator end to radiator end.
- Fresh air inlets shall draw air directly from the outdoors and are to be located as far from the generators and as low as possible.
- Ventilation air should be exhausted directly to the outdoors from the engine room at the highest point possible, preferably directly over the engine and on the downwind side of the building.
- Ventilation air inlets should be positioned so as to prevent exhaust air from being drawn into the inlets (recirculation) and to prevent pockets of stagnant air forming, especially in the vicinity of the generator combustion air inlet.
- Where possible, individual exhaust suction points can be located directly above primary heat sources to remove heat before it has a chance to mix with engine room air. This practice must also have supply air distributed around the primary sources and is impractical in NL Hydro's generator plants.
- Avoid ventilation air supply ducts that blow cool air directly toward hot engine components. This mixes the hottest building air with incoming cold air and raises the average temperature.
- For installations that draw engine combustion air from within the engine room, the coolest combustion air should be provided to the turbocharger inlets.
- Multiple engine sites will generally utilize multiple ventilation fans, dedicated to each engine.

The figure below shows an example of the preferred routing in a multi-engine plant.

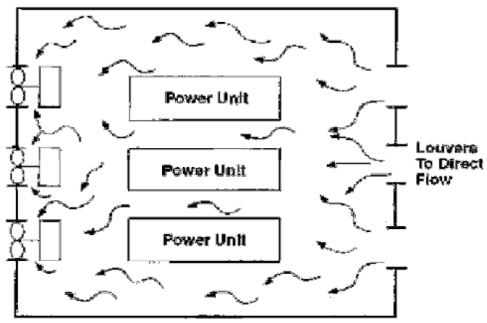

Figure 3-4: Correct Airflow Pattern in a Multi-Engine Plant[2]

Exhaust fans and louvres should be thermostatically controlled to allow for adequate generator combustion air and a modulating amount of cooling air to control the temperature in the building. In the hottest summer periods when all generators are operating at full load, louvres should be fully open with fans at full speed. Louvres should be open only partially and fans decreased to low speed (or turned off in facilities with multiple fans) as temperatures and operations decrease to avoid overcooling of the building.

3.2.2.3 *Crankcase Ventilation*

Engine crankcase ventilation systems exhaust oil-laden air into the engine room. The oil can then foul intake air filters and be deposited on other equipment, impeding operation. Use of crankcase ventilation breather traps or venting of the crankcase to the outdoors is best practice.

Additional benefits of crankcase ventilation filters include:

- cleaner ambient air; and
- reduced oil consumption when oil droplets are returned to the sump.

Ventilation breather traps, while effective, can block maintenance access and quickly plug. They will often be removed by maintenance personnel after the first filter is spent.

Vent mist eliminators on the other hand, are wall-mounted away from the generator allowing normal access and require less frequent maintenance. They are the preferred method of crankcase ventilation treatment.[3]

3.2.2.4 *Insulation Blankets*

Heat radiation can be reduced by covering engine and exhaust components with high temperature insulation, preferably in the form of a removable style blanket. Insulating blankets are made of an insulating inner layer and a thermal cloth outer layer. They are typically held in place with stainless steel buttons and wire which is laced over the blankets.

Insulation blankets can reduce heat rejection from exhaust piping systems by as much as 95%. When installed on engine exhaust manifolds, they can reduce overall generator heat rejection by around 5%.[4] It is not recommended to use blankets on turbochargers as use may lead to premature failure of parts.

Additional benefits of insulating blankets include:

- low installation and tooling costs (no requirement for highly skilled technicians);
- removable and reusable for inspection and maintenance;
- modular design making for east replacement of damaged parts;
- protection of personnel from burns from hot exhaust piping; and
- noise control capabilities.

3.3 Remediation Options

Three tiers of options have been investigated with varying degrees of performance and cost impacts. They range from the minimum requirements to basic improvements to complete redesign and system modifications. Details of each option are presented below.

3.3.1 Minimum Requirements

The minimum requirements for the Charlottetown plant include:

- decommissioning of the supply fans;
- repairing the remaining existing system components; and
- addition of a window air conditioning unit in the kitchen.

A schematic of this option is shown below:

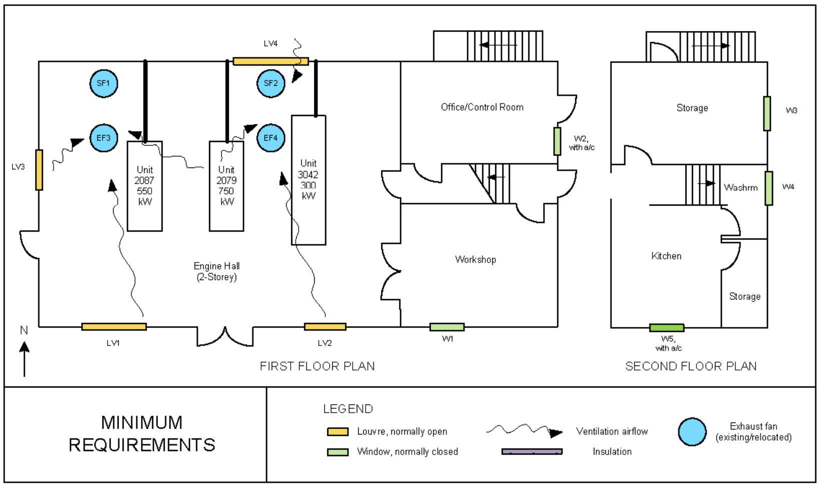

Figure 3-5: Charlottetown – Minimum Requirements Schematic

Heat rejection from all three generator sets running on full load is 493 kW without insulating the exhaust piping. This equates to a maximum ventilation requirement of 162,639 Am^3/h (154,251 Am^3/h cooling airflow and 8,388 Am^3/h combustion airflow) to achieve a temperature rise of no more than 10°C.

The capacity of the existing roof exhausters, at 101,162 Am^3/hr (0.125" w.g. static), does not meet the current ventilation requirement. All four roof exhausters operating at design would result in a maximum temperature rise of 16°C, which is likely intolerable. Alternatively, the decommissioned supply fans could be relocated to the roof in place of any of the existing roof exhausters to increase capacity. With this configuration air flow could be increased to 140,693 Am^3/hr, which would result in a maximum 12°C temperature rise. This may be acceptable for the plant.

In addition, a window air conditioner unit installed in the second level kitchen will allow for spot cooling on this level for relief in the warmest periods, regardless of operation of the generators.

Prior to committing to this refurbishment work, more information regarding the inoperable equipment is recommended (i.e., a detailed inspection of all ventilation system components and the identification of degree of repair required for each). If there are simple fixes to get equipment functioning correctly again, such as replacing fan belts, cleaning corrosion and debris, etc, this solution would be of minimal cost. If however, existing equipment is severely damaged, this option may not be practical.

The total capital cost for minimum requirements is estimated at $60,000, with a $20,000 material cost allowance for the refurbishment work, as detailed below. If estimates for repairs exceed this amount, it is advisable to instead look at replacement options.

Table 3-2: Charlottetown – Order of Magnitude (+/- 30%) Capital Cost Estimate – Minimum Requirements

DESCRIPTION	QTY.	UNIT	MATERIAL (CAD/UNIT)	MATERIAL COST (CAD)	LABOUR (25% of Estimate) COST (CAD)	TOTAL (CAD)
Mechanical Equipment						
Air conditioner for kitchen	1	unit	1,200	1,200	300	1,500
Repair/refurbishment allowance	1	package	20,000	20,000	5,000	25,000
Mechanical Total						**26,500**
Based on 35% of Mechanical Total for Civil/Structural						9,275
Civil/Structural Total						**9,275**
Based on 10% of Mechanical Total for Electrical Equipment						2,650
Electrical Total						**2,650**
Based on 10% of Mechanical Total for Instrumentation						2,650
Instrumentation Total						**2,650**
DIRECT COST TOTAL						**41,075**
INDIRECT COST						
Based on 20% of Direct Cost for Engineering, Procurement and Construction Management						8,000
Based on 5% of Direct Cost for other Indirects including spares and freight						2,000
INDIRECT COST TOTAL						**10,000**
			ESTIMATED TOTAL			**50,000**
			Contingency (20% of Estimate)			**10,000**
			TOTAL CAPITAL COST (+/- 30%)			**60,000**

Even with ventilation capacity increased to design requirements, no measures are currently in place to reduce heat rejection from the generator sets. Furthermore, airflow routing in the building as is it currently set up is not ideal. There are improvements that could be made to address these issues.

3.3.2 Basic Improvements

Basic improvements for the Charlottetown plant would include:

- installation of 2 new 'corrosion resistant', direct-drive roof exhausters in place of EF1 and EF2;
- closure of 1 supply louvre on the back wall relative to the generator sets (LV4) to improve ventilation airflow routing;
- replacement of the 2 existing south wall louvres (LV1 and LV2) with larger ones (equivalent to 1.5m x 1.5m each);
- replacement in-kind of the remaining existing louvre on the west wall (LV3), assuming it is beyond repair;
- installation of insulation blankets on the exhaust piping;

- addition of a window air conditioning unit in the kitchen;
- installation of generator mounted crankcase breather filters to remove oil from the building atmosphere; and
- decommission the existing exhaust and supply fans and seal the existing exhaust fan roof openings.

  A schematic of this option is shown below:

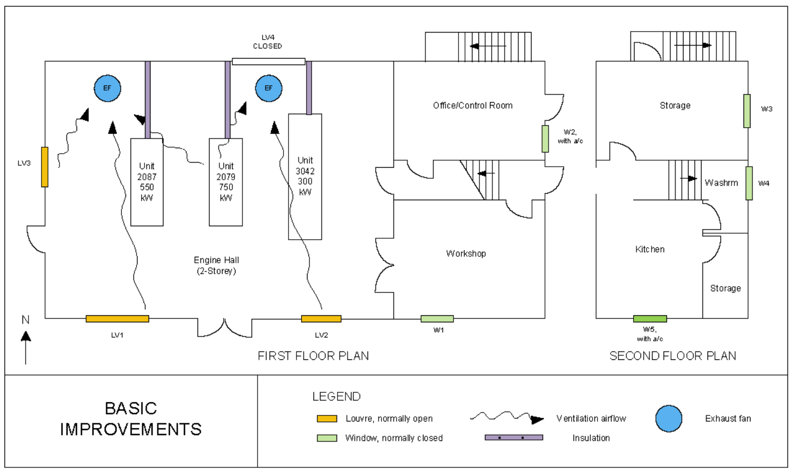

Figure 3-6: Charlottetown – Basic Improvements Schematic

In this scenario, heat rejection from all three generator sets running on full load is 329 kW with insulation on exhaust piping, which is a 33% reduction of the heat rejection rate to the building from the existing scenario. This equates to a maximum ventilation requirement of 111,243 Am^3/h (102,855 Am^3/h cooling airflow and 8,388 Am^3/h combustion airflow).

The reduced ventilation rate could be achieved with two new direct-drive exhaust fans, each rated for 60,000 Am^3/h installed in the locations of current EF1 and EF2. Fans suitable for the harsh climate will be constructed from either stainless steel or fibreglass reinforced plastic (FRP). It is also recommended that the fans be direct-driven than belt-driven to decrease maintenance requirements. The existing ladder on the south side of the plant allows access to the roof exhausters for regular inspection and maintenance.

This solution would provide adequate ventilation to ensure no more than a 10°C temperature rise in the generator building. Air flow will improve as it would generally “sweep” from the front to rear of the generator sets, although the south side wall louvres must be replaced with larger ones and the west side wall louvre must remain to allow reasonable inlet velocities and building static pressures. Supply velocity to the building will be approximately 8 m/s which correspond to a static pressure of 0.21" w.g.

By reusing existing fan locations, it is not possible to have a dedicated exhaust point for each generator.

This option includes generator-mounted crankcase ventilation filters to prevent oil-laden vapours from condensing on walls and surrounding machinery and to improve air quality in the generator hall. It is important that these filters are replaced as required to maintain the benefits of their use.

An additional window air conditioner unit installed in the second level kitchen will allow for spot cooling on this level for relief in the warmest periods, regardless of operation of the generators and ventilation system.

The total capital cost for basic improvements is estimated at $110,000, as detailed below.

Table 3-3: Charlottetown – Order of Magnitude (+/- 30%) Capital Cost Estimate – Basic Improvements

DESCRIPTION	QTY.	UNIT	MATERIAL (CAD/UNIT)	MATERIAL COST (CAD)	LABOUR (25% of Estimate) COST (CAD)	TOTAL (CAD)
Mechanical Equipment						
60,000 Am^3/h direct drive fan	2	unit	10,080	20,160	5,040	25,200
Exhuast piping insulating blanket	1	package	4,500	4,500	1,125	5,625
Louvre	3.62	m^2	323	1,170	293	1,463
Intake Hood	3	unit	500	1,500	375	1,875
Intake Screen	3	unit	500	1,500	375	1,875
Damper	2	unit	1,000	2,000	500	2,500
Actuator	2	unit	1,000	2,000	500	2,500
Crankcase ventilation generator-mounted filter	3	unit	500	1,500	375	1,875
Air conditioner for kitchen	1	unit	1,200	1,200	300	1,500
Mechanical Total						**44,413**
Based on 35% of Mechanical Total for Civil/Structural						15,545
Civil/Structural Total						**15,545**
Based on 10% of Mechanical Total for Electrical Equipment						4,441
Electrical Total						**4,441**
Based on 10% of Mechanical Total for Instrumentation						4,441
Instrumentation Total						**4,441**
DIRECT COST TOTAL						**68,840**
INDIRECT COST						
Based on 20% of Direct Cost for Engineering, Procurement and Construction Management						14,000
Based on 5% of Direct Cost for other Indirects including spares and freight						3,000
INDIRECT COST TOTAL						**17,000**
			ESTIMATED TOTAL			**90,000**
			Contingency (20% of Estimate)			**20,000**
			TOTAL CAPITAL COST (+/- 30%)			**110,000**

3.3.3 *Redesign and System Modifications*

A complete redesign and modification of the ventilation system to optimize performance would include the following:

- Installation of three new ‘corrosion resistant’, direct-drive roof exhausters in new locations in the engine hall.
- Closure of supply louvres on the back and side walls relative to the generator sets (LV3 and LV4) to improve ventilation airflow routing.
- Replacement of the two existing louvres on the south wall (LV1 and LV2) with larger ones (equivalent to 1.8 m x 1.8 m each).
- Installation of insulation blankets on the exhaust piping and manifolds.
- Installation of insulation on the wall between the engine hall and the second-storey kitchen and storage rooms.
- Addition of a window air conditioning unit in the kitchen.
- Installation of three (1 for each generator) wall-mounted crankcase mist eliminators to remove oil from the building atmosphere.
- Decommission the existing exhaust and supply fans and seal the existing exhaust fan roof openings.

A schematic of this option is shown below.

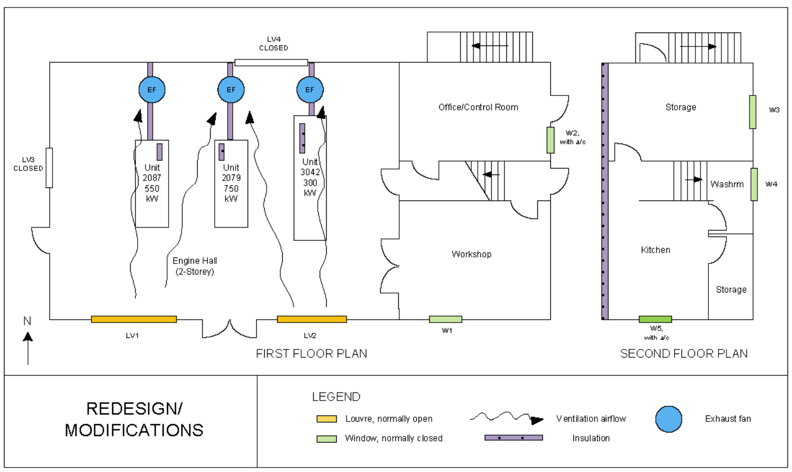

Figure 3-7: Charlottetown – Redesign/Modification Schematic

Heat rejection from all three generator sets running on full load is 313 kW with insulation on exhaust piping and manifolds which is a 37% reduction of the heat rejection rate from the existing scenario. This equates to a maximum ventilation requirement of 106,235 Am^3/h (97,847 Am^3/h cooling airflow and 8,388 Am^3/h combustion airflow).

The reduced ventilation rate could be achieved with three new direct-drive exhaust fans, each rated for 40,000 Am^3/h installed in new locations dedicated to and directly above the back end of each generator set. Fans suitable for the harsh climate will be constructed from either stainless steel or FRP. It is also recommended that the fans be direct-driven than belt-driven to decrease maintenance requirements. The existing ladder on the south side of the plant will continue to allow access to the roof exhausters for regular inspection and maintenance.

This solution would provide adequate ventilation to ensure no more than a 10°C temperature rise in the generator building. Air flow will improve as it will better "sweep" from the front to rear of the generator sets where there is a dedicated outlet point for each generator. A dedicated inlet louvre cannot be supplied for the middle generator (Unit #2079) as it is directly in front of the main doors and a louvre above these would be too high to be effective. Increasing the size of the inlet louvres on either side of the main doors however, allows the airflow path to cross this unit while maintaining reasonable inlet velocities and building static pressure. Supply velocity to the building will be approximately 7 m/s which correspond to a static pressure of 0.16" w.g.

This option includes wall-mounted crankcase mist eliminators for each generator. These units require less maintenance than generator-mounted filters but are more costly.

Insulating the second storey interior wall shields this area from the warm, rising air in the engine hall. In addition, a window air conditioner unit and a dedicated exhaust fan in the second level kitchen permits spot cooling and removal of heat when needed, regardless of operation of the generators and the rest of the ventilation system.

The total capital cost for redesign/modifications is estimated at $160,000, as detailed below.

Table 3-4: Charlottetown – Order of Magnitude (+/- 30%) Capital Cost Estimate – Redesign/Modifications

DESCRIPTION	QTY.	UNIT	MATERIAL (CAD/UNIT)	MATERIAL COST (CAD)	LABOUR (25% of Estimate) COST (CAD)	TOTAL (CAD)
Mechanical Equipment						
40,000 Am3/h direct drive fan	3	unit	6,720	20,160	5,040	25,200
Exhuast piping insulating blanket	3	unit	1,500	4,500	1,125	5,625
Exhaust manifold insulating blanket	3	unit	300	900	225	1,125
Louvre	4.01	m^2	400	1,605	401	2,007
Intake Hood	2	m^2	700	1,400	350	1,750
Intake Screen	2	m^2	700	1,400	350	1,750
Damper	3	unit	1,000	3,000	750	3,750
Actuator	3	unit	1,000	3,000	750	3,750
Wall Insulation	23	m^2	10	230	58	288
Crankcase ventilation wall-mounted filter	3	unit	6,000	18,000	4,500	22,500
Air conditioner for kitchen	1	unit	1,200	1,200	300	1,500
Mechanical Total						**69,244**
Based on 35% of Mechanical Total for Civil/Structural						24,235
Civil/Structural Total						**24,235**
Based on 10% of Mechanical Total for Electrical Equipment						6,924
Electrical Total						**6,924**
Based on 10% of Mechanical Total for Instrumentation						6,924
Instrumentation Total						**6,924**
DIRECT COST TOTAL						**107,329**
INDIRECT COST						
Based on 20% of Direct Cost for Engineering, Procurement and Construction Management						21,000
Based on 5% of Direct Cost for other Indirects including spares and freight						5,000
INDIRECT COST TOTAL						**26,000**
			ESTIMATED TOTAL			**130,000**
			Contingency (20% of Estimate)			**30,000**
			TOTAL CAPITAL COST (+/- 30%)			**160,000**

4. Makkovik

4.1 Existing Conditions

Makkovik's generator plant is a single storey building which consists of an engine hall, an office, lunchroom, washroom, workshop and storage areas above the office, lunchroom, washroom and workshop.

The building is constructed with metal siding and roofing. Over the years, the siding has become damage and weathered. Also, there are many patches around the perimeter due to repairing the damaged areas and covering unused equipment penetrations. Figure 4-1 shows an example of the damaged metal siding on the north side of the building.

Figure 4-1: Makkovik Generator Plant North End

4.2 Basis of Estimate

Replacement cost for metal siding are based unit rates from Hanscomb 2012 Yardsticks For Costing - Canadian Construction Cost Data, for St. John's, NL.

The unit costs for replacement are estimated as follows.

Table 4-1: Siding Replacement Unit Cost

ID	Description	Unit Cost
A	Composite Siding Install Cost (from Yardsticks)	$320/m^2
B	Siding Market Price (from Yardsticks)	$93/m^2
C	Siding Install Labour Cost (A-B)	$227/m^2
D	Siding Removal (Assume 1/2 of Install Rate, i.e. C/2)	$113/m^2
E	Total Labour (C+D)	$340/m^2
F	Total Unit Cost for Siding Replacement (B+E)	$433/m^2

External door replacement cost has been estimated in the same manner as presented for the siding.

Labour has been estimated based on $75/person/hr and 10hr/person/day. Mobilization/ demobilization have been estimated at $2000/person. Living allowance/per diems has been estimated at $200/person/day. Material shipping cost has been estimated has $2000/shipping container.

A 20% allowance has been made for engineering and construction management.

A 20% contingency has been added to the total estimated cost.

4.3 Cost Estimate

Cost estimates were developed for three options:

1. Siding replacement for north wall only.
2. Siding replacement for 50% of the building.
3. Siding replacement for the entire building.

Table 4-2: Makkovik – Order of Magnitude (+/- 30%) Capital Cost Estimate – Siding Replacement (North Wall Only)

Description	Qty	Unit	$/unit	Total $
Mobilization/ De-mobilization	3	people	$2,000	$6,000
Living Allowance/Per Diems	18	person-days	$200	$3,600
Material Shipment to/from Site	1	Containers	$2,000	$2,000
Siding Replacement	38	m2	$433	$16,454
Metal Door and Hardware Replacement	1	ea	$2,023	$2,023
Total Direct				**$30,077**
Engineering and Construction Supervision			20%	$6,015
Total Indirect				**$6,015**
			Estimated Total	**$37,000**
			Contingency (20%)	**$8,000**
			Total Capital Cost (+/-30%)	**$45,000**

Table 4-3: Makkovik – Order of Magnitude (+/- 30%) Capital Cost Estimate – Siding Replacement (50% of the Building)

Description	Qty	Unit	$/unit	Total $
Mobilization/ De-mobilization	5	people	$2,000	$10,000
Living Allowance/Per Diems	50	person-days	$200	$10,000
Material Shipment to/from Site	2	Containers	$2,000	$4,000
Siding Replacement	98	m^2	$433	$42,434
Windows	3	ea	$1,282	$3,846
Metal Door and Hardware Replacement	3	ea	$2,023	$6,068
Total Direct				**$76,348**
Engineering and Construction Supervision			20%	$15,270
Total Indirect				**$15,270**
			Estimated Total	**$92,000**
			Contingency (20%)	**$19,000**
			Total Capital Cost (+/-30%)	**$111,000**

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Phase II - Final Report - April 12, 2013

Table 4-4: Makkovik – Order of Magnitude (+/- 30%) Capital Cost Estimate – Siding Replacement (Entire Building)

Description	Qty	Unit	$/unit	Total $
Mobilization/ De-mobilization	5	people	$2,000	$10,000
Living Allowance/Per Diems	100	person-days	$200	$20,000
Material Shipment to/from Site	2	Containers	$2,000	$4,000
Siding Replacement	195	m^2	$433	$84,503
Windows	8	ea	$1,282	$10,256
Metal Door and Hardware Replacement	3	ea	$2,023	$6,068
Total Direct				**$134,828**
Engineering and Construction Supervision			20%	$26,966
Total Indirect				**$26,966**
			Estimated Total	**162,000**
			Contingency (20%)	**$33,000**
			Total Capital Cost (+/-30%)	**195,000**

H342925-0000-00-124-0002, Rev. 0
Page 21

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5. Paradise River

5.1 Existing Conditions

Paradise River's generator plant is a single storey building constructed in 1971 with an extension which was added some time after the original construction. The engine hall is in the original main building. There is a small storage room, workshop, and office which is located primarily in the building extension and partially within the main original building. There is no washroom in the building. In addition, there is no water or sewer service.

The original building appears to have a shallow concrete foundation supporting the exterior walls with a concrete slab on grade floor. The building extension appears to be constructed with a wooden floor on grade without a foundation wall extending below grade. The building is of wood frame construction with wooden roof trusses. It was reported that the building envelope develops open gaps during winter primarily along the connection between the original building and the extension.

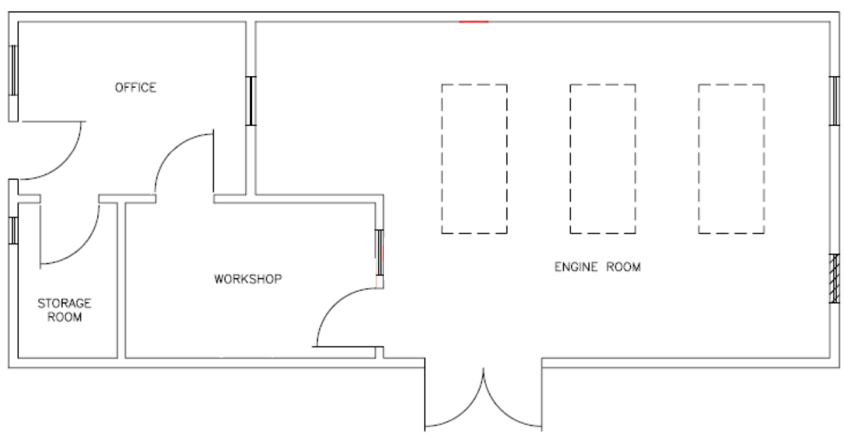

Figure 5-1: Paradise River Original Floor Layout (Extension Not Shown)

5.2 Structural Upgrades

A structural problem was identified in the original building along the wall closest to the ocean. It appears the concrete foundation supporting this wall has moved outward and the wall is bowed out so it is no longer vertical. A section of the concrete floor slab in this area also appears to have settled and cracked. At a minimum it is necessary to support and realign this wall while replacing the sections of concrete foundation wall and floor slab.

Other structural and construction related issues identified include shallow foundations likely results in frost heave during winter, different foundation types may result in differential heaving and settling throughout the year, drainage around the building may be poor, the wood trusses and wooden frame walls are more than 40 years old and may not meet current standards, a considerable amount of equipment is mounted on the wall that has the most significant structural problems, repairing one wall alone may unintentionally transfer stresses to other sections of the building, operating the diesel plant during construction may be challenging, and replacing only one section of wall and foundation while leaving the remainder of the building intact may result in significant constructability problems.

Two preliminary options were considered for upgrading structural problems within the existing building.

Option A is to replace only the 9.5 m long section of exterior wall that appears to have moved and the shallow concrete footing that has cracked as well as the section of the interior concrete slab that has settled and cracked.

Option A provides immediate repairs to the wall and concrete footing that are in distress but does not address investigating the source of the structural problems or carrying out additional work to prevent similar problems from occurring in the future.

Option B is to carry out more extensive repairs to the existing building. Option B would include a geotechnical investigation to determine the location and characteristics of the soil and bedrock in the vicinity of the building. It would include replacing the existing shallow concrete foundations with deeper concrete foundations more suitable for the Labrador climate.

It would be necessary to replace all concrete foundation walls in Option B requiring either the difficult task of temporarily supporting exterior walls and roof trusses during construction or replacing all exterior walls as well as the roof and trusses. Considering the age and possible structural deficiencies of the existing walls and roof in addition to constructability issues it was considered prudent to assume it would be necessary to replace the walls as well as the roof and trusses in the original building and to demolish and remove the building extension.

Under both Option A and Option B electrical wiring upgrades are assumed to be necessary for walls that are replaced. It is assumed that for both options the Owner would need to relocate and replace switchgear and other wall mounted equipment as well as provide a temporary generator to ensure construction worker safety as well as a continuous supply of electricity for customers in Paradise River during the construction period. NL Hydro should review those assumptions.

Option A only involves replacement of the distressed wall and foundation with a new wall and footing of similar construction. Option B only involves replacement of the original structure with new materials in the original building footprint with the extension demolished and removed. For both options, the deficiencies related to the lack of space, washroom facilities and ventilation are excluded from this estimate but addressed in the following sections.

The cause of the concrete foundation movement is unknown. The movement could be caused by frost or water flowing beneath the building or some other reason. There appears to be a quite high water table on one corner of the building and possibly some sections of the building could be constructed on bedrock while other sections are constructed on soil. A geotechnical investigation including test pits is recommended to evaluate site conditions and determine the reason for the foundation movement.

It is also recommended that Option A or Option B be implemented in the very near future. If the options cannot be addressed immediately due to budgetary or other constraints it is recommended that some form of temporary bracing and/or shoring be installed during the interim.

5.3 Office/Control Room, Workshop, Washroom and Storage

Due to the structural deficiencies with the existing building extension, it is recommended that it be removed and additional floor area added for an office/control room, workshop, washroom and storage.

During the 2009 condition assessment, NL Hydro advised that St. Lewis is their benchmark plant. This plant has been used in a relative way to determine the additional floor area requirements for Paradise River.

As shown below, the office/control room, washroom, workshop and storage area of the St. Lewis plant is 52% of the total building floor area.

Table 5-1: Floor Area of St. Lewis Plant

St. Lewis (Benchmark)		
Description	**Floor Area (m2)**	**% of Total**
Total Building	338	100%
Engine Hall	145	43%
Kitchen	17	5%
Office/Control Room	**37**	**11%**
Washroom	**6**	**2%**
Workshop	**24**	**7%**
Storage	**109**	**32%**

The existing plant at Paradise River does not have a washroom, workshop or dedicated storage area.

Table 5-2: Floor Area of Existing Paradise River Plant

Paradise River (Existing)		
Description	**Floor Area (m^2)**	**% of Total**
Total Building	50	100%
Engine Hall	45	90%
Office/Control Room	5	10%
Workshop	**0.0**	**0%**
Washroom	**0.0**	**0%**
Storage	**0.0**	**0%**

By adding additional floor area of 44 m^2, and utilizing the existing 5m^2 from the existing office, the office/control room, workshop, washroom and storage area will total 49 m^2 and equate to 52% of the total floor area.

Table 5-3: Floor Area of New Paradise River Plant

Paradise River (New)		
Description	**Floor Area (m2)**	**% of Total**
Total Building	94	100%
Engine Hall	45	48%
Office/Control Room, Workshop, Washroom, Storage	**49**	**52%**

5.4 Water and Sewer Services

In addition to the space required to install the new washroom facilities at the plant, the provision of water and sewer service to the plant is required. Since there are no existing town services, a new artesian well to provide the water will have to be drilled. There are two options for sewer service.

- Option 1 - Septic tank with a traditional leeching field. This option may require land acquisition due to the limited space around the existing plant.
- Option 2 - Hold tank which will be required to be pumped out on a regular basis.

5.5 Ventilation Remediation Options

The existing ventilation system consists of two turbine ventilators in the roof, soffit vents and an A/C unit in the office/control room.

Since there are various options for the structural repairs and layout upgrades for Paradise River, it is likely the repaired/upgraded plant will be quite different than the existing. Design of a ventilation system for the existing plant will likely be inadequate for a repaired/

upgraded plant. However, an estimate has been prepared using the existing generating capacity and approximate building size as a design basis.

5.6 Cost Estimate

5.6.1 Structural Upgrades

Cost estimates are provided for both Option A and Option B.

Option A assumes a work crew averaging 5 people for 15 work days to complete the project. Option B assumes a work crew averaging 5 people for 30 work days to complete the project. Those work crews are assumed to complete all work except geotechnical investigations, engineering and supervision, and owner's cost items such as providing a temporary generator and temporary switchgear relocation if deemed necessary.

It was assumed in the estimate that sufficient workers would be available in the Labrador region to complete the work in a timely manner paying premium but reasonable wages and benefits for the semi-isolated area.

It was also assumed that materials and equipment would be supplied at premium but reasonable rates from either Cartwright, Happy Valley - Goose Bay area, southern Labrador area, or western Newfoundland. It was assumed all workers, materials, and equipment would access the site by highway or in some cases by ferry at reasonable cost.

Table 5-4: Paradise River – Order of Magnitude (+/-30%) Capital Cost Estimate – Structural Upgrades Option A

Description	Qty	Unit	$/Unit	Total $
Mobilization/ De-mobilization	5	people	$2,000	$10,000
Living Allowance/Per Diems	75	person-days	$200	$15,000
Material Shipment to/from Site	3	Trucks	$2,000	$6,000
Demolition and Removal	1	LS	$5,000	$5,000
Wooden Frame Exterior Wall Replacement and Siding	30	m^2	$1,167	$35,000
Electrical Wiring	1	LS	$5,000	$5,000
Concrete Footing Replacement (900 mm deep)	10	m	$4,000	$40,000
Concrete Floor Slab Replacement	5	m^2	$2,000	$10,000
Temporary Generator (Owner's Cost)	1	ea	$50,000	$50,000
Temporary Switchgear Relocation (Owner's Cost)	1	ea	$50,000	$50,000
Subtotal				**$226,000**
Contingency			25%	$56,500
Subtotal				**$282,500**
Engineering and Construction Supervision			15%	$42,500
Total Capital Cost (+/-30%)				**$325,000**

Table 5-5: Paradise River – Order of Magnitude (+/-30%) Capital Cost Estimate – Structural Upgrades Option B

Description	Qty	Unit	$/Unit	Total $
Geotechnical Investigation and Report	1	ea	$25,000	$25,000
Mobilization/ De-mobilization	5	people	$2,000	$10,000
Living Allowance/Per Diems	150	person-days	$200	$30,000
Material Shipment to/from Site	6	Trucks	$2,000	$12,000
Demolition and Removal	1	LS	$10,000	$10,000
Wooden Frame Exterior Wall Replacement and Siding	107	m^2	$463	$49,500
Concrete Footing Replacement (2400 mm deep)	30	m	$3,833	$115,000
Concrete Floor Slab Replacement	5	m^2	$2,000	$10,000
Roof and Wooden Truss Replacement	50	m^2	$500	$25,000
Electrical Wiring	1	LS	$10,000	$10,000
Windows	4	ea	$2,500	$10,000
Metal Door and Hardware Replacement	3	ea	$2,500	$7,500
Temporary Generator (Owner's Cost)	1		$50,000	$50,000
Temporary Switchgear Relocation (Owner's Cost)	1		$50,000	$50,000
Subtotal				**$414,000**
Contingency			25%	$103,500
Subtotal				**$517,500**
Engineering and Construction Supervision			15%	$77,500
Total Capital Cost (+/-30%)				**$595,000**

5.6.2 Office/Control Room, Workshop, Washroom and Storage

For the purposes of this estimate, it has been assumed that the additional area required will be added by constructing a new standalone building. This estimate includes electrical and plumbing. A vendor quotation was obtained for supply and delivery of material for the new building.

A work crew averaging 5 people for 10 work days was assumed necessary to complete the project.

Mobilization/demobilization has been estimated at $2000/person. Living allowance/per diems has been estimated at $200/person/day.

A 20% allowance has been made for engineering and construction management.

A 20% contingency has been added to the total estimated cost.

Table 5-6: Paradise River – Order of Magnitude (+/-30%) Capital Cost Estimate - Additional Floor Area

Description	Qty	Unit	$/unit	Total $
Mobilization/ De-mobilization	5	people	$2,000	$6,000
Living Allowance/Per Diems	50	person-days	$200	$10,000
Material Shipment to/from Site	1	Container	$2,000	$2,000
Material	1	Lot	$24,000	$24,000
Labour	44	m^2	$852	$37,500
Total Direct				**$79,500**
Engineering and Construction Supervision			20%	$15,900
Total Indirect				**$15,900**
		Estimated Total		**$96,000**
		Contingency (20%)		**$19,000**
		Total Capital Cost (+/-30%)		**$115,000**

5.6.3 *New Power House*

5.6.3.1 *Basis of Estimate:*

- Customer load addressed using 3 x 50 kW generators (N+1) paralleled mounted in building
- Existing fuel tanks to be re-used.
- Automatic paralleling LV switchgear with 3 x generator breakers plus outgoing breaker with switchyard
- Purpose built power house with 50m2 engine room + 50m2 office/shop/washroom space
- Engineering, Construction Mgmt, & QA support. Assumes new powerhouse will be constructed on current site.

Table 5-7: Paradise River – Order of Magnitude (+/-30%) Capital Cost Estimate – New Power House

Description	Qty	Units	$/Unit	Total $
Generators - 50 kW ea.	3	ea	$50,000	$150,000
Paralleling Switchgear	1	lot	$225,000	$225,000
Water & Sewer	1	Lot	$150,000	$150,000
Pre-engineered building - NLH std	1	lot	$490,000	$490,000
Labour & Material - civil	1	Lot	$675,000	$675,000
Labour & Material - M&E	1	Lot	$1,850,000	$1,850,000
Commissioning	1	Lot	$155,000	$155,000
Total Direct				**$3,695,000**
Engineering and Construction Supervision			20%	$739,000
Total Direct				**$739,000**
			Estimated Total	**$4,434,000**
			Contingency (20% of Estimate)	**$887,000**
			Total Capital Cost (+/-30%)	**$5,321,000**

5.6.4 *Water and Sewer Services*

For the purposes of this estimate, it has been assumed that an artesian well is required to provide potable water to the plant. A vendor quotation was obtained for drilling. Vendor quotations were also obtained for septic services. Both options are estimated to be the same cost.

Table 5-8: Paradise River – Order of Magnitude (+/-30%) Capital Cost Estimate - Water and Sewer Services

Description	Qty	Unit	$/unit	Total $
Potable Water Service	1	ea	$100,000	$100,000
Septic Service	1	ea	$50,000	$50,000
Total Direct				**$150,000**
Engineering and Construction Supervision			20%	$30,000
Total Indirect				**$30,000**
			Estimated Total	**$180,000**
			Contingency (20%)	**$36,000**
			Total Capital Cost (+/-30%)	**$216,000**

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5.6.5 Ventilation Remediation Options

Since there is no currently no mechanical ventilation at the plant in Paradise River, a new system design is required. The new system will include:

- installation of two new corrosion resistant direct-drive roof exhausters;
- installation of new louvers with approximate total intake area of 0.5 m^2;
- installation of insulation blankets on the exhaust piping and manifolds;
- installation of two wall-mounted crankcase mist eliminators to remove oil from the building atmosphere;
- new air conditions for the office/washroom/control room area; and
- decommission existing ventilators and seal roof openings.

The estimated costs for ventilation upgrade options at Paradise River are:

Table 5-9: Paradise River – Order of Magnitude (+/-30%) Capital Cost Estimate – Ventilation Redesign/Modifications

DESCRIPTION	QTY.	UNIT	MATERIAL (CAD/UNIT)	MATERIAL COST (CAD)	LABOUR (25% of Estimate) COST (CAD)	TOTAL (CAD)
Mechanical Equipment						
5,000 Am^3/h direct drive fan	3	unit	840	2,520	630	3,150
Exhuast piping insulating blanket	3	unit	800	2,400	600	3,000
Exhaust manifold insulating blanket	3	unit	150	450	113	563
Louvre	0.50	m^2	400	200	50	250
Intake Hood	2	unit	500	1,000	250	1,250
Intake Screen	2	unit	500	1,000	250	1,250
Damper	3	unit	500	1,500	375	1,875
Actuator	3	unit	500	1,500	375	1,875
Crankcase ventilation wall-mounted filter	2	unit	1,000	2,000	500	2,500
Air conditioner for personnel area	1	unit	800	800	200	1,000
Mechanical Total						**16,713**
Based on 50% of Mechanical Total for Civil/Structural						8,356
Civil/Structural Total						**8,356**
Based on 10% of Mechanical Total for Electrical Equipment						1,671
Electrical Total						**1,671**
Based on 10% of Mechanical Total for Instrumentation						1,671
Instrumentation Total						**1,671**
DIRECT COST TOTAL						**28,411**
INDIRECT COST						
Based on 20% of Direct Cost for Engineering, Procurement and Construction Management						6,000
Based on 5% of Direct Cost for other Indirects including spares and freight						1,000
INDIRECT COST TOTAL						**7,000**
			ESTIMATED TOTAL			**40,000**
			Contingency (20% of Estimate)			**10,000**
			TOTAL CAPITAL COST (+/- 30%)			**50,000**

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6. Postville

6.1 Existing Conditions

Postville's generator plant is a single storey building which consists of an engine hall, an office and a washroom. The plant currently has no workshop or dedicated storage areas.

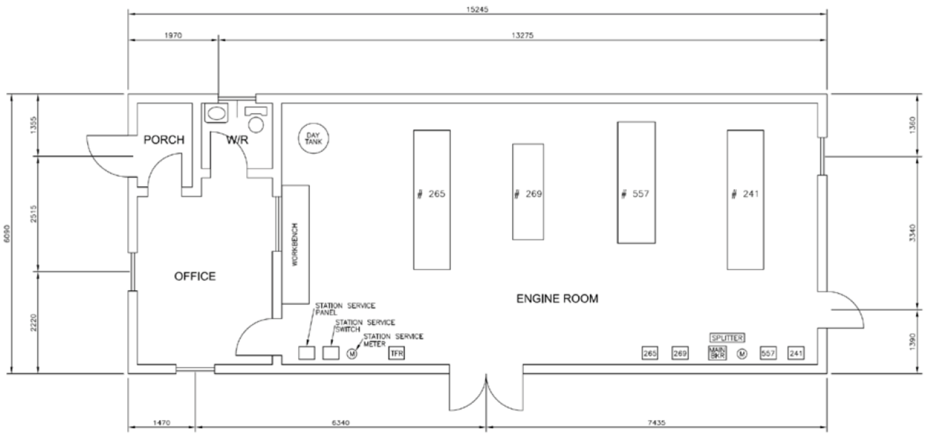

Figure 6-1: Postville Floor Layout

6.2 Basis of Estimate

During the 2009 condition assessment, NL Hydro advised that St. Lewis is their benchmark plant. This plant has been used in a relative way to determine the additional floor area requirements for Postville.

As shown below, the workshop and storage area of the St. Lewis plant is 39% of the total building floor area.

Table 6-1: Floor Area of St. Lewis Plant

St. Lewis (Benchmark)		
Description	**Floor Area (m^2)**	**% of Total**
Total Building	338	100%
Engine Hall	145	43%
Kitchen	17	5%
Office/Control Room	37	11%
Washroom	6	2%
Workshop	**24**	**7%**
Storage	**109**	**32%**

The existing plant at Postville does not have a workshop or dedicated storage area.

Table 6-2: Floor Area of Existing Postville Plant

Postville (Existing)		
Description	**Floor Area (m^2)**	**% of Total**
Total Building	93	100%
Engine Hall	72	78%
Kitchen	0	0%
Office/Control Room	14	15%
Washroom	3	3%
Porch	4	4%
Workshop	**0**	**0%**
Storage	**0**	**0%**

An additional floor area of 60 m^2, for a total of 153 m^2 is required such that the workshop and storage area equates to 39% of the total floor area.

Table 6-3: Floor Area of Postville Plant with Added Storage

Postville (New)		
Description	**Floor Area (m^2)**	**% of Total**
Total Building (new)	153	100%
Engine Hall	72	48%
Kitchen	0	0%
Office/Control Room	14	9%
Washroom	3	2%
Porch	4	2%
Workshop and Storage	**60**	**39%**

6.3 Cost Estimate

For the purposes of this estimate, it has been assumed that the additional area required will be added by constructing a new standalone building. A vendor quotation was obtained for supply and delivery of material and labour for the new building.

Mobilization/demobilization has been estimated at $2000/person. Living allowance/per diems has been estimated at $200/person/day.

A 20% allowance has been made for engineering and construction management.

A 20% contingency has been added to the total estimated cost.

Table 6-4: Postville – Order of Magnitude (+/-30%) Capital Cost Estimate

Description	Qty	Unit	$/Unit	Total $
Mobilization/ De-mobilization	3	people	$2,000	$6,000
Living Allowance/Per Diems	27	person-days	$200	$5,400
Material Shipment to/from Site	1	Container	$2,000	$2,000
Material	1	Lot	$24,000	$24,000
Labour	60	m^2	$322	$19,320
Total Direct				**$56,720**
Engineering and Construction Supervision			20%	$11,344
Total Indirect				**$11,344**
			Estimated Total	**$69,000**
			Contingency (20%)	**$14,000**
			Total Capital Cost (+/-30%)	**$83,000**

7. Ramea

The Ramea plant is located in and serves the community of Ramea, on the Northwest Island off the south east coast of Newfoundland. Similar to Charlottetown, the ventilation system at the plant was selected for remediation by NL Hydro because the plant is too warm.

7.1 Existing Conditions

Ramea's generator building consists of a 2-storey engine hall containing three gensets which is adjacent to a downstairs workshop, switchgear room, washroom and control room with a kitchen and storage area above. There is a heat recovery unit (HRU) with supply and return air ducting serving these two levels of rooms adjacent to the engine hall. The exhaust and supply louvre for the HRU has motorized dampers. There is also an exhaust fan dedicated to the workshop.

There is no insulation on the genset turbochargers, engine exhaust manifolds or exhaust ducting and mufflers. The engine hall ventilation system consists of 2 roof-mounted exhaust fans, 2 wall-mounted fan-forced supply louvres and 3 additional passive-ventilation wall louvres. The ventilation equipment is summarized in Table 7-1 below. Equipment locations are shown in the building drawings in Appendix A.

Table 7-1: Ramea Equipment

Diesel Gensets						
Unit #	**Model #**	**Gen. (kW)**	**Exh. Dia. (m)**	**Exh. Mat.**	**Exh. Ht. (m)**	
2045	Cat. 3512	925	0.254	S.S.	12.00	
2046	Cat. 3512	925	0.254	S.S.	12.00	
2047	Cat. 3512	925	0.254	S.S.	12.00	
Exhaust Fans						
ID	**Make**	**Model**	**Cat #**	**Power (hp)**	**SP (" w.g.)**	**Q (Am^3/hr)**
EF1	unknown -assumed capacity of intake fans and louvres				0.125	43,435
EF2	unknown -assumed capacity of intake fans and louvres				0.125	43,435
Supply Fans						
ID	**Make**	**Model**	**Cat #**	**Power (hp)**	**SP (" w.g.)**	**Q (Am^3/hr)**
SF1	Penn Ventilator	Breezeway	BF30	1	0.125	16,143
SF2	Penn Ventilator	Breezeway	BF30	1	0.125	16,143
Louvres						
ID	**Location**	**Length (m)**	**Width (m)**	**Free (%)**	**Free (m^2)**	
LV1	South side -for supply fan 1	1.22	1.22	60	0.9	
LV2	West side -for supply fan 2	1.22	1.22	60	0.9	
LV3	East side	0.91	0.91	60	0.5	
LV4	South side -low	1.22	1.22	60	0.9	
LV5	South side -high	0.91	0.91	60	0.5	

Historical weather data most representative of the Ramea location was obtained from Environment Canada's Port aux Basques station. The mean daily maximum temperature in August is 18°C (considered to be summer maximum) while the mean daily minimum temperature in February is -10°C (considered to be winter minimum). Winds are most frequently from the east at an average speed of 24.4 km/h. Exposure to the harsh climate and high levels of salt in the air has been the main cause of ventilation system equipment failure at this plant.

There was no Phase I site visit conducted at Ramea due to its remote location. An assessment of the ventilation system was completed using data from NL Hydro. A schematic of the current ventilation system is shown below.

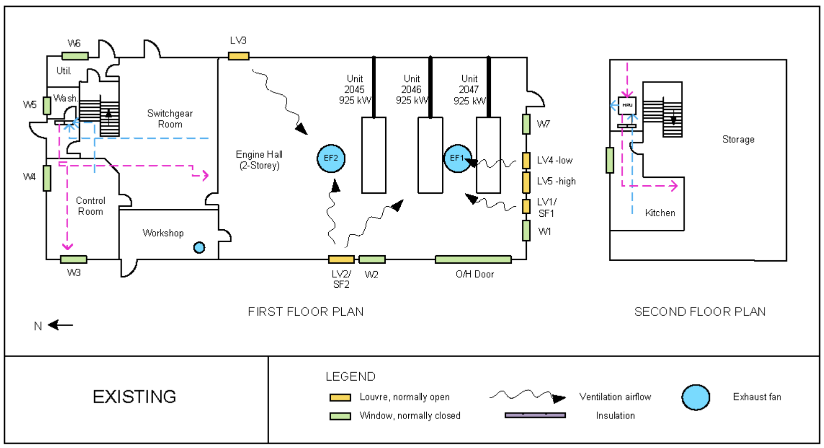

Figure 7-1: Ramea – Existing Ventilation System

Heat rejection from all 3 generator sets running on full load is 718 kW without insulating the exhaust piping/mufflers. This equates to a maximum ventilation requirement of 237,864 Am^3/h (224,742 Am^3/h cooling airflow and 13,122 Am^3/h combustion airflow) to achieve a temperature rise of no more than 10°C.

The capacity of the existing roof exhausters, at 86,869 Am^3/hr, is significantly below the current ventilation requirement. When all gensets are at full load and both roof exhausters are operating at design, the resulting maximum temperature rise would be 26°C, which is intolerable.

Additionally, air flow in the engine hall is routed from all around the generators, not in a "sweeping" motion across the units which results in unnecessary movement of air through areas where heat is not generated and inadequate movement of air across the gensets where it is needed.

7.2 Generator Building Ventilation Considerations

Refer to Section 3.2.

7.3 Remediation Options

Three tiers of options have been investigated with varying degrees of performance and cost impacts. They range from the minimum requirements to basic improvements to complete redesign and system modifications. Details of each option are presented below.

7.3.1 Minimum Requirements

The minimum requirements for the Ramea plant would include:

- decommissioning of the supply fans;
- repairing the remaining existing system components; and
- restricting generator operation during warm ambient periods.

A schematic of this option is as per the existing system depicted in Figure 7-1.

Even with repairs to make the existing ventilation system operable, it would not meet the airflow requirements for the installed generators. Therefore, this option would only be feasible if generator operation was reduced.

Heat rejection from two generator sets running on full load is 493 kW without insulating the exhaust piping. This equates to a maximum ventilation requirement of 158,576 Am^3/h (149,828 Am^3/h cooling airflow and 8,748 Am^3/h combustion airflow) to achieve a temperature rise of no more than 10°C.

Reducing operation further to one generator set running on full load decreases heat rejection to 239 kW which corresponds to 79,288 Am^3/h (74,914 Am^3/h cooling airflow and 4,374 Am^3/h combustion airflow).

The capacity of the existing roof exhausters would meet the current ventilation requirement only if generator operation was restricted to one unit on.

It is not viable to restrict generator operation to meet ventilation requirements. Therefore improvements to the system, rather than repairs are necessary at Ramea.

7.3.2 Basic Improvements

Basic improvements for the Ramea plant would include:

- installation of 2 new 'corrosion resistant', direct-drive roof exhausters;
- closure of 1 supply louvre on the east/back wall relative to the generator sets (LV3) and 1 supply louvre on the second storey of the south wall (LV5) to improve ventilation airflow routing;
- replacement in-kind of the remaining existing louvres on the south and west walls (LV1, LV2 and LV4), assuming they are beyond repair;

- replacement of the window on the west wall of the engine hall (W2) with a supply louvre (LV6);
- installation of insulation blankets on the exhaust piping and mufflers;
- installation of generator mounted crankcase breather filters to remove oil from the building atmosphere;
- addition of a window air conditioning unit in the kitchen; and
- decommission the existing exhaust and supply fans and seal the roof and wall openings.

A schematic of this option is shown below:

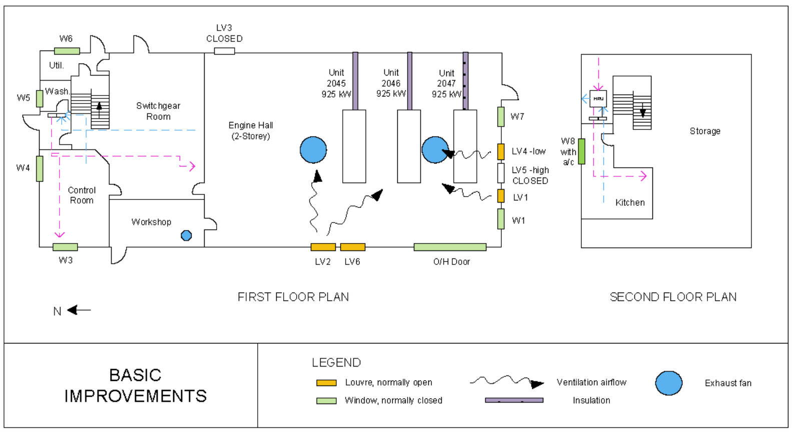

Figure 7-2: Ramea – Basic Improvements Schematic

In this scenario, heat rejection from all 3 generator sets running on full load is 355 kW with insulation on exhaust piping and mufflers, which is a 51% reduction of the heat rejection rate to the building from the existing scenario. This equates to a maximum ventilation requirement of 124,255 Am^3/h (111,133 Am^3/h cooling airflow and 13,122 Am^3/h combustion airflow).

The reduced ventilation rate could be achieved with 2 new direct-drive exhaust fans, each rated for 65,000 Am^3/h installed in the locations of the current roof exhausters. Fans suitable for the harsh climate will be constructed from either stainless steel or FRP. It is also recommended that the fans be direct-driven than belt-driven to decrease maintenance requirements. A ladder added to the exterior of the plant (similar to that at Charlottetown) would allow access to the fans for regular inspection and maintenance.

This solution would provide adequate ventilation to ensure no more than a 10°C temperature rise in the generator building. Air flow will improve as it will generally “sweep” from the front to rear of the generator sets, although replacement of the west side window (W2) with a supply louvre is required to allow sufficient inlet velocities and building static pressure. Supply velocity to the building will be approximately 8 m/s which correspond to a static pressure of 0.25" w.g.

This option includes generator-mounted crankcase ventilation filters to improve air quality in the generator hall. It is important that these filters are replaced as required to maintain the benefits of their use.

An additional window air conditioner unit installed in the second level kitchen will allow for spot cooling on this level for relief in the warmest periods, regardless of operation of the generators and ventilation system.

No changes will be made to HRU and associated ducting.

The total capital cost for basic improvements is estimated at $120,000, as detailed below:

Table 7-2: Ramea – Order of Magnitude (+/- 30%) Capital Cost Estimate – Basic Improvements

DESCRIPTION	QTY.	UNIT	MATERIAL (CAD/UNIT)	MATERIAL COST (CAD)	LABOUR (25% of Estimate) COST (CAD)	TOTAL (CAD)
Mechanical Equipment						
65,000 Am^3/h direct drive fan	2	unit	10,920	21,840	5,460	27,300
Exhuast piping insulating blanket	3	unit	1,821	5,464	1,366	6,831
Louvre	3.57	m^2	400	1,427	357	1,784
Intake Hood	4	unit	500	2,000	500	2,500
Intake Screen	4	unit	500	2,000	500	2,500
Damper	2	unit	1,000	2,000	500	2,500
Actuator	2	unit	1,000	2,000	500	2,500
Crankcase ventilation generator-mounted filter	3	unit	500	1,500	375	1,875
Exterior roof access ladder	1	unit	500	500	125	625
Air conditioner for kitchen	1	unit	1,200	1,200	300	1,500
Mechanical Total						**49,915**
Based on 35% of Mechanical Total for Civil/Structural						17,470
Civil/Structural Total						**17,470**
Based on 10% of Mechanical Total for Electrical Equipment						4,991
Electrical Total						**4,991**
Based on 10% of Mechanical Total for Instrumentation						4,991
Instrumentation Total						**4,991**
DIRECT COST TOTAL						***77,368***
INDIRECT COST						
Based on 20% of Direct Cost for Engineering, Procurement and Construction Management						15,000
Based on 5% of Direct Cost for other Indirects including spares and freight						4,000
INDIRECT COST TOTAL						**19,000**
			ESTIMATED TOTAL			**100,000**
			Contingency (20% of Estimate)			**20,000**
			TOTAL CAPITAL COST (+/- 30%)			**120,000**

7.3.3 *Redesign and System Modifications*

A complete redesign and modification of the ventilation system to optimize performance would include the following:

- installation of 3 new 'corrosion resistant', direct-drive roof exhausters in new locations in the engine hall;
- closure of 1 supply louvre on the east/back wall relative to the generator sets (LV3) and 2 supply louvres on the south wall (LV1 and LV5) to improve ventilation airflow routing;
- replacement of 1 existing louvre on the south wall (LV4) and 1 existing louvre on the west wall (LV2) with larger ones (equivalent to 1.2m x 2.4m each);
- installation of insulation blankets on the exhaust piping and mufflers;
- installation of insulation on the engine exhaust manifolds;
- installation of insulation on the wall between the engine hall and the 2nd-storey kitchen and storage rooms;
- installation of a 3 (1 for each generator) wall-mounted crankcase mist eliminators to remove oil from the building atmosphere;
- addition of a window air conditioning unit in the kitchen; and
- sealing of the existing exhaust and supply fan and 2 window roof and wall opening.

A schematic of this option is shown below:

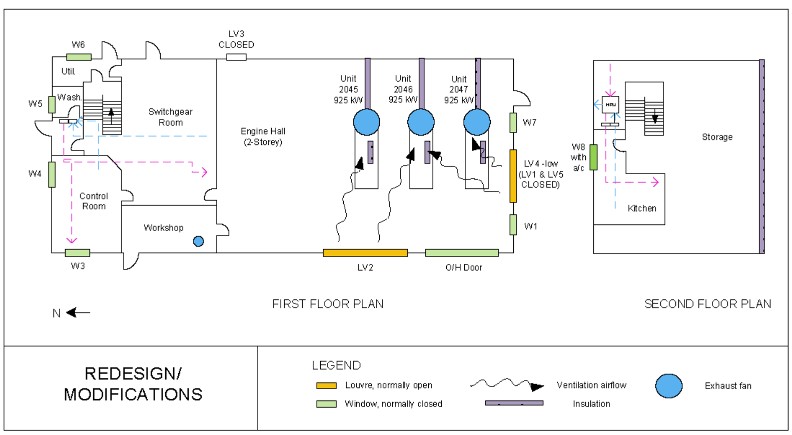

Figure 7-3: Ramea – Redesign/Modification Schematic

Heat rejection from all 3 generator sets running on full load, is 341 kW with insulation on exhaust piping/mufflers and manifolds which is a 53% reduction of the heat rejection rate from the existing scenario. This equates to a maximum ventilation requirement of 119,845 Am^3/h (106,723 Am^3/h cooling airflow and 13,122 Am^3/h combustion airflow).

The reduced ventilation rate could be achieved with 3 new direct-drive exhaust fans, each rated for 40,000 Am^3/h installed in new locations dedicated to and directly above the back end of each generator set. Fans suitable for the harsh climate will be constructed from either stainless steel or FRP. It is also recommended that the fans be direct-driven rather than belt-driven to decrease maintenance requirements. A ladder added to the exterior of the plant (similar to that at Charlottetown) would allow access to the fans for regular inspection and maintenance.

This solution would provide adequate ventilation to ensure no more than a 10°C temperature rise in the generator building. Air flow will improve as it will better flow in a “sweeping” motion from the front to rear of the generator sets where there is a dedicated outlet point for each generator. A dedicated inlet louvre cannot be supplied for the southernmost generator (unit #2047) as it is directly in front of an overhead door and a louvre above this would be too high to be effective. Increasing the size of the inlet louvres on either side of the main doors however, allows the airflow path to cross this unit while maintaining reasonable inlet velocities and building static pressure. Supply velocity to the building will be approximately 8 m/s which correspond to a static pressure of 0.23” w.g.

This option includes wall-mounted crankcase mist eliminators for each generator. These units require less maintenance than generator-mounted filters but are more costly.

An additional window air conditioner unit installed in the second level kitchen will allow for spot cooling on this level for relief in the warmest periods, regardless of operation of the generators and ventilation system.

No changes will be made to HRU and associated ducting. However, insulating the 2nd storey interior wall shields this area from the warm, rising air in the engine hall allowing it to cool more effectively during warm periods.

The total capital cost for redesign/modifications is estimated at $170,000, as detailed below:

HATCH™

Newfoundland and Labrador Hydro - Diesel Plant Remediation
Phase II - Final Report - April 12, 2013

Table 7-3: Ramea – Order of Magnitude (+/- 30%) Capital Cost Estimate – Redesign/Modifications

DESCRIPTION	QTY.	UNIT	MATERIAL (CAD/UNIT)	MATERIAL COST (CAD)	LABOUR (25% of Estimate) COST (CAD)	TOTAL (CAD)
Mechanical Equipment						
40,000 Am3/h direct drive fan	3	unit	6,720	20,160	5,040	25,200
Exhuast piping insulating blanket	3	unit	1,822	5,465	1,366	6,831
Exhaust manifold insulating blanket	3	unit	300	900	225	1,125
Louvre	3.57	m^2	400	1,428	357	1,785
Intake Hood	2	unit	1,000	2,000	500	2,500
Intake Screen	2	unit	1,000	2,000	500	2,500
Damper	3	unit	1,000	3,000	750	3,750
Actuator	3	unit	1,000	3,000	750	3,750
Wall Insulation	40	m^2	10	400	100	500
Crankcase ventilation wall-mounted filter	3	unit	6,000	18,000	4,500	22,500
Exterior roof access ladder	1	unit	500	500	125	625
Air conditioner for kitchen	1	unit	1,200	1,200	300	1,500
Mechanical Total						72,566
Based on 35% of Mechanical Total for Civil/Structural						25,398
Civil/Structural Total						25,398
Based on 10% of Mechanical Total for Electrical Equipment						7,257
Electrical Total						7,257
Based on 10% of Mechanical Total for Instrumentation						7,257
Instrumentation Total						7,257
DIRECT COST TOTAL						112,477
INDIRECT COST						
Based on 20% of Direct Cost for Engineering, Procurement and Construction Management						22,000
Based on 5% of Direct Cost for other Indirects including spares and freight						6,000
INDIRECT COST TOTAL						28,000
			ESTIMATED TOTAL			140,000
			Contingency (20% of Estimate)			30,000
			TOTAL CAPITAL COST (+/- 30%)			170,000

H342925-0000-00-124-0002, Rev. 0
Page 41

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Project Title: Install Fall Protection Equipment

Location: Various Sites

Category: Transmission and Rural Operations - Transmission

Definition: Pooled

Classification: Mandatory

Project Description:

This project is required to design, supply and install fall protection systems at several Hydro facilities. It includes the installation of a roof fall protection system on the control building at the St. Brendan's Terminal Station and the Bishop's Falls Office Building, installation of lifelines on the Bishop's Falls Service Building, the installation of a suitable access to aircraft warning lights at the Salmon Spillway, installation of railing around the Upper Salmon unit powerhouse, and the installation anchor plates for transformers where needed.

The budget estimate for the project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	30.0	0.0	0.0	30.0
Labour	79.5	0.0	0.0	79.5
Consultant	20.0	0.0	0.0	20.0
Contract Work	22.0	0.0	0.0	22.0
Other Direct Costs	34.7	0.0	0.0	34.7
Interest and Escalation	13.0	0.0	0.0	13.0
Contingency	0.0	0.0	0.0	0.0
TOTAL	**199.2**	**0.0**	**0.0**	**199.2**

Operating Experience:

Hydro initiated a five year program in 2005 to install fall protection systems on transformers, fuel tanks and roofs at its facilities. At the start of the five year plan in 2005, only sites having a high priority need for fall protection systems were identified. During the execution of the program, Hydro developed a comprehensive listing of all sites that required fall protection systems. Because of the large number of sites, (see Appendix A) Hydro realized that all required fall protection systems could not be installed in the original five year program. This is the tenth year of the program which started in 2005 and has proceeded on a priority basis.

Below is a summary of the three basic types of fall protection systems installed by Hydro. The photographs illustrate how each system is used.

Roof Fall Protection System

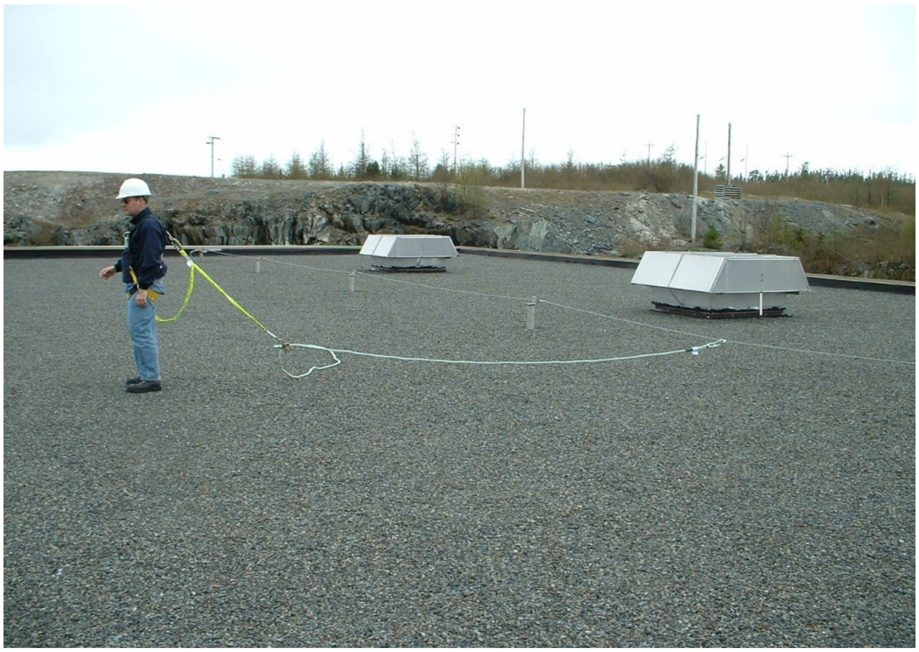

Figure 1: Roof Fall Protection System

Generally, a fall protection system is not a complex system. Figure 1 above shows a worker tethered to a permanently installed system comprised of a cable secured to the roof by a series of fall arrest anchors. The tether is called a lifeline and the anchors are travel restraints. As the worker moves around on the roof, he is able to attach the lifeline between the anchors as needed. If a fall occurs, the anchors will arrest the fall thereby saving the worker's life.

Ladder Fall Protection System

In this system, a safety cable is installed vertically on the side of the ladder as shown in Figures 2 and 3 to the right. The workers secure themselves to the ladder fall protection system by attaching themselves to a D ring, as shown in the picture, that is attached to a cable grab which in turn rides on the cable. The cable grab allows the worker to move with ease up the ladder but in the event of a sudden downward movement, as in a fall, the cable grab is designed to abruptly grab the cable, securing the worker and preventing a fall. This action is similar to the operation of a seat belt in a car.

Figures 2 and 3: Ladder Fall Protection System

Transformer Fall Protection System

Figure 4 illustrates a transformer fall protection system used by the three workers standing on top of a transformer. This system is a portable system. The fall protection system is mounted on a fixed anchor plate welded to the top of the transformer. When work is completed, the fall protection system can be taken to another site.

The three basic types of fall protection systems shown above are for illustrative purposes. Systems may vary when they are installed because of, for example, extra cable arrangements or the need for railings. The systems will be inspected annually. The anticipated useful life of a fall protection system is 20 years.

Figure 4: Transformer Fall Protection System

Project Justification:

This project is justified on the requirement to provide a safe work environment and to comply with Sections 140, 141, and 142, under Part X: Fall Protection, of the Occupational Health and Safety Regulations. Fall protection systems are required to perform work safely at elevations above 3.05 meters. Hydro must conform to these sections of the Occupational Health and Safety Regulations. Section 141 “General Requirements” states in part “where a worker is exposed to the hazard of falling from a work area that is: 3 meters or more above the nearest safe surface or water; above a surface or thing that could cause injury to the worker if the worker were to fall on the surface or thing; or above any open tank, pit or vat containing hazardous material, the employer shall ensure that the worker is provided with a fall arrest system that meets the requirements of section 142”. The complete regulations contained under sections 140, 141, and 142 are presented in Table 3. Without proper fall protection systems in place, a worker can refuse to perform his/her assigned duties.

The fall protection system program, started in 2005, did not provide for installations at all of Hydro’s sites where fall protection systems were needed. New sites were identified throughout the course of the program. Table 2 presents annual capital budget and actual expenditures for years 2008 to 2012.

Table 2: Capital Expenditure History

Year	Capital Budget ($000)	Actual Expenditures ($000)	Comments
2013B	196.6		Ladders and roofs
2012	199.2	186.5	Ladders and roofs
2011	198.4	213.2	Ladders and roofs
2010	198.4	215.5	Ladders, transformers and roofs
2009	321.7	302.7	Tanks, transformers and roofs
2008	404.5	193.9[1]	Tanks, transformers and roofs

[1]Operations personnel were scheduled to install roof lines on three powerhouse buildings but could not meet the obligation due to other commitments. It was too late to tender when this was discovered. Also some design changes to the fall protection system for the penthouse roof at the Holyrood Thermal Generating Station also provided significant savings.

In order to be compliant with Section 140 "Fall Protection Systems", Section 141 “General Requirements” and Section 142 “Fall Arrest Systems”, under Part X: Fall Protection, of the Occupational Health and Safety Regulations, this work must continue until all facilities are properly equipped with fall protection systems.

Table 3: Section 140 “Fall Protection Systems”, Section 141 “General Requirements” And Section 142 “Fall Arrest System”, Part X: Fall Protection of the Provincial Occupational Health and Safety Regulations

Fall protection systems

140. Where an employer determines it is impractical to provide adequate work platforms or staging, the employer shall ensure that fall protection systems are used by all workers who are exposed to the hazard of falling, as required in section **141**.

General requirements

141. Where a worker is exposed to the hazard of falling from a work area that is

(a) 3 metres or more above the nearest safe surface or water;

(b) above a surface or thing that could cause injury to the worker if the worker were to fall on the surface or thing; or

(c) above an open tank, pit or vat containing hazardous material,

the employer shall ensure that

(d) the worker is provided with a fall arrest system that meets the requirements of section **142** ;

(e) a guardrail that meets the requirements of section **28** is constructed or installed at the work area;

(f) a personnel safety net that meets the requirements of section **143** is installed at the work area;

(g) temporary flooring that meets the requirements of section **146** is constructed or installed at the work area; or

(h) the worker is provided with another means of fall protection that provides a level of safety equal to or greater than a fall arrest system that meets the requirements of section **142**.

Fall arrest system

142. (1) A fall arrest system that is provided in accordance with section **141** shall

(a) be adequately secured to

(i) an anchorage point, or

(ii) a lifeline that is

(A) securely fastened to anchor points, or

(B) attached to a static line that is securely fastened to anchorage points and that is capable of withstanding either the maximum load likely to be imposed on the anchorage point or a load of 22.2 kilonewtons, whichever is the greater;

(b) include a lanyard

(i) that is attached to an anchorage point or lifeline, where practicable, above the shoulder of the worker, and

(ii) that complies with CSA Standard Z259.11 "Energy Absorbers and Lanyards";

(c) prevent a free fall greater than 1.22 metres where

(i) the fall arrest system is not equipped with a shock absorption system that complies with CSA Standard Z259.11 "Energy Absorbers and Lanyards" and that reduces the shock level of a fall to less than 4 kilonewtons, or
(ii) the combined free fall and shock absorbed deceleration distance exceeds the distance between the work area and a safe surface; and

(d) include a full body harness that
(i) is attached to a lanyard,
(ii) is adjusted to fit the user of the harness, and
(iii) complies with CSA Standard Z259.10 "Full Body Harnesses".

(2) Where a fall arrest system includes a lifeline, the lifeline shall
(a) comply with CSA Standard Z259.2.1 "Fall Arresters, Vertical Lifelines and Rails";
(b) extend to a safe surface below the work area and be securely attached to an anchorage point;
(c) be secured at the bottom of the lifeline to prevent tangling or disturbance of the line and be free of knots, lubricants and imperfections;
(d) be free of splices, except where they are necessary to connect the lifeline to an anchorage point;
(e) be provided with softeners at all sharp edges or corners to protect against cuts or chafing; and
(f) be clearly identified as a lifeline by colour or by another means that provides an equivalent level of safety.

(3) No worker shall
(a) use a lifeline in a fall arrest system while that fall arrest system is being used by another worker; or
(b) provide a rope for use, or permit a rope to be used, as a lifeline in a fall arrest system where the rope has been used for another purpose.

(4) Where a fall arrest system provided to a worker includes a ropegrab, the ropegrab used shall comply with CSA Standard Z259.2.1 "Fall Arresters, Vertical Lifelines and Rails".
(5) An employer who provides a worker with a fall arrest system shall ensure the fall arrest system is inspected by a qualified person before each work shift undertaken by the worker.

(6) A qualified person who carries out an inspection of a fall arrest system shall advise the employer where a component of the system is defective in condition or function and the employer shall ensure that the system is not used until the defective component is replaced or repaired.

(7) Where a fall arrest system has arrested the fall of a worker at a work area, the employer shall ensure that the fall arrest system
(a) is removed from service and inspected by a qualified person; and
(b) is repaired, before it is reused, to the original manufacturer's specifications, where an inspection under paragraph (a) reveals that a component of the system is defective.

(8) Where a fall arrest system includes a static line, the static line shall
- (a) have a nominal diameter of at least 12.7 millimetres and be made of improved plow wire rope;
- (b) be equipped with vertical supports at least every 9 metres and have a maximum deflection, when taut, of no greater than 381 millimetres for a 9 metre span;
- (c) be equipped with turnbuckles or other comparable tightening devices that provide an equivalent level of protection, at the ends of the static line;
- (d) be equipped with softeners at all sharp edges or corners to protect against cuts or chafing;
- (e) be made only of components that are able to withstand either the maximum load likely to be imposed on the components or a load of 8 kilonewtons, whichever is the greater; and
- (f) comply with CSA Standard Z259.13 "Flexible Horizontal Lifeline Systems" and CSA Standard Z259.16 "Design of Active Fall Protection Systems".

(9) Where a fall arrest system is provided to an arborist, the fall arrest system shall
- (a) include a tree climbing or tree trimming harness or saddle;
- (b) be adequately secured to
  - (i) an anchorage point, or
  - (ii) a lifeline that is
    - (A) securely fastened to anchorage points, or
    - (B) attached to a static line that is securely fastened to anchorage points;
- (c) include a climbing rope or safety strap;
- (d) where practicable, include a second climbing rope or safety strap that
  - (i) provides additional stability, and
  - (ii) back-up fall protection; and
- (e) be capable of withstanding either the maximum load likely to be imposed or a load of 22.2 kilonewtons, whichever is the greater.

(10) Where an employer uses a fall arrest system or a personnel safety net as a means of fall protection, the employer shall have a written fall protection plan that specifies
- (a) the procedure to assemble, maintain, inspect, use and disassemble the fall arrest system or personnel safety net; and
- (b) the procedure for the rescue of a worker who has fallen and is suspended by the fall arrest system or personnel safety net, but is unable to effect self-rescue.

Future Plans:

A list of future fall protection installations are included in Appendix A and will be proposed in future capital budget applications. See five-year capital plan (Capital Plan 2014 Tab, Appendix A).

APPENDIX A

FALL PROTECTION PROJECT LIST

Fall Protection Project List

Location	Description	Comment
Bay d'Espoir		
General	Surge tank #1 Fall Arrest System	Planned for 2013
Up-Country	Burnt catwalk for gate control building	Planned for 2013
	Burnt gate control building access ladder	Planned for 2013
Upper Salmon	Rotor access platform/stairway-powerhouse	Planned for 2013
Central		
Bishop's Falls	Fall protection system on diesel building roof	Planned for 2013
Bottom Brook Terminal Station	Fall protection system on control building roof	Planned for 2013
Stony Brook Terminal Station	Fall protection system on control building roof	Planned for 2013
Sunnyside Terminal Station	Fall protection system on control building roof	Planned for 2013
Holyrood		
Holyrood Terminal Station	Fall protection system on control building roof	Planned for 2013
Holyrood	Four ladder cable systems for pumphouse	Planned for 2013
Bay d'Espoir		
Up Country	Suitable Access to Aircraft Warning Lights at Salmon	Planned for 2014
Upper Salmon	Spillway	Planned for 2014
	Install Railing Around Unit Powerhouse	
Central		
Bishop's Falls	Lifelines on Service Building	Planned for 2014
	Fall Protection System on Office Building	Planned for 2014
St. Brendans	Fall protection system on control building roof	Planned for 2014
Various Transformers	Anchor plates for transformers	Planned for 2014

Location	Description	Comment
Bay 'Espoir		
Cat Arm	Intake ladder Slider	Future projects
	New ladder for spherical valve pit	Future projects
	Rail for stairs to fire pump room	Future projects
	Remove penstock access ladder safety slide	Future projects
	Ladder System on Powerhouse Roof	Future projects
General	Support for Oil Tank Rescue	Future projects
	Intake #4 gate control access rail	Future projects
	Access catwalk for installing stoplogs	Future projects
	Intake #2 Access ladder modifications/safety slide	Future projects
	Intake #3 Access ladder modifications/safety slide	Future projects
	Intake #4 Access ladder modifications/safety slide	Future projects
	Spillway Gate Handrails	Future projects
	Platform Access to hoist control panel at Salmon Spillway	Future projects
	Surge Tanks 1, 2 & 3 balcony gates	Future projects
Granite Canal	Intake railing modifications	Future projects
	By-pass stoplog railing	Future projects
	Gap in Rail on overhead crane landing	Future projects
	Modify rail to fire pump room	Future projects
	Extend ladder side rails for overhead crane	Future projects
	Draft tube crane access mezzanine extension	Future projects
	Install anchor points for changing lights	Future projects
Hinds Lake	Sump pit ladder at powerhouse	Future projects
	Ladder cable system at warehouse roof	Future projects
	Ladder with barrier at draft tube area – powerhouse	Future projects
	Spillway ladder modification/safety slide	Future projects
	Install handrail for stairs leading to penstock-powerhouse	Future projects
	Extend handrail near control room to close gap-powerhouse	Future projects
	Remove intake safety slide rail	Future projects
	Remove control structure safety slide rail	Future projects
	Intake ladder modification/safety slide	Future projects
	Ladder with barrier at east end of powerhouse	Future projects
	Ladder with barrier at west end of powerhouse	Future projects
Paradise River	Platform for powerhouse overhead crane	Future projects
	Install intermediate rail	Future Projects
	Overhead crane ladder modification/safety slide	Future projects
	Install flip rail or gate	Future projects
	Remove penstock access ladder safety slide	Future projects
	Install penstock access fall arrest	Future projects
	Railing around top of unit	Future projects

Location	Description	Comment
Bay 'Espoir		
Powerhouse 1	Cable tunnel shelter ladder	Future projects
	PH1 Overhead crane ladder/support	Future projects
	Fabricate/install Spherical valve platform #1	Future projects
	Fabricate/install Spherical valve platform #2	Future projects
	Fabricate/install Spherical valve platform #3	Future projects
	Access ladder attached to mobile crane	Future projects
	Sump pit #1 ladder	Future projects
	Sump pit #2 ladder	Future projects
	Sump pit #3 ladder	Future projects
	Railing to Fire Pump area	Future projects
Powerhouse 2	Sump pit ladder	Future projects
	Ladder to upper deck at Victoria Control Structure	Future projects
Up Country	Ladder with barrier to Staff gauge at Victoria Control Structure	Future projects
	Burnt Diesel Tank Modifications	Future projects
	Burnt Spillway access catwalk for installing stoplogs	Future projects
	Ladder system at Burnt Dam spillway	Future projects
	Ladder cable system at North Salmon spillway roof	Future projects
	Ladder cable system at West Salmon spillway roof	Future projects
Upper Salmon	Ladder cable system at warehouse roof	Future projects
	Intake ladder modification/safety slide-powerhouse	Future projects
Central		
Bishop's Falls	Fall protection system on salvage stores	Future projects
Francois	Fall protection system on diesel plant roof	Future projects
Various Transformers	Anchor plates for transformers	Future projects

Project Title: Legal Survey of Primary Distribution Line Right of Ways

Location: Various Sites

Category: Transmission and Rural Operations - Properties

Definition: Other

Classification: Normal

Project Description:

Hydro owns and operates approximately 2,370 km of distribution lines located on Crown land, which is owned by the provincial government. In 2004, Hydro initiated a program to obtain easements on the land on which these lines are located. From 2004 to 2012, a total of 1,034 km of distribution line has been surveyed and is being processed through the Department of Environment and Conservation, Lands Division (Crown Lands). In 2013, 151 km of distribution line are planned to be surveyed and processed. Table 2 provides the details of the length of lines surveyed to date. This project is required to continue the program to acquire legal surveys and prepare documentation to acquire Crown Land easements for the 151 km of primary distribution line in operation throughout the Province. Easements are granted for a term of 50 years. Hydro can renew the easements granted for a further period of 50 years if the renewal is requested in writing before the expiration of the existing easement.

The work will be completed in two years to allow sufficient time for the contractor to develop detailed legal surveys and also allow for the processing of the legal surveys at Crown Lands. Processing of distribution line legal surveys at Crown Lands takes longer than 12 months. Once reviewed by Crown Lands, the contractor has to make any corrections as requested and resubmit the legal surveys for review. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	2.8	2.5	0.0	5.3
Labour	9.0	9.0	0.0	18.0
Consultant	113.0	20.0	0.0	133.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	7.0	2.5	0.0	9.5
Contingency	25.0	6.3	0.0	31.3
TOTAL	**156.8**	**40.3**	**0.0**	**197.1**

Operating Experience:

Hydro's older distribution lines were constructed without obtaining easements. Hydro's effort to obtain easement title to the primary distribution lines on Crown Land began in 2004. Assuming continued funding, title for the distribution systems located on Crown Land will be in place by the end of 2021. Surveys in 2011, 2012 and 2013 were contracted out and it is planned that Hydro will continue this practice in 2014 and beyond.

This capital budget has been adjusted based on the bids received for the 2011 surveys. The cost of survey work ranged from $1,248 to $1,575 per km so this capital budget was adjusted based on the lowest quote of $1,248 per km. This added a number of years to the project with program completion now being 2021.

Table 2: Length of Lines Surveyed

Year	Length (km)	Comments
2012	199	Fogo, Change Islands and Farewell Head, St. Brendan's
2011	43	Little Bay Islands, Flatwater Pond Park, and Jackson's Arm
2010	89	Barachois distribution lines and partial surveying of English Harbor West distribution lines
2009	150	Northern distribution lines
2008	43	Northern distribution lines
2007	160	Northern distribution lines
2004-2006	350	Baie Verte Area, South Brook, Little Bay, Rencontre East, Come By Chance, Monkstown, South East Bight, Coombs Cove to English Harbor West, Westport to Baie Verte

Table 3 shows the history of expenditures for this project for the five-year period 2007 to 2012 and the budget for 2013.

Table 3: Budget History

Year	Budget ($000)	Actual ($000)
2013B	196.2	0.0
2012	197.9	190.4
2011	78.7	66.0
2010	65.4	65.0
2009	56.0	54.6
2008	52.0	54.3

In 2007, Crown Lands performed a review of the Hydro surveys, which were completed by an outside consultant during the period 2004 through 2006. Hydro's surveys required editing to comply with current Crown Lands Standards, and in 2008, Hydro spent much of the approved capital budget to have Hydro's outside consultant edit and correct these drawings for re-submission to Crown Lands. Issues included surveying roads and including them in the drawings, adding a legend on the drawings, and editing features to make them more distinctive. Due to Sections 33 and 34 of the Land Surveyors Act, 1991, Hydro could not use its own surveyors to make corrections to these drawings. The Land Surveyors Act, 1991, Section 33, Use of Seal states that:

> *"A Land Surveyor shall not affix his or her seal to a plan or document prepared in the practice of land surveying unless the plan or document was prepared by or under the personal supervision, direction or control of that Land Surveyor." Furthermore, Section 34, Survey Plan Documents, states that "(1) A master plan and duplicates of all survey plans, records and documents prepared by or under the direction of a Land Surveyor shall be retained by that Land Surveyor; (2) A person shall not, without the prior written consent of the Land Surveyor who prepared a land survey plan, alter, add to or delete from that plan or a copy or reproduction of that plan; and (3) A person who contravenes subsection (2) commits an offence."*

In 2011, it was anticipated that 180 kilometers of distribution lines would be surveyed but due to higher than expected costs for surveying, a total of 43 kilometers were surveyed in order to remain within budget.

There are approximately 2,370 kilometers of distribution lines for which Hydro has no title. Applications for title to surveyed lines have been submitted to Crown Lands and are currently being processed. From 2004 to the end of 2013, 1,185 kilometers of distribution line will have been surveyed. The legal surveys are being completed and obtaining title is currently in progress for some these surveyed lines. Hydro has obtained easements to its Westport to Baie Verte, Rencontre East, Coomb's Cove area, Monkstown and

South East Bight distribution lines. The Baie Verte area and South Brook applications are at the Crown Lands title office for preparation of the easement documents. All of the Great Northern Peninsula applications are also at the Crown Lands title office.

There are a number of applications which were submitted to Crown Lands and they are at various stages of the approval process. The province is divided into regions by Crown Lands and requests for land must be submitted to the applicable region. The various application stages include:

- Hydro is waiting for approval of the survey or for comments on the surveys;
- Crown Lands is waiting for survey submissions from consultants and/or Hydro; or
- Hydro and/or consultants are waiting on responses to requests for information from Crown Lands.

In early 2011, Hydro personnel met with the Director of Crown Lands to help find a solution to the long time required for processing applications, but were informed that workloads and staff shortages, including a shortage of professional surveyors, were an issue and that there was a backlog within the department. Hydro was also informed that it must follow the Crown Lands process, but priority requests for land may be expedited.

Project Justification:

Some of Hydro's distribution lines occupy Crown land without title, contrary to the Lands Act (SNL 1991 Chapter 36). Lack of adequate title is a risk to the operation of the lines should competing requirements for the lands arise. Hydro receives many referrals from Crown Lands and the Interdepartmental Land Use Committee (ILUC) where other parties are attempting to obtain Crown Land in the vicinity of Hydro's lines.

Upon purchase of Crown land, a resident receives title and it becomes private land. Although Hydro's access to Crown land has not been directly challenged, private land owners have requested that Hydro move poles and lines off private land in instances where Hydro has not acquired easements. Hydro has obliged since it has no right to cross the land to access the poles and lines.

Maintaining the status quo is unacceptable. In the absence of title, other parties may be able to construct, develop or otherwise use the property on which Hydro's lines are located without Hydro being consulted. Obtaining title ensures that developments do not interfere with Hydro operations.

Future Plans:

Approximately 1,185 kilometers of distribution lines remain to be surveyed. Table 4 presents Hydro's future plan for surveying lines.

Table 4: Length of Lines to be Surveyed

Year	Budget ($000)	Proposed Survey Length to be Completed (km)	Length Remaining to be Surveyed at Year End (km)
2014	196.8	152	1,033
2015	197.8	153	880
2016	197.3	154	726
2017	197.4	155	571
2018	197.3	155	416
2019	197.4	155	261
2020	197.4	155	106
2021	135.0	106	0

Future projects for legal surveys will be proposed in future capital budget applications. See five-year plan (2014 Capital Plan Tab, Appendix A).

The anticipated project schedule is shown in Table 5.

Table 5: Project Schedule

Activity	Start Date	End Date
Project initiation and design transmittal completion	February 2014	February 2014
Prepare survey scope of work and plan field work	February 2014	March 2014
Complete surveying	April 2014	September 2014
Preparation and review of legal survey documents Submission of legal plans to Crown Lands Update of surveys based on Crown Lands review and resubmission	May 2014 September 2014 January 2015	November 2014 December 2014 May 2015
Close out and documentation	December 2015	December 2015

Project Title: Purchase Meters, Equipment and Metering Tanks

Location: Various Sites

Category: Transmission and Rural Operations - Metering

Definition: Other

Classification: Normal

Project Description:

This project consists of purchasing 350 demand meters, 600 residential meters with automated meter reading capability and associated equipment for use in revenue metering applications which require replacement each year due to government retest, technology changes or obsolescence. The project also includes purchasing six dry-type metering units (Meter Tanks) to replace existing aging and obsolete 2.5 element units. Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	128.0	0.0	0.0	128.0
Labour	25.0	0.0	0.0	25.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	15.4	0.0	0.0	15.4
Contingency	30.6	0.0	0.0	30.6
TOTAL	**199.0**	**0.0**	**0.0**	**199.0**

Operating Experience:

Meters of the electromechanical design have reached or surpassed their life expectancy of 25 years. Furthermore, new electromechanical meters can no longer be purchased from meter manufacturers; therefore electronic meters are the only option.

At the beginning of 2013, there were 69 oil-filled metering tanks remaining of which 30 are in service and 39 in storage. These are all 2.5 element units, ranging in age from 23 to 42 years, and Measurement Canada no longer permits these units to be installed for replacements or for new customer services. In 2012 during an inspection, two tanks were identified to be replaced due to deterioration and hot spots.

Project Justification:

Meters/metering equipment obsolescence and failure requires spares to be purchased so that equipment is available to replace defective or worn out equipment. As the meters that are of the electromechanical design are becoming obsolete and can no longer be purchased, failure to replace this equipment would affect metering accuracy and reliability. Furthermore in 2011, Measurement Canada has introduced more stringent guidelines (Specification S-S-06 – attached as Appendix A) related to compliance testing of electromechanical meters that will result in fewer meters passing compliance testing. Compliance testing is a process where a sample of meters is taken from a group of in-service meters which are homogeneous with respect to design, production and quality characteristics. This process is based on ISO 2859-2:1985, Sampling procedures for inspection by attributes – Part 2: Sampling plans indexed by limiting quality (LQ) for isolated lot inspection.

Hydro's metering tanks are reaching the end of their useful life and require replacement to prevent failures. Refurbishment of existing units is not permitted by Measurement Canada as all existing units are a 2.5 element design and Measurement Canada requires all new and reconstructed applications to use a 3 element design.

Measurement Canada's Bulletin E-24-E (rev.1) states that 2.5 element meters along with the 2.5 element metering tanks were designed to reduce costs associated with metering, by using one less instrument transformer and associated components internal to the meter. Although 2.5 element metering is a legal and approved form of metering used in Canada for existing services, there is a potential for error when certain technical conditions exists. See Appendix B.

Due to the above concern with 2.5 element metering, a national survey was completed by industry representatives of the Canadian Electricity Association and supported by Measurement Canada to determine the actual impact of 2.5 element metering on the Canadian market. The results of that survey were discussed by Measurement Canada and industry during the Canadian Forum on Trade Measurement in 2001 and a number of recommendations were agreed on to reduce the impact of this potential error. Subsequently, effective April 2, 2003, all new and all reconstruction of existing, 3-phase 4-wire wye configured metering installations shall use 3-element metering.

Furthermore, there are environmental benefits of having dry-type metering units versus oil-filled units due to the fact that there is the potential for environmental hazards from oil leaks.
Table 2 shows the history of expenditures for this project for the two year period from 2011 to 2012 and the budget for 2013.

Table 2: Budget History

Year	Budget ($00)	Actual ($000)
2013B	199.5	
2012	190.4	193.3
2011	77.4	72.8

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Prepare order	January 2014	January 2014
Design	Prepare drawings	January 2014	January 2014
Procurement	Order meters and tanks	January 2014	March 2014
Construction	Install meters and tanks	May 2014	October 2014
Commissioning	Verify installations	May 2014	October 2014
Closeout	Close out projects	December 2014	December 2014

Future Plans:

Hydro's plan is to replace all electromechanical meters with electronic meters over a period of seven years and replace all metering tanks over a period of five years. This is the fourth year of that plan that started in 2011 and ends in 2015 for metering tanks and 2017 for electromechanical meters.

APPENDIX A

Measurement Canada / Mesures Canada
An Agency of Industry Canada / Un organisme d'Industrie Canada

Specifications

Category: **STATISTICAL METHODS**	Specification: **S-S-06**	Page: **1 of 12**
Document(s): **S-S-06 Implementation, Information Bulletin (2010-02-08)**	Issue Date: **2010-06-21**	Effective Date: **2011-01-01**
	Supersedes: **PS-S-04, LMB-EG-04**	

Sampling Plans for the Inspection of Isolated Lots of Meters in Service

1.0 Scope

This specification establishes the requirements that are applicable to in-service isolated lots of homogeneous electricity or gas meters, where a meter owner has chosen to utilize sampling inspection for the purposes of extending the reverification period of an in-service lot of meters. Where applicable, this specification may be utilized as an alternative to performing 100% meter reverification, upon expiry of a meter lot's initial or subsequent reverification period.

NOTE: Sampling plans, by design, contain inherent risks and limitations with regard to their usage and the conclusions they may or may not provide. Meter owners are therefore advised that, although conformity with the requirements of this specification may allow for the extension of a meter's reverification period, relying solely on the use of the sampling plans contained in this specification will not provide users with an assurance of compliance with the metering accuracy obligations prescribed under the *Electricity and Gas Inspection Act*.

2.0 Authority

This specification is issued under the authority of section 19 of the *Electricity and Gas Inspection Regulations*.

3.0 Normative References

3.1 ISO 2859-2:1985, *Sampling procedures for inspection by attributes – Part 2: Sampling plans indexed by limiting quality (LQ) for isolated lot inspection*. Table A - Single sampling plans indexed by limiting quality (LQ) (Procedure A).

3.2 S-S-01, *Specifications for Random Sampling and Randomization*

3.3 Relevant Measurement Canada specification for the verification and reverification of the meter under test.

4.0 Administrative Requirements

Sampling inspection shall be carried out well in advance of the expiry of the reverification period of the meters so that in the case of non-conformity with the requirements, all meters forming part of the lot can be removed from service prior to the expiry of the reverification period.

Canada

Category: **STATISTICAL METHODS**	Specification: **S-S-06**	Page: **2 of 12**
Document(s): **S-S-06 Implementation, Information Bulletin (2010-02-08)**	Issue Date: **2010-06-21**	Effective Date: **2011-01-01**
	Supersedes: **PS-S-04, LMB-EG-04**	

5.0 Sampling Inspection Requirements

5.1 Lot Formation

5.1.1 The lot shall be formed from meters that are homogeneous with respect to the requirements in Annex A.

5.1.2 At the discretion of a meter owner, larger lots may be reformed into multiple lots of smaller size.

5.2 Sample Selection

5.2.1 The sample shall be drawn at random, without replacement, from the lot listing, using authorized random sampling software that meets the requirements referenced in section 3.2. (Systematic sampling shall not be used).

5.2.2 The size of the sample shall be one obtained from the table in Annex C as per the sampling instructions provided by this specification. The sample representing the lot shall correspond to a value between n_{min} and n_{max} as identified in the table of Annex B.

5.2.3 Meter owners shall be responsible for assuring that the meters which are included in the sample meet the following criteria:

(a) the identified meter is one which is currently installed in service;

(b) the identified meter's metrological parameters have not been adjusted post installation;

(c) the identified meter is homogeneous with regard to the criteria of A.1 of Annex A: and

(d) the identified meter meets the total time on test criteria of A.2 of Annex A.

5.2.4 Where a sample meter does not qualify for inclusion as per the requirements of 5.2.3, meter owners shall not consider this meter as part of the sample group for performance testing purposes, and shall replace it with the sequentially subsequent meter on the preselected unsorted sample meter listing meeting the applicable criteria. The exclusion rationale for the subject meter(s) shall be reported as per the requirements of 5.3.4.

5.2.5 Where a meter, which has been removed from service, is not capable of having its performance assessed in accordance with the requirements of this document, the meter owner shall replace it with the sequentially subsequent meter on the preselected unsorted sample listing of meters available for testing. All meters and their associated test results shall be included unless compelling evidence for exclusion is identified and reported as per the requirements of 5.3.4.

5.2.6 Meters which have been excluded as sample meters as a result of not satisfying either 5.2.3 (a), 5.2.3 (b), 5.2.3 (c), 5.2.3 (d) or 5.2.5 shall not be returned to the parent lot.

5.2.7 Lots failing to meet the minimum sample size (n_{min}) criterion as a result of the total number of exclusions under 5.2.3, are not considered to be homogeneous and are not acceptable for seal extension. Where a lot is deemed to be nonhomogeneous, meter owners shall implement one of the following actions:

(a) Re-form the lot on the basis of both the lot and sample homogeneity criteria contained in Annex A;

(b) Assign a lower initial reverification period to the lot as per the requirements of section 5.7; or

(c) Remove the lot from service.

Category: **STATISTICAL METHODS**	Specification: **S-S-06**	Page: **3 of 12**
Document(s): **S-S-06 Implementation, Information Bulletin (2010-02-08)**	Issue Date: **2010-06-21**	Effective Date: **2011-01-01**
	Supersedes: **PS-S-04, LMB-EG-04**	

5.3 Meter Sampling Records

5.3.1 For each lot assessed, a meter owner shall maintain records documenting:

(a) a unique, owner-assigned lot number or record reference which includes an ordinal number indicating the lot's occurrence for assessment under this specification (including the current - i.e. 1st, 2nd, 3rd, etc.);

(b) the homogeneity criteria details specified in A.1;

(c) the utility number and manufacturer's serial number for each meter.

5.3.2 All meters identified by the owner as forming part of the lot, shall be listed in ascending order based on meter identification numbers or an inventory number generated by the associated informatics system.

5.3.3 The identification of each unsorted sample meter (n to n_{max}) selected from the lot, the sample meters tested, the quality characteristics examined, and the test results obtained, shall be documented.

5.3.4 All sample meters selected but not involved in the final calculations shall be accounted for by the meter owner and the reasons for exclusion shall be documented and, on request, made available for Measurement Canada review. Evidence of deliberate exclusion or improper accounting may disqualify the results of the sample's analysis.

5.4 Meter Inspection, Quality Characteristics, and Corrective Actions

5.4.1 Each sample meter shall be examined for conformance to all pertinent requirements as prescribed by reference 3.3.

5.4.2 Sample meters shall be inspected under identical conditions and within as short a time period as is practicable to achieve valid inspection results.

5.4.3 Each defective meter excluded from the final calculations shall be preserved for Measurement Canada review and shall be the subject of an investigation by the meter owner to determine the cause of the defect or defects. In the case of defective meters, a report shall be prepared and shall include the following information associated with this investigation:

(a) details of the meter's make, model, Notice of Approval number, seal year, and identification numbers;

(b) a description of the defect and its effect on the meter's operation, including performance test results where feasible;

(c) a description of the steps taken to investigate the cause of the defect, including identification of the personnel both performing the investigation and providing information for its purpose;

(d) an explanation of how the defect occurred, including where it occurred in the process;

(e) an evaluation of the extent of the defect in the immediate situation as well as in situations likely to be similarly affected; and

(f) details of the corrective and preventive action proposed or performed to address the cause and symptoms of the defect.

Category: **STATISTICAL METHODS**	Specification: **S-S-06**	Page: **4 of 12**
Document(s): **S-S-06 Implementation, Information Bulletin (2010-02-08)**	Issue Date: **2010-06-21**	Effective Date: **2011-01-01**
	Supersedes: **PS-S-04, LMB-EG-04**	

5.4.4 In cases where a defective meter is encountered, the report required by clause 5.4.3 shall be provided to the local Measurement Canada representative for review prior to deciding upon the acceptability of the affected lot. Decisions regarding acceptability of the affected lot and the possible need for further investigation or corrective action shall not be made until Measurement Canada has evaluated the report and the statistical analysis of the data from the sample meters involved in the final calculations.

5.5 Acceptance Criteria

5.5.1 Individual Meters

5.5.1.1
Each meter in the sample can be considered acceptable if the following conditions are met:

(a) the meter complies with all specified reverification performance requirements (reference 3.3);

(b) the meter does not possess any defect which could affect its ability to meet specified requirements during its usage;

(c) the meter has been obtained from a population whose seal year is still valid;

(d) the meter has been received with a broken seal and an exclusion as per 5.3.4 cannot be justified.

5.5.1.2
To maintain overall homogeneity of the lot, sample meters, obtained from lots qualifying for an extension, which meet reverification requirements and which have been granted the same extension as the parent lot, shall, wherever possible, be returned to the parent lot and reinstalled following acceptance of the lot. Alternatively, these meters can be reverified.

5.5.1.3
Where sample meters require their seals to be broken in order to conduct meter performance testing, precautions should be taken to ensure the integrity of the results. If the lot is acceptable, the individual sample meters that are also acceptable shall be resealed with an additional identifier indicating the original seal year in the sealing assembly. Alternatively, these meters shall be reverified.

5.5.1.4
Sample meters that meet reverification requirements, yet have been obtained from lots not qualifying for an extension or sample meters not returned to the parent lot, shall be governed by Measurement Canada bulletins E-26 *Reverification Periods for Electricity Meters and Metering Installations* or G-18 *Reverification Periods for Gas Meters, Ancillary Devices and Metering Installations,* with respect to the assigned reverification period.

5.5.2 Meter Lots

5.5.2.1
The sampling plan parameters of ISO 2859-2 (reference 3.1) as modified in Annex C of this document, shall be utilized for the inspection of isolated lots of meters in service.

5.5.2.2
The acceptability of the lot for the purposes of extending its reverification period, shall be established on the basis of the performance results of the sample with regard to the number of marginally conforming meters (C_1) and the number of nonconforming meters (C_2) evidenced, as defined in section 5.5.3.

Category: **STATISTICAL METHODS**	Specification: **S-S-06**	Page: **5 of 12**
Document(s): **S-S-06 Implementation, Information Bulletin (2010-02-08)**	Issue Date: **2010-06-21**	Effective Date: **2011-01-01**
	Supersedes: **PS-S-04, LMB-EG-04**	

5.5.2.3
Contractors are responsible for ensuring the performance quality of the in-service meter lots which they own. Where a seal extension period is available under this specification, contractors shall give consideration to their statutory obligation for keeping meters in good repair, when selecting the seal extension period to be applied from those which are available. Specifically, the conformance quality of an in-service lot of meters shall, in all cases, meet or exceed the declared limiting quality that is associated with level 5.

5.5.3 Meter Performance Test Limits

5.5.3.1
For all performance tests, required to be conducted as per the reverification specification applicable to the subject meter type or class, a Type 1 (C_1) marginally conforming meter is one whose performance error exceeds ± 2.0% at any test point.

5.5.3.2
For all performance tests, required to be conducted as per the reverification specification applicable to the subject meter type or class, a Type 2 (C_2) nonconforming meter is one whose performance error exceeds ± 2.9% at any test point.

5.5.3.3
For the purposes of section 5.5.2.2, a Type 2 (C_2) nonconforming meter is also counted as a Type 1 (C_1) marginally conforming meter.

5.5.4 Seal Extension Levels

5.5.4.1
Where a lot of meters is assessed against the requirements of this specification, the maximum seal extension level available for application to the lot, shall be established on the basis of satisfying the following criteria when applied to the n_{min} sample size as specified in a column of the applicable Annex C table:

Maximum Extension Level Criteria:

(i) $c1 \leq Ac_{\text{type 1}}$
(ii) $c2 \leq Ac_{\text{type 2}}$

5.5.4.2
Subject to the requirements of section 5.6, the maximum seal extension level that may be available for application to a lot, is the seal extension level associated with the limiting quality column of the applicable table in Annex C, C-1 or C-2 which satisfies the requirements of 5.5.4.1 for the established sample size n_{min}.

5.5.4.3
Where the maximum level of extension available to a lot of meters is determined to be level 4, the applicable seal extension period, as determined under Annex E, may be repeated without limitation on an ongoing basis where the applicable level 4 limiting quality criteria of Annex C, C-1 or C-2 and the Time on Test criteria of Annex E are met.

5.5.4.4
Subject to section 5.5.4.5, lots failing to meet at least level 4 criteria are not acceptable for extension. All meters in non-acceptable lots shall be removed from service.

Category: **STATISTICAL METHODS**	Specification: **S-S-06**	Page: **6 of 12**
Document(s): **S-S-06 Implementation, Information Bulletin (2010-02-08)**	Issue Date: **2010-06-21**	Effective Date: **2011-01-01**
	Supersedes: **PS-S-04, LMB-EG-04**	

5.5.4.5
Where a lot failing to meet level 4 criteria is capable of meeting the limiting quality criteria of level 5 (where available), the applicable level 4 extension period available as per Annex E, may be applied to the lot. However, upon expiry of this period, the lot cannot be re-sampled and must be removed from service.

5.5.4.6
Where a lot fails to meet at least level 4 criteria and this failure is as a result of not meeting the requirements of sec 5.5.4.1(ii), all sample meters identified as C_2 meters under section 5.5.3.2 shall be held in storage until Measurement Canada authorizes their further processing. Sample meters shall not be required to be held in storage (without just cause) after December 31st of the calendar year in which the sampling was conducted.

5.6 Use of Sampling Tables (Annex C, C-1, and C-2)

5.6.1 The value of n_{min} shall be established on the basis of the lot size and the maximum seal extension level being targeted. Once the n_{min} sample size has been determined, it is this value that shall be utilized for establishing the maximum seal extension level, where further movement within the table is limited to either the horizontal or a diagonal downward direction for the same n_{min}.

5.6.2 Notwithstanding the seal extension level available under the requirements of section 5.5.4.1, and subject to section 5.6.3, the maximum seal extension level that may be applied to the lot shall be established on the basis of the lot's ordinal sampling occurrence under this specification as specified in Annex D.

5.6.3 Where the maximum seal extension level available to the lot under Annex D is longer in duration than the previous seal extension period granted to the lot, the period applied shall not be greater than one level better than the previous extension level and this eligibility for the application of a longer period, is limited to a single occurrence within a meter lot's in-service life.

5.6.4 Where a lot population has never been assessed against the requirements of this specification, the seal extension period of reference for the purposes of 5.6.3, shall be the last extension period granted to the lot under the previously authorized compliance sampling program.

5.6.5 Where a lot population is re-formed under the requirements of 5.1.2 or 5.2.7, the maximum seal extension levels available to the re-formed lot shall be established in accordance with the requirements of 5.6.2, 5.6.3, and 5.6.4, as applicable to the parent lot before re-formation.

5.6.6 Where a lot's population size is 500 meters or less, a meter owner may, at their discretion, utilize the sampling plan as specified in Annex C-1. Where the sampling plan of Annex C-1 is utilized, the seal extension periods available under Annex E are reduced by 50% (rounded down to the nearest whole year).

5.6.7 Where a lot's population size is 60 meters or less, a meter owner may, at their discretion, utilize the sampling plan as specified in Annex C-2. Where the sampling plan of Annex C-2 is utilized, the only seal extension periods available under Annex E are those associated with a level 4 extension.

5.7 Seal Extension Periods (Annex E)

5.7.1 For meter lots still within their initial reverification period, the time on test (TT) requirements which need to be met or surpassed by each meter in the sample (as per the homogeneity requirements of A.2), shall be established on the basis of the meter's initial reverification period and the minimum period (in months) prescribed under Annex E.

Category: **STATISTICAL METHODS**	Specification: **S-S-06**	Page: **7 of 12**
Document(s): **S-S-06 Implementation, Information Bulletin (2010-02-08)**	Issue Date: **2010-06-21**	Effective Date: **2011-01-01**
	Supersedes: **PS-S-04, LMB-EG-04**	

5.7.2 For meter lots still within their initial reverification period, a sample meter's time on test (in months) is established from the date the sample meter is placed into service, to the date that it is removed from service (rounded down to the nearest whole month). For the purposes of this section and section 5.7.4, where months are established on the basis of day counts, one month is to be considered 31 days. Alternatively, months may be established on the basis of actual month days where this information is tracked on an ongoing basis relative to true months completed within a calendar period.

5.7.3 Subject to section 5.7.5, where a meter lot is no longer within its initial reverification period, the time on test (TT) requirements that need to be met or surpassed by each meter in the sample (as per the homogeneity requirements of A.2), shall be established on the basis of the previous seal extension period granted to the lot and the applicable subsequent extension percentage prescribed for the subject row as per Annex E.

5.7.4 For meter lots no longer within their initial reverification period, a sample meter's time on test (in months) is established from the date that the certificate was issued relative to the meter lot's last seal extension, to the date that the sample meter is removed from service (rounded down to the nearest whole month). Alternatively, a meter's time on test requirement is satisfied where it can be demonstrated that the sample meter has continuous uninterrupted service.

5.7.5 Meter lots that are sampled on an annual basis under this plan, are not subject to the time on test requirements of Annex E.

5.7.6 Where the time on test requirements for the 1st extension or subsequent extensions of a lot have not been met or where a sample is deemed non-homogeneous relative to the applicable time on test requirement, a lower initial reverification period (where the time on test requirements are satisfied) may be assigned to the lot.

5.7.7 Once a lower initial reverification period row has been assigned to a lot, further movement within the table is limited to either the horizontal, downward or diagonal downward directions (i.e. the initial reverification period reference cannot be increased on subsequent samplings of the lot).

5.8 Reverification Date Calculations

5.8.1 Subject to 5.8.2 , where a seal period extension is granted under Annex E, the meters in the lot, less any nonconforming meters, shall be considered due for reverification on or before December 31 of the calendar year calculated as the sum of the year in which the first sample meter was removed from service and the extension period granted under Annex E (in years).

5.8.2 Where the first sample meter is removed from service in the calendar year which immediately precedes the meter lot's seal expiration year, the meters in the lot, less any nonconforming meters, shall be considered due for reverification on or before December 31 of the calendar year calculated as the sum of the lot's seal expiration year and the extension period granted under Annex E (in years).

5.8.3 Subject to 5.8.4, where a lot of meters fails to meet the requirements for an extension of its reverification period, the meters in the lot shall be considered due for reverification on the date established by the previous verification or reverification, as the case may be.

5.8.4 In the case of a lot of meters which fails to meet the requirements for an extension of its reverification period and the first sample meter was removed from service in a calendar year which preceded the meter lot's seal expiration year by more than one (1) calendar year, the meters in the lot shall be considered due for 100% reverification, on or before December 31st of the calendar year which postdates the year in which the first sample meter was removed from service.

Category: **STATISTICAL METHODS**	Specification: **S-S-06**	Page: **8 of 12**
Document(s): **S-S-06 Implementation, Information Bulletin (2010-02-08)**	Issue Date: **2010-06-21**	Effective Date: **2011-01-01**
	Supersedes: **PS-S-04, LMB-EG-04**	

Annex A
(normative)

A.1 Lot Homogeneity Requirements

Where applicable, the meters in the lot shall be homogeneous with respect to the following characteristics:

Electricity Meters

(a) type (transformer or self contained);

(b) manufacturer and model, unless otherwise authorized in accordance with clause A.1.1;

(c) voltage or voltage range;

(d) maximum current range, unless otherwise authorized in accordance with clause A.1.1;

(e) measurement functions (e.g. measured quantities, energy, demand), unless otherwise authorized in accordance with clause A.1.1;

(f) firmware version, unless otherwise authorized in accordance with clause A.1.1;

(g) frequency rating;

(h) same model or type of telemetering device (if so equipped), unless otherwise authorized in accordance with clause A.1.1;

(i) configuration / form (i.e. number of elements*, wye, delta or auto configuration);

(j) status at time of last inspection (i.e. new, renewed, or reserviced);and

(k) seal year (same seal year or two consecutive seal years, provided both are valid);

***With the exception that 1-element and 1.5-element meters may be mixed to form a lot.**

Natural Gas Meters

(a) manufacturer and model, unless otherwise authorized in accordance with clause A.1.1.

(b) same or similar capacity rating, unless otherwise authorized in accordance with clause A.1.1.

(c) measurement functions (e.g. measured quantities, temperature/pressure conversion).

(d) firmware version, unless otherwise authorized in accordance with clause A.1.1.

(e) same model or type of telemetering device or auxiliary attachment (if so equipped), unless otherwise authorized in accordance with clause A.1.1.

(f) status at time of last inspection (i.e. new, renewed, or reserviced).

(g) seal year (same seal year or two consecutive seal years, provided both are valid).

Category: **STATISTICAL METHODS**	Specification: **S-S-06**	Page: **9 of 12**
Document(s): **S-S-06 Implementation, Information Bulletin (2010-02-08)**	Issue Date: **2010-06-21**	Effective Date: **2011-01-01**
	Supersedes: **PS-S-04, LMB-EG-04**	

A.1.1 Forming Lots with Mixed Meters

Where a lot includes meters which, for the purposes of lot homogeneity, are ones which possess a similar characteristic rather than a characteristic which can be readily identified as being the same, meter owners are responsible for maintaining documented records identifying the similarities which support the homogeneity conclusion (as concerns including these meters within the subject lot). For the purposes of compliance sampling, if an accredited organization wishes to combine, in one lot, various models or vintages of meters, and/or meters equipped with and without a telemetering device, the accredited organization shall submit a request to MC with accompanying documentation in support of their claim that these differing meters can be considered homogeneous.

A.2 Sample Homogeneity Requirements

The meters in a sample shall be homogeneous with respect to similar time in usage. For a sample meter to be considered homogeneous with regard to similar time in use, a meter shall have been in service for a time period that meets or exceeds the applicable time on test (TT) requirements of Annex E. Where n_{min} is not achieved with regard to this criteria, a meter owner may re-form the lot or reduce the seal period extensions available as per the requirements of section 5.7.

Annex B
(normative)

Table of n_{min} to n_{max} Sample Sizes

Single Sampling	
n_{min}	n_{max}
30	37
42	52
44	55
65	81
80	100
125	156
200	250
315	394

Category: **STATISTICAL METHODS**	Specification: **S-S-06**	Page: **10 of 12**
Document(s): **S-S-06 Implementation, Information Bulletin (2010-02-08)**	Issue Date: **2010-06-21**	Effective Date: **2011-01-01**
	Supersedes: **PS-S-04, LMB-EG-04**	

Annex C - Single Sampling Plans Indexed by Quality Level (LQ)
(normative)

Lot Size		Limiting Quality (LQ)				
		3.15 (Level 1)	**5.0** (Level 2)	**8.0** (Level 3)	**12.5** (Level 4)	**20** (Level 5)
Up to 500	n_{min}	80	65			
	Ac $_{type\ 1}$	0	0			
	Ac $_{type\ 2}$	0	0			
501 to 1200	n_{min}	125	80	65	42	42
	Ac $_{type\ 1}$	1	1	1	2	4
	Ac $_{type\ 2}$	1	0	0	0	0
1201 to 3200	n_{min}	125	125	80	65	65
	Ac $_{type\ 1}$	1	3	3	4	8
	Ac $_{type\ 2}$	1	1	0	0	0
3201 to 10000	n_{min}	200	200	125	80	80
	Ac $_{type\ 1}$	3	5	5	5	10
	Ac $_{type\ 2}$	3	3	1	1	1
10001 to 35 000	n_{min}	315	315	200	125	125
	Ac $_{type\ 1}$	5	10	10	10	18
	Ac $_{type\ 2}$	5	5	3	3	3
	n_{min}			315	200	200
	Ac $_{type\ 1}$			18	18	32
	Ac $_{type\ 2}$			5	5	5

NOTE:
As per 5.5.3.1, Type 1 (C_1) > 2.0%
As per 5.5.3.2, Type 2 (C_2) > 2.9%

Category: **STATISTICAL METHODS**	Specification: **S-S-06**	Page: **11 of 12**
Document(s): **S-S-06 Implementation, Information Bulletin (2010-02-08)**	Issue Date: **2010-06-21**	Effective Date: **2011-01-01**
	Supersedes: **PS-S-04, LMB-EG-04**	

Annex C1 - Single Sampling Plans Indexed by Quality Level (LQ)
Small Lot Size Plan (with increased sampling frequency)
(normative)

Lot Size		Limiting Quality (LQ)			
		5.0 (*Level 1)	**8.0** (*Level 2)	**12.5** (*Level 3)	**20** (*Level 4)
Up to 500	n_{min}	44	44	44	44
	Ac $_{type\ 1}$	0	1	2	4
	Ac $_{type\ 2}$	0	0	0	0

NOTE:
* Extension period as per section 5.6.6.
As per 5.5.3.1, Type 1 (C_1) > 2.0%
As per 5.5.3.2, Type 2 (C_2) > 2.9%

Annex C2 - Single Sampling Plans Indexed by Quality Level (LQ)
Very Small Lot Size Plan
(normative)

Lot Size		Limiting Quality (LQ) 5.0 (Nonconforming)
		Level 4
Up to 60	n_{min}	30
	Ac $_{type\ 1}$	0
	Ac $_{type\ 2}$	0

NOTE:
As per 5.5.3.1, Type 1 (C_1) > 2.0%
As per 5.5.3.2, Type 2 (C_2) > 2.9%

Category: **STATISTICAL METHODS**	Specification: **S-S-06**	Page: **12 of 12**
Document(s): **S-S-06 Implementation, Information Bulletin (2010-02-08)**	Issue Date: **2010-06-21**	Effective Date: **2011-01-01**
	Supersedes: **PS-S-04, LMB-EG-04**	

Annex D - Available Extension Levels
(normative)

Ordinal Sampling Occurrence	Maximum Seal Period Extension Levels Available			
1st	Level 1	Level 2	Level 3	Level 4
2nd		Level 2	Level 3	Level 4
3rd			Level 3	Level 4
4th (and higher)				Level 4

Annex E - Time on Test (TT) Requirements and Maximum Seal Period Extensions
(normative)

Initial Reverification Period (years)	1st Extension (Months)	Subsequent Extensions*	Maximum Seal Period Extension (years)			
			Level 1	Level 2	Level 3	Level 4
12	115	75%	10	8	5	2
11	105	75%	9	7	5	2
10	84	70%	8	6	4	2
9	75	70%	7	5	3	2
8	67	70%	6	4	3	2
7	58	70%	5	4	2	1
6	50	70%	4	3	2	1
5	42	70%		3	2	1

***Subsequent extension TT based on indicated percentage multiplied by the previous extension (rounded up to the next whole month).**

Alan E. Johnston
President

APPENDIX B

Measurement Canada | Mesures Canada

Bulletin

Category: ELECTRICITY	Bulletin: E-24-E (rev. 1)	Date: 2002-11-29	Page: 1 of 2
Document(s):		Supercedes:	

Policy on Approval an Use of 2½ Element Metering

1.0 Scope

This bulletin applies to 2½ element electricity meters used for revenue metering in Canada.

2.0 Background

The 2½ element meters were designed to reduce costs associated with metering, by using one less instrument transformer and associated components internal to the meter. Although 2½ element metering is a legal and approved form of metering used in Canada, there is a potential for error as a result of its noncompliance to Blondel's theorem when certain conditions of application are not met. This potential for error was considered negligible while presenting significant cost benefits to the electricity utilities. However, the electricity industry and Measurement Canada (MC) have recently questioned this potential error and the appropriateness of using 2½ element metering in light of today's market and technology.

A national survey was completed by industry representatives of the Canadian Electricity Association and supported by MC to determine the actual impact of 2½ element metering on the Canadian market. The results of that survey[1] were discussed by MC and industry during the Canadian Forum on Trade Measurement 2001 and a number of recommendations were agreed on to reduce the impact of this potential error.

The purpose of this bulletin is to provide policies to reduce the potential for error in the application of 2½ element metering.

3.0 Terminology

Blondel's Theorem: In a system of *N* conductors, *N*-1 meter elements, properly connected, will correctly measure the power or energy taken. The connection must be such that all potential coils have a common tie to the conductor in which there is no current coil.

Self-contained Meter: A meter designed to be connected directly to a power circuit, without the use of external devices such as instrument transformers or shunts.

Transformer Type Meter: A meter designed to be used with instrument transformers.

4.0 Approval Policy

4.1 Applications for approval of self contained 2½ element meters will no longer be accepted by Measurement Canada after December 31, 2002.

4.2 Applications for approval of transformer type 2½ element meters will continue to be accepted by Measurement Canada.

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1 National Statistical Survey of The Impact Of Zero Sequence Voltage on 2½ Element metering for 3-Phase Distribution Systems, CEA Report T984700-5201, Powertech Labs Inc., Dec. 2000

Category: ELECTRICITY	Bulletin: E-24-E (rev. 1)	Date: 2002-11-29	Page: 2 of 2
Document(s):		Supercedes:	

5.0 Installation Policy

5.1 Effective April 1, 2003;

(a) all new, and

(b) all reconstruction of existing,

3-phase 4-wire wye configured metering installations shall use metering that is compliant to Blondel's theorem such as 3-element metering.

Note: An example of a reconstructed metering installation may include service upgrades and, or instrument transformer replacement. Reconstruction of existing metering installation, sites that do not have sufficient physical space to accommodate the additional voltage transformer will not be required to meet 5.1 above.

5.2 All 2½ element meters installed on 3-phase 4-wire wye configured services prior to April 1, 2003 may remain in service under the following conditions:

(a) 2 ½ element meters continue to be verified and reverified as per Measurement Canada's legal requirements.

(b) The risk of error associated with 2½ element metering remaining in service has been minimized, by ensuring that feeder loads are reasonably balanced.

6.0 Additional Considerations

6.1 For the application of 2½ element meters, contractors are advised of the potential for error due to zero sequence voltage. If the contractor assesses the service or loading to be of such nature that the potential for sustained error could be higher than the dispute tolerances prescribed under the *Electricity and Gas Inspection Regulations*, then the service should be converted to a 3-element metering installation.

6.2 The long-term expectation is that:

(a) Self-contained 2½ element meters will be replaced with self-contained 3-element meters through obsolescence of the meters, and

(b) Transformer type, 2 ½ element meters will be replaced with transformer type 3-element meters, on an opportunity basis, through obsolescence or reconstruction of the metering installation.

7.0 Additional Information

For additional information regarding this provisional specification, please contact the undersigned. For more information regarding Measurement Canada, please visit our web site at http://mc.ic.gc.ca.

David Flieler
Senior Program Officer, Electricity
Program Development Directorate

Project Title: Purchase Track Mounted Backyard Radial Boom Derrick

Location: Bishop Falls

Category: General Properties - Transportation

Definition: Other

Classification: Normal

Project Description:

The scope of this project is to purchase a mini track mounted backyard radial boom derrick (RBD) to be used throughout Hydro's operating area. The RBD has the capacity to handle loads up to 5,000 pounds.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	141.7	0.0	0.0	141.7
Labour	1.0	0.0	0.0	1.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	3.0	0.0	0.0	3.0
Interest and Escalation	5.7	0.0	0.0	5.7
Contingency	7.3	0.0	0.0	7.3
TOTAL	**158.7**	**0.0**	**0.0**	**158.7**

Operating Experience:

As this is a new piece of equipment, Hydro has no in house experience with the equipment. Presently, the line crews use pike poles and rope to erect poles in remote communities because there is no proper equipment available. The mini RBD would enable Hydro to install poles and related equipment in remote communities.

Project Justification:

This project is justified on the need to acquire appropriate equipment to perform work in a safe and efficient manner. Equipment for the safe placement of heavy material is unavailable in Hydro's remote operating areas such as Francois, William's Harbour, or Black Tickle. To address safety, environmental, and ergonomic issues related to the installation of heavy equipment such as distribution poles, transformers, or voltage regulators Hydro requires the use of an RBD. The RBD is a mini digger derrick that can access backyards through gates as small as 36 inches, and travel across lawns without disturbing the landscaping. Using the present method of manually replacing distribution poles, transformers, or voltage regulators could result in property damage or oil spills from a dropped unit..

The use of the mini RBD to access structures that are off road would reduce the need for muskegs and excavators around congested residential areas such as backyard fences, sheds, wells and septic systems. This equipment can be transported to isolated diesel communities to allow safe handling, transport and installation of wood poles because the unit is designed for pole erection and material handling. Jobs can be better planned and scheduled using this equipment as local equipment is not always available or does not meet Hydro's requirements. As this unit is smaller, lighter and more mobile than Hydro's existing equipment such as muskegs, it is able to meet Hydro's distribution needs in isolated communities, as well as densely populated residential areas in communities on the Island Interconnected System.

The mini digger derrick would provide a means to more effectively perform maintenance and capital work in difficult to reach areas in rural residential communities.

Future Plans:

None.

Project Title: Replace Excavator

Location: St. Anthony

Category: General Properties - Transportation

Definition: Other

Classification: Normal

Project Description:

The scope of this project is to replace Unit No. 7833, a 1994 model, mid-size excavator, stationed in St. Anthony, with a similar unit. This excavator will be 20 years old at the time of replacement. The budget estimate for the project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	100.0	0.0	0.0	100.0
Labour	1.0	0.0	0.0	1.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	3.9	0.0	0.0	3.9
Contingency	5.1	0.0	0.0	5.1
TOTAL	**110.0**	**0.0**	**0.0**	**110.0**

Operating Experience:

Mid-size excavators have an average life expectancy which ranges from 15 to 20 years, dependent on location and usage. This unit is utilized extensively for excavating and hoisting utility poles by the distribution line crews in their daily work assignments.

Project Justification:

Excavators are an integral part of the line crew equipment and are utilized extensively for excavation and pole erection by the distribution line crews. Technological improvements in newer cab design have reduced the noise and heat levels in the cab. Safety improvements include interlocks on the doors, to prevent operation of the unit with the doors open, an automatic braking system and integral holding valves to prevent boom drop while erecting poles.

This project is justified on the need to replace obsolete equipment. This project provides for the normal replacement of a mid-size excavator due to its age and condition. This unit will be 20 years old at replacement. In the past two years, Hydro has spent $24,000 for hydraulic repairs and track maintenance. The unit is rusty and would require a major overhaul in 2014 if it were to remain in service, as an alternative to purchasing a new excavator. A cost benefit analysis was performed to evaluate the two alternatives. Alternative 1 is to purchase a new excavator. Alternative 2 is to refurbish the existing one through a major overhaul. Operating and maintenance costs were considered for both alternatives in the cost benefit analysis.

Table 2 shows the results of the cost benefit analysis.

Table 2: Cost Benefit Analysis Results

Replace Excavator V7833		
Alternative Comparison ***Cumulative Net Present Value*** ***To The Year*** **2018**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Purchase New Unit	73,328	0
Refurbish Unit	151,207	77,879

As can be seen from Table 2, the purchase option is the least cost alternative. By purchasing the new excavator, Hydro will realize a cost savings of $77,879 over the five year period to 2018.

Future Plans:

None.

Project Title: Purchase Portable Vibration Testing Equipment

Location: Various Sites

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Normal

Project Description:

The scope of this project is to purchase portable vibration monitoring equipment and associated trending software for all of Hydro's regions. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	48.0	0.0	0.0	48.0
Labour	0.0	0.0	0.0	0.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	3.0	0.0	0.0	3.0
Contingency	9.6	0.0	0.0	9.6
TOTAL	**60.6**	**0.0**	**0.0**	**60.6**

Operating Experience:

Within Hydro there are approximately 90 diesel engines in service that currently do not have any routine vibration checks completed. The only time vibration checks are performed are either thorough the manufacturer during commissioning or through the generator set supplier if there are suspected vibration concerns.

Project Justification:

Vibration monitoring is a condition based tool to aid in the early detection of potential machine failures, allowing machinery to be repaired before failure occurs. Early detection of mechanical fatigue can be accomplished through vibration monitoring. Ongoing monitoring of the equipment vibration signature allows signs of wear and damage to be identified, well before the damage progresses to failure and down time. Condition based monitoring is able to assist Hydro in determining and managing the health of its diesel engines.

Project Schedule:

The anticipated project schedule is shown in Table 2:

Table 2: Budget Schedule

Activity		Start Date	End Date
Planning	Check market	January 2014	February 2014
Design	Prepare specification	February 2014	February 2014
Procurement	Prepare and issue tender	March 2014	April 2014
Construction	Receive unit	May 2014	May 2014
Commissioning	Commission and place in service	May 2014	June 2014
Closeout	Closeout	July 2014	August 2014

Future Plans:

None.

Project Title: Perform Minor Application Enhancements

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

Hydro's many computer applications are used daily by employees to run the business. Examples of these applications include the JD Edwards Enterprise Resources Planning Suite, the Lotus Notes Email and Collaboration Suite, the Showcase Business Intelligence and Reporting Suite, and the Microsoft Office Productivity Suite. This project is necessary to enhance these applications to support changing business requirements. The application enhancement project provides for minor enhancements to applications in response to unforeseen requirements such as regulatory and changing business needs.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	2014	2015	Beyond	Total
Material Supply	24.0	0.0	0.0	24.0
Labour	12.8	0.0	0.0	12.8
Consultant	73.5	0.0	0.0	73.5
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	6.1	0.0	0.0	6.1
Contingency	22.1	0.0	0.0	22.1
Sub-Total	138.6	0.0	0.0	138.6
Cost Recoveries	(51.3)[5]	0.0	0.0	(51.3)
TOTAL	**87.3**	**0.0**	**0.0**	**87.3**

Operating Experience:

This project has been used in the past to fund enhancements to applications such as the safety and audit databases, full time equivalent reporting, and equalized billing. In 2012, the most recent year for which actual data is available, the following application enhancements were made:

[5] *The Information Systems shared services methodology for calculating appropriate charges to non-regulated components is based on a ratio considering the average of the number of full time equivalents and Lower Churchill contractors, email users, personal computers and JD Edwards users across each line of business.*

- Enhancements to Lotus Notes email system.
- Upgrade to document management systems.
- Upgrade to substation modeling and analysis software.

Project Justification:

This project is justified on the basis of operational efficiency and response to regulatory and legislative requirements. As part of normal Information Systems department work, this project is necessary to enhance existing applications to support changing business and regulatory requirements.

Table 2 shows the total budget compared to actual expenditures for application enhancements before cost recoveries that have occurred from 2008-2013B.

Table 2: Application Enhancements

Year	Budget ($000)	Actual ($000)	Comments[6]
2013B	126.8[7]	0.0	Upgrade
2012	123.4	113.3	Upgrade
2011	120.7	142.8	Upgrade
2010	120.7	122.9	Upgrade
2009	120.2	120.6	Upgrade
2008	372.5	369.8	Upgrade

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning	January 2014	April 2014
Design	February 2014	June 2014
Procurement	March 2014	August 2014
Construction	March 2014	November 2014
Commissioning	May 2014	November 2014
Closeout	May 2014	December 2014

Future Plans:

Future enhancements will be proposed in future capital budget applications. Also see five-year capital plan (Capital Plan 2014 Tab, Appendix A).

[6] *Upgrade refers to adding or extending functionality of applications.*
[7] *Previous Budgets included the Intranet and/or Internet Refresh Proposals. These have now been moved to distinct proposals.*

Project Title: Upgrade Energy Management System

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

This project is required to upgrade the OSI Monarch Energy Management System (EMS). The system software is upgraded on a yearly basis to allow for the inclusion of fixes and functionality changes to the software.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	34.6	0.0	0.0	34.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	115.7	0.0	0.0	115.7
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	7.5	0.0	0.0	7.5
Contingency	30.1	0.0	0.0	30.1
TOTAL	**187.9**	**0.0**	**0.0**	**187.9**

Operating Experience:

The EMS was purchased from Open Systems International and commissioned in June 2006. It has been in continuous operation since commissioning. The software has been upgraded on a yearly basis from 2007 to 2013. The importance of this software to the operation of power system requires that the software is upgraded on a yearly basis to remove any software bugs and to be able to take advantage of any functionality that would benefit the operating of the power system.

Project Justification:

This project is a normal continuation of upgrades to ensure proper functionality. The EMS is essential to the continued efficient and reliable operation of the provincial transmission grid and generation facilities operated by Hydro. The EMS provides a critical function for Hydro and the operation of the Island Interconnected System. Remote control of any station would be impossible and therefore all major stations would have to be staffed. This project will start in April 2014 and end in August 2014.

Project Schedule:

This project will be started in April 2014 and completed by the end of July 2014.

Future Plans:

The software will continue to be upgraded on a yearly basis to keep it current and up to date. See five year plan (2014 Capital Plan Tab, Appendix A).

Project Title: Replace Network Communications Equipment

Location: Various Sites

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This project is to replace the frame relay wide area network (WAN) service at Springdale, Stephenville and Deer Lake with internet protocol virtual private network (IPVPN) internet service along with replacing frame relay service at Sop's Arm with digital subscriber line (DSL) internet service.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	20.0	0.0	0.0	20.0
Labour	46.5	0.0	0.0	46.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	3.6	0.0	0.0	3.6
Interest and Escalation	6.9	0.0	0.0	6.9
Contingency	14.0	0.0	0.0	14.0
TOTAL	**91.0**	**0.0**	**0.0**	**91.0**

Operating Experience:

There have not been any problems with the existing services. However, all new third party WAN circuits commissioned by Hydro are either IPVPN or DSL (where IPVPN is not available). Migrating from frame relay to IPVPN and DSL will increase operational efficiencies by reducing the number of technologies which must be maintained.

Project Justification:

Frame relay service is obsolete and will be discontinued in the near future although a definite date has not been announced by Bell Aliant. For this reason, Hydro is taking a proactive approach to systematically replace its frame relay circuits as part of an ongoing migration strategy. The frame relay replacements to date, or in progress, are shown in Table 2. In addition, IPVPN and DSL service provides higher speeds to the end user, and thus greater productivity. Furthermore, the IPVPN service in particular provides advanced yet commonly used features such as quality of service and allows for segregation of data based on security requirements. DSL is to be used where IPVPN is not available.

Table 2: Frame Relay Replacements to Date

Site Name	Date of Replacement
Whitbourne Office	2012
Cat Arm Site	2012
St. Anthony Office	2013
Port Saunders Office	2013 (in progress)

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Create work breakdown schedule and open job.	January 2014	February 2014
Design	Complete detailed configuration design	March 2014	April 2014
Procurement	Order services from Aliant.	May 2014	June 2014
Construction and Commissioning	Complete installations and commissioning on same trip.	May 2014	August 2014
Closeout	Complete all project reports and as-built drawings.	September 2014	December 2014

Future Plans:

Other frame relay sites will be addressed in future proposals include:

- L'Anse-au-Loup Line Depot;
- Happy Valley Office; and
- Bear Cove Terminal Station

Project Title: Replace Telephone System

Location: Stephenville

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This project consists of replacing the existing Nortel Norstar telephone system at Hydro's Stephenville office with an Avaya Private Branch Exchange (PBX) system. The system is used by office staff and line personnel for daily telephone communication.

The budget estimate for this proposal is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	40.1	0.0	0.0	40.1
Labour	54.2	0.0	0.0	54.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	14.2	0.0	0.0	14.2
Interest and Escalation	9.7	0.0	0.0	9.7
Contingency	21.7	0.0	0.0	21.7
TOTAL	**139.9**	**0.0**	**0.0**	**139.9**

Operating Experience:

The telephone system was originally installed in the 1980s by Newtel Communications and rented by Hydro. In 1995, Hydro purchased the systems and all maintenance since this date has been performed by Hydro personnel. This system has performed well with minimal failures but has become obsolete. In particular, it cannot be expanded to provide common user productivity features such as voice mail and auto attendant.

Project Justification:

The existing system was manufacturer discontinued in 2007 with no further support or parts available. The system has a fixed capacity and cannot be expanded. The proposed system has voice mail capabilities and automated attendant features such as routing calls to the appropriate persons without assistance of a switchboard operator. This system will allow voice communications within the office and to external warehouses, garages and line depot to remain functional in the event of a loss of service from Bell Aliant. This is critical for safe and efficient operations and is consistent with past telephone system replacements in other Hydro offices.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Complete site surveys. Gather such information as back up power requirements, number and locations of new phones requested, new paging speakers requirement, voice mail and auto attendant specifics, required number of trunk lines.	February 2014	February 2014
Design	Prepare design brief; make hardware selection; prepare dial plans, technical and functional design.	February 2014	March 2014
Procurement	Prepare and review technical specifications for tender; award tender.	April 2014	May 2014
Construction	Model entire system in Hydro's lab to verify configuration and system functionality, performance and features.	May 2014	June 2014
Commissioning	Travel to site to install new telephone system paging speakers and test and verify customer acceptance.	August 2014	September 2014
Closeout	Complete as build diagrams and finalize technical documentation, lessons learned and project closeout and completion certificate.	October 2014	October 2014

Future Plans:

A similar replacement is planned for the Deer Lake Office in 2015. See the Five-Year Capital Plan (2014 Capital Plan Tab, Appendix A)

Project Title: Replace Wescom Scanner

Location: Corner Brook

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This proposal is to replace the Wescom Scanner system that provides remote monitoring of the Corner Brook Frequency Converter (CBF) from the Energy Control Center (ECC) in St. John's. Equipment for this system is located at both the Corner Brook Frequency Converter and the Massey Drive Terminal Station (MDR). Status points are routed on this system from the Corner Brook Frequency Converter to the remote terminal unit (RTU) at the Massey Drive Terminal Station and then back to the Energy Control Center. A RTU at the Frequency Converter is proposed as a replacement.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	22.0	0.0	0.0	22.0
Labour	36.8	0.0	0.0	36.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	4.3	0.0	0.0	4.3
Interest and Escalation	6.0	0.0	0.0	6.0
Contingency	12.6	0.0	0.0	12.6
TOTAL	**81.7**	**0.0**	**0.0**	**81.7**

Operating Experience:

This equipment has been in service for 30 years and is no longer available from the vendor. Maintenance support and spare parts are also no longer provided. All existing spares have been used. While this system has performed reliably over the years, a failure would cause the system to be inoperable, which would impact the ability of the Energy Control Center to know the state of devices in the station. This could in turn indirectly cause a power outage or delay recovery in the event of an outage. The system is based on an obsolete technology and is the only installation of this vintage in-service at Hydro.

Project Justification:

This project is justified on the need to replace obsolete equipment. Remote monitoring of the Corner Brook Frequency Converter from ECC is necessary to support a reliable supply of power to the Corner Brook Pulp and Paper Mill and is an integral part of the system design. Spare parts are no longer available for the existing equipment and available spares have been used

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Create work breakdown structure with a planned outage	January 2014	March 2014
Design	Confirm design and detail equipment	February 2014	March 2014
Procurement	Order and receive equipment	February 2014	June 2014
Construction	Install RTU at CBF	August 2014	August 2014
Commissioning	Commission RTU through MDR	August 2014	August 2014
Closeout	Complete as built drawings	November 2014	November 2014

Future Plans:

None.

PROJECT DESCRIPTION	Expended to 2013	2014	Future Years	Total	Definition
			($000)		
MANDATORY PROJECTS					
Perform Grounding Upgrades - Various Sites	329.0	337.1	1,025.1	1,691.2	Pooled
Replace Economizer Inlet Valves - Holyrood		192.0	329.1	521.1	Other
TOTAL MANDADORY PROJECTS	329.0	529.1	1,354.2	2,212.3	
NORMAL PROJECTS					
Install New Transformer - Oxen Pond	3,823.6	15,310.4		19,134.0	Other
Additions for Load Growth - Isolated Generation Stations - Various Sites	2,040.2	9,357.9		11,398.1	Pooled
Upgrade Distribution Systems - Various Sites (2014-2015)		2,499.8	4,850.1	7,349.9	Pooled
Provide Service Extensions - All Service Areas		6,170.0		6,170.0	Pooled
Upgrade Distribution Systems - Various Sites (2013-2014)	1,940.1	3,995.5		5,935.6	Pooled
Upgrade Circuit Breakers - Various Sites		3,695.4	1,642.5	5,337.9	Pooled
Overhaul Turbine/Generator Unit 2 - Holyrood		5,147.0		5,147.0	Other
Rewind Stator Unit 3 - Bay d'Espoir		4,343.9		4,343.9	Other
Replace Instrument Transformers - Various Sites	593.2	552.8	2,522.0	3,668.0	Pooled
Upgrade Distribution Systems - All Service Areas		3,370.0		3,370.0	Pooled
Upgrade Gas Turbine Plant Life Extension - Stephenville		2,995.0		2,995.0	Other
Replace Vehicles and Aerial Devices - Various Sites (2014-2015)		1,809.1	1,091.0	2,900.1	Other
Replace Diesel Units - Port Hope Simpson and Mary's Harbour		208.9	2,377.7	2,586.6	Pooled
Perform Wood Pole Line Management Program - Various Sites		2,564.2		2,564.2	Pooled
Replace Compressed Air Systems - Stoney Brook and Sunnyside	303.0	2,105.9		2,408.9	Other
Refurbish Surge Tank 3 - Bay d'Espoir		2,265.0		2,265.0	Other
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside		1,191.7	988.2	2,179.9	Other
Replace Vehicles and Aerial Devices - Various Sites (2013-2014)	1,302.3	679.2		1,981.5	Other
Upgrade Power Transformers - Various Sites		1,904.4		1,904.4	Other
Upgrade Terminal Station - Wiltondale	697.7	1,173.3		1,871.0	Other
Complete Condition Assessment Phase 2 - Holyrood		1,476.8		1,476.8	Other
Replace Off Road Track Vehicles - Various Sites (2013-2014)	416.8	1,054.1		1,470.9	Pooled
Upgrade Burnt Dam Spillway - Bay d'Espoir		110.2	1,201.9	1,312.1	Other
Replace MDR4000 Microwave Radio (West) - Various Sites	539.0	706.9		1,245.9	Other
Perform Arc Flash Remediation - Various Sites	391.0	401.8	413.1	1,205.9	Other
Upgrade Gas Turbine Controls - Happy Valley	61.4	1,128.6		1,190.0	Other
Upgrade Excitation Systems Units 1 and 2 - Holyrood		654.3	456.6	1,110.9	Other
Upgrade Microsoft Office Products - Hydro Place	420.3	291.3	297.7	1,009.3	Other
Replace Disconnect Switches - Various Sites		815.9	189.5	1,005.4	Pooled
Install Fire Protection System - Nain		107.1	892.2	999.3	Other
Replace Guy Wires Doyles to Grand Bay - TL215	350.1	530.0		880.1	Other
Overhaul Diesel Engines - Various Sites		823.5		823.5	Pooled
Upgrade Diesel Plant Production Data Collection Equipment - Various Sites		268.9	550.5	819.4	Other

PROJECT DESCRIPTION	Expended to 2013	2014	Future Years	Total	Definition
			($000)		
NORMAL PROJECTS (cont'd.)					
Upgrade Shoreline Protection - Cat Arm		55.3	708.1	763.4	Other
Replace Battery Banks and Chargers - Various Sites		267.0	398.0	665.0	Other
Additions to Accomodate Load Growth - Hopedale		641.2		641.2	Other
Upgrade North Cut-Off Dam Access Road - Bay d'Espoir		631.7		631.7	Other
Automate Generator Deluge Systems Units 3 and 6 - Bay d'Espoir		612.0		612.0	Other
Replace Light Duty Mobile Equipment - Various Sites		579.1		579.1	Other
Upgrade Plant Elevators - Holyrood		533.2		533.2	Other
Upgrade Vibration Monitoring System - Holyrood		524.9		524.9	Other
Install Cold-Reheat Condensate Drains and High Pressure Heater Trip Level Unit 3 - Holyrood		49.8	467.4	517.2	Other
Upgrade Enterprise Storage Capacity - Hydro Place[1]		326.2		326.2	Other
TOTAL NORMAL PROJECTS	12,878.7	83,929.2	19,046.5	115,854.4	
JUSTIFIABLE PROJECTS					
Install Variable Speed Drives on 6 Forced Draft Fans - Holyrood	697.6	2,659.7		3,357.3	Other
Install Automated Meter Reading - Various Sites (2014-2015)		356.9	340.2	697.1	Other
Install Automated Meter Reading - Various Sites (2013-2014)	287.7	258.8		546.5	Other
TOTAL JUSTIFIABLE PROJECTS	985.3	3,275.4	340.2	4,600.9	

PROJECT DESCRIPTION	Expended to 2013	2014	Future Years	Total	Definition
			($000)		
MANDATORY PROJECTS					
Remove Safety Hazards - Various Sites		257.8		257.8	Other
Replace Fuel Storage Tank - Ramea		234.2		234.2	Other
TOTAL MANDATORY PROJECTS		492.0		492.0	
NORMAL PROJECTS					
Upgrade Victoria Control Structure - Bay d'Espoir		495.1		495.1	Other
Inspect Fuel Storage Tanks - Various Sites		495.0		495.0	Other
Upgrade IP SCADA Network - Various Sites		254.2	238.7	492.9	Other
Replace Personal Computers - Various Sites		489.8		489.8	Other
Overhaul Turbine/Generator Units - Bay d'Espoir and Hinds Lake		485.0		485.0	Other
Replace Insulators - Various Sites	187.1	287.9		475.0	Pooled
Upgrade Generator Bearings Unit 2 - Bay d'Espoir		18.9	396.0	414.9	Other
Install Fire Protection Upgrades - Holyrood		56.6	312.5	369.1	Other
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir		352.8		352.8	Pooled
Replace Radomes - Various Sites		324.9		324.9	Pooled
Upgrade Server Technology Program - Hydro Place		286.0		286.0	Other
Upgrade Ventilation System - Ramea		263.0		263.0	Other
Install Additional Washrooms - Various Sites		251.0		251.0	Other
Replace Automatic Greasing Systems Units 5 and 6 - Bay d'Espoir		233.4		233.4	Other
Install Handheld Pendant to Overhead Crane - Bay d'Espoir		49.9	170.8	220.7	Other
Replace Peripheral Infrastructure - Various Sites		200.7		200.7	Other
TOTAL NORMAL PROJECTS	187.1	4,544.2	1,118.0	5,849.3	
JUSTIFIABLE PROJECTS					
TOTAL JUSTIFIABLE PROJECTS	0.0	0.0	0.0	0.0	

PROJECT DESCRIPTION	Expended to 2013	2014	Future Years	Total	Definition
			($000)		
MANDATORY PROJECTS					
Install Fall Protection Equipment - Various Sites		199.2		199.2	Pooled
TOTAL MANDATORY PROJECTS		199.2		199.2	
NORMAL PROJECTS					
Replace Generator Bearing Coolers Units 4 and 5 - Bay d'Espoir		199.0		199.0	Pooled
Purchase Meters, Equipment and Metering Tanks - Various Sites		199.0		199.0	Other
Upgrade Terminal Station Foundations - Various Sites		197.9		197.9	Other
Legal Survey of Primary Distribution Line Right of Ways - Various Sites (2014-2015)		156.8	40.3	197.1	Other
Legal Survey of Primary Distribution Line Right of Ways - Various Sites (2013-2014)	156.2	40.0		196.2	Other
Replace Recloser Control Panels - Various Sites		111.3	84.4	195.7	Pooled
Overhaul Boiler Feed Pump East Unit 3 - Holyrood		194.9		194.9	Other
Upgrade Energy Management System - Hydro Place		187.9		187.9	Other
Replace Optimho Relays on TL203 - Western Avalon to Sunnyside		89.1	96.9	186.0	Other
Construct Storage Facility - Postville		183.8		183.8	Other
Replace Surge Arresters - Various Sites		181.9		181.9	Other
Replace DC Distribution Panels and Breakers - Holyrood		174.2		174.2	Other
Purchase Track Mounted Backyard Radial Boom Derrick - Bishop Falls		158.7		158.7	Other
Replace Spherical By Pass Valves Units 1 and 2 - Bay d'Espoir		57.5	96.3	153.8	Other
Replace Fall Arrest on Surge Tank 1 - Bay d'Espoir		142.8		142.8	Other
Replace Telephone System - Stephenville		139.9		139.9	Other
Replace Turbine/Generator Cooling Water Flow Meters - Upper Salmon		139.7		139.7	Other
Upgrade Waste Water Basin Building - Holyrood		136.7		136.7	Other
Upgrade Underground Plant Drainage System - Holyrood		112.6		112.6	Other
Replace Excavator Unit 7833 - St. Anthony		110.0		110.0	Other
Raise Height of Earth Dam - Paradise River		98.7		98.7	Other
Overhaul Cooling Water Pump East Unit 1- Holyrood		98.4		98.4	Other
Overhaul Extraction Pump South Unit 1 - Holyrood		96.8		96.8	Other
Replace Network Communications Equipment - Various Sites		91.0		91.0	Other
Perform Minor Application Enhancements - Hydro Place		87.3		87.3	Other
Replace Wescom Scanner - Corner Brook		81.7		81.7	Other
Replace Engine on Emergency Lift System - West Salmon Spillway		67.1		67.1	Other
Purchase Portable Vibration Testing Equipment - Various Sites		60.6		60.6	Other
TOTAL NORMAL PROJECTS	156.2	3,595.3	317.9	4,069.4	
JUSTIFIABLE PROJECTS					
Install Automated Fuel Monitoring System at West Salmon Spillway - Bay d'Espoir		193.2		193.2	Other
TOTAL JUSTIFIABLE PROJECTS		193.2		193.2	

Type	Number	($000)
Clustered	0	0.0
Pooled	19	55,117.9
Other	77	78,352.8
Total	**96**	**133,470.7**

* *Includes multi-year projects but excludes contingency fund*

2014 LEASING COSTS

THERE ARE NO ITEMS FOR THIS SECTION

	ACTUALS				BUDGET					
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
GENERATION	9,592	16,337	13,131	24,297	64,392	73,649	72,582	23,972	14,672	13,434
TRANSMISSION AND RURAL OPERATIONS	32,988	28,681	41,251	45,705	43,183	70,998	127,421	128,918	117,630	119,267
GENERAL PROPERTIES	11,572	10,535	8,734	7,250	8,127	6,802	9,006	11,311	12,252	7,740
TOTAL CAPITAL EXPENDITURES	54,152	55,553	63,116	77,252	115,702	151,449	209,008	164,201	144,555	140,441

2013 Capital Budget Variance Overview ($000)

	Board Approved Budget	Total Expend.	Variance
HYDRAULIC PLANT	22,767	23,282	515
THERMAL PLANT	19,442	21,353	1,910
GAS TURBINES	7,745	6,390	(1,355)
TERMINAL STATIONS	31,021	35,071	4,050
TRANSMISSION	3,954	3,954	-
DISTRIBUTION	32,509	32,330	(179)
GENERATION	15,443	15,729	287
PROPERTIES	1,074	1,074	-
METERING	1,627	1,781	154
RURAL SYSTEMS TOOLS AND EQUIPMENT	3,369	3,363	(6)
INFORMATION SYSTEMS	3,656	3,656	-
TELECONTROL	2,777	2,777	-
TRANSPORTATION	4,912	4,912	-
ADMINISTRATIVE	340	340	-
ALLOWANCE FOR UNFORESEEN	1,000	1,000	-
PROJECTS APPROVED BY PU BOARD	52,451	53,248	797
PROJECTS APPROVED FOR LESS THAN $50,000	61	61	-
TOTAL CAPITAL BUDGET	204,147	210,318	6,172

2013 Capital Expenditures By Year
($000)

Summary	Capital Budget[1]							Actual Expenditure and Forecast								
	2009	2010	2011	2012	2013	2014 and Beyond	Total	2009	2010	2011 [2]	2012	Actual YTD 2013	Forecast July-Dec 2013	2014 and Beyond	Total	Variance
2013 Projects	-	-	-	-	81,945.7	42,422.0	124,367.7	-	-	-	231.9	19,096.8	62,764.4	42,422.0	124,515.1	147.4
2012 Projects	-	-	-	19,915.4	9,111.9	-	29,027.3	-	-	-	11,309.4	8,768.8	8,555.9	-	28,634.1	(393.2)
2011 Projects	-	-	4,671.7	6,646.0	3,577.4	2,027.4	16,922.5	-	-	2,706.4	5,976.2	1,651.8	8,662.6	2,027.4	21,024.4	4,101.9
2010 Projects	-	2,540.6	6,836.8	10,235.7	1,566.1	-	21,179.2	-	2,453.0	6,431.3	6,489.2	2,426.9	2,623.4	-	20,423.8	(755.4)
2009 Projects	100.8	1,693.5	7,105.7	3,750.0	-	-	12,650.0	291.8	1,693.5	6,022.7	7,320.1	1,401.3	(1,008.4)	-	15,721.0	3,071.0
Grand Total	100.8	4,234.1	18,614.2	40,547.1	96,201.1	44,449.4	204,146.7	291.8	4,146.5	15,160.4	31,326.8	33,345.6	81,597.9	44,449.4	210,318.4	6,171.7

2013 Capital Budget Approved by Board Order No. P.U. 4 (2013)	62,272.5
New Project Approved by Board Order No. 25 (2012)	2,252.1
New Project Approved by Board Order No. 26 (2012)	1,295.0
New Project Approved by Board Order No. 35 (2012)	189.5
New Project Approved by Board Order No. 1 (2013)	284.1
New Project Approved by Board Order No. 12 (2013)	5,198.2
New Project Approved by Board Order No. 14 (2013)	12,809.7
New Project Approved by Board Order No. 15 (2013)	3,823.6
New Project Approved by Board Order No. 20 (2013)	8,015.8
2013 New Projects under $50,000 Approved by Hydro	60.6
Total Approved Capital Budget Before Carryovers	96,201.1
Carryovers from 2012 to 2013	19,500.8
TOTAL APPROVED CAPITAL BUDGET	115,701.9

[1] Annual budgets previous to 2013 pertain to projects that have expenditures in 2013.

[2] There has been a restatement of expenditures in 2011 resulting from the conversion to new accounting standards.

2013 Capital Expenditures By Category
($000)

Hydraulic Plant	Capital Budget					Actual Expenditure and Forecast							
	2011	2012	2013	2014 and Beyond	Total	2011	2012	Actual YTD 2013	Forecast July-Dec 2013	2014 and Beyond	Total	Variance	Notes
2013 Projects													
Replace Automatic Transfer Switches - Hinds Lake	-	-	314.7	-	314.7	-	-	13.3	301.4	-	314.7	-	
Install Automatic Fuel Monitoring System - Upper Salmon	-	-	192.7	-	192.7	-	1.9	12.8	178.0	-	192.7	-	
Replace Emergency Diesel Fuel Tank - Paradise River	-	-	46.3	-	46.3	-	-	5.0	41.3	-	46.3	-	
Replace Stator Windings Units 1, 3 and 4 - Bay d'Espoir	-	-	5,663.5	-	5,663.5	-	8.8	1,771.1	3,883.6	-	5,663.5	-	
Automate Generator Deluge Systems - Bay d'Espoir	-	-	532.0	-	532.0	-	3.9	39.8	488.3	-	532.0	-	
Upgrade Units 1 to 6 By-Pass Valves - Bay d'Espoir	-	-	141.9	-	141.9	-	3.0	1.2	137.7	-	141.9	-	
Upgrade Generator Bearings - Bay d'Espoir	-	-	480.9	-	480.9	-	5.3	11.6	464.0	-	480.9	-	
Upgrade Burnt Dam Spillway - Bay d'Espoir	-	-	885.8	-	885.8	-	15.0	39.5	831.3	-	885.8	-	
Purchase Low Pressure Screw Compressor Set - Bay d'Espoir	-	-	97.3	-	97.3	-	3.3	47.6	46.4	-	97.3	-	
Upgrade Public Safety Around Dams and Waterways - Bay D'Espoir	-	-	298.1	-	298.1	-	3.4	21.0	273.7	-	298.1	-	
Replace Fall Arrest System on Surge Tank 1 and 2 - Bay d'Espoir	-	-	153.0	-	153.0	-	3.1	5.6	144.3	-	153.0	-	
Replace Cooling Water Pumps - Bay d'Espoir	-	-	175.4	-	175.4	-	2.0	8.0	165.4	-	175.4	-	
Replace North End Equipment Door - Bay d'Espoir	-	-	265.5	-	265.5	-	-	6.9	258.6	-	265.5	-	
Install Waste Oil Storage Tank for PCB's - Bay d'Espoir	-	-	48.9	-	48.9	-	-	9.1	39.8	-	48.9	-	
Replace Units 1 to 6 Auto Greasing Systems - Bay d'Espoir	-	-	260.1	-	260.1	-	-	8.4	251.7	-	260.1	-	
Upgrade Water Flow Control Structure RR Pond - Granite Canal	-	-	43.5	-	43.5	-	3.6	5.0	34.9	-	43.5	-	
Replace MicroSCADA Computers - Granite Canal	-	-	297.4	-	297.4	-	6.1	23.5	267.8	-	297.4	-	
Overhaul Turbine/Generator Units - Cat Arm and Bay D'Espoir	-	-	428.1	-	428.1	-	-	0.4	427.7	-	428.1	-	
Purchase Tools and Equipment Less than $50,000	-	-	82.8	-	82.8	-	-	19.2	63.6	-	82.8	-	
2012 Projects													
Rewind Stators Unit 4 - Bay d'Espoir	-	4,953.8	-	-	4,953.8	-	2,548.7	1,540.6	(37.1)	-	4,052.2	(901.6)	1
Replace Emergency Diesel Generator - Bay d'Espoir	-	611.4	282.7	-	894.1	-	80.0	165.5	648.6	-	894.1	-	
Upgrade Burnt Dam Spillway - Bay d'Espoir	-	523.8	-	-	523.8	-	168.9	293.5	880.2	-	1,342.6	818.8	2
2011 Projects													
Replace Static Excitation Systems - Upper Salmon, Holyrood and Hinds Lake[3]	16.8	1,797.1	2,295.2	-	4,109.1	16.8	818.8	465.2	2,808.3	-	4,109.1	-	
Upgrade Generating Station Service Water System - Cat Arm	360.4	440.0	-	-	800.4	349.3	259.6	95.8	95.7	-	800.4	-	
Upgrade Burnt Dam Spillway Structure - Bay d'Espoir	257.9	-	-	-	257.9	154.8	70.2	36.6	192.2	-	453.8	195.9	3
Upgrade Intake Gate Controls - Bay d'Espoir	352.3	468.0	-	-	820.3	507.0	373.6	44.9	296.3	-	1,221.8	401.5	4
Total Hydraulic Plant	987.4	8,794.1	12,985.8	-	22,767.3	1,027.9	4,379.2	4,691.1	13,183.7	-	23,281.9	514.6	

[3] Original budget was $4,109.1 (2010 - $1,214.3, 2011 - $1,528.0, 2012 - $1,366.8) Approved by Order No. P.U. 38 (2010). The revised budget was approved by Order No. P.U. 2 (2012). The second revised budget was approved by Order No. P.U. 4 (2013)

2013 Capital Expenditures By Category
($000)

Thermal Plant	Capital Budget 2010	Capital Budget 2011	Capital Budget 2012	Capital Budget 2013	Capital Budget 2014 and Beyond	Capital Budget Total	Actual 2010	Actual 2011	Actual 2012	Actual YTD 2013	Forecast July-Dec 2013	2014 and Beyond	Total	Variance	Notes
2013 Projects															
Complete Condition Assessment Phase 2 (Year 2) - Holyrood	-	-	-	1,170.2	-	1,170.2	-	-	5.0	349.4	815.8	-	1,170.2	-	
Overhaul Turbine Valves - Holyrood	-	-	-	993.9	-	993.9	-	-	-	657.3	336.6	-	993.9	-	
Overhaul Boiler Feed Pumps - Holyrood	-	-	-	178.5	-	178.5	-	-	-	-	178.5	-	178.5	-	
Overhaul Extraction Pumps - Holyrood	-	-	-	101.5	-	101.5	-	-	-	-	101.5	-	101.5	-	
Upgrade Fuel Oil Day Tank - Holyrood	-	-	-	584.2	-	584.2	-	-	11.5	21.4	551.3	-	584.2	-	
Install Variable Frequency Drives on Forced Draft Fans - Holyrood	-	-	-	697.6	2,659.7	3,357.3	-	-	13.8	-	683.8	2,659.7	3,357.3	-	
Replace Condensate Polisher Annunciator Panels - Holyrood	-	-	-	123.5	-	123.5	-	-	0.3	1.4	121.8	-	123.5	-	
Install Backup System for Raw Water Supply and Clarifier - Holyrood	-	-	-	955.6	-	955.6	-	-	2.4	96.4	856.8	-	955.6	-	
Purchase Tools and Equipment Less than $ 50,000	-	-	-	10.5	-	10.5	-	-	-	-	10.5	-	10.5	-	
2012 Projects															
Refurbish Fuel Storage Facility - Holyrood	-	-	2,641.2	-	-	2,641.2	-	-	1,767.1	894.7	(20.6)	-	2,641.2	-	
Upgrade Forced Draft Fan Ductwork Unit 2 - Holyrood	-	-	928.6	-	-	928.6	-	-	102.4	(102.4)	-	-	-	(928.6)	5
Replace Fuel Oil Heat Tracing - Holyrood	-	-	1,474.3	1,413.9	-	2,888.2	-	-	783.4	307.8	1,797.0	-	2,888.2	-	
Condition Assessment and Life Extension Phase 2 - Holyrood	-	-	1,215.7	-		1,215.7	-	-	565.2	151.8	498.7	-	1,215.7	-	
2011 Projects															
Replace Relay Panels Unit 3 - Holyrood	-	277.1	553.6	-	-	830.7	-	134.2	121.5	400.4	1,049.0	-	1,705.1	874.4	6
Upgrade Electrical Equipment - Holyrood[3]	-	179.6	30.0	212.1	-	421.7	-	179.6	41.9	15.3	184.9	-	421.7	-	
Upgrade Hydrogen System - Holyrood	-	1,191.9	800.4	-	-	1,992.3	-	270.5	1,194.5	246.4	1,776.4	-	3,487.8	1,495.5	7
2010 Projects															
Replace Pumphouse Motor Control Centres - Holyrood	50.2	998.6	-	-	-	1,048.8	99.5	1,070.2	285.7	44.3	17.9	-	1,517.6	468.8	8
Total Thermal Plant	50.2	2,647.2	7,643.8	6,441.5	2,659.7	19,442.4	99.5	1,654.5	4,894.7	3,084.2	8,959.9	2,659.7	21,352.5	1,910.1	

3 Original budget was $678.8 (2011 - $188.0, 2012 - $206.3, 2013 - $284.5) Approved by Order No. P.U. 38(2010). The revised Budget was approved by Order No. P.U. 4 (2013).

2013 Capital Expenditures By Category
($000)

Gas Turbines	Capital Budget						Actual Expenditure and Forecast								
	2010	2011	2012	2013	2014 and Beyond	Total	2010	2011	2012	Actual YTD 2013	Forecast July-Dec 2013	2014 and Beyond	Total	Variance	Notes
2013 Projects															
Upgrade Gas Turbine PLC - Happy Valley	-	-	-	61.4	1,128.6	1,190.0	-	-	2.3	1.6	57.5	1,128.6	1,190.0	-	
2010 Projects															
Upgrade Glycol Systems - Stephenville	261.3	298.9	-	-	-	560.2	3.3	517.9	113.2	585.1	(42.0)	-	1,177.5	617.3	9
Upgrade Gas Turbine Plant Life Extension - Hardwoods[4]	704.5	1,009.8	4,280.4	-	-	5,994.7	704.5	1,168.9	505.7	645.4	998.2	-	4,022.7	(1,972.0)	10
Total Gas Turbines	965.8	1,308.7	4,280.4	61.4	1,128.6	7,744.9	707.8	1,686.8	621.2	1,232.1	1,013.7	1,128.6	6,390.2	(1,354.7)	

[4] Original budget was $5,994.7 (2010 - $1,304.5, 2011 - $1,323.6, 2012 - $3,366.6) Approved by Order No. P.U. 1 (2010). The revised Budget was approved by Order No. P.U. 2 (2012).

2013 Capital Expenditures By Category
($000)

Terminal Stations	Capital Budget 2009	2010	2011	2012	2013	2014 and Beyond	Total	Actual Expenditure and Forecast 2009	2010	2011	2012	Actual YTD 2013	Forecast July-Dec 2013	2014 and Beyond	Total	Variance	Notes
2013 Projects																	
Upgrade Circuit Breakers - Various Sites	-	-	-	-	2785.3	-	2,785.3	-	-	-	12.2	522.2	2,250.9	-	2,785.3	-	
Replace Surge Arrestors - Various Sites	-	-	-	-	121.3	-	121.3	-	-	-	3.4	-	117.9	-	121.3	-	
Replace Instrument Transformers - Various Sites	-	-	-	-	593.2	3,074.8	3,668.0	-	-	-	9.6	9.9	573.7	3,074.8	3,668.0	-	
Upgrade Power Transformers - Various Sites	-	-	-	-	1621.1	-	1,621.1	-	-	-	7.5	12.4	1,601.2	-	1,621.1	-	
Replace Disconnects - Various Sites	-	-	-	-	492.6	-	492.6	-	-	-	14.5	63.0	415.1	-	492.6	-	
Replace Insulators - Various Sites	-	-	-	-	187.1	287.9	475.0	-	-	-	5.1	35.2	146.8	287.9	475.0	-	
Replace Optimho Relays on TL242 - Holyrood to Hardwoods	-	-	-	-	189.2	-	189.2	-	-	-	2.3	4.4	182.5	-	189.2	-	
Install Online Vibration Monitoring System																	
- Corner Brook Frequency Converter	-	-	-	-	382.8	-	382.8	-	-	-	4.6	-	378.2	-	382.8	-	
Install Transformer Fans - Conne River	-	-	-	-	114.9	-	114.9	-	-	-	-	4.1	110.8	-	114.9	-	
Replace 230 kV Breaker Controls - Bottom Brook	-	-	-	-	68.9	-	68.9	-	-	-	-	10.4	58.5	-	68.9	-	
Upgrade Terminal Station - Wiltondale	-	-	-	-	697.7	1,173.3	1,871.0	-	-	-	10.7	13.0	674.0	1,173.3	1,871.0	-	
Replace Compressed Air System - Various Sites	-	-	-	-	303.0	2,105.9	2,408.9	-	-	-	17.2	-	285.8	2,105.9	2,408.9	-	
2012 Projects																	
Replace Compressed Air Piping and Install Dew Point Monitor - Buchans	-	-	-	28.4	278.3	-	306.7	-	-	-	-	32.8	273.9	-	306.7	-	
2011 Projects																	
Perform Grounding Upgrades - Various Sites	-	-	321.2	324.0	329.0	682.5	1,656.7	-	-	287.6	240.7	73.8	372.1	682.5	1,656.7	-	
Replace Compressed Air System - Bay d'Espoir	-	-	83.9	563.6	-	-	647.5	-	-	83.7	1,084.2	53.2	83.7	-	1,304.8	657.3	11
Install Alternate Station Services - Stony Brook and Massey Drive	-	-	86.0	109.2	-	-	195.2	-	-	5.5	155.7	16.0	18.0	-	195.2	-	
Replace Compressor, Dryer and Air Piping Header System -																	
Corner Brook Frequency Converter Station	-	-	280.2	-	-	-	280.2	-	-	141.8	139.2	13.4	108.7	-	403.1	122.9	12
Upgrade Substation - Wabush	-	-	459.3	626.4	-	-	1,085.7	-	-	13.8	907.6	77.5	285.1	-	1,284.0	198.3	13
2009 Projects																	
Upgrade Terminal Stations to 25 kV - Labrador City[5]	100.8	1,693.5	7,105.7	3,750.0	-	-	12,650.0	291.8	1,693.5	6,022.7	7,320.1	1,401.3	(1,008.4)	-	15,721.0	3,071.0	14
Total Terminal Stations	100.8	1,693.5	8,336.3	5,401.6	8,164.4	7,324.4	31,021.0	291.8	1,693.5	6,555.1	9,934.6	2,342.6	6,928.5	7,324.4	35,070.5	4,049.5	

[5] Original budget was $9,990.6 (2009 - $283.2, 2010 - $3,894.8, 2011 - $5,812.6) Approved by Order No. P.U. 36 (2008). The revised Budget was approved by Order No. P.U. 2 (2012).

2013 Capital Expenditures By Category
($000)

Transmission	Capital Budget 2011	Capital Budget 2012	Capital Budget 2013	Capital Budget 2014 and Beyond	Capital Budget Total	Actual 2011	Actual 2012	Actual YTD 2013	Forecast July-Dec 2013	Forecast 2014 and Beyond	Total	Variance	Notes
<u>2013 Projects</u>													
Perform Wood Pole Line Management Program - Various Sites	-	-	2466.7	-	2,466.7	-	-	565.1	1,901.6	-	2,466.7	-	
<u>2011 Projects</u>													
Replace Guy Wires TL-215 - Doyles to Grand Bay	288.8	318.0	350.1	530.0	1,486.9	447.6	256.0	81.8	171.5	530.0	1,486.9	-	
Total Transmission	288.8	318.0	2,816.8	530.0	3,953.6	447.6	256.0	646.9	2,073.1	530.0	3,953.6	-	

2013 Capital Expenditures By Category
($000)

Distribution	Capital Budget						Actual Expenditure and Forecast								
	2010	2011	2012	2013	2014 and Beyond	Total	2010	2011	2012	Actual YTD 2013	Forecast July-Dec 2013	2014 and Beyond	Total	Variance	Notes
2013 Projects															
Replace Recloser Control Panels - Various Sites	-	-	-	209.7	-	209.7	-	-	5.4	32.1	172.2	-	209.7	-	
Provide Service Extensions - All Service Areas	-	-	-	5,006.0	-	5,006.0	-	-	-	2,237.2	2,768.8	-	5,006.0	-	
Upgrade Distribution Systems - All Service Areas	-	-	-	2,790.0	-	2,790.0	-	-	-	1089.1	1700.9	-	2,790.0	-	
Additions for Load - Distribution Systems - Various Sites	-	-	-	3,114.7	-	3,114.7	-	-	-	1527.5	1587.2	-	3,114.7	-	
Upgrade Distribution Systems - Various Sites	-	-	-	1,940.1	3,995.5	5,935.6	-	-	-	807.5	1132.6	3,995.5	5,935.6	-	
2012 Projects															
Upgrade Distribution Lines - Bay d'Espoir, Parsons Pond and Plum Point	-	-	1,385.2	1,110.5	-	2,495.7	-	-	1,189.1	450.6	677.1	-	2,316.8	(178.9)	
2010 Projects															
Voltage Conversion - Labrador City	1,088.9	3,501.2	3,840.7	969.5	-	9,400.3	1,524.6	2,825.0	4,120.6	685.1	245.0	-	9,400.3	-	
Upgrade L2 Distribution Feeder - Glenburnie	267.3	578.2	2,114.6	596.6	-	3,556.7	109.9	402.4	1,382.7	492.0	1,169.7	-	3,556.7	-	
Total Distribution	1,356.2	4,079.4	7,340.5	15,737.1	3,995.5	32,508.7	1,634.5	3,227.4	6,697.8	7,321.1	9,453.5	3,995.5	32,329.8	(178.9)	

2013 Capital Expenditures By Category
($000)

Generation	Capital Budget						Actual Expenditure and Forecast								
	2010	2011	2012	2013	2014 and Beyond	Total	2010	2011	2012	Actual YTD 2013	Forecast July-Dec 2013	2014 and Beyond	Total	Variance	Notes
2013 Projects															
Overhaul Diesel Units - Various Sites	-	-	-	977.8	-	977.8	-	-	-	491.1	486.7	-	977.8	-	
Additions for Load Isolater Generation Stations-Various Sites	-	-	-	2,040.2	9,357.9	11,398.1	-	-	27.8	74.4	1,938.0	9,357.9	11,398.1	-	
2012 Projects															
Perform FEED for Diesel Plant Remediation - Various Sites	-	-	110.4	-	-	110.4	-	-	43.6	65.4	1.4	-	110.4	-	
2011 Projects															
Perform Arc Flash Remediation - Various Sites	-	429.5	380.3	391.0	814.9	2,015.7	-	103.5	91.7	19.7	985.9	814.9	2,015.7	-	
Replace Mini Hydro Turbine - Roddickton	-	86.8	235.4	-	-	322.2	-	10.7	221.0	11.8	234.8	-	478.3	156.1	15
2010 Projects															
Replace Diesel Unit 2001 and Engine 566 - Francois	168.4	450.1	-	-	-	618.5	11.2	446.9	81.3	(25.0)	234.6	-	749.0	130.5	16
Total Generation	168.4	966.4	726.1	3,409.0	10,172.8	15,442.7	11.2	561.1	465.4	637.4	3,881.4	10,172.8	15,729.3	286.6	

2013 Capital Expenditures By Category
($000)

Properties	Capital Budget					Actual Expenditure and Forecast							
	2011	2012	2013	2014 and Beyond	Total	2011	2012	Actual YTD 2013	Forecast July-Dec 2013	to 2014	Total	Variance	Notes
2013 Projects													
Install Automatic Fire Sprinkler System - Bay d'Espoir	-	-	429.9	-	429.9	-	-	10.3	419.6	-	429.9	-	
Install Fall Protection Equipment - Various Sites	-	-	196.6	-	196.6	-	-	0.9	195.7	-	196.6	-	
Install Additional Washrooms - Various Sites	-	-	250.9	-	250.9	-	-	-	250.9	-	250.9	-	
Legal Survey of Primary Distribution Line Right of Ways - Various Sites 2013	-	-	156.2	40.0	196.2	-	-	-	156.2	40.0	196.2	-	
										-			
Total Properties	-	-	1,033.6	40.0	1,073.6	-	-	11.2	1,022.4	40.0	1,073.6	-	

2013 Capital Expenditures By Category
($000)

Metering	Capital Budget 2011	2012	2013	2014 and Beyond	Total	Actual Expenditure and Forecast 2011	2012	Actual YTD 2013	Forecast July-Dec 2013	2014 and Beyond	Total	Variance	Notes
2013 Projects													
Purchase Meters, Equipment and Metering Tanks - Various Sites	-	-	199.5	-	199.5	-	-	60.2	139.3	-	199.5	-	
Purchase 10 Position Meter Calibration Test Console - Hydro Place	-	-	192.5	-	192.5	-	-	-	192.5	-	192.5	-	
Install Automatic Meter Reading - Glenburnie and Rocky Harbour	-	-	397.9	258.8	656.7	-	-	152.0	399.6	258.8	810.4	153.7	17
2012 Projects													
Install Automatic Meter Reading - Various Sites	-	290.4	287.7	-	578.1	-	309.7	214.3	54.1	-	578.1	-	
Total Metering	0.0	290.4	1,077.6	258.8	1,626.8	0.0	309.7	426.5	785.5	258.8	1,780.5	153.7	

2013 Capital Expenditures By Category
($000)

Tools and Equipment	Capital Budget					Actual Expenditure and Forecast							
	2011	2012	2013	2014 and Beyond	Total	2011	2012	Actual YTD 2013	Forecast July-Dec 2013	2014 and Beyond	Total	Variance	Notes
2013 Projects													
Replace Off Road Track Vehicles													
- Whitbourne, Port Saunders and Happy Valley	-	-	416.8	1,054.1	1,470.9	-	-	-	416.8	1,054.1	1,470.9	-	
Replace Light Duty Mobile Equipment - Various Sites	-	-	476.5	-	476.5	-	-	50.8	425.7	-	476.5	-	
Tools and Equipment Less than $50,000	-	-	525.3	-	525.3	-	-	133.3	385.7	-	519.0	(6.3)	
2012 Projects													
Replace Off Road Track Vehicles - Flowers Cove and Cow Head	-	482.5	395.6	-	878.1	-	-	-	878.1	-	878.1	-	
Tools and Equipment Less than $50,000	-	18.3	-	-	18.3	-	-	-	18.3	-	18.3	-	
Total Tools and Equipment	0.0	500.8	1,814.2	1,054.1	3,369.1	-	-	184.1	2,124.6	1,054.1	3,362.8	(6.3)	

2013 Capital Expenditures By Category
($000)

Information Systems	Capital Budget 2010	2011	2012	2013	2014 and Beyond	Total	Actual Expenditure and Forecast 2010	2011	2012	Actual YTD 2013	Forecast July-Dec 2013	2014 and Beyond	Total	Variance	Notes
<u>2013 Projects</u>															
Perform Minor Application Enhancements - Hydro Place	-	-	-	126.8	-	126.8	-	-	-	14.1	112.7	-	126.8	-	
Cost Recoveries	-	-	-	(45.7)	-	(45.7)	-	-	-	(5.1)	(40.6)	-	(45.7)	-	
Upgrade Energy Management System - Hydro Place	-	-	-	129.9	-	129.9	-	-	-	0.8	129.1	-	129.9	-	
Upgrade Microsoft Project - Hydro Place	-	-	-	656.7	920.3	1,577.0	-	-	-	513.0	143.7	920.3	1,577.0	-	
Cost Recoveries	-	-	-	(236.4)	(331.3)	(567.7)	-	-	-	(184.7)	(51.7)	(331.3)	(567.7)	-	
Upgrade Business Intelligence Software - Hydro Place	-	-	-	576.9	-	576.9	-	-	-	169.5	407.4	-	576.9	-	
Cost Recoveries	-	-	-	(207.7)	-	(207.7)	-	-	-	(61.0)	(146.7)	-	(207.7)	-	
Replace Personal Computers - Various Sites	-	-	-	463.9	-	463.9	-	-	-	324.4	139.5	-	463.9	-	
Replace Peripheral Infrastructure - Various Sites	-	-	-	309.9	-	309.9	-	-	-	65.2	244.7	-	309.9	-	
Upgrade Enterprise Storage Capacity - Hydro Place	-	-	-	194.9	-	194.9	-	-	-	38.5	156.4	-	194.9	-	
Cost Recoveries	-	-	-	(70.2)	-	(70.2)	-	-	-	(13.9)	(56.3)	-	(70.2)	-	
Upgrade Server Technology Program - Hydro Place	-	-	-	499.4	-	499.4	-	-	-	268.7	230.7	-	499.4	-	
Cost Recoveries	-	-	-	(131.8)	-	(131.8)	-	-	-	(70.9)	(60.9)	-	(131.8)	-	
Upgrade Computer Room Air Conditioner - Hydro Place	-	-	-	130.0	-	130.0	-	-	-	8.0	122.0	-	130.0	-	
Cost Recoveries	-	-	-	(46.8)	-	(46.8)	-	-	-	(2.9)	(43.9)	-	(46.8)	-	
Replace Helpdesk Service Manager Application - Hydro Place	-	-	-	96.5	-	96.5	-	-	-	0.0	96.5	-	96.5	-	
Cost Recoveries	-	-	-	(34.7)	-	(34.7)	-	-	-	0.0	(34.7)	-	(34.7)	-	
<u>2012 Projects</u>															
Upgrade JD Edwards - Hydro Place	-	-	284.0	587.6	-	871.6	-	-	518.3	439.4	(86.1)	-	871.6	-	
Cost Recoveries	-	-	(96.6)	(199.8)	-	(296.4)	-	-	(176.2)	(149.4)	29.2	-	(296.4)	-	
Upgrade Computer Room - Hydro Place	-	-	122.0	-	-	122.0	-	-	9.3	10.5	102.2	-	122.0	-	
Cost Recoveries	-	-	(41.5)	-	-	(41.5)	-	-	(3.2)	(3.6)	(34.7)	-	(41.5)	-	
Total Information Systems	-	-	267.9	2,799.4	589.0	3,656.3	-	-	348.2	1,360.6	1,358.5	589.0	3,656.3	-	

2013 Capital Expenditures By Category
($000)

Telecontrol	2013	2014 and Beyond	Total	2012	Actual YTD 2013	Forecast July-Dec 2013	2014 and Beyond	Total	Variance	Notes
2013 Projects										
Replace MDR 4000 Microwave Radio (West) - Various Sites	539.0	706.9	1,245.9	2.9	42.0	494.1	706.9	1,245.9	-	
Replace Radomes - Various Sites	336.0	-	336.0	2.6	167.3	166.1	-	336.0	-	
Replace Battery Banks and Chargers - Various Sites	782.0	-	782.0	3.8	90.0	688.2	-	782.0	-	
Replace Network Communications Equipment - Various Sites	182.4	-	182.4	2.4	151.1	28.9	-	182.4	-	
Replace Telephone Systems - Various Sites	135.4	-	135.4	2.4	78.2	54.8	-	135.4	-	
Upgrade Site Facilities - Various Sites	49.8	-	49.8	-	5.7	44.1	-	49.8	-	
Purchase Tools and Equipment less than $50,000	45.6	-	45.6	-	4.1	41.5	-	45.6	-	
Total Telecontrol	2,070.2	706.9	2,777.1	14.1	538.4	1,517.7	706.9	2,777.1	-	

2013 Capital Expenditures By Category
($000)

Transportation	2012	2013	2014 and Beyond	Total	2012	Actual YTD 2013	Forecast July-Dec 2013	2014 and Beyond	Total	Variance	Notes
2013 Projects											
Replace Vehicles and Aerial Devices (2013-2014) - Various Sites	-	1302.3	679.2	1,981.5	-	354.8	947.5	679.2	1,981.5	-	
2012 Projects											
Replace Vehicles and Aerial Devices (2012-2013) - Various Sites	1,711.4	1,218.8	-	2,930.2	1,594.1	107.4	1,228.7	-	2,930.2	-	
Total Transportation	1,711.4	2,521.1	679.2	4,911.7	1,594.1	462.2	2,176.2	679.2	4,911.7	-	

Administration	2012	2013	2014 and Beyond	Total	2012	2013	2013 Remain	2014 and Beyond	Total	Variance	Notes
2013 Projects											
Remove Safety Hazards - Various Sites	-	250.5	-	250.5	2.8	-	247.7	-	250.5	-	
Purchase Tools and Equipment Less than $50,000	-	89.9	-	89.9	-	0.8	89.1	-	89.9	-	
Total Administation	-	340.4	-	340.4	2.8	0.8	336.8	-	340.4	-	

2013 Capital Expenditures By Category
($000)

Allowance For Unforeseen	Capital Budget					Actual Expenditure and Forecast							
	2011	2012	2013	2014 and Beyond	Total	2011	2012	Actual YTD 2013	Forecast July-Dec 2013	2014 and Beyond	Total	Variance	Notes
2013 Projects													
	-	-	1,000.0	-	1,000.0	-	-	-	599.5	-	599.5	(400.5)	
Refurbish 230 kV Breakers - Holyrood and Buchans	-	-	-	-	-	-	-	207.0	-	-	207.0	207.0	
Black Tickle Plant Rehabiliation	-	-	-	-	-	-	-	193.5	-	-	193.5	193.5	
Total Allowance For Unforeseen	-	-	1,000.0	-	1,000.0		-	400.5	599.5	-	1,000.0	0.0	

Unbudgeted Projects Approved by PUB	Capital Budget					Actual Expenditure and Forecast							
	2011	2012	2013	2014 and Beyond	Total	2011	2012	2013	2013 Remain	2014 and Beyond	Total	Variance	Notes
2013 Projects													
Refurbish Stoplogs - Burnt Dam Spillway	-	-	284.1	-	284.1	-	-	-	284.1	-	284.1	-	
Refurbish Marine Terminal - Holyrood	-	-	5,198.2	-	5,198.2	-	-	163.7	5,034.5	-	5,198.2	-	
Restore Unit 1 - Holyrood	-	-	12,809.7	-	12,809.7	-	-	5,419.3	7,390.4	-	12,809.7	-	
Increase 230 kV Transformer Capacity - Oxen Pond	-	-	3,823.6	15,310.4	19,134.0	-	-	-	3,823.6	15,310.4	19,134.0	-	
Replace Alternator - Hardwoods	-	-	8,015.8	-	8,015.8	-	-	4.4	8,011.4	-	8,015.8	-	
2012 Projects													
Increase Generation - Mary's Harbour	-	321.4	1,295.0	-	1,616.4	-	51.0	152.8	1,412.6	-	1,616.4	-	
Rewind Gas Turbine Alternator - Stephenville	-	2,940.5	2,252.1	-	5,192.6	-	1,758.0	4,197.1	34.6	-	5,989.7	797.1	18
Replace Penthouse Roof - Hydro Place	-	10.2	189.5	-	199.7	-	-	-	199.7	-	199.7	-	
Total Unbudgeted Projects Approved by PUB	-	3,272.1	33,868.0	15,310.4	52,450.5		1,809.0	9,937.3	26,190.9	15,310.4	53,247.6	797.1	

Projects Less than $50,000 Approved by Hydro	Capital Budget					Actual Expenditure and Forecast							
	2011	2012	2013	2014 and Beyond	Total	2011	2012	2013	2013 Remain	2014 and Beyond	Total	Variance	Notes
2013 Projects													
Replace Loggers - Hydrometric Stations	-	-	41.9		41.9	-	-	43.0	-1.1	-	41.9	-	
Replace Structure - TL259	-	-	18.7		18.7	-	-	25.6	-6.9	-	18.7	-	
Total Projects Less than $50,000 Approved by Hydro	0.0	0.0	60.6	0.0	60.6	-	0.0	68.6	(8.0)	0.0	60.6	0.0	

1. **<u>Rewind Stators Unit 4 – Bay d'Espoir</u>**

Budget: $4,953.8 **Total: $4,052.2** **Variance: ($901.6)**

This is a one year project that was carried over into 2013. The budget decrease is due to lower than estimated construction labour and material costs. These cost savings resulted in less interest cost and no contingency funds being utilized. This project is now complete.

2. **<u>Upgrade Burnt Dam Spillway - Bay d'Espoir</u>**

Budget: $523.8 **Total: $1,342.6** **Variance: $818.8**

This is a one-year project which has been carried over into 2013. There is a budget increase of $270,000 due to the difference between the budgeted and actual tendered costs for the disassembly and inspection contract and the consultant design cost. An additional $550,000 is required to complete the approved scope of work. Specifically, additional funds are required for internal costs including labour, material, travel, interest and contingency not originally approved as part of this project. The project was carried over into 2013 as a result of having to reapply for a project to refurbish the stop logs to allow for the approved inspections to be completed safely.

3. **<u>Upgrade Burnt Dam Spillway Structure- Bay d'Espoir</u>**

Budget: $257.9 **Total: $453.8** **Variance: $195.9**

This is a one-year project initiated in 2011 that was carried over into 2012 and 2013. The budget increase is due to the use of external resources to design and oversee project execution. In addition, contract pricing obtained through competitive bid process was higher than estimated. The internal review and approval of the budget variances resulted in delayed tender award for the execution of the work. This project will be completed in 2013.

4. **<u>Upgrade Intake Gate Controls - Bay d'Espoir</u>**

Budget: $820.3 **Total: $1,221.8** **Variance: $401.5**

This is a two-year project initiated in 2011. The scope of this project remains unchanged however the timing and the complexity of the work resulted in increased labour costs. The work planned for 2011 was completed; however the work to be completed in 2012 has been delayed until at least 2013 due to system constraints which prevented a suitable outage window to complete the work.

5. Upgrade Forced Draft Fan Ductwork Unit 2 – Holyrood

Budget: $928.6 Total: $0.0 Variance: ($928.6)

This project has been cancelled. A component of the original project justification was based on a cost benefit analysis. With the updated long-term plan for Holyrood, an updated cost benefit analysis was completed. Unit 2 will no longer be required to operate after 2017 as a generator, resulting in a reduced study period. In addition, the forecasted pricing of No. 6 fuel oil is lower than that used in the original cost benefit analysis. As a result, it is no longer economically feasible to complete the project.

6. Replace Relay Panels Unit 3 – Holyrood

Budget: $830.7 Total: $1,705.1 Variance: $874.4

This is a two-year project initiated in 2011. Additional engineering and plant resource time was required in 2012 in order to complete the field investigations to bring the existing Unit 3 relay panel control schematics and termination schedules up to 'as-built' status. As these 'as-built' drawings form the basis of the control panel design, the contract for the design and supply of the new control panel will now be executed in 2013. As a result, the project was carried over into 2013.

The installation time for the control panel will be longer than anticipated due to the greater than originally estimated number of cables and conductors entering the Unit 3 relay panel. Cables must be properly labeled and organized for successful commissioning. Also, the commissioning period will be longer in 2013 because in addition to the new control processor being added to the project, the existing Unit 3 control processors will have to be partially re-commissioned. These factors have increased the outage from eight to 12 weeks and have increased both labour and construction costs.

7. Upgrade Hydrogen Systems - Holyrood

Budget: $1,992.3 Total: $3,487.8 Variance: $1,495.5

An increase in the original capital project budget was required to complete the original project deliverables. This budget increase is a result of a divergence between the budgeted and actual cost for engineering design, materials, and the construction contract. The procurement of long lead items was completed in 2011 and was on budget. The engineering design and public tendering of the construction contract was completed in the Spring of 2012. One tender was received at a price of $1,242,335, compared to the budgeted contract cost of $290,000. The contract was not awarded. At this point, Hydro reviewed and confirmed the project scope and justification. Following the announcement of the Muskrat Falls Project in the Fall of 2012, there was a change in the long term asset plan for Holyrood, and the conversion of Units 1 and 2 to synchronous condensers is no longer required. This necessitated a further review and confirmation of the project justification, and adjustments to the project scope. The original project justification remains unchanged; the upgrades of the hydrogen system are necessary to improve the safety and reliability of the system.

The project was carried over into 2013 and the construction specification was re-designed to address the scope adjustments resulting from the change in the long term asset plan for Holyrood. A revised construction contract was publically tendered in the Spring of 2013 and five tenders were received. The lowest evaluated tender was $996,998. This contract was awarded and work is in progress, with an expected in service date of November 2013.

The resultant 75 percent project budget increase is apportioned as follows:

- 31 percent due to contract cost exceeding the budget amount;
- 20 percent due to additional project management and engineering effort, including both internal resources and external consultants, associated with reviewing scope and justification, re-designing and re-tendering the work;
- 20 percent due to electrical and controls systems materials costs exceeding the budget amount; and
- 4 percent for additional interest during construction, as a result of carrying the project over into 2013.

8. <u>Replace Pumphouse Motor Control Centres - Holyrood</u>

Budget: $1,048.8 Total: $1,517.6 Variance: $468.8

This is a two-year project initiated in 2010 which was carried over into 2012 and 2013. The engineering design and construction specification prepared for this work did not cover all the aspects of work required to complete this project. This resulted in increased costs for labour and for the installation contract. The installation and commissioning of the Units 1 and 2 pumphouse motor control centers (MCCs) will now be completed during the scheduled 2013 unit outages.

9. Upgrade Glycol Systems - Stephenville

Budget: $560.2 Total: $1,177.5 Variance: $617.3

This is a two-year project initiated in 2010 which was carried over into 2012 and 2013 due to multiple tenders being required to secure suitable bids. While the construction work was planned to be completed in the spring of 2012, it was postponed as a result of the alternator failure at the Stephenville Gas Turbine. The glycol system upgrade project could not be commissioned and placed in service until the alternator refurbishment work is completed. This work is now complete and the system is in service. The cost of this project has increased due to an increase in engineering, labour and material costs and also as a result of project delays.

10. Upgrade Gas Turbine Plant Life Extension - Hardwoods

Budget: $5,994.7 Total: $4,022.7 Variance: ($1,972.0)

The budget for this project has been reduced to remove the cost allocated for the alternator and excitation system inspection and refurbishment. This work is now being completed under a separate approved project as per Board Order No. 20 (2013).

11. Replace Compressed Air System - Bay d'Espoir

Budget: $647.5 Total: $1,304.8 Variance: $657.3

This is a two-year project initiated in 2011 which has been carried into 2013. The project is approximately 90 percent complete; however it was not completed in 2012 due to limited breaker outage availability. The increase in project cost is primarily due to tendered cost for construction that was higher than estimated.

12. Replace Compressor, Dryer, and Air Piping Header System - Corner Brook Frequency Converter Station

Budget: $280.2 Total: $403.1 Variance: $122.9

This project was originally planned to be completed in 2011 and was carried into 2012 due to difficulties in obtaining bids for the work in 2011. The contract work for this project was combined with other project work and tendered a second time which resulted in contract pricing which was higher than estimated.

In addition to increased contract pricing, design changes were required in the course of the project which resulted in increased engineering and material costs. The material required to complete the design changes could not be delivered in 2012 and, as a result, this project has been carried into 2013. This project is expected to be completed in the fall of 2013.

13. Upgrade Substation - Wabush

Budget:	**$1,085.7**	**Total:**	**$1,284.0**	**Variance:**	**$198.3**

This is a two-year project initiated in 2011 which has been carried into 2013. During the detail design phase, additional required design work was identified related to the grounding and yard upgrade work which affected both the project budget and schedule. The project scope includes grounding upgrades within the substation that, for safety reasons, could not be completed late in the year. These upgrades will now be completed during the construction season in the summer of 2013. The overall budget for this project has increased due to higher than anticipated contract pricing.

14. Upgrade Terminal Stations to 25 kV - Labrador City

Budget:	**$12,650**	**Total:**	**$15,721.0**	**Variance:**	**$3,071.0**

The original budget was submitted as a three-year project to construct two new 46/25 kV terminal stations. Each station will have two new 46/25 kV, 15/20/25 MVA power transformers, new 46 kV and 25 kV electrical equipment and new control buildings. The budget for this project was previously increased to $12,650,000 and the 2012 budget has been adjusted to incorporate the change in the overall budget.

This project was estimated in 2008 based on market conditions at the time and using standard escalation indices for future year expenditures. The market conditions realized in Labrador West during the project execution phase have been atypical, driven by strong economic activity in the area. The outcome was an escalation beyond Hydro’s anticipation in construction contracts, materials and labour.

An additional $3.1 million was required to complete this project as a result of contract pricing increases above estimated amounts for contracts, use of consultants for design review, commissioning cost estimates which were low compared to the actual cost to commission the specific type and size of stations involved, and additional material costs. Additional commissioning costs and interest also contributed to the variance. Both terminal stations are now in service.

15. **<u>Replace Mini Hydro Turbine - Roddickton</u>**

Budget:	**$322.2**	**Total:**	**$478.3**	**Variance:**	**$156.1**

This is a two-year project initiated in 2011. The increase in project cost compared to budget is due to a scope change to include a generator replacement. The generator rotor shaft failed in 2010. This failure occurred after the project proposal was submitted for approval. A cost-benefit analysis was performed to compare the feasibility of replacing the generator at additional cost under the same project, postponing the work, or cancelling the current project and shutting down the plant. The results of the cost-benefit analysis favoured proceeding with the turbine overhaul and replacement of the generator.

This project has been carried over into 2013 as a result of longer than anticipated lead time for procurement of a replacement generator.

16. **<u>Replace Diesel Unit 2001 and Engine 566 - Francois</u>**

Budget:	**$618.5**	**Total:**	**$749.0**	**Variance:**	**$130.5**

This project is a two-year project initiated in 2010. The replacement genset for Unit 566 was installed and commissioned in 2011, but delivery of the replacement genset for Unit 2001 was delayed. During factory acceptance testing, the unit did not meet the specified vibration limits. Factory troubleshooting of this issue was on-going with resolution in December 2012. The replacement genset will now be delivered in 2013.

The project cost has increased as a result of increased genset installation costs for Unit 566 and additional engineering costs associated with troubleshooting of engine issues and extension of the project schedule.

17. Install Automatic Meter Reading – Various Sites

Budget: $656.7 Total: $810.4 Variance: $153.7

There are two approved capital projects currently in progress for installation of automatic meter reading. One project was originally budgeted to install automatic meter reading in the service areas of Rocky Harbour and Glenburnie in 2012 and 2013, and the second project was originally budgeted to install automatic meter reading in the service areas of Plum Point and Bear Cove in 2013 and 2014. The anticipated retirement dates of the respective meter readers changed, and a decision was made in 2012 to swap the two projects. The meter reader for Rocky Harbour and Glenburnie also reads the meters for the service areas of Wiltondale and Sally's Cove. These areas were not originally budgeted but are necessary to achieve the benefit of eliminating a meter reader position. An updated cost benefit analysis was completed which demonstrated that installation of automatic meter reading in Rocky Harbour, Glenburnie, Wiltondale and Sally's Cove is the least cost alternative compared to the status quo, with a $32,000 difference in net present value. The cost increase is associated with the materials and labour associated with Wiltondale and Sally's Cove.

18. Rewind Gas Turbine Alternator - Stephenville

Budget: $5,192.6 Total: $5,989.7 Variance: $797.1

The increase in costs for the rewind of the alternator at the Stephenville Gas Turbine is due to extra work requirements discovered during disassembly of the unit. The alternator and oil cooler were leaking and in poor condition, as well as other components such as hinges, seals, piping and bearings that required replacement or retrofit. There were also additional electrical and protection and control work required. This added work is necessary in order to get the gas turbine operational.

Plan of Projected Operating

Maintenance Expenditures

2014 - 2023

For Holyrood Generating Station

Newfoundland and Labrador Hydro

July 2013

Table Of Contents

INTRODUCTION

In the Decision and Order No. P. U.14 (2004) of the Board of Commissioners of Public Utilities ("the Board"), dated May 4, 2004, (the 'Order) Newfoundland and Labrador Hydro ("Hydro") is required to **"file a ten year plan of maintenance expenditures for the Holyrood Generating Station with its annual capital budget application, until otherwise directed by the Board"** (p. 64 and Paragraph 12, p. 166 of the Order).

This requirement is specifically related to system equipment maintenance (SEM) costs; therefore, capital expenditures have not been included in the following report. Capital expenditures for Holyrood are submitted annually to the Board with other Hydro capital proposals as part of annual capital budget applications, vary from year to year.

This report addresses the identified and expected maintenance expenditures for the years 2014 to 2023 inclusive. With respect to these expenditures it must be noted that Units 1 and 2, as well as, two of the main fuel storage tanks, and other associated ancillary equipment, are in excess of 40 years old. Unit 3 and its associated equipment, is in excess of 30 years old. While many components of this equipment have been replaced and additional items added through the maintenance and capital program over the years, numerous pieces of equipment and components are original.

An accurate, uniform ten year plan of SEM is difficult to complete given the harsh operating environment, varied production requirements and the age of units may trigger revision of the maintenance plan to control unforeseen events. Even though expenses for major overhauls are included in capital rather than operating budgets, some variability in the annual budget will remain as a result of the complexity of numerous components and integrated systems that form a fossil fired thermal electric generating system. This report will endeavor to identify the regular variations in the annual operating costs for the Holyrood Thermal plant.

MAINTENANCE PHILOSOPHY

The Board, in its Order as related to the Holyrood Thermal Plant, noted at p. 64 that **"The Board will require NLH's 10 year plan of maintenance expenditures for the Holyrood Generating Station to be updated annually to reflect changing operating circumstances."**

The maintenance effort aims to prevent functional failure and extend the operational life of assets, helping to minimize total asset life cycle cost.

The type and amount of maintenance applied is dependent on the criticality of the asset and the impact of failure on service delivery.

Hydro seeks to balance the cost of maintenance against the cost of failure and the impact on safe, reliable service when applying maintenance strategies and tactics.

The following are the three main types or categories of maintenance undertaken at Holyrood:

1) **<u>Preventive Maintenance</u>**

   While it is true that any plant will incur greater maintenance costs as it ages, Holyrood has used, and continues to use, up-to-date maintenance techniques and practices to maintain plant efficiency, availability and reliability. These include preventive, predictive and condition-based maintenance techniques, which are usually referred to by the overall term of "Preventive Maintenance". The basic principle underlying this approach to maintenance is timely intervention to prevent imminent or catastrophic failure which may cause a substantial safety exposure, an increase in cost, or an extended unavailability of the unit or system.

   Preventive maintenance comprises routine inspections, minor checks and component replacement at specific time intervals, to prevent failures known, or reasonably expected to occur within a definable time or operating hour interval during the life of the equipment (e.g. generator brush wear, air and oil filter replacements). This also includes discarding equipment or components rather than repairing them when it is less expensive to do so.

Predictive maintenance involves routine testing of equipment to determine deterioration rates and initiating and carrying out repairs in a timely manner before a failure occurs, (e.g. ultrasonic thickness checks on fluid lines to monitor erosion wear rates, non-destructive testing of boiler and turbine components to determine fatigue, wear or corrosion rates and remaining life). Predictive maintenance items include such things as boiler and auxiliary equipment annual overhaul, among other items, wherein an assessment is made of components or subsystems that are only accessible during these overhauls.

There is also regular or continual monitoring of equipment operating parameters with a comparison of the results with optimum conditions to determine the most economic time to intervene and perform remedial work that is intended to return the equipment to optimum performance levels (e.g. air heater washes, generator winding insulation condition, oil sampling and testing).

As of 2008, the Preventive Maintenance program has been enhanced to include the extra costs associated with plant cleaning in areas where asbestos and heavy metals have been identified as potential health hazards.

2) <u>Corrective Maintenance</u>

In addition to the preventive maintenance tactics outlined in 1) above, there are also corrective maintenance requirements. This includes work performed to identify, isolate and restore equipment, machines or systems to a level in which it can be operated safely and used for its intended purpose. The requirement of corrective maintenance may arise for various reasons including failure, wear and tear and harsh environments (humidity, salt laden atmosphere). Examples include wear and tear on pumps, pipes and valves in the main and auxiliary systems.

3) Projects

Operating projects are low cost repairs and annual inspections that are required to return structures and equipment to their original or near original condition, to maintain structural integrity, improve efficiency, improve availability and prevent or reduce environmental risks. Such projects include emissions monitoring and testing and periodic basin cleaning in the Waste Water Treatment Plant.

COST VARIABILITY

Preventive maintenance costs are generally incurred annually at a constant level and do not fluctuate significantly. This does not apply to corrective maintenance costs, which are unavoidable and unpredictable due to the changing energy production demands on the units from year to year. Due to the accounting methodology changes approved under Board Order P.U. 13 (2012), major overhauls and inspections with a frequency of greater than one year are capitalized, reducing the fluctuation in maintenance expenditures experienced in prior periods. Projects for the Holyrood Thermal plant are planned on a five-year basis, but as with any plan, it is not 'fixed' or definitive, as other events can cause a shift in the prioritization of such projects. This five-year maintenance plan is regularly updated as time progresses.

DETAILED ANALYSIS

Attached are Appendices A to D, which set out the ten-year maintenance plan for the Holyrood Thermal Plant, as requested by the Board. Appendix A is a summary and indicates the expected expenditures in each of the major equipment groupings containing SEM costs for the years 2014 to 2023. Appendices B to D, inclusive, show the expected SEM costs categorized according to Preventive, Corrective, Annual Overhauls and Operating Projects for each of the major equipment groupings containing SEM costs.

It should be noted that the ten year plan spans the period during which the role of Holyrood will change as a result of the Labrador Interconnection. This significantly impacts cost and activity levels for Holyrood for the stand by period 2018 through 2020/2021 and also post Generation 2021 onward.

This plan was prepared using the 2013 preventive, corrective and annual overhaul data and the current 2014 to 2018 project lists from Hydro's five-year plan for the Holyrood Thermal Plant as the base data. Considerable judgment of plant personnel had to be used to prepare a ten-year plan.

Hydro does not normally use any escalation in its five-year operating plan at the Plant or regional level. The five-year plan is primarily used for internal purposes and generation of work plans rather than detailed financial planning. However, in the attached ten-year plan, an escalation factor has been used, the source of which is the Fall 2012 Hydro forecast. A single escalation rate was used in this exercise and assumed a 50 percent weighting of labour escalation and 50 percent of Material escalation, and is as follows:-

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
%	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5

Appendix B lists the categories of SEM costs for generating units for the years 2014 to 2023 in each of the major equipment groupings. The categories listed are:

Preventive	Routine preventive maintenance activities carried out every year
Corrective	Typical but unknown breakdown/emergency repairs carried out during the year
Boiler	Boiler overhauls carried out annually with one unit per year overhauled on a reduced scope as a result of better fuel quality
Operating Projects	Non-capitalized projects, justified on the basis of safety, environment, reliability or cost benefit analyses

Appendices C and D are for the remaining equipment groupings of Common Equipment, Building and Grounds, Water Treatment Plant, Waste Water Treatment Plant and Environmental Monitoring and use only Preventive, Corrective and Operating Projects.

It must be noted that the appendices do not itemize preventive and corrective items. The preventive maintenance program consists of approximately 1,200 preventive maintenance work orders performed on plant equipment annually. Corrective items include a large number of low cost jobs, the majority of which are largely unknown until they happen; thus, it is not practical to provide a breakout of the costs.

SUMMARY

This Plan is based on the 2013 system equipment maintenance budget and adjusted using the best available information including up to date maintenance tactics and known restoration and inspection work to establish a ten-year forecast of the maintenance projects for the Holyrood Plant. As with any forecast, it is subject to change depending on the operating demands of the plant, the results of inspections and assessments of changing equipment conditions.

APPENDIX A

TOTAL HOLYROOD 10 YEAR SYSTEM EQUIPMENT MAINTENANCE EXPENDITURES
($000)

	Base Year 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unit 1 Total	1,091	2,001	2,050	1,175	1,616	1,656	949	581	596	611
Unit 2 Total	1,952	2,001	1,146	2,102	1,616	926	1,697	1,224	334	342
Unit 3 Total	1,952	1,118	2,050	2,102	903	1,656	1,697	325	596	611
Common Equipment Total	1,732	1,775	1,820	1,865	1,434	1,470	1,506	517	530	543
Buildings and Grounds Total	399	409	419	430	330	339	347	119	122	125
Water Treatment Plant Total	107	110	112	115	89	91	93	32	33	34
Waste Water Treatment Plant Total	22	23	23	24	18	19	19	7	7	7
Environmental Monitoring Total	166	170	174	179	137	141	144	50	51	52
Total Operating Projects	755	301	356	1,131	885	724	699	88	145	92
Total Holyrood System Equipment Maintenance	**8,176**	**7,907**	**8,151**	**9,122**	**7,028**	**7,021**	**7,153**	**2,943**	**2,413**	**2,417**

APPENDIX B

10 YEAR SYSTEM EQUIPMENT MAINTENANCE EXPENDITURES FOR GENERATING UNITS
($000)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unit No. 1										
Preventive	545	559	573	587	451	462	474	163	167	171
Corrective	325	333	341	350	269	276	283	97	99	102
Boiler O/H	221	1,109	1,136	238	896	918	192	322	330	338
Subtotal	1,091	2,001	2,050	1,175	1,616	1,656	949	581	596	611
Operating Projects										
Boiler Chemical Clean					463					
Projects - Lump Sum	42	43	44	45	35	36	36	13	13	13
Total Op Projects - Unit 1	42	43	44	45	498	36	36	13	13	13
Total - Unit No. 1	**1,133**	**2,044**	**2,094**	**1,220**	**2,113**	**1,692**	**985**	**594**	**609**	**624**
Unit No. 2										
Preventive	545	559	573	587	451	462	474	163	167	171
Corrective	325	333	341	350	269	276	283	97	99	102
Boiler O/H	1,082	1,109	232	1,165	896	188	941	965	67	69
Subtotal	1,952	2,001	1,146	2,102	1,616	926	1,697	1,224	334	342
Operating Projects										
Boiler Chemical Clean				452						
Projects - Lump Sum	42	43	44	45	35	36	37	13	13	13
Total Op Projects - Unit 2	42	43	44	497	35	36	37	13	13	13
Total - Unit No. 2	**1,994**	**2,044**	**1,190**	**2,599**	**1,651**	**961**	**1,734**	**1,237**	**346**	**355**
Unit No. 3										
Preventive	545	559	573	587	451	462	474	163	167	171
Corrective	325	333	341	350	269	276	283	97	99	102
Boiler O/H	1,082	226	1,136	1,165	183	918	941	66	330	338
Subtotal	1,952	1,118	2,050	2,102	903	1,656	1,697	325	596	611
Operating Projects										
Boiler Chemical Clean						475				
Projects - Lump Sum	0	13	13	14	10	11	11	4	4	4
Total Op Projects - Unit 3	0	13	13	14	10	486	11	4	4	4
Total - Unit No. 3	**1,952**	**1,131**	**2,063**	**2,116**	**914**	**2,142**	**1,708**	**329**	**600**	**615**

APPENDIX C

10 YEAR SYSTEM EQUIPMENT MAINTENANCE EXPENDITURES FOR ANCILLARY UNITS
($000)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Common Equipment										
Preventive	1,571	1,610	1,651	1,692	1,301	1,333	1,366	469	481	493
Corrective	161	165	169	173	133	137	140	48	49	51
Subtotal	1,732	1,775	1,820	1,865	1,434	1,470	1,506	517	530	543
Operating Projects										
Pipe Surveillance	57	58	60	61	47	48	50	17	17	18
Plant Color Coding	16	16	17	17	13	14	14	5	5	5
Total Projects - Common	73	75	77	79	60	62	63	22	22	23
Total - Common Equipment	**1,805**	**1,850**	**1,896**	**1,944**	**1,494**	**1,532**	**1,570**	**539**	**553**	**566**
Buildings and Grounds										
Preventive	346	355	364	373	286	294	301	103	106	109
Corrective	53	54	56	57	44	45	46	16	16	17
Subtotal	399	409	419	430	330	339	347	119	122	125
Operating Projects										
Exhaust Stack Repairs	300			325			350			
Total Projects - Buildings and Grounds	300	0	0	325	0	0	350	0	0	0
Total - Buildings and Grounds	**699**	**409**	**419**	**755**	**330**	**339**	**697**	**119**	**122**	**125**
Water Treatment Plant										
Preventive	21	22	22	23	17	18	18	6	6	7
Corrective	86	88	90	93	71	73	75	26	26	27
Subtotal	107	110	112	115	89	91	93	32	33	34
Operating Projects										
Resin Replacement	74	76	78	80	61	63	64	22	23	23
Total Op Projects - Waste Water Treatment Plant	74	76	78	80	61	63	64	22	23	23
Total - Water Treatment Plant	**181**	**186**	**190**	**195**	**150**	**154**	**157**	**54**	**55**	**57**

APPENDIX D

10 YEAR SYSTEM EQUIPMENT MAINTENANCE EXPENDITURES FOR ANCILLARY UNITS
($000)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Environmental Monitoring										
Preventive	88	90	92	95	73	75	77	26	27	28
Corrective	78	80	82	84	65	66	68	23	24	24
Subtotal	166	170	174	179	137	141	144	50	51	52
Operating Projects										
Emmissions Monitoring	50	51	53	54	41	42	43	15	15	16
Stack Emmissions Testing	116				128					
Tube Bundle Replacement	35			38			41			
Total Projects - Environment	201	51	53	92	169	42	84	15	15	16
Total - Environmental Monitoring	**367**	**221**	**227**	**271**	**307**	**183**	**229**	**65**	**66**	**68**
Waste Water Treatment Plant										
Preventive	1	1	1	1	1	1	1	0	0	0
Corrective	21	22	22	23	17	18	18	6	6	7
Subtotal	22	23	23	24	18	19	19	7	7	7
Operating Projects										
Waste Water Treatment Plant										
Periodic Basin Cleaning	23		24		26		27		28	
Continuous Basin Clean-Out			24		25		26		27	
Total Projects - Waste Water Treatment Plant	23	0	48	0	51	0	53	0	55	0
Total - Waste Water Treatment	**45**	**23**	**71**	**24**	**69**	**19**	**72**	**7**	**62**	**7**

	2012	2011
	($000)	
Capital Assets[1]	1,510,595	2,191,991
Less:		
Accumulated Depreciation[1]	(88,865)	(707,241)
Contributions in Aid of Construction[1]	(14,052)	(98,054)
Asset Retirement Obligations[2]	(22,878)	(19,126)
Asset Retirement Obligation Accumulated Amortization[2]	3,193	1,149
Holyrood Fuel Oil Heat Tracing[3]	(783)	-
Holyrood Fuel Oil Heat Tracing Accumulated Amortization[3]	8	-
Net Capital Assets[1]	1,387,218	1,368,719
Net Capital Assets, Previous Year	1,368,719	1,357,664
Unadjusted Average Capital Assets	1,377,969	1,363,192
Less:		
Average Net Assets Not In Service	(1,040)	(423)
Average Capital Assets	1,376,929	1,362,769
Cash Working Capital Allowance	7,805	4,626
Fuel Inventory	50,308	33,680
Supplies Inventory	25,339	24,096
Average Deferred Charges	65,670	68,047
Average Rate Base	1,526,051	1,493,218

[1] 2012 capital asset value reflects adjustments approved by the Board in Order No. P.U. 13 (2012).
[2] The asset retirement obligation is comprised of $20,772 (2011 - $16,953) related to the Holyrood Generating Station and $2,106 (2011 – $2,163) related to the disposal of Polychlorinated Biphenyls (PCB).
[3] In accordance with Order No. P.U. 5 (2012), the capital additions of $783 in 2012 (2011 – nil) for Holyrood fuel oil heat tracing was approved but Hydro is not permitted to recover the costs of the project unless otherwise ordered by the Board.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador DAVID W. HICKS SIGNATURE July 29/2013 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Rewind Stator Unit 3

Bay d'Espoir

February 2013

newfoundland labrador
hydro
a nalcor energy company

SUMMARY

The replacement of the stator winding on hydroelectric generator Unit 3 is the final unit for the stator winding replacement project, and was completed on Units 2, 4 and 1 in 2010, 2012 and 2013 respectively.

Unit 3's stator winding has similar indicators of deterioration as found on Units 2, 4 and 1 previously, with dripping asphalt from the insulation and stator core components. In addition to the physical visual indicators of the stator condition, the electrical testing has verified that the insulation in the stator winding is weakening. As the insulation is weakening the deterioration is increasing and the probability of failure of the stator winding during unit operation is becoming more probable. A replacement in 2014 is recommended.

The replacement of the stator winding includes the removal, installation and commissioning of 360 coils that form the stator winding. This replacement project will also include the refurbishment of rotor components and upgrades to generator protection.

TABLE OF CONTENTS

1 INTRODUCTION

Hydro's largest hydroelectric generating station on the Island Interconnected System is located at Bay d'Espoir, on Newfoundland's south coast. The Bay d'Espoir Hydroelectric Generating Station consists of seven hydro generating units producing a total capacity of 604 MW which is approximately 39 percent of the Island Interconnected System's installed capacity.

The Bay d'Espoir facility was built in three stages. Stage 1 includes generating units 1 through 4, which are similar in design and functionality. The focus of this report is the replacement of the stator winding on Unit 3. The nameplate ratings[1] for Units 1, 2, 3 and 4 are as follows:

Table 1: Unit Ratings

Rated Output Power	85 MVA, 76.5 MW
Rated Voltage	13.8 kV
Rated Frequency	60 Hz
Rated Speed	300 rpm
Rated Power Factor	0.90
Rated Field Voltage	125 V
Rated Field Amperage	1500 A
Temperature Rise of Armature	60 °C
Temperature Rise of Field	60 °C
Cooling Air Temperature	30 °C
Insulation Class of Armature	Class B (Mica tape and Asphalt)
Insulation Class of Fielding Winding	Class B (Shellac and Asphalt)
Shaft Position	Vertical
Number of Slots	360
Commissioning Year – Units 1, 2 and 3	1967
– Unit 4	1968

Unit 3 is approximately three meters high with an approximate diameter of six meters. A generator, such as Unit 3, consists of two main parts: a rotor and a stator. The rotor, being mechanically connected to the turbine, will rotate with the force of moving water on the turbine's runner blades. The stator is the stationary part of the generator, composed of a

[1] Partially based on information contained in report by AMEC Americas Limited "Bay d' Espoir Generating Station Powerhouse No. 1 Unit Generators #1, #3 and #4 Condition Assessment Report", (Attached as Appendix A) pg. 1.

series of copper coils that as a complete unit form the stator winding. Physically, the rotor is a series of large magnets that when rotated inside the stator's ring of copper coils will produce electricity. The stator winding on Unit 3 has an asphalt mica tape design to insulate the copper coils. An insulation system is required to prevent the copper coils from coming in contact with each other and the amount of electrical protection from the insulation is known as the dielectric strength. Because of age, the asphalt mica tape insulation on the Unit 3's stator coils have become dry and brittle, reducing the mechanical and dielectric strength of the insulation, making it more susceptible to failure. The repair or replacement of any one stator coil is quite complex and involves the removal of approximately 25 additional coils due to the inter-twining coil design of the stator winding and its coils. Due to aging and the brittle nature of the coils, any attempted stator coil repairs are expected to lead to additional failures in other adjoining stator coils because of the disturbance caused by their removal.

The inter-twining design of each coil is shown in Figure 1.

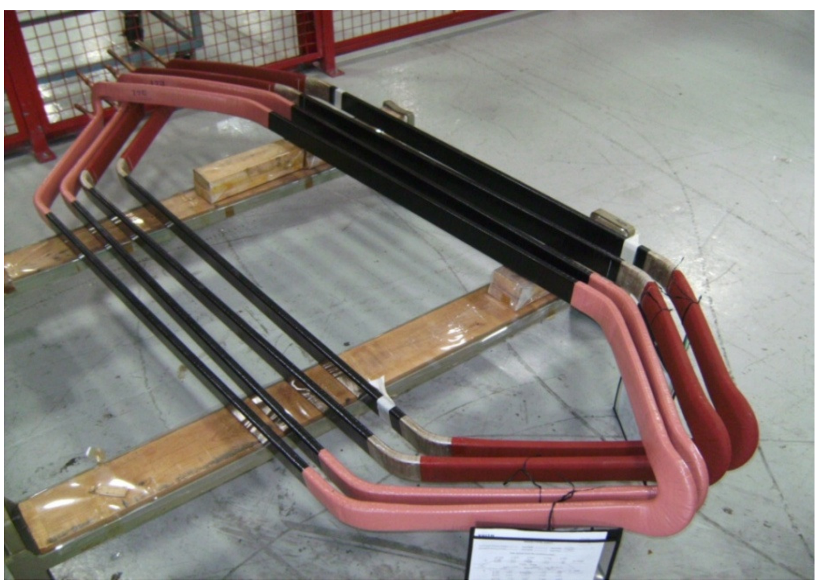

Figure 1: Stator Coils (4 individual coils are shown)

Based on previous stator winding replacements on Units 2, 4 and 1 the operating lifecycle of the stator winding on Unit 3 is known. The physical condition of the stator winding for Unit 3 is showing similar indicators of deterioration as Units 2, 4 and 1 did at the same period of their lifecycle. This deterioration includes cracking in the winding insulation and asphalt seeping from the winding, all being indicators of the insulation breakdown. The Unit 3 stator winding was assessed, with the 2012 results from AMEC Americas Limited (AMEC) attached as Appendix A. This report concluded that the stator winding of Unit 3 has reached the end of its useful serviceable life and a planned replacement should be executed. Hydro is proposing this project to replace Unit 3 stator winding before a failure or unplanned outage of Unit 3 occurs.

Figure 2 below shows the Unit 2 stator winding completed in 2010. The work to be completed on Unit 3 would be very similar in nature.

Figure 2: Stator at Bay d'Espoir with Rotor Removed

The replacement of stator windings in Bay d'Espoir has been on-going for several years. In 2010, Hydro received approval from the Board, under Order No. P.U. 1 (2010) to replace Unit 2's stator winding; Unit 2 was completed in 2010. In 2011, to provide further justification for the replacement of stator winding on the remaining three units, AMEC, an engineering consultant, was engaged to complete a condition assessment of the Bay d'Espoir Generator Units 1, 3 and 4. This assessment indicated the need for an immediate replacement of Unit 4 stator winding, and as approved under Board Order No. P.U.2 (2012) this work was completed in 2012. The 2012 Board Order also directed that Hydro reapply for the remaining two units. In 2012, AMEC Americas Limited also completed an updated report for Units 1 and 3. Using this information as justification, the stator winding replacement on Unit 1 was approved in 2013. The current proposal is the final proposal for stator work on stage 1, with Unit 3 scheduled to be completed in 2014.

2 PROJECT DESCRIPTION

This proposal is for the final stator winding due for replacement under the stator replacement work that had Units 2, 4 and 1 completed in 2010, 2012 and 2013 respectively. This proposal is a one-year project for the rewind of Unit 3 stator winding.

The stator winding on Unit 3 in the Bay d'Espoir Generating Station is the last original stator winding left on stage 1 units. Unit 3 was installed in 1967 and is approximately 46 years old. The coils on Unit 3 are a Class B type, manufactured with asphalt mica material and are considered an older design than Class F type of coils. The lifecycle for an asphalt mica type coil is generally accepted by the utility industry to be 40 years. AMEC stated in its 2011 report "According to industry experiences, the asphalt mica winding insulation on these three units has a life expectancy of 40 to 45 years." [2] As such, the stator winding on Unit 3 is considered to be at the end of its useful service life. This information, combined with the poor to marginal test results; as shown in Appendix A, is the basis of the justification of the replacement of the stator winding on Unit 3.

It is important to understand the components of a stator winding, its installation and the technical terms used. A stator winding is comprised of coils that have a series of tensioning components known as the packing system between each coil. This packing system mounts and secures each stator coil against the stator core. An illustration of the packing system for one section of stator coil is shown in Figure 3.

[2] Bay d'Espoir Generating Station Powerhouse No.1 Unit Generators #1 and #3 Condition Assessment Report, AMEC Americas Limited, September 1, 2011, pg 3.

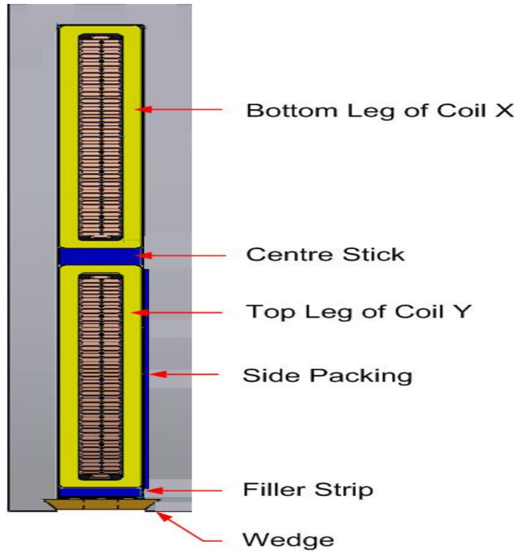

Figure 3: Illustration of Packing System on One Section of Stator Winding (Two Coils)

Unit 3, as with the other six generating units at Bay d'Espoir, is critical to the Island Interconnected System. Units 1 and 3 also provide station service power within the Bay d'Espoir Generating Station. The loss of either unit would reduce the overall reliability of the powerhouse and the Island Interconnected System.

The hydroelectric generating units at Bay d'Espoir have a major impact on the reliability of the Island Interconnected System. As such the availability and reliability of each generating unit has to be maintained. Hydro and its consultant, AMEC, have determined that Unit 3 should be replaced once Units 1, 2 and 4 are completed. AMEC states "The rewind of Unit #3 should therefore be planned to be completed after Unit #1 has been rewound. We suggest that this occur no later than spring or summer of 2014."[3]

Another area of concern involves the work previously completed on the removal of the stator winding from Unit 2, where the stator coils were found to be migrating from their stator core slots, or moving out of alignment. The stator core is a mechanical circular structure compiled from a series of steel laminations that physically supports the stator coils inside individual slots. During the removal of Unit 2, it was discovered that the laminations had shifted and were slowly moving out of alignment. The area of concern with

[3] Bay d'Espoir Generating Station Powerhouse No.1 Unit Generators 1 and 3 Condition Assessment Follow-up Report, AMEC Americas Limited, May 24, 2012 Rev 1, pg 3.

stator core migration is the tension normally on the coil in the core slot is now being migrated on a coil against the stator core and not a slot. The core begins to cut into the coil, eventually getting through the insulation to the conductor creating a coil failure and an electrical fault. The situation is analogous to cables chafing against each other and wearing through their insulation. Figure 4 shows the misalignment of the laminations discovered on Unit 2 in 2010. Unit 3 is similar in age and construction and concern is raised as it may exhibit similar issues.

Figure 4: Migration of Stator Core Laminations–Looking Downward with Stator Winding Removed

The replacement of the stator winding involves the removal of the existing 360 stator coils along with the supply, installation and commissioning of new stator coils. The scope of work is to be completed by a contract manufacturer, including abatement if required, as was previously done on Units 2, 4 and 1. The work would also include an upgrade to the generator protection and the refurbishment of rotor pole components. This work is required to ensure the new stator will operate to its full capability.

3 JUSTIFICATION

The replacement of Unit 3 is the final winding replacement of the stage 1 units, all of which were beyond their useful service life of 40 years and have deteriorated to a level of possible failure during operation. During regular preventative work on Unit 3, as with the previous units of stage 1, Unit 3 has shown signs of deterioration that include brittle insulation as shown in Figure 5 below, along with seeping asphalt from many locations of the winding, both being indicators of increased wear, insulation breakdown and the end of serviceable life for the winding. Unit 3 electrical testing for partial discharge (PD) produced poor results showing the winding is within the 90th percentile, indicating future problems. See Appendix A, section 4.3, page 13. This level of partial discharge indicates Unit 3 has poor insulation levels and has a high risk of failure.

Figure 5: Existing Stator Winding

In 2010, Unit 2's stator winding was removed and replaced. During this work, stator core migration was found. Although this issue was not found on Unit 4 in 2012, this area of concern remains for Unit 1 in 2013 and Unit 3 in 2014, as the potential for insulation failure is high. One additional area of concern is the possibility of broken rotor bus bars as was discovered on Unit 2. This type of deterioration will eventually lead to insulation damage on the stator winding. Both of these conditions are major issues and cannot be detected without a rebuild. Since 2010, and the Unit 2 work, Hydro's concern has been heightened as to the level of deterioration on the remaining units constructed during stage 1, including Unit 3. This project, as with the previous projects, is justified on the minimization of impacts to system performance and the additional cost incurred if a generating unit did suffer damage as a result of a stator winding failure.

The reliability of Unit 3 is critical to the Island Interconnected System and maintaining Unit 3 to be reliable follows a similar justification as was previously presented for the replacement of stator winding on Units 2, 4 and 1. Hydro must maintain the reliability of each generating unit to minimize failures occurring. Should a stator winding fail during operation it would cause significant damage to the stator and its rotor.

As presented in the 2012 budget proposal for the Unit 4 stator winding replacement, AMEC recommended further testing in 2012 on Units 1 and 3 to determine if the deterioration had worsened since the units last testing in 2007. AMEC states "Follow up testing should be performed annually …"[4] AMEC's 2012 report states "… that due to their deteriorated condition, they should be rewound as soon as possible. Yearly testing will not provide information that would support a decision to delay this work, but rather might give information that would give reason to accelerate the work."[5]

In 2012, the condition of Unit 3 was considered better than Unit 1, but both units are 46 years old with deterioration that is physically present and testing shows deteriorating insulation levels. Failure of either unit was probable, with AMEC recommending the

[4] Bay d'Espoir Generating Station Powerhouse No.1 Unit Generators 1 and 3 Condition Assessment Report, AMEC Americas Limited, September 1, 2011, pg 13.

[5] Bay d'Espoir Generating Station Powerhouse No.1 Unit Generators 1 and 3 Condition Assessment Follow-up Report, AMEC Americas Limited, May 24 Rev. 1, 2012, pg 1.

replacement of stator winding of Unit 1 before Unit 3 but on both units before the end of 2014. To reference both AMEC reports, see Appendix A.

To ensure improved functionality of all generator components, the generator protection equipment will be upgraded from electro-mechanical relaying to electronic relaying. In the event of an electrical fault, the level of damage mitigation on a faulted generating unit is directly proportional to the speed of operation for a protection relay. With modern electronic relaying having response times approximately 10 times faster than the existing electro-mechanical relays, and considering the asset cost of new stator winding, it is prudent to upgrade the generator protection with the replacement of the Unit 3 stator winding.

The issue of stator core migration is a particularly difficult issue to estimate a budget and develop scope around, as the winding has to be removed before the level of deterioration to the stator winding can be determined. One engineering practice would be to use previous condition data from similar stator windings that have been removed and use this information for the BDE winding going forward. The migration of the stator core is a particularly troublesome issue, as the risk of failure increases in many more areas, including a higher risk of electrical fault as one or more of the steel laminations could possibly create an electrical short with one or more of the stator coils, rendering the generator unusable. The combined physical effects of possible core migration and the visual deterioration of the stator winding present a risk of imminent failure to Unit 3. If a stator winding failure did occur, it is very likely that damage would result to both the stator and the rotor, as both components are in close proximity. The existing electro-mechanical protection equipment cannot prevent this potential damage and must be upgraded. AMEC states "The existing generator protection relays are electromechanical relays which have been in service for more than 40 years. It is recommended that the protection be upgraded to modern microprocessor based relays at the same time as the generator refurbishment."[6]

[6] Bay d'Espoir Generating Station Powerhouse No.1 Unit Generators 1 and 3 Condition Assessment Report, AMEC Americas Limited, September 1, 2011, pg 15.

During the completion of a stator winding replacement, the identification and abatement of asbestos from the stator packing system would be completed, thus removing an environmental and health concerns from this workplace.

3.1 Existing System

Unit 3 is a 46 year old hydroelectric generator that has signs of reduced insulation levels through electrical PD testing. Also there are physical indicators that its insulation is cracking and brittle when dry. Once heated, the insulation begins to drip asphalt, reducing the insulation's dielectric strength and physically covering the surrounding area in asphalt. Both of these electrical and physical indicators on Unit 3 were also present on the previous three units and indicate that the stator winding insulation level has degraded and is losing its dielectric strength to a point that failure is probable.

Unit 3 is designed for continuous operation with varying loads to meet system requirements. With the exception of maintenance outages, Unit 3 has been operating continuously, within its design capabilities, since it was commissioned in 1967.

Since its installation in 1967, Unit 3 has had minimal preventive maintenance costs related to its stator winding. Typically, the preventive maintenance cost on the complete generator has averaged $1,000 annually and generally includes a visual inspection and standard electrical testing.

For corrective maintenance, the stator related corrective maintenance repairs on Unit 3 include: replacement of two damaged coils, the cleaning of the stator and rotor from dripping asphalt and a stator wedge inspection. As listed in Table 2, Unit 3 has had several repairs and upgrades since its installation in 1967.

Table 2: Major Work and/or Upgrades

Year	Major Work and/or Upgrade
2009	Unit 3 – Generator cooler replaced and stator coil wedging inspection.
2008	Unit 3 – Isolated phase bus damaged and repaired.
2000	Unit 3 – Dry ice cleaning of stator and rotor.
1998	Unit 3 – Asphalt leaking from coils
1997	Unit 3 – DC exciter replacement
	Unit 3 – Two stator coils damaged and repaired
1991	Unit 3 – Stator re-wedging

3.2 Operating Experience

The stator winding on Unit 3 in the Bay d'Espoir Hydroelectric Generating Station is 46 years old and is operating beyond its expected useful service life. The stage 1 units in the Bay d'Espoir Generating Station are operated continuously, within the economic dispatch levels of the unit capabilities. As well, Hydro has a preventative maintenance program to maintain the reliability of these hydro generators. Inspections and electrical testing have confirmed that Unit 3 now requires a complete stator winding as there is a high probability of failure during operation.

3.2.1 Environmental Performance

As part of the stator winding removal procedure, asbestos abatement methods will be followed. There are no other specific environmental issues related to this project.

3.2.2 Industry Experience

The asphalt insulated, Class B multi-turn coil stator winding, which was manufactured by General Electric (GE) between the years 1930 and 1969, was a common design installed on most hydroelectric generators built during this period. Today the Class B winding is considered an older design as it has been replaced by the Class F winding.

Multi-turn coil windings with asphalt mica insulation have varying service lives, which are dependent on operating conditions and regular maintenance. Generally, the Class B winding, operating under normal conditions has an expected useful service life of 40 years.

GE has indicated that the majority of generators with the Class B design throughout the world have already undergone a stator rewind.

3.2.3 Vendor Recommendations

GE is the manufacturer of the Unit 3 stator winding and has participated in various inspections throughout its lifecycle. The latest inspection for Unit 3 was completed in 2007. Based on past inspections and the results of testing performed by Hydro, GE maintained in 2007 that the end of serviceable life for this unit was near and its replacement should be considered in the short term. The most prudent action is replacement of the stator winding.

GE halted production of these particular types of stator coils in 1969, shortly after Unit 3 was installed. GE, as well as the other large generator manufacturers, can provide replacement stator coils that are designed specifically for the Bay d'Espoir units and provide delivery times suitable to meet the schedule for this project.

3.2.4 Historical Information

The completion of stator winding replacements on Units 2 and 4 in 2010 and 2012 respectively has produced the following historical data:

Table 3: Historical Data

Description	Budget ($000)	Actual ($000)
Unit 2 Replacement (2010)	4,687.1	4,487.7
Unit 4 Replacement (2012)	4,953.8	4,087.2

3.3 Development of Alternatives

The only viable alternative for Unit 3 stator winding is its replacement. Maintaining the status quo would expose the generating unit to high likelihood of damage and failure due to the deterioration of the stator winding.

4 CONCLUSION

Unit 3 at the Bay d'Espoir Hydroelectric Generating Station has been in service since its commissioning in 1967 and is original equipment. The stator winding on Unit 3 has now exceeded the end of its useful service life of 40 years. The stator winding is showing indications of increased physical deterioration both physically and through electrical testing. The results show that if Unit 3 is left in service it has a high probability of failure during operation. Hydro and its consultant AMEC agree that the Unit 3 stator winding must be replaced in 2014.

4.1 Budget Estimate

The budget estimate for the replacement of the stator winding on Unit 3 is $4.34 million in 2014. The budget estimate is shown in Table 4.

Table 4: Project Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	662.9	0.0	0.0	662.9
Labour	503.0	0.0	0.0	503.0
Consultant	7.0	0.0	0.0	7.0
Contract Work	2,148.7	0.0	0.0	2,148.7
Other Direct Costs	80.4	0.0	0.0	80.4
Interest and Escalation	261.5	0.0	0.0	261.5
Contingency	680.4	0.0	0.0	680.4
TOTAL	**4,343.9**	**0.0**	**0.0**	**4,343.9**

4.2 Project Schedule

The anticipated schedule for this project is shown in Table 5 below.

Table 5: Project Schedule for Unit 3 in 2014

Activity		Start Date	End Date
Planning	Outage request and project planning for Unit 3	January 2014	March 2014
Procurement	Tendering, equipment ordering and delivery for 2014 FAT testing	April 2014	May 2014
Construction	Unit outage, removal of Unit 3, install stator winding, rotor upgrades, generator protection on Unit 3	May 2014	September 2014
Commissioning	Commissioning Unit 3	October 2014	October 2014
Closeout	Project closeout Unit 3	November 2014	December 2014

APPENDIX A

Unit Generators Condition Assessment Reports
By
AMEC Americas Limited

BAY D'ESPOIR GENERATING STATION

POWERHOUSE NO. 1

UNIT GENERATORS #1, #3 AND #4

CONDITION ASSESSMENT REPORT

Newfoundland and Labrador Hydro

Prepared for:

Newfoundland and Labrador Hydro

Prepared by:

AMEC Americas Limited
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REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
ANDREW DUPLESSIS
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Sept. 1/2011
DATE
NEWFOUNDLAND & LABRADOR

Date: September 1st, 2011

AMEC Ref. No.: 168688 Rev. 1

BAY D'ESPOIR GENERATING STATION

POWERHOUSE NO. 1

UNIT GENERATORS #1, #3 AND #4

CONDITION ASSESSMENT REPORT

FOR

NEWFOUNDLAND AND LABRADOR HYDRO

1	September 1st, 2011	Issued Final (minor non-technical changes)	DVT	CD	AD	
0	August 22, 2011	Issued Final	DVT	CD	AD	
B	August 12, 2011	Issued for Client Review (Draft)	DVT	CD	AD	
REV.	DATE	REVISION(S)	PREPARED BY	CHECK	APP	CLIENT

amec	BAY D'ESPOIR GENERATING STATION POWERHOUSE NO. 1	AMEC JOB NO. 168688	
		REPORT NO. 168688	REV. 1
		PAGE 1 OF 1	

TABLE OF CONTENTS

APPENDICES:

EXECUTIVE SUMMARY

The purpose of this study is to assess the current condition of the generators at Newfoundland and Labrador Hydro's Bay d'Espoir Hydro-Electric Generating Station. Units #1 through 4 in Powerhouse No. 1, excluding No. 2, are in need of major upgrades, more specifically the stator windings are in poor condition. These three units have been ranked in order of precedence for a replacement plan.

Data was collected from all plant maintenance inspections, PM6 (annual) and PM9 (approximately every six years), along with the staff interview and the most recent data collected on a site visit (July 4 to 7, 2011). This data was analyzed and used to perform an assessment of the current condition of these units.

From our assessment of the three generators it is apparent that Unit #4 is in the worst condition. Based on the test results, the stator windings will need to be rewound as soon as possible or a failure during operation will be imminent. The most reasonable time to schedule this work is during the spring or summer of 2012.

Unit #1 has already had one coil failure during a Hypot test and the latest test results indicate weaknesses in the winding insulation. In order to maintain reliability, the stator rewinding is planned to follow Unit #4, while maintaining regular plant maintenance. It is recommended that this occur in 2013.

Unit #3 is expected to operate until the other two units are replaced. Annual maintenance and follow up testing should be performed to closely monitor any unexpected changes in the condition of the winding insulation until the stator is rewound. It is recommended that this occur in 2014.

Additional work on the rotors and auxiliary systems is recommended to occur at the same time as the stator rewinds.

An additional recommendation is to revise the DC voltage control step test to make this test a diagnostic test and not as destructive as the current testing method.

1.0 INTRODUCTION

The hydro generating station at Bay d'Espoir, NL consists of six generating units. The focus of this study is to assess the condition of Units #1, #3 and #4. A major overhaul to Unit #2 was carried out in 2010, which included a complete stator rewind. This unit is therefore not considered in this study. The three units have identical 85 MVA generators and therefore can be compared with one another in terms of condition assessment.

The ratings for Units #1, #3 and #4 are as follows:

Rated Output Power:	85 MVA
Rated Power Factor:	0.9
Rated Voltage:	13.8 kV
Rated Speed:	300 RPM
Rated Frequency:	60Hz
Field Amperage:	1500 A
Field Voltage:	125 V
Insulation Class of Armature:	Class B (Mica tape & Asphalt)
Insulation class of Field Windings:	Class B (Shellac and Asphalt)
Cooling Air Temperature:	30 °C
Temperature Rise of Armature:	60 °C
Temperature Rise of Field:	60 °C
Shaft Position:	Vertical
Number of Slots:	360
Commissioning Year:	Units #1,#3: 1967 Units #4: 1968

2.0 METHODOLOGY OF ASSESSMENT

This assessment was conducted using the level one methodology from a three level detailed procedure of increasing detail developed by the Electric Power Research Institute (EPRI).

The level one condition assessment consists of the following:

- Failure history from plant records
- Operation condition (i.e. temperature)
- Maintenance records including tests and repairs.
- A site visit to conduct a walkthrough, a visual inspection and data collection from plant and plant staff interviews based on the equipment.

2.1 Site Visit

A site visit was conducted in July of 2011 to collect test data from Units #1 through #4, perform a visual inspection of the equipment and to meet with plant staff to discuss any problems. Unfortunately, due to system demand, only Unit #4 was arranged to be shut down for a visual inspection. A major overhaul to Unit #4 was just completed in May 2011 and had only been back on line for a little more than a month when the visual inspection took place (see report in Appendix A).

2.2 Background Review

Plant historical records were submitted by plant staff following the site visit in July for detailed review/analysis as follows:

- Major outage reports
- Failure reports
- Maintenance and inspection reports
- Testing reports

3.0 ANALYSIS

A review of all the available records for the generators on Units #1, #3 and #4 was performed. The following aspects were examined.

3.1 Thermal Aging of Winding Insulation

Units #1 and #3 are 44 years old and Unit #4 is 43 years old. According to industry experiences, the asphalt mica winding insulation on these three units has a life expectancy of 40 to 45 years. Therefore the generator winding insulation on these units is approaching the end of its life cycle.

Based on the 2010 operating data, the typical full load power on Units #1, #2 and #4 are as follows (see Appendix B).

- Unit #1 had almost 60 occurrences when the output power reached 80MW to 84MW.
- Unit #3 reached an output power of 83.3MW once and every other reading was below 80MW.
- Unit #4 peaked at 79MW once; every other reading was below 78MW.

As confirmed by plant staff the reactive power output of the three units is always maintained close to zero (unity power factor), therefore the 84MW real power output of unit one is still below the rated output 85kVA apparent power of the generator.

In order to determine if there are any effects of temperature that will affect the life expectancy of the winding insulation, the stator temperature trending for each unit was reviewed as follows (see Appendix B).

- Unit #1: The generator stator winding temperature (measured by RTD's) trending from January 1, 2000 to January 31, 2011 (11 years) has shown that the generator stator temperatures are around 60-65 degrees Celsius, except in 2006 when it spikes to 75 degrees Celsius and a short span operating at 80 degrees Celsius. These trends do not result in shortening the life expectancy of the winding insulation.

- Unit #3: The generator stator winding temperature trending from January 3, 2000 to March 14, 2011 has shown an average of 60-65 degrees Celsius, except for seven spikes of around 75 degrees Celsius and six spikes of around 78 degrees Celsius. These trends also do not result in shortening the life expectancy of the winding insulation.

- Unit #4: The generator stator winding temperature trending from January 3, 2000 to June 27, 2011, has shown an average of 65 degrees Celsius or below due to multiple start/stops. There are five spikes of 75 degrees Celsius and one spike at around 88 degrees Celsius. These cyclic changes of winding temperatures may cause more harm to the insulation than the steady temperatures of Units #1 and 3.

Based on the above stator temperatures trending, the winding temperatures of all three units are below the limit which can cause over temperature life reduction as in Montsinger's Law.

3.2 Generator Testing

As per normal practice at Bay d'Espoir, a number of tests are carried out annually during annual maintenance (PM6) outages and every six years during major maintenance (PM9) outages. The results of four of these tests, the Megger test, the Doble test, the PDA online measurements and the DC high potential tests have been analyzed. These four tests have been listed in order of increasing importance, with the DC high potential and PDA tests being the most useful test for determining the condition of the windings.

3.2.1 Megger Test

Megger testing is performed on the complete stator windings with or without the IPB (Isolated Phase Bus) and exciter rectifier transformer. This test only provides the global insulation resistance of all three phase windings to ground so it is not possible to compare the winding insulation resistances to see if they are comparable among phases.

3.2.2 Doble Test

Doble testing (power factor and tip up tests) of the generator windings was performed routinely on Bay d'Espoir generators since 1972. The generator winding under test has all split phases separated with test results on each split (6 in total) of the rotor windings. The test voltages are at 2, 4, 6, 8 and 10kVAC.

The trending of the Doble test is provided in (Appendix C.1) with the following observations:

Units #1 and #3 indicate good average power factor values at 2kV and 10kV without increasing in tip-up. Unit #4 also indicates good average power factor values at 2kV and 10kV up to 1989, when the power factor values start to increase until the latest tests in 2011 (the highest power factor of one split phase value is 4.6% at 10kV).

Based on the Doble test, the generator winding insulation to ground on Units #1 and #3 are acceptable. Conversely the generator winding insulation to ground is degraded on Unit #4.

3.2.3 PDA Online Measurements

The PDA activities on Units #1, #3 and #4 were reviewed in a detailed report from 1993 by Black and Veatch and again in 1998 by GE Armstrong Inc. These reports were based on the simple methods to interpret PD data on rotating machine stator windings.

With PDA-H tests in 1992 (Appendix C.2) the following were observed:

- Unit #1 stator windings have shown Qm values around the 90th percentile (508mV) of 13.8kV air cooled generators based on IEEE Objective Methods to Interpret Partial-Discharge Data on Rotating-Machine Stator Windings, G. Stone.
- Unit #3 stator windings have shown a number of Qm values exceeding the 90th percentile.
- Unit #4 stator windings have shown high Qm values exceeding the 90th percentile Phase A, BC2, and C of Unit #4 are well above the 90th percentile.

Qm values well above the 90th percentile indicate a high risk of failure.

3.2.4 DC High Potential Tests

The Bay d'Espoir generating station has been using the DC high potential step voltage controlled tests in 3kVDC step/3 minutes up to 27kV (or 30kVDC) to test generator stator windings. At the last step of 27kVDC the duration stays for 10 minutes before ending the test. This step controlled voltage test is a very effective test to evaluate the weakness or deterioration of the stator winding insulation, particularly if it is performed on each phase with the other two phases grounded.

Based on test results (Appendix C.3):

- Unit #1 stator winding insulation to ground starts to show weakness from 15kVDC to 27kVDC.
- Unit #3 stator winding insulation to ground is good until the highest voltage of 27kVDC. With my experience in reviewing this type of test, there is no concern that this generator winding insulation will fail in service within the near future.
- Unit #4 stator winding insulation to ground has shown signs of deterioration since 2001 and later. This trend may indicate a potential winding insulation failure. Unit #1 may be similar or better then unit #4 because the test data for Unit #1 is limited to one measurement.

3.3 Generator Major Incidents/Electrical Maintenance

Using the timeline from commissioning year to present year (2011) the major incidents/maintenance of all three units are as listed below and summarized (in Appendix D).

3.3.1 Unit #1

1993

- Complete stator re-wedging using piggyback wedges, replacing old GE split wedges.

1994

- New maintenance forms started being used.
- PM6 is the annual maintenance or inspection sheet with the rotor in place.
- PM9 is major maintenance with the rotor removed. This maintenance is typically performed every 6 years.

1998

- A complete static exciter replacement with better performance.
- Asphalt leaking out of stator coils at the bottom end was detected by visual inspection.
- With the implementation of the new maintenance program, any deficiencies found during PM9 are to be corrected before re-assembly of the unit.

1999

- Replacement of loose wedges.

2000

- During PM9 one stator coil failed under Hypot test at 27kV and it was replaced.
- Repair loose V-block shim (micarta) between poles #18 & #19.
- Repair field leads.

2004

- During PM6, repair done to the flexible leads connecting the rotor bus leads to the slip rings.

2007

- PM9 Hypot test results at 27kV creeping up from 180 to 230 micro-amps during tests before and after cleaning.
- Replace slip rings by robbing unit #2 slip rings.

2008 – 2011

- Only annual PM6, all megger test results during PM6 since 1994 are normal and acceptable.

3.3.2 Unit #3

1991

- Complete stator and rotor re-wedging using piggyback wedges to replace old GE split wedges.

1994

- Start new preventative maintenance forms for annual PM6 and a 6 year cycle for PM9.

1995

- Slip rings dirty, meggered result only 45 Mega-ohms.

1997

- Exciter replacement.
- Stator core found damaged on phase B between 345-346 slots.

1998

- PM6: asphalt leaking out of stator bars in the coil.

1999

- Major work done during this PM.

2000

- Dry ice cleaning of stator and rotor.

2001 – 2007

- PM6, no abnormality found, PI tests are within normal range and acceptable.

2008

- Unit relayed out: IPB connection to the unit transformer damaged and broken then repair done.
- Slip ring needs cleaning, top of rotor cleaned with dry rags.

2009

- PM6: Generator cooler replaced.
- Wedge inspection.

3.3.3 Unit #4

1992

- Complete stator re-wedging using piggyback wedges replacing the old GE split wedges.
- Generator trip on stator ground fault: problem found at one of the main leads: bus was reinsulated.

1993

- Inspection: Loose core laminations, 12 to 16 shorted laminations.
- Need cleaning & epoxy coating.

1994

- PM6: PI test has a good result.
- Wedge inspection.

1995

- Inspection: No comment (OK).

1996

- Re-tape the rotor pole jumpers.

1997

- Start-up inspection (OK).

1998

- Exciter replacement.
- PM6: PI test barely acceptable (2.46).

1999

- PM9: Stator re-wedge with piggyback wedges.
- Re-tape generator rotor pole leads on stator line side connection and neutral leads..
- Repair four rotor rim keys.
- Re-torque stator core bolts.
- Install shims to tighten and fingers/repair 6 loose fingers.
- Correct shorted laminations in stator core.
- Clean rotor.

2000

- PM6: Wedge inspection, two slots loose.
- Section of stator insulation repaired.

2001

- PM6: PI = 3.6 before cleaning and 3.4 after cleaning which is within normal range.

2002

- PM6: PI = 3 (OK).

2003

- Major incident: Unit breaker malfunction (open and closed repeatedly). During investigation, stator windings were found damaged on the upper end turns of six stator coils (near the coil exit from the stator core). An in place repair was completed using RTV silicone and over taped with self amalgamating electrical insulation tape.

2004

- PM6: PI = 3.64 (OK).

2005 - 2006

- PM6: PI = 2.5 before cleaning and 3 after cleaning (OK).
- PM9: PI = 1.7 and 650M-Ohms at 10 minutes (this is below the minimum acceptance of 2).
- Dry ice cleaning of stator & rotor.
- Exciter has a lot of dust.
- Two brushes replaced.

2007

- PM6: Detailed inspection of slip ring and 9 brushes were replaced.

2008

- PM6: PI test result 2.91 (OK).
- Two rotor leads need to be re-taped.
- Stator needs cleaning.

2009

- PM6: PI = 3.27 (OK).
- Rotor bus corona found.
- Stator cleaned.

2010

- PM6: PI = 3.55 (OK).

2011

- PM6: PI = 3.27 (OK).
- PM9: loose pole keys on 6 rotor poles fixed.
- Damaged taping on poles.
- Shorted core laminations on stator repaired.
- Rotor pole leads re-taped.
- Wedge inspection.
- Stator and rotor cleaned.

3.3.4 Summary of Maintenance Reports

Unit #1 had one coil failure under a Hypot test. The failed coil was replaced but several other top coils in the span had to be pulled to replace the failed coil. This failure under test did not cause any detrimental effects to other windings. There was nothing abnormal reported on the stator, its frame or the IPB connections to the unit transformer. The generators rotor interpole V-block shims (spacers) between poles 18 and 19 were replaced along with the field leads and the rotor pole voltage drop test results are within acceptable limits. Water was leaking from the North upstream air cooler.

Unit #3 had a stator ground fault caused by a failure with the IPB (Isolated Phase Bus) flexible connections to the transformer, there was no effect on the stator windings. The stator core was damaged on phase B between slots 345 and 346 and was repaired the following year. Several items were addressed on the generator rotor including a pole adjustment, re-taping the pole leads and the slip rings were repaired. The rotor pole voltage drop test results are within acceptable limits. The IPB connections to the unit transformer were damaged on phase B and then repaired. No cooler water leaks were reported.

Unit #4 experienced loose wedges in 1999 (following a complete re-wedging in 1992) and was re-wedged. During an inspection in 2000, two slots wedges were found loose. Based on the finding of these loose wedges, it appears that the cyclic operation has affected the tightness of the stator coils. In 1993 the stator core had loose and shorted core laminations. In 1999 six loose press fingers of the core were repaired by shimming and tightening and the stator bolts were re-torqued.

In 2003 Unit #4 suffered a major incident due to multiple opening/closing actions on the unit breaker due to a malfunction. The end turns of six stator coils were damaged (just outside the coil exit from the core), apparently by a stray bolt. A compromised method of repair was done in place without pulling out the coils from the stator slots. This incident caused a significant impact on the generator both mechanically and electrically.

Other problems encountered on the Unit #4 stator include loose core laminations in the stator core were repaired by re-torquing the bolts, six loose press fingers were repaired by installing shims to tighten the end fingers and 12 to 16 shorted laminations were found and repaired. Several problems on the generator rotor were also addressed including re-taping of the rotor jumpers, repairs to four rim keys, detection of rotor bus corona by plant staff, loose pole keys on six rotor poles were fixed and damaged taping on the poles was corrected. The rotor pole voltage drop test also revealed deficiencies on five poles. There was nothing abnormal with the IPB connections to the unit transformer.

3.4 Unit #2 Used Coil Examination

One piece of used coil, approximately 12 inches long and from the slot of the core, was removed from Unit #2 in 2010 during the stator rewinding. This piece of coil was provided to AMEC for examination.

A visual examination was conducted, yielding the following comments:

- Oil mixed with black dirt is soaked into the outside overall tape of the coil. It is evident that the oil leaking problem that entered the stator slot from the top of the core is very serious.
- The insulation swell is observed at the core vent hole.
- Asphalt has migrated downward and the mica tape has a lack of asphalt on many layers.
- Mica tape delamination is evident.
- Turn insulation is not examined.

All of the observations above support the PDA monitoring in the past, indicating high activities of PD in the slots and delamination of the insulation. Over the long term, the common problem of oil leakage must be corrected for all units. The common long term oil leak problems for all units must be fixed.

3.5 Feedback from Voith during Unit #2 Complete Rewind of Stator

Feedback obtained from a Voith specialist is as follows:

- Stator coils were asphalt mica with heavy indications of slot discharges.
- Wedges were very loose.
- Coils were severely delaminated as the asphalt had migrated down.

- Stator core splits were OK.
- Rotor pole V-block were loose due to shrinkage in the micarta spacers.

At Bay d'Espoir, both Unit #2 and #4 have multiple start/stop cycles compared to the base load operation of Units #1 and #3. Therefore the condition of Unit #4 is likely similar to Unit #2.

4.0 CONCLUSION

Taking into account the analysis of the three units, the condition assessment is as follows.

4.1 Unit #4

Unit #4 is in the worst condition of the three units. Its reliable operation is uncertain and may lead to failure of the stator windings following an electrical system disturbance. With a major overhaul this year, Unit #4 is expected to operate until spring 2012 without a high risk of major problems, except for the fact that the winding insulation is weak. A complete stator rewind should be planned for spring or summer 2012, together with a stator repair to restore the integrity of the core for the life of the new stator windings. The rotor poles field windings are also to be re-insulated, V-blocks to be fixed and with other maintenance work performed.

4.2 Unit #1

Although weakness of the stator winding insulation to ground already shown in testing, it is likely able to operate without high probability of major failure on the stator windings until the spring of 2013. Follow up testing should be performed annually and a complete stator rewind should be scheduled for spring/summer 2013, together with reinsulation of the rotor poles field windings and other maintenance work.

4.3 Unit #3

The Unit #3 stator winding insulation is still in good condition, except the PDA measurements are around the 90th percentile, indicating future problems. With annual follow-up testing Unit #3 can be expected to be in service for a few years. It is recommended to follow the current schedule to replace the stator windings in the spring/summer of 2014, together with reinsulation of the rotor poles field windings and other maintenance work.

It is notable that Units #1 and #3 provide station services for the Bay d'Espoir generating plant. Therefore if Unit #1 and #3 are scheduled for stator rewind, it is worthwhile to consider to have redundant station service available by back feeding the unit transformer, with temporary ground fault protection set up for the ungrounded 13.8kV bus, or to move the station service to Unit #2 or #4.

4.4 Environmental Influences

The environmental influences on the insulation life as mentioned in IEEE Std. 434-2006 include moisture, oil vapor, carbon dust, brake dust and other contaminants. At the Bay d'Espoir plant, it appears that the oil leaks and carbon dust problems have been present for a long time on units one through four. No solution has surfaced to eliminate or reduce these effects. It is recommended that more effort be put into fixing these problems.

4.5 Work to be Carried Out During Generator Stator Re-wind

The stator re-wind will extend the life expectancy of the generator windings for another 40 years or more. It is recommended that other generator main components be repaired (or replaced) to match the life extension of the windings.

- Generator Core/Frame

  Major maintenance work should be carried out during the rewind outage to restore the core/frame integrity after the removal of the old windings and are as follows:

  - A thorough inspection after cleaning to identify core/frame deficiencies (backcore and inside the bore, core splits, etc.).
  - A thorough inspection of stator air vents to ensure that all air vents conditions are acceptable.
  - A core full flux test or an ELCID low flux test, to detect defects on the core laminations. (The ELCID is also a good tool to check/compare the core repair result with a good portion of the core).
  - A test for loose laminations at the step-down section of the core to detect loose pressure fingers. Corrective action would have to be done including shimming or re-torquing the stator finger bolts.

- Generator Rotor

  To extend the life of the rotor to match with the new stator rewind, the following work should be done:

  - In order to maintain the integrity of the field winding insulation, the pole field windings must be reinsulated with modern non-asbestos Class F insulating material (NOMEX).
  - All the inter-pole leads and main field leads (copper bars) connected to slip rings must be checked for cracks and re-taped properly.
  - The slip ring condition must be checked and re-machined if necessary.
  - The rotor rim and spiders must be examined by non-destructive testing (NDT) before re-assembling the poles.
  - Generator air coolers are to be cleaned and tested for leaks.

- Generator isolated phase bus (IPB) is to be inspected, particularly the flexible connections at both ends (generator & transformer).

- Generator Protection

  The existing generator protection relays are electromechanical relays which have been in service for more than 40 years. It is recommended that the protection be upgraded to modern microprocessor based relays at the same time as the generator refurbishment. Modern relays offer faster response, better reliability and less routine maintenance.

- Generator Online Monitoring
  - The existing partial discharge analyzer (PDA) should remain in use.
  - The existing stator winding temperature monitoring should remain the same.
  - The generator air gap monitoring system should be installed during this re-wind (as already done for Unit #2).
  - It is worthwhile to add/to enable the rotor field temperature monitoring in the existing static excitation system.
  - The vibration monitoring should remain the same.

- Generator synchronizer

  The generator auto synchronizer performance is to be checked to conform to IEEE Std. C50.12.2005.

  Unit transformer and unit breakers have not been included in this scope.

4.6 Recommendations

Units #1, #3 and #4 are scheduled for refurbishment as per the following schedule.

- Unit #4 – As soon as possible. The earliest this refurbishment could reasonably occur is in the spring or summer of 2012.
- Unit #1 – Spring or summer of 2013.
- Unit #3 – Spring or summer of 2014.

For the annual follow-up DC controlled voltage tests, we suggest that the test procedure be revised as follows:

- The 3kVDC step/ 3 minutes appear to be too large. It is worthwhile to consider a 2kVDC/2 minutes step from 12kVDC and up (i.e. 14, 16, 18, 20, 22, 24, 26 and 27kV). As well, the charging current should be kept at 100-150 micro-amps maximum for each step.
- The current versus voltage curve should be plotted with the test results from each step, such that the test is aborted when the current is measured to be excessive. This will reduce the likelihood that the DC step control voltage test causes further damage.

These tests should be performed on Units #1, #3 and #4 every year until they have been refurbished. Poor test results may indicate a requirement for a more aggressive refurbishment schedule. However, because of other factors relating to the condition of these units, successful test results should not be used as a reason to delay refurbishment past the schedule outlined above.

5.0 BIBLIOGRAPHY

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[2] IEEE Trial-Use Guide to the Measurement of Partial Discharges in Rotating Machinery. *IEEE Std 1434-2000.* April 26. 2000.

[3] IEEE Std 1147-2005, IEEE Guide for the Rehabilitation of Hydro-Electric Power Plants.

[4] IEEE Std. 434-2006, IEEE Guide for Functional Evaluation of Insulation Systems for AC Electric Machines Rated 2300 V and Above.

[5] C. Wendel. C-E. Stephen. T. Kunz. (2010, Nov.). Predicting the Remaining Life of Generator Components. Renewable Energy World. [Online]. Available: http://www.renewableenergyworld.com/rea/news/article/2010/11/predicting-the-remaining-life-of-generator-components

Appendix A: Project Site Report (July 4-7, 2011)

PROJECT SITE REPORT

PROJECT: Generation Windings
Nalcor Energy Bay D'Espoir

REFERENCE NO.: 168688-9.4

CLIENT: Nalcor Energy

REPORT DATE: July 29, 2011

CONTRACTOR:

VISIT DATE: July 4 – 7, 2011

REPORT BY: David Jones and Jonathan Flynn

CATEGORY:	**Civil:** ☐	**Arch:** ☐	**Mech:** ☐	**Elect: X**	**Struct:** ☐
PURPOSE:	**Quality/Progress Review:**	**See Below**	**Site Coordination:** ☐	
	Substantial Performance: ☐		**Final Performance:** ☐	
PROGRESS:	**Scheduled: ______%**		**Actual: ______%**	

Participants:

Bob Woodman, Nalcor, Bay D'Espoir
Louis Barnes, Nalcor, Bay D'Espoir
Ron Bartlett, Nalcor, Bay D'Espoir
Dave Jones, AMEC
Jonathan Flynn, AMEC

Purpose: **To collect information and data regarding generator windings.**

Monday, July 4, 2011

Dave Jones and Jonathan Flynn arrived at Nalcor, Bay D'Espoir, Powerhouse #1, at approx. 2:00pm, and were received by Bob Woodman, who carried out Site Orientation as per the Manual: BDE-Contractor Orientation Manual, Chapter 4, Appendices A & B. (Acceptance of Safety Requirements and dated signatures, are on file).

Following the orientation, Dave Jones, Jonathan Flynn and Bob Woodman, reviewed the Documents that were forwarded by Dat Tran on 07 June, 2011, with the following comments and understandings, in respect to units 1, 3 and 4.

1. Nalcor was asked to provide a 3-line diagram, as it would provide full details of unit protection typical of all units.
2. Nameplate ratings of generators and power transformers would be photographed.

PMF.06 Rev. 1

3. Nalcor forwarded a stator wiring diagram, typical for all generators.
4. Generator excitation is static type for all units.
5. Operating histories for units 1, 2 and 3 will be provided, with the exception of core ELCID tests, which are not carried out.
6. Excitation system annual- maintenance histories will be provided. Bob Woodman will provide a brief write-up of the Bay D'Espoir operating history, which will include that units 1 and 3 are the station service units and their usage in the dispatch orders. Also the use of units based on island loads and system water management.
7. Information will be provided regarding any forced synchronization, and the resulting coil repairs, in the FO-03-002 Report.
8. Work Order Listings will be provided that arose due to electrical faults.
9. Any water cooler leaks, and repairs information will be provided by Nalcor, St. John's.
10. A section of used coil will be provided, if available. It may not be able to determine where the actual sample was taken from.
11. The FM Global Insurance Report will be provided.
12. Unit 2 Voith Rewind Report will be provided.
13. Information will be forwarded form the Maintenance Data Register.

Tuesday, July 5, 2011

Teleconference was held at 8:00am, with Bob Woodman (Nalcor), Andrew Duplessis (AMEC), Dat Tran (AMEC), Dave Jones (AMEC) and Jonathan Flynn)AMEC). Discussions took place on the information requested from Dat Tran and the decisions made as itemized Monday July 4, 2011.

After the meeting, information was gathered regarding Units 1, 2 and 4 power transformers and generators, and a quick look at the P and C panels in the control room.

Unit 4 was locked out by Nalcor personnel in readiness for our inspection. After a review of the Options Order 11385/11386/11389/11390 sheets, Bob, Dave and Jonathan walked through the isolations to ensure unit was locked out to their satisfaction.

After a satisfactory walk through, a visual inspection complete with photographs, was carried out of the stator, rotor and generator housing.

The top of the stator and rotor windings were in a clean and good condition with some dirt and dust contamination, no insulation damage or loose bindings and wedges.

Photograph 009 – Stator top windings looking clean.

Photograph 013 – Stator top windings showing dusty conditions.

Photograph 016 – Indicates some vibration. See the paint stripped where the pipe slip fits in the bracket.

Photograph 020 – Terminations at one end of stator top windings indicates old dust and dirt contamination although there has been cleaning.

Photograph 023 – Top of stator and rotor showing the air gap. Although cleaned still shows old contamination.

The bottom of the stator and rotor showed no loose wedges and bindings, but showed more dirt and oil contamination.

Photograph 036 – Stator bottom windings showing age and ingrained dust and oil contamination.

Photograph 041 – Oil contamination on the underside of the generator. This area has been cleaned but still shows the old contamination.

Photographs 046 – Stator winding has been cleaned. Rotor does not appear to have been cleaned.

Photographs 047 – Stator bottom winding. Although having been cleaned show oil and dust contamination from the years of service.

Photograph 050 – Oil film near brakes. Can see silhouette of the junction box in the horizontal surface.

The floor and concrete beneath the windings showed no signs of cracking but although being recently cleaned showed many years of oil contamination.

Bob arranged for a meeting with ourselves, Louis Barnes and Don Bartlett to discuss operation of the units and any major failures of the units. It was determined that the stator frames were provided in 4 sections and the cores stacked for site assembly. Major inspections are carried out on a 6 year basis. PDA monitoring was installed on all units in the 1990's. The generators are usually run at base load (60-65 MW). Units 1 and 3 are the first units on and last units off as they provide stator service. All other units are put on line randomly.

There have been no major failures of any of the units. It was thought that Unit 4 was taken off under load at one time, but Nalcor personnel were unsure.

<u>Wednesday, July 6, 2011</u>

Units 1, 3 and 4 maintenance files were looked at and copies of check sheets, reviews and all associated data made.

Maintenance files included all information relevant to the stators, rotors, slip-rings and excitation of units 1, 3 and 4.

<u>Thursday, July 7, 2011</u>

Final discussions took place between Bob, Dave and Jonathan to ensure that as much relevant data had been collected. An electronic copy of all information gathered reports and pictures from annual maintenance on generators was supplied by Nalcor. See information collected during Site Visit in Table 1.

Outstanding information will follow from Nalcor and will include those items in Table 2.

Following the gathering of all information Dave and Jonathan left Nalcor, Bay D'Espoir at approximately 1:00 pm.

<u>Attachments:</u>
Table 1
Table 2
Photos

AMEC Americas Limited
Power & Process

David Jones

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BAY D'ESPOIR WINDING ASSESSMENTS

Information Collected During Site Visit

Table 1

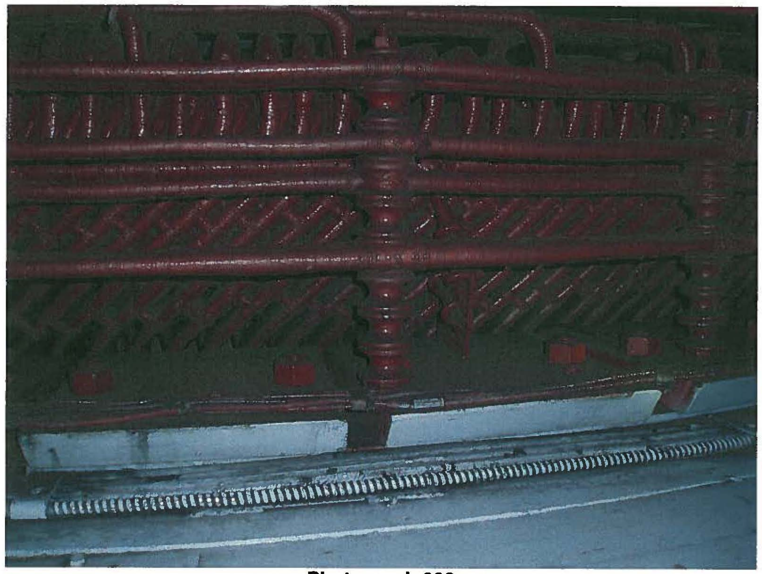
Description	Common	Unit 1	Unit 2	Unit 3	Unit 4
Bay D'Espoir Operating History	×				
Operation Records	×				
Stator Winding Temp, Trending	×				
Generator Plan and Sections	×				
Winding Details	×				
Unit 4, 3-Line Diagram	×				
Voith Unit 2 Rewind Final Documentation			×		
Voith Unit 2 Rewind OM Manual			×		
Voith Unit 2 Rewind Final Test Report			×		
Voith Unit 2 Rewind Drawings			×		
PDA Database	×				
Unit 3 Site Inspection Photographs				X	
2009 Inspection Details		×			
2010 Inspection Details		×			×
2010 Inspection Pictures		×	×	×	
2011 Inspection Pictures		×		×	×
Generator Corrective Work History		×	×	×	×
Generator Rotor Corrective Work History		×	×	×	×
Generator Stator Corrective Work History		×	×	×	×
PD Standard Report (Iris Power)		×		×	×
PD Trend Analyses (Iris Power)		×		×	×
Preventive Maintenance Check sheets		×		×	×
Double Test Sheets		×		×	×
Hi-Pot Test Sheets		×		×	×
Polarization Index Check sheets		×			×
Wedge Inspection				×	×
Hyd. Equipment Register Activity Sheet		×		×	×

BAY D'ESPOIR WINDING ASSESSMENTS

Information to be sent by Nalcor after Site Visit

Table 2

Description
FM Global Project Report
Unit & Stator Winding Damage Report
Operating History Report
Replacement of Stator Windings Report
Analysis of Turbo-Generator Core Inspection Assessment C/W Photographs, Annual Inspector Reports, Ground Fault Reports, etc.
Generator and Stator Exciter Condition Study
Water Cooling Problems
Section of Used Coil



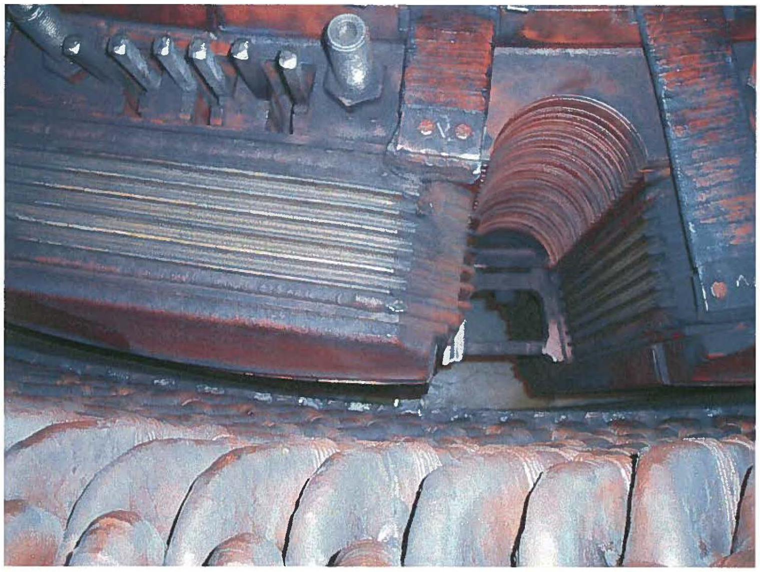
Photograph 009

Photograph 013

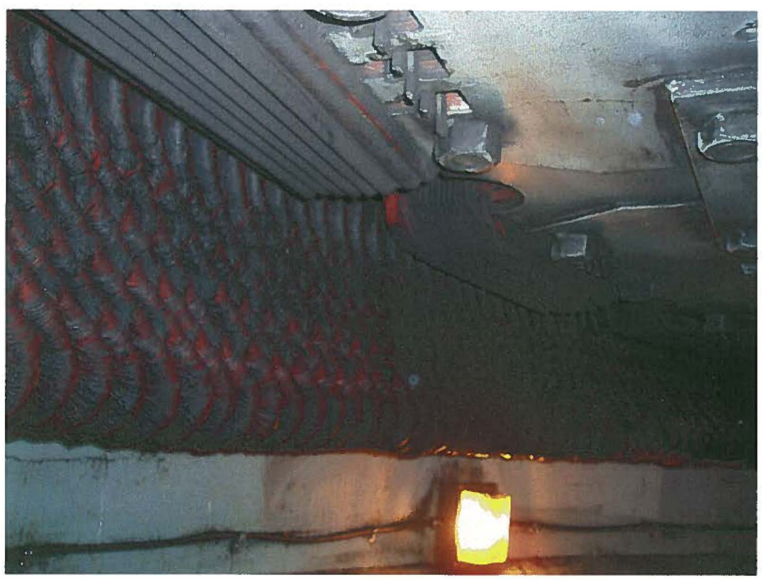
AMEC Ref. 168688 **July 29, 2011**

Photograph 016

Photograph 020

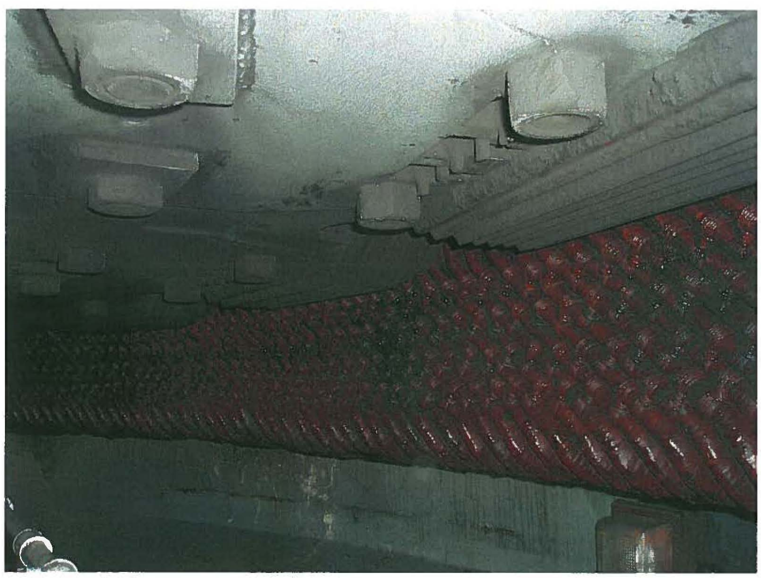


Photograph 023



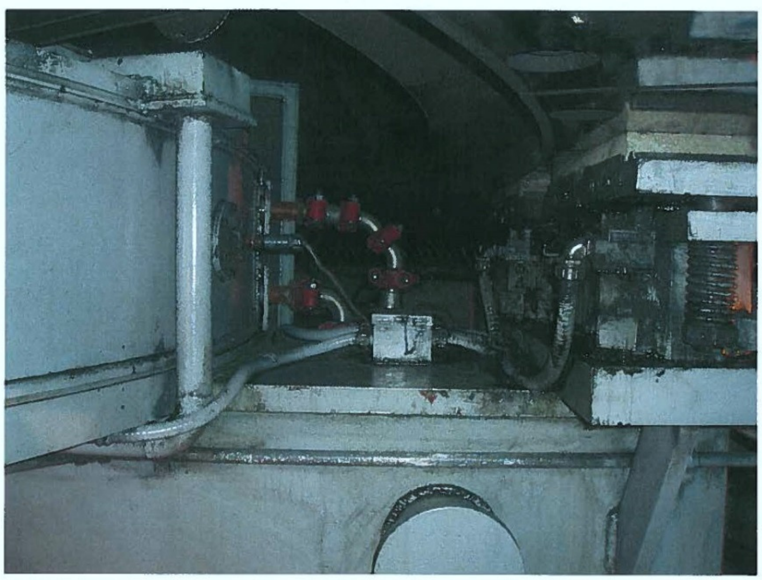
Photograph 036

Photograph 041



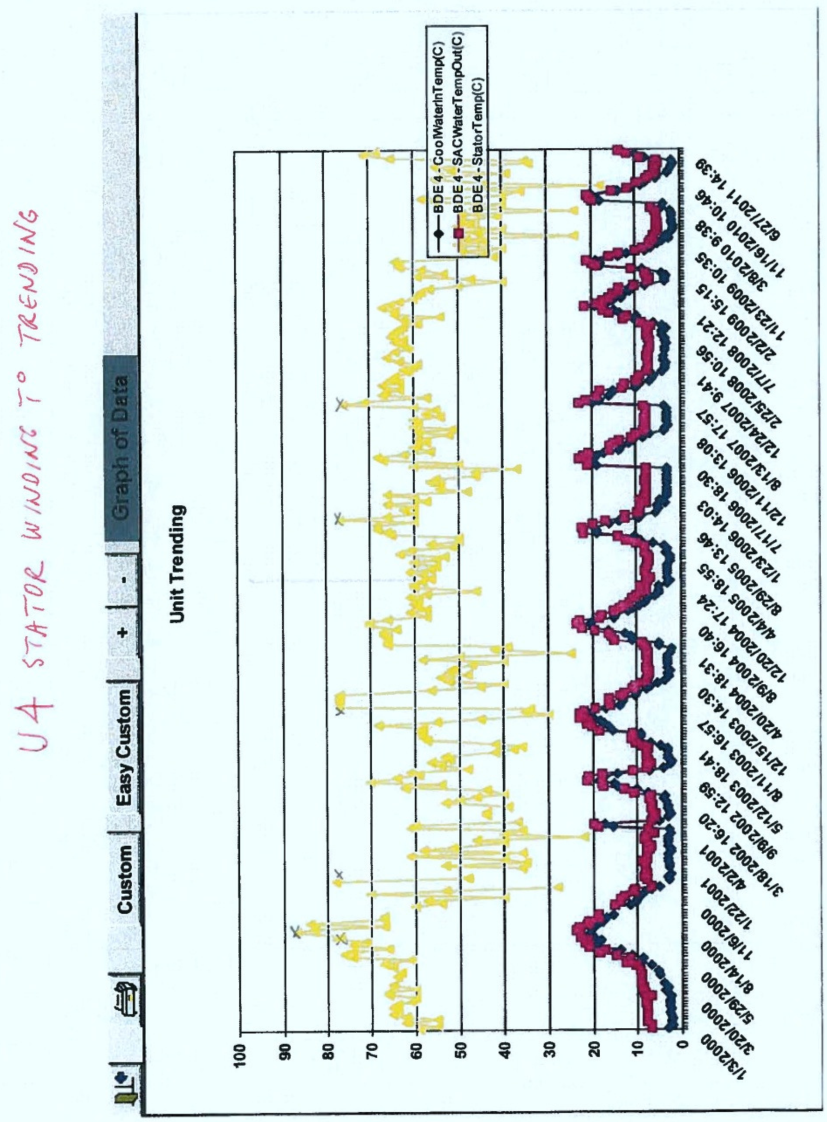
Photograph 046

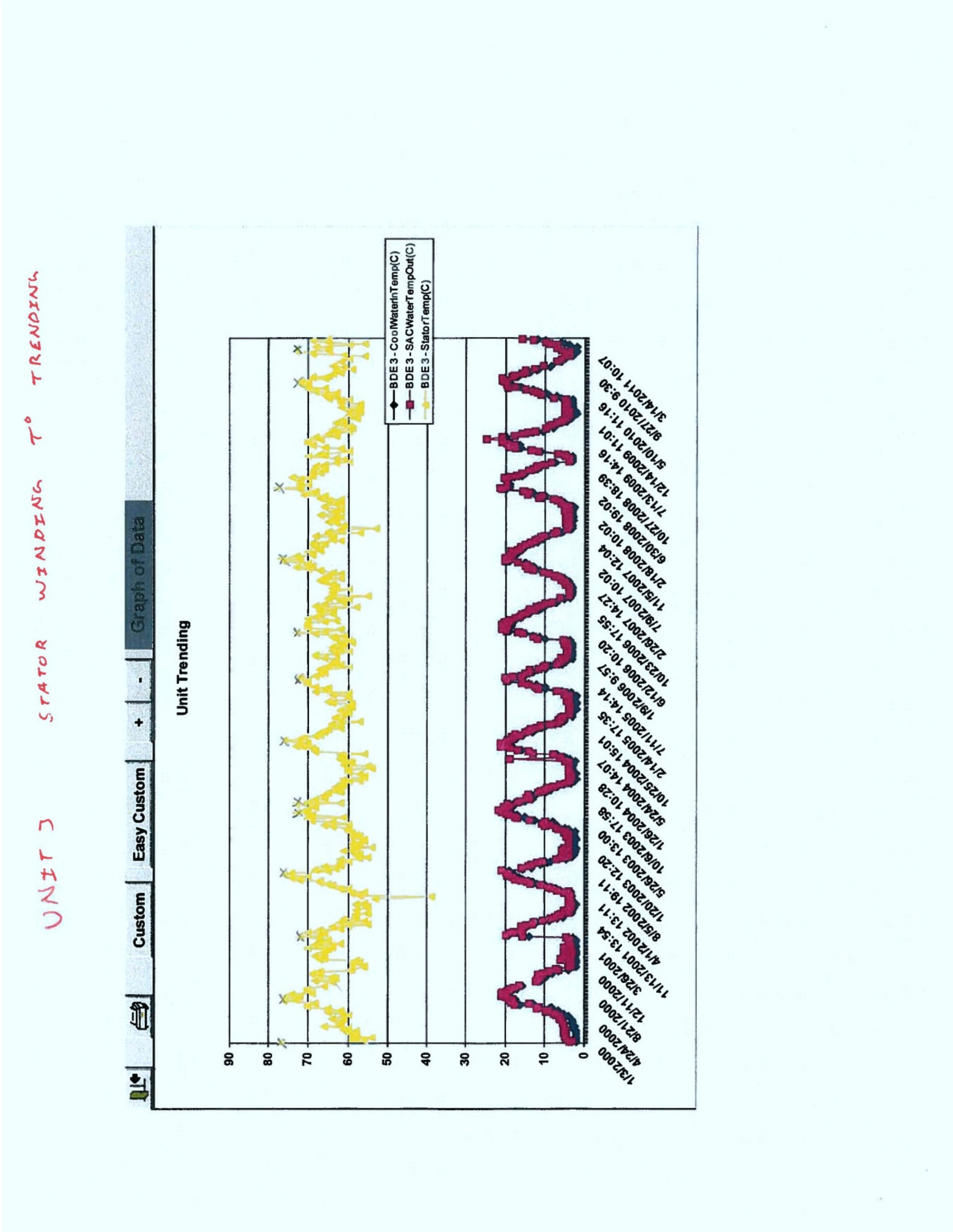
Photographs 047

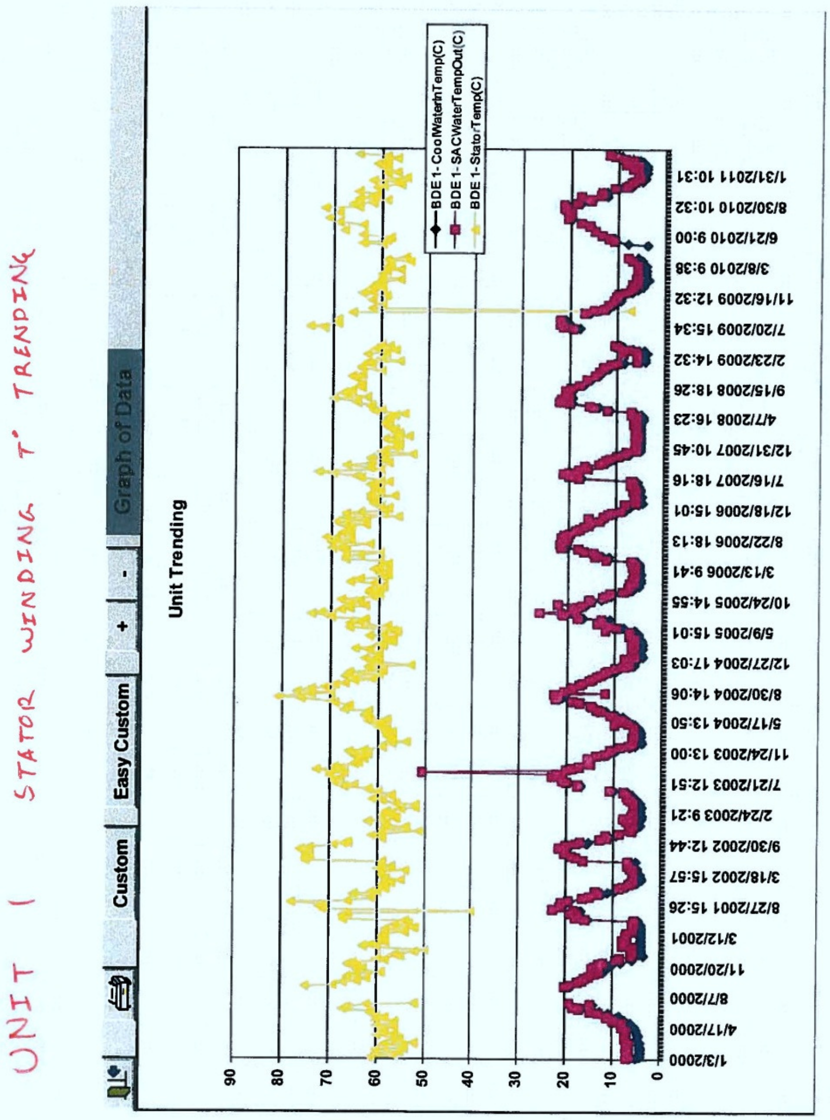


Photograph 050

Appendix B: Operating Temperature


U4 STATOR WINDING T° TRENDING
Custom
Easy Custom
Graph of Data
Unit Trending
BDE 4 - CoolWaterInTemp(C)
BDE 4 - SACWaterTempOut(C)
BDE 4 - StatorTemp(C)
100
90
80
70
60
50
40
30
20
10
0


UNIT 3 STATOR WINDING T° TRENDING
Custom
Easy Custom
+
-
Graph of Data
Unit Trending
BDE 3 - CoolWaterInTemp(C)
BDE 3 - SACWaterTempOut(C)
BDE 3 - StatorTemp(C)
90
80
70
60
50
40
30
20
10
0
1/3/2000
4/24/2000
8/21/2000
12/11/2000
3/28/2001
11/13/2001 13:54
3/14/2011 10:07


UNIT 1 STATOR WINDING T° TRENDING
Custom
Easy Custom
Graph of Data
Unit Trending
BDE 1- CoolWaterInTemp(C)
BDE 1- SACWaterTempOut(C)
BDE 1- StatorTemp(C)

Appendix C.1: Doble Test Summary

All Doble test data provided for Units #1, #3 and #4 over the past 30 years were compiled and trends were plotted according to the tests conducted at voltages of 10kV and 2kV for each coil. Analysis of the trends on the tests for each coil is as follows.

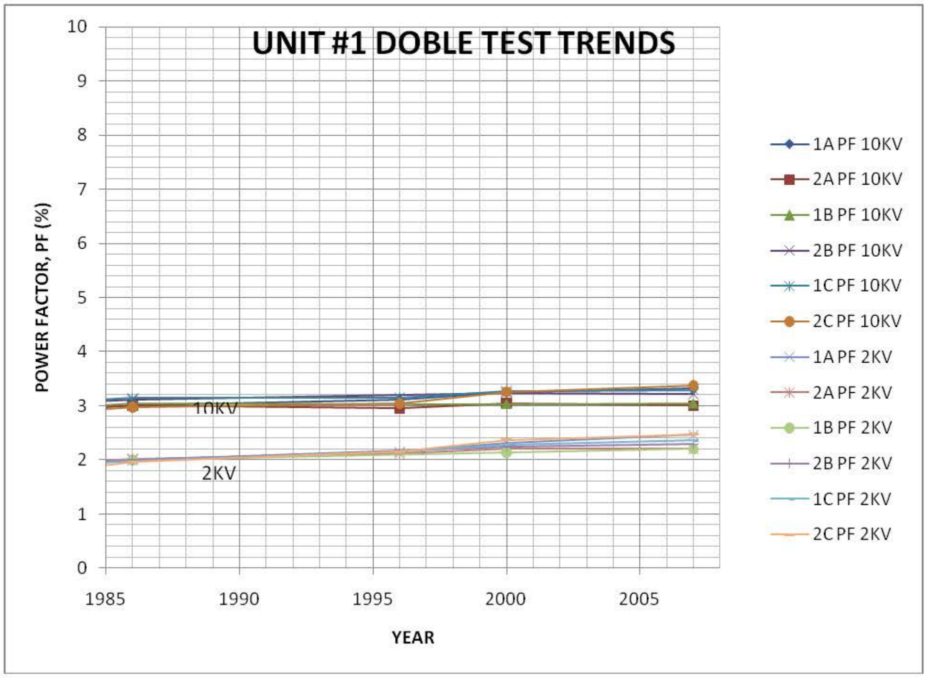
Unit #1 holds a consistent power factor of 3% at a test voltage of 10kV and as well at a test voltage of 2kV with a power factor a little above 2%.

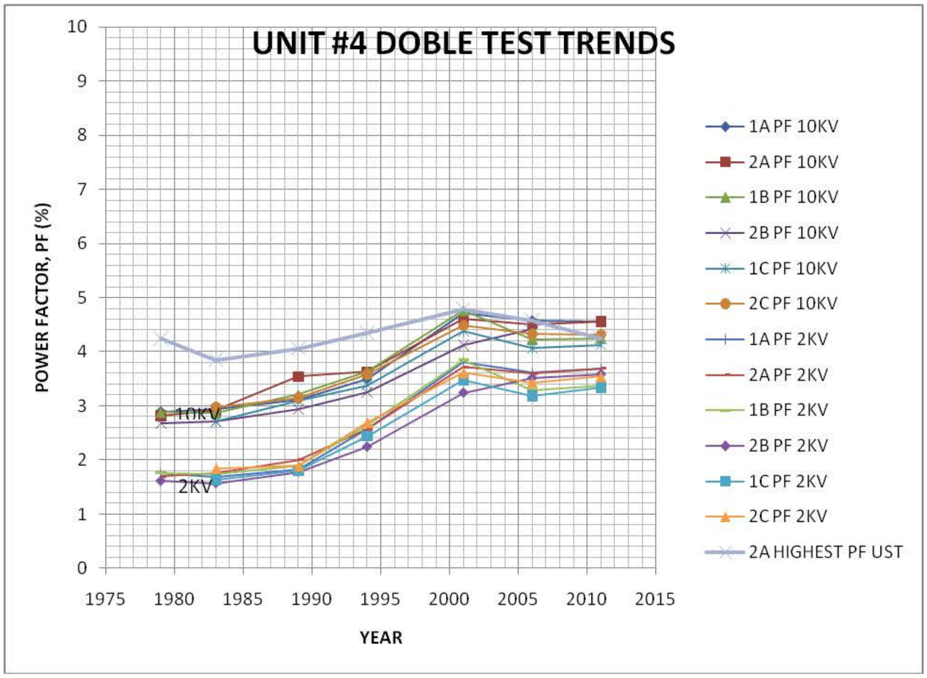
Unit #3 follows a similar trend to Unit #1 until the later tests where the slope is gradually increasing.

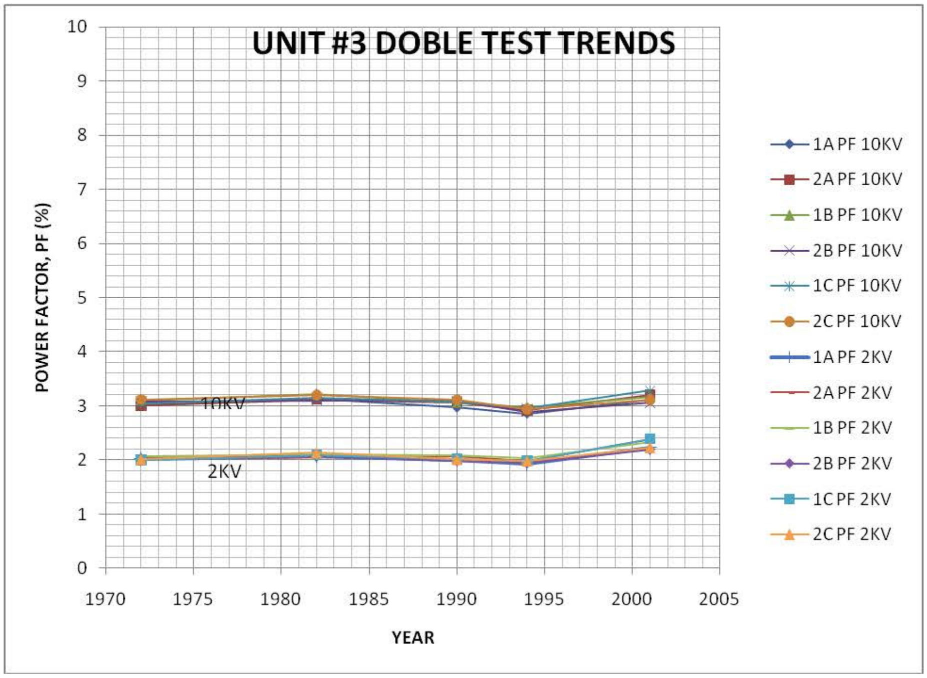
Unit #4 follows consistently linear trends until 1989 when all three phases had similar power factors of 2 and 3 percent at their respective test voltages of 2kV and 10kV. From the most current tests the second coil in Phase A reaches a power factor of 4.6% at a test voltage of 10kV and a power factor of 3.7% at 2kV. The power factor varies from zero to six percent between coils within a single year of tests; this is a sign of deterioration within the winding insulation.

According to these Doble tests, Unit #4 continues to have the worst trends between the three units. Units #1 and #3 have significantly better trends and follow the same power factors at both test voltages throughout the entire period of testing.

Prepared by: Bradley Jones
July 28, 2011


UNIT #1 DOBLE TEST TRENDS
POWER FACTOR, PF (%)
YEAR
10KV
2KV
0
1
2
3
4
5
6
7
8
9
10
1985
1990
1995
2000
2005
1A PF 10KV
2A PF 10KV
1B PF 10KV
2B PF 10KV
1C PF 10KV
2C PF 10KV
1A PF 2KV
2A PF 2KV
1B PF 2KV
2B PF 2KV
1C PF 2KV
2C PF 2KV


UNIT #4 DOBLE TEST TRENDS
POWER FACTOR, PF (%)
YEAR
0
1
2
3
4
5
6
7
8
9
10
1975
1980
1985
1990
1995
2000
2005
2010
2015
10KV
2KV
1A PF 10KV
2A PF 10KV
1B PF 10KV
2B PF 10KV
1C PF 10KV
2C PF 10KV
1A PF 2KV
2A PF 2KV
1B PF 2KV
2B PF 2KV
1C PF 2KV
2C PF 2KV
2A HIGHEST PF UST


UNIT #3 DOBLE TEST TRENDS
POWER FACTOR, PF (%)
YEAR
10KV
2KV
1A PF 10KV
2A PF 10KV
1B PF 10KV
2B PF 10KV
1C PF 10KV
2C PF 10KV
1A PF 2KV
2A PF 2KV
1B PF 2KV
2B PF 2KV
1C PF 2KV
2C PF 2KV
0
1
2
3
4
5
6
7
8
9
10
1970
1975
1980
1985
1990
1995
2000
2005

Appendix C.2: PDA Test Summary

To be able to determine how to interpret the PDA test results on each unit from Bay D'Espoir, the document [1] was reviewed. From this document Qm values are classified based on statistics from more than 6000 tests on different machines in order determine how likely it is that the machine has a problem in Table 1. Looking at these statistics with an operating voltage level of 13.8kV, the Qm value would have to be less than 508mV to be within the 90 percentile.

Table 1: Distribution of Qm for Air-Cooled Stators. 80-pF Sensors on the Terminals

Oper. Volts	2-4 kV	6-8 kV	10-12 kV	13-15 kV	>16 kV
25%	7 mV	17 mV	35 mV	44 mV	37 mV
50%	27	42	88	123	69
75%	100	116	214	246	195
90%	242	247	454	508	615*

The Qm value is determined by taking the highest PD pulse in mV with a minimum repetition rate of ten pulses per second.

Analyzing the results from the PDA-H tests done in 1992 on the three units of interest, 1, 3 and 4, the Qm value had to be derived from the provided plots. This was determined by taking the highest PD pulse in mV with a minimum repetition rate of ten pulses per second. Summarizing these derived Qm values in Table 2, the majority of the Qm values do not or barely fall within the 90 percentile for all three units.

Table 2: BDE PDA-H Test 1992, Qm Results Summary

	Unit #1 (mV)		Unit #3 (mV)		Unit #4 (mV)	
	"+Qm"	"-Qm"	"+Qm"	"-Qm"	"+Qm"	"-Qm"
Phase A, C1	-	-	1800	1500	2300	2450
Phase A, C2	675	625	2000	1800	1900	2100
Phase B, C1	475	475	450	575	200	675
Phase B, C2	450	440	580	400	700	700
Phase C, C1	620	375	2100	300	1700	1700
Phase C, C2	375	375	1800	400	700	800

From the PDA-IV test done in 2011 shown in Table 3, Unit #1 seems to have Qm values within the 90 percentile for all three phases as well as all three phases in Unit # 3. The Qm values for Phase A, C and B C2 on Unit #4 are well above the 90 percentile, but Phase B C1 is within the 90 percentile.

Table 3: BDE Differential PDA Test 2011, Qm Results Summary (Estimated from PD Trends)

	Unit #1 (mV)		Unit #3 (mV)		Unit #4 (mV)	
	"+Qm"	"-Qm"	"+Qm"	"-Qm"	"+Qm"	"-Qm"
Phase A, C1	138	98	N/A	N/A	1019	1284
Phase A, C2	104	94	368	N/A	N/A	N/A
Phase B, C1	100	100	100	1700	200	200
Phase B, C2	200	400	200	200	680	750
Phase C, C1	200	500	100	100	650	520
Phase C, C2	100	100	400	100	-	-

Possible problems attributed to these high PD levels are as follows (IEEE Std 1434-2000);

1. If a positive polarity PD pulse is high relative to the negative polarity pulse, this may indicate loose stator coils or bars in the slot.

2. Inversely if the negative polarity pulse is dominant, the problem may be traced near the copper strands and indicate a bad bond between the insulation and copper.

Comparing the two sets of PD results it is clear that Unit #4 remains the worst throughout both tests. Unit #3 has improved from high PD values in 1992 through to values within the 90 percentile in 2011. Unit #1 has also improved PD values from being on the edge of the 90 percentile in 1992 to being within the 75 percentile in 2011. Conclusions cannot be made according to these PD values, but these are good indications of potential problems, further investigation will be required in order to establish their significance.

Prepared by: Bradley Jones
July 26, 2011

[1] G. C. Stone and V. Warren. "Objective Methods to Interpret Partial-Discharge Data on Rotating-Machine Stator Windings." *IEEE Trans. Industry Application*, vol. 42, no. 1, pp. 195-200. Jan/Feb 2006.

[2] IEEE Trial-Use Guide to the Measurement of Partial Discharges in Rotating Machinery. *IEEE Std 1434-2000*. April 26. 2000.

Appendix C.3: DC High Potential Test Summary

The DC high potential tests from Units #1, #3 and #4 were all compiled and compared graphically to their respective units. Analysis of the trends between tests and units is as follows.

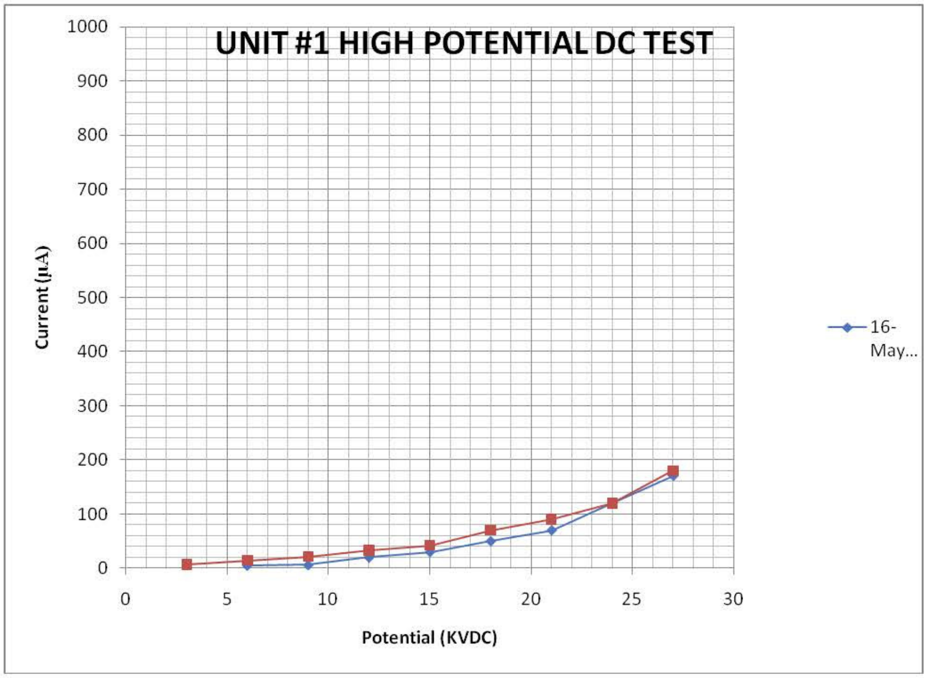
The only hypot tests provided on Unit #1 were completed in 2007, before and after cleaning in May and July respectively. Both tests follow similar a trend, gradually increasing slope with higher test voltages. Significant increases in slope begin to arise at 15kV, increasing by twice the slope in May and by almost three times in July. Both trends keep increasing in slope until the final test voltage of 27kV. Due to the lack of test data, conclusive evidence cannot be taken from these two trends, even though the available data does clearly expose weaknesses within the winding insulation.

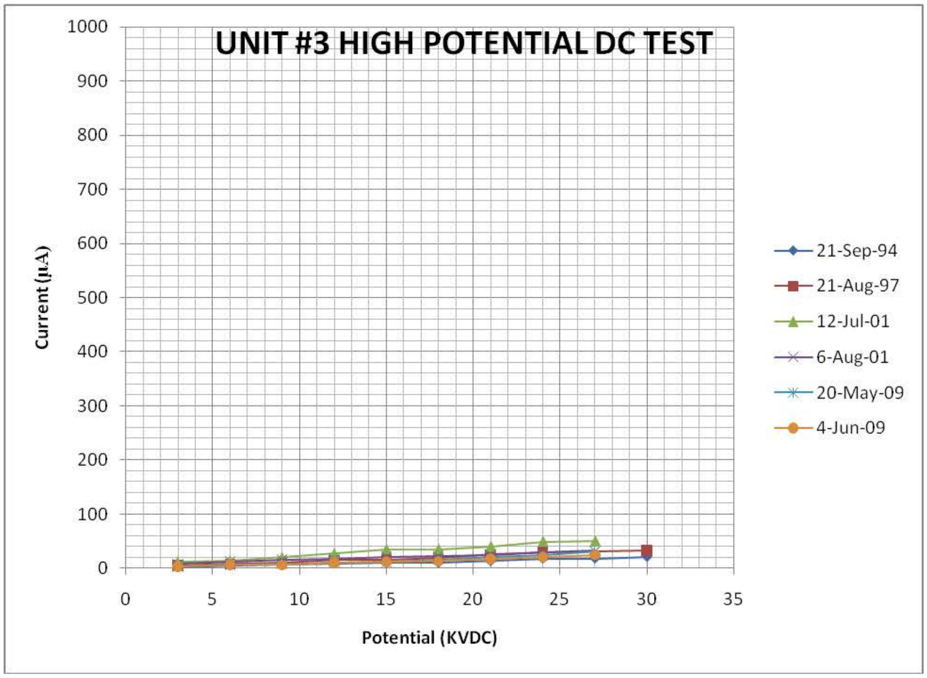
All tests completed on Unit #3 show consistently linear trends which is a good indication of acceptable test results.

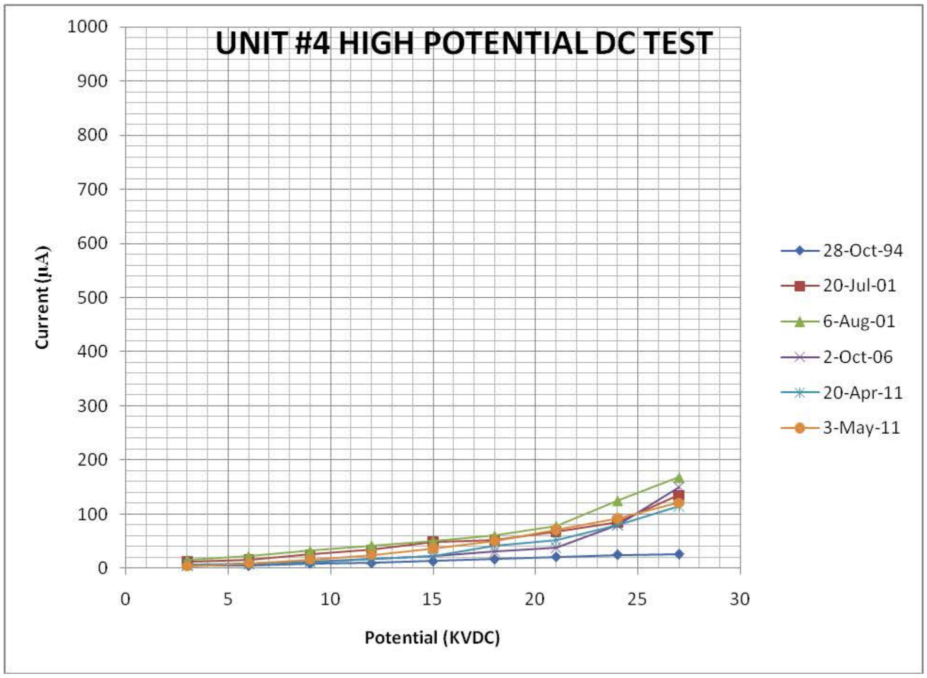
The first hypot test, done on Unit #4 in 1994, follows a linear trend with very small amounts of leakage current. Conversely, the five tests done within the last ten years show results that are not as desirable. The trends seem to remain consistently linear until a test voltage of 15kV when they begin to increase gradually, with slope changes increasing by about 5 times in 2001 and then by about 6 times in 2006. The slope changes are not as sharp in 2011 but leakage current levels are high, peaking at 120µA.

Comparing the three units, Unit #4 consistently shows the worst hypot test data out of the three, therefore would have the most deteriorated winding insulation to ground. Unit #1 would follow, having the next weakest winding insulation, but not conclusive due to the lack of data provided. Unit #3 demonstrates the strongest winding insulation to ground compared to the others.

Prepared by: Bradley Jones
July 28, 2011


UNIT #1 HIGH POTENTIAL DC TEST
Current (μA)
Potential (KVDC)
0
100
200
300
400
500
600
700
800
900
1000
0
5
10
15
20
25
30
16-May...


UNIT #3 HIGH POTENTIAL DC TEST
Current (µA)
1000
900
800
700
600
500
400
300
200
100
0
0
5
10
15
20
25
30
35
Potential (KVDC)
21-Sep-94
21-Aug-97
12-Jul-01
6-Aug-01
20-May-09
4-Jun-09


UNIT #4 HIGH POTENTIAL DC TEST
Current (μA)
1000
900
800
700
600
500
400
300
200
100
0
0
5
10
15
20
25
30
Potential (KVDC)
28-Oct-94
20-Jul-01
6-Aug-01
2-Oct-06
20-Apr-11
3-May-11

Appendix C.4: Rotor Pole Voltage Drop Test

UNIT #1, POLE DROP TEST

Deviation = (1-(Voltage/Mean))*100%

	Voltage (V)		Deviation (%)	
Pole #	5/18/2007	5/25/2007	5/18/2007	5/25/2007
1	5	5	2.0	1.8
2	5	5	2.0	1.8
3	5	5	2.0	1.8
4	4.9	4.9	0.0	0.3
5	4.9	4.9	0.0	0.3
6	4.9	4.9	0.0	0.3
7	5	5	2.0	1.8
8	4.9	4.9	0.0	0.3
9	4.9	4.9	0.0	0.3
10	4.8	4.8	2.0	2.3
11	4.9	4.8	0.0	2.3
12	4.9	5	0.0	1.8
13	4.9	4.9	0.0	0.3
14	4.9	4.9	0.0	0.3
15	4.9	4.9	0.0	0.3
16	4.9	4.8	0.0	2.3
17	4.9	4.9	0.0	0.3
18	4.8	4.8	2.0	2.3
19	4.9	5	0.0	1.8
20	4.8	4.9	2.0	0.3
21	4.9	4.9	0.0	0.3
22	4.9	4.9	0.0	0.3
23	4.8	4.9	2.0	0.3
24	4.9	5	0.0	1.8
Total:	117.6	117.9		
Mean:	4.9	4.9		
Applied Voltage:	120	120		

Comments: Considering that the error of the measuring device is about 0.1 V which is equivalent to a 2% deviation, the test results do not exceed this deviation. Therefore the test can be considered acceptable.

Prepared by: Bradley Jones
Date: August 11, 2011

UNIT #3, POLE DROP TEST

Deviation = (1-(Voltage/Mean))*100%

	Voltage (V)		Deviation (%)	
Pole #	7/8/1997	8/20/1997	7/8/1997	8/20/1997
1	4.8	4.86	0.00	1.77
2	4.9	5.1	2.08	3.08
3	4.9	5.14	2.08	3.89
4	4.8	4.92	0.00	0.56
5	4.9	4.98	2.08	0.66
6	4.9	4.91	2.08	0.76
7	4.8	4.8	0.00	2.98
8	4.9	4.9	2.08	0.96
9	4.9	4.94	2.08	0.15
10	4.8	4.92	0.00	0.56
11	4.8	4.93	0.00	0.35
12	4.9	4.92	2.08	0.56
13	4.9	5	2.08	1.06
14	4.1	4.84	14.58	2.17
15	4.2	4.85	12.50	1.97
16	4.7	4.97	2.08	0.45
17	4.9	5.01	2.08	1.26
18	4.8	4.9	0.00	0.96
19	4.8	4.97	0.00	0.45
20	5	5.04	4.17	1.87
21	4.9	4.81	2.08	2.78
22	4.8	4.82	0.00	2.58
23	4.8	5.08	0.00	2.68
24	5	5.13	4.17	3.69
Total:	115.2	118.74		
Mean:	4.8	4.9		
Applied Voltage:	119.6	118.0		

Comments: Looking at the test done in July of 1997, the voltage drops across all of the poles do not add up to the voltage applied, this is due to a dip in voltage at the 17 and 18th pole. This problem is not seen in August 1997, which would imply that either the poles were repaired or the earlier test was faulty.
Considering that the error of the measuring device is about 0.1 V which is equivalent to a 2% deviation, the test results for the latest test do not show anything abnormal.

Prepared by: Bradley Jones
Date: August 11, 2011

UNIT #4, POLE DROP TEST

Deviation = (1-(Voltage/Mean))*100%

	Voltage (V)		Deviation (%)	
Pole #	6/21/2006	7/7/2006	6/21/2006	7/7/2006
1	3.77	3.8	23.79	23.13
2	5.1	5.11	3.09	3.37
3	4.51	4.53	8.84	8.36
4	5.22	5.22	5.52	5.60
5	4.73	4.72	4.39	4.52
6	6.42	6.45	29.77	30.48
7	6.27	6.28	26.74	27.04
8	4.83	4.83	2.37	2.29
9	5.35	5.35	8.14	8.23
10	4.71	4.56	4.79	7.75
11	5.2	5.2	5.11	5.19
12	3.51	3.5	29.05	29.20
13	3.47	3.46	29.86	30.01
14	5.06	5.05	2.28	2.16
15	4.7	4.7	4.99	4.92
16	5.19	5.19	4.91	4.99
17	4.57	4.57	7.62	7.55
18	6.57	6.56	32.81	32.70
19	6.42	6.43	29.77	30.07
20	4.53	4.52	8.43	8.56
21	5.13	5.13	3.70	3.78
22	4.75	4.75	3.98	3.91
23	5.21	5.2	5.31	5.19
24	3.51	3.53	29.05	28.59
Total:	118.73	118.64		
Mean:	4.95	4.9		
Applied Voltage:	118.20	118.0		

Comments: Considering that the error of the measuring device is about 0.1 V which is equivalent to a 2% deviation, only a 2% error can be expected. All of the test results for both sets of data show signs of problems and are not acceptable.

Prepared by: Bradley Jones
Date: August 11, 2011

Appendix D: Generator Major Incidents/Electrical Maintenance

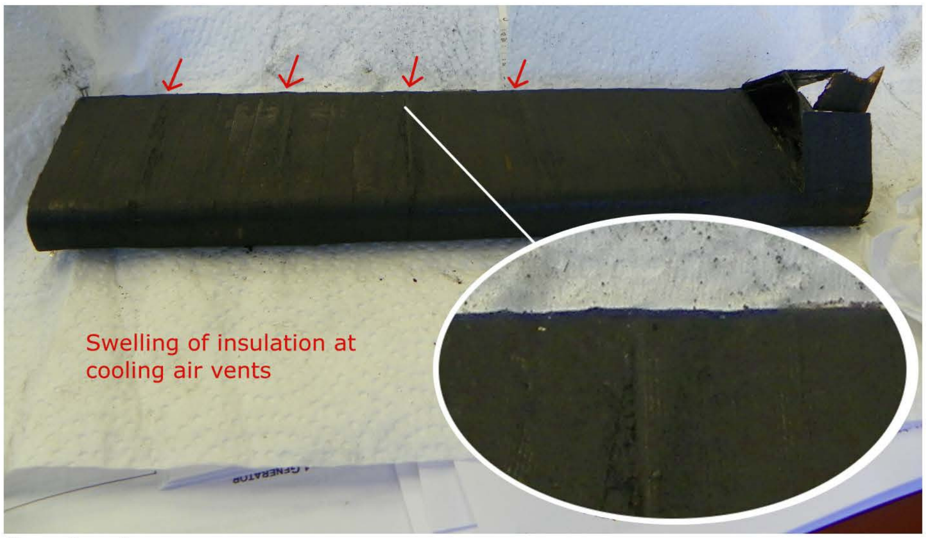
	UNIT #1	UNIT #3	UNIT #4
1967	Commissioned	Commissioned	
1968			Commissioned
1991		Stator re-wedged with piggyback wedges	
1992			Wedge inspection Stator re-wedged with piggyback wedges Generator trip (ground fault on phase A), problem found to be a fault on one of the main leads, the bus was reinsulated and put back into service
1993	Stator re-wedged with piggyback wedges		Inspection: Loose core laminations 12 to 16 shorted laminations Need cleaning and epoxy coating
1994	PM6 - PI test(6.6, after 10min 4000MΩ)	PM6 - PI test(3.85, after 10min 2500MΩ) PM9, Wedge inspection	PM6 - PI test before cleaning(3.6, after 10min 1800), after cleaning(4.5, after 10min 1800MΩ) PM9, Wedge inspection
1995	PM6 (limited time shutdown)	PM6 - PI test(2.7, after 10min 2500MΩ) slip rings dirty Megger test 45MΩ	Inspection
1996			Re-tape rotor jumpers
1997	Stator and rotor test inspection, Result: nothing abnormal PM6 - PI test	PM6 - PI test(4, after 10min 2000MΩ) PM8, 87SP-A trip, Stator and rotor inspection Start up inspection Stator core damaged on phase B between 345 and 346 Exciter replacement	Start up inspection
1998	PM6 - PI test(4.5 stator) Exciter replacement Ashphalt leaking out of stator bars	PM6 - PI test(3.2, after 10min 800MΩ) Stator and rotor inspection Ashphalt leaking out of stator bars	PM6 - PI test(2.46, after 10min 1600MΩ) Inspection Exciter replacement

1999	Replace loose wedges on stator Clean entire stator Clean oil and carbon dust under generator rotor Re-paint the overhead portion of stator	Install piggy back wedges into stator slots Stator core repair Re-tape generator pole leads, stator high side connections and stator neutral connections, Repair and clean rotor pole Re-tape main lead by #2 pole near the connection Replace smoke detectors Reverse polarity on #3 collector rings at exciter end Repair cooling water leaks Split phase protection trip Conduct air gap readings in stationary position, split pahse current problems Adjust poles on rotor	Stator re-wedged with piggyback wedges Re-tape generator rotor pole leads, stator line side connection and neutral leads Rotor cleaned Repairs to four rotor rim keys Re-torque stator core bolts Install shims to tighten endfingers Correct shorted laminations in stator core Repairs to six loose press fingers in stator
2000	PM9 - One failed coil on stator Hypot test at 27kV The faulty coil was replaced Repairs to field leads using burndy connectors Cleaned underneath rotor and turbine pit Repair loose V-block shim between poles #18 & 19	Dry ice cleaning on stator and rotor	PM6 Sections of stator insulation repaired Wedge inspection, 2 slots loose
2001	PM6 - PI test(2.5, after 10min 1500MΩ) turn test on stator	PM6 - PI test(3.37, after 10min 1350MΩ)	PM6 - PI test before cleaning (3.6, after 10min 900MΩ), after cleaning (3.4, after 10min 700MΩ)
2002	PM6 - PI test(4, after 10min 2000MΩ)	PM6 - PI test(3.8, after 10min 950MΩ)	PM6 - PI test(3, after 10min 800MΩ)
2003	PM6 - PI test(3.7, after 10min 1500MΩ)	PM6 - PI test(4.4, after 10min 4400MΩ) PM9	PM6 - PI test(3.4, after 10min 1200MΩ) Unit very dirty on bottom, Cleaned with safe-sol PM9 B2T4 open and closed repeatedly which caused station alarm, During investigation, damage was found on the upper end turns of six stator coils, an in place repair was completed using RTV silicone overtapped with self -amalgamiting electrical insulating tape Start up inspection
2004	PM6 - PI test (2.64, after 10min 2600MΩ). Repair flexible jumper leads that connects the rotor bus lead to the slip ring	PM6 - PI test(3.3, after 10min 2000MΩ)	PM6 - PI test(3.64, after 10min 1200MΩ)

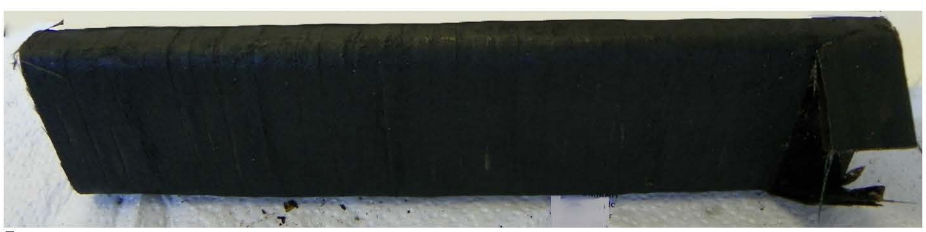
2005	PM6 - PI test(3.33, after 10min 1500MΩ)	PM6 - PI test(3.46, after 10min 2250MΩ)	
2006	PM6 - PI test(5.3, after 10min 800MΩ, still hot) PM9, PDA couplers checked	PM6 - PI test(3.28, after 10min 2300MΩ) Start up inspection	PM6 - PI test in October, before cleaning (2.5, after 10min 1100MΩ), after cleaning (3, after 10min 1200MΩ) PI test in July(1.71, after 10min 650MΩ) PM9, Exciter has a lot of dust Dry ice cleaning on stator and rotor Replaced 2 brushes
2007	PM6, PI test before cleaning(3, after 10min 1800MΩ), after cleaning(2.6, after 10min 800MΩ) PM9, Nothing abnormal on the pole drop test Hypot test - Result: increases from 180 to 230 before and similar after cleaning Slip ring from Unit #2 placed in to Unit #1,PDA connections checked, Stator and Rotor cleaning Wedge inspection	PM6 - PI test(3, after 10min 1800MΩ) Repair two sets of slip rings	PM6 Replaced 9 brushes Detailed inspection of slip ring
2008	PM6 - PI test with IPB(2.29, after 10min 800MΩ), without IPB(1.82, after 10min 500MΩ) Slip ring machining, North upstream SAC cooler leaking	PM6 - PI test(4.6, after 10min 700MΩ) PM8, PM9, Forced trip Slip rings need cleaning Top of rotor cleaned with dry rags Inspection of IPB connection to XFMR, Result: Phase B damaged, broken connection at XFMR	PM6 - PI test(2.91, after 10min 800MΩ) PM8 Two rotor leads need to be re-taped Stator needs cleaning
2009	PM6 - PI test(3.75, after 10min 1500MΩ)	PM6 - PI test(3.18, after 10min 1750MΩ) cooling water replaced Wedge inspection Pre-start up inspection PM9	PM6 - PI test(3.66, after 10min 1100MΩ) Rotor bus corona Cleaned stator
2010	Generator tests	Generator tests	PM6 - PI test(3.55, after 10min 800MΩ) Generator tests

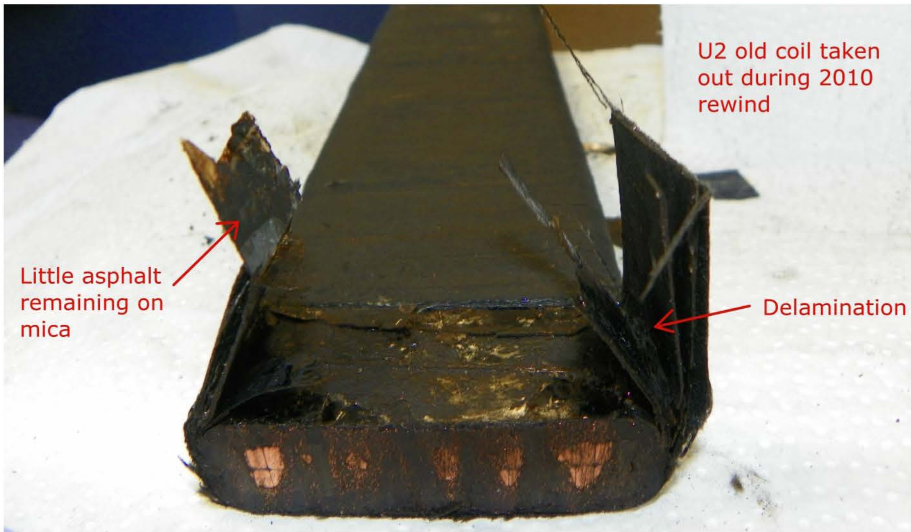
2011			PM6 - PI test(3.27, after 10min 900MΩ) Slip ring brushes replace Loose pole keys on 6 rotor poles and damaged taping on poles Shorted core laminations on stator repaired Re-tape rotor pole leads Wedge inspection Stator and rotor cleaning Start-up inspection

Appendix E: Used Coil Photos



Air vent swell


Bar



Delamitation

Fretting

Appendix F: Qualifications, Dat V Tran

Dat Van Tran, P. Eng.

Senior Engineering Specialist

Professional summary

Mr. Tran has 43 years experience in operation, maintenance, inspection and testing of thermal/hydro/nuclear turbine driven generators and auxiliaries equipment for generating stations (large motors, exciters (rotating or static), UPS systems and vital power systems). He has expertise in testing and troubleshooting large electrical generators, motors and excitation systems (rotating or static).

Professional qualifications/Registration(s)

Professional Engineer #M2379, Association of Professional Engineers and Geoscientists of New Brunswick

Education

BS, Electrical Engineering, University of Saigon, Saigon, South Vietnam, 1964

Languages

English

Employment history

AMEC, Senior Engineering Specialist, Fredericton, NB

Representative projects

Power
Vietnam Power Company
Served as Technical Service Engineer, Operations Shift Engineer, Chief of Operations of the Thuduc Thermal Complex and as Assistant to the Direction of Production.

Dalhousie – Eel River HV-DC Area
Electrical Engineer responsible for providing technical support for Dalhousie Unit No. 1 – 100 MW oil fired fossil generation station and the 320 MW HVDC converter station.

Central Technical Services Electrical Engineer
NB Power's generator and large motor specialist. Provided electrical engineering support for NB Power's Central Technical Services Group which provided technical support to all of NB Power's generating stations.

Senior Specialist Electrical Generation and Control Equipment

As Senior Specialist Electrical Generation and Control Equipment was accountable for developing, monitoring and evaluating maintenance criteria for all rotating electrical equipment and auxiliaries within the plant system and was accountable for troubleshooting and solving major problems in the associated equipment control as well as providing a corporate resource for NB Power. The NB Power system had about 4200 MW of installed capacity with up to 42 generating units ranging in size from less than 1 MW to 680 MW (gross).

Senior Engineering Specialist

Design Engineer for various projects including the Coleson Cove Refurbishment project. Responsibilities as Senior Engineering Specialist include engineering review and equipment selection of replacement motors for a nuclear generating station, generator assessment review for a combined cycle station, and generator/exciter assessment for a generating utility.

amec

BAY D'ESPOIR GENERATING STATION

POWERHOUSE NO.1

UNIT GENERATORS #1 AND #3

CONDITION ASSESSMENT FOLLOW-UP REPORT

Newfoundland and Labrador Hydro

Prepared for:

Newfoundland and Labrador Hydro

Prepared by:

AMEC Americas Limited
P.O. Box 9600
133 Crosbie Road
St. John's, NL
A1A 3C1

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
ANDREW DUPLESSIS
A.B. Duplessis
SIGNATURE
May 8/12
DATE
NEWFOUNDLAND & LABRADOR

Date: May 8, 2012

AMEC Ref No.: 168688

Reference: Unit Generators #1, #3 and #4 Condition Assessment Report No. 168688 Rev 1. Sept 1st, prepared by AMEC for Newfoundland and Labrador Hydro.

1. General

As recommended in the above report, diagnostic testing on these generators is to be performed annually to reassess their condition until they have been rewound. The report states that due to their deteriorated condition, they should be rewound as soon as possible. Yearly testing will not provide information that would support a decision to delay this work, but rather might give information that would give reason to accelerate the work.

A complete rewind of Unit #4 was performed this year (2012), leaving Units #1 and #3 to be rewound.

Bay D'Espoir generating station staff performed tests on the Unit #3 generator on March 17, 2012 and the Unit #1 generator on April 12, 2012. The tests performed were the Megger and Polarization Index (PI) 10 minute Test and the DC Controlled Voltage Step Test. These tests were carried out shortly after unit shutdown but before cleaning to minimize the effect of moisture penetration in the winding insulation.

AMEC has reviewed these test results and the analysis is included in Section 2 below.

2. AMEC Review of Test Results

2.1. Unit #1 Generator

2.1.1 Megger and PI 10 minute test at 2500 VDC

The results of the Megger and PI tests were plotted on the attached Graph #1. The polarization index is 2.9, which is typical when using asphalt mica insulation.

2.1.2 DC Controlled Voltage Step Test

The normal DC controlled voltage step test maximum limit commonly used by utilities when testing 13.8kV Generator stator insulation is 30 kVDC. When the insulation system is in good condition the leakage current is linearly proportional to applied voltage up to 30 kVDC.

The DC controlled voltage step test was carried out at 3kV/3minutes for the first 4 steps to 12kV then at 2kV/2 minutes steps from 12kV to 16kV. The results of this test are included on Graph #2. The leakage current measured at the 16kV step was so high that the technician stopped the test to avoid damaging the machine. The curve fit extrapolation shown in Graph #3 shows that a failure under test is likely if the test were to be continued up to 26 kVDC.

The level of 16kVDC is barely acceptable for generator operation and indicates that the stator insulation is approaching the end of its life. The degraded insulation carries a high risk of an in-service failure.

2.2. Unit #3 Generator

2.2.1 Megger and PI 10 minute test at 2500 kVDC

The test results plotted on the attached Graph #1 indicate that the generator winding insulation resistance is worse than the Unit #1 in insulation resistance after 10 minutes. This is possibly affected by the surface tracking of the windings (i.e. windings contaminated with dirt), therefore the PI is only 2.60. The IEEE STD 43 minimum recommended value of PI is 2, but the typical acceptable range for machines with asphalt mica insulation is 2.5 – 3.5.

2.2.2 DC Controlled Voltage Step Test

The DC controlled voltage step test was carried out at 3kV/3minutes for the first 4 steps to 12kV then in 2kV/2 minutes steps from 12kV to 26kV. The curve shows that the slope starts to increase during the last step from 24 to 26kV. The leakage current would be expected to be much higher if the step 26 – 28kVDC were to be carried out. This shows that the insulation is weakened but it would likely survive another year of operation.

3. Review of Past Results

3.1 Unit #1

Based on the results of these tests, the Unit #1 generator winding insulation has deteriorated to the same condition that the Unit #4 generator was in last year. To avoid a failure in operation this unit requires a rewind as soon as possible.

3.2 Unit #3

Besides the surface contamination seen by Megger and PI test, the DC controlled voltage test results are comparable to those of the previous test in 2009. It shows a slight increase in leakage current at 24 – 26kV step. In our experience, we expect that this generator can remain online for another year without a high risk of winding failure. Ideally it would be rewound as soon as possible, but to suit operational requirements it could be rewound in the spring or summer of 2014.

4. Conclusion

Normal utility practise requires that generator major outages for rewinds be planned ahead of time (regardless of duration) so energy replacement can be arranged in advance at a reasonable cost. Any unplanned long outage will result in costly power replacement. This is even more important to the Newfoundland and Labrador Hydro system because it is an independent grid without the ability to import power.

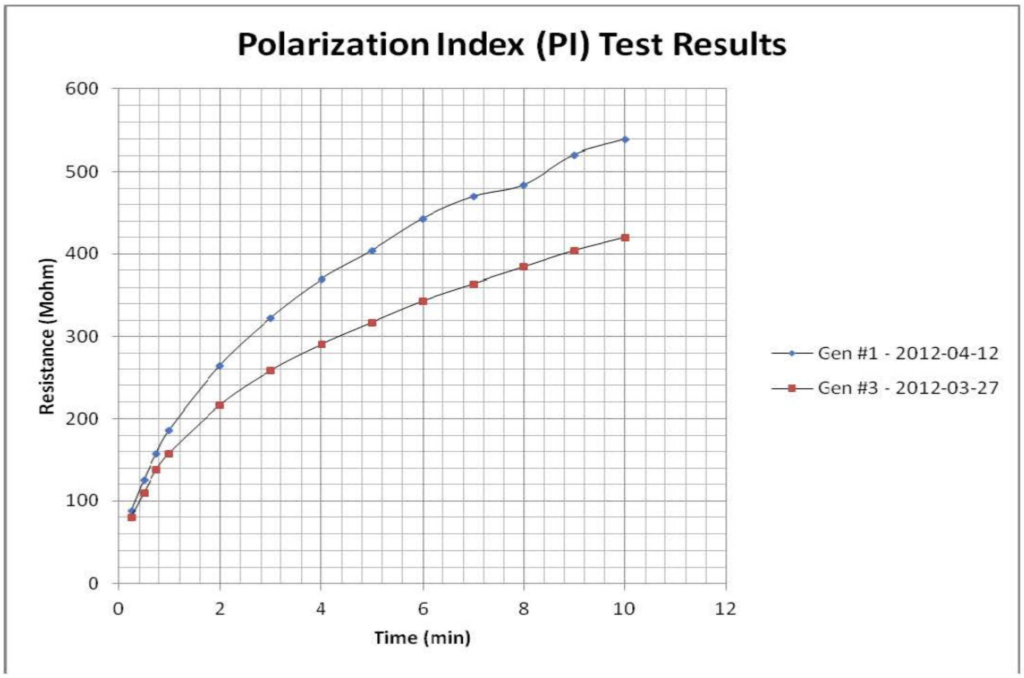
We strongly recommend the following actions:

4.1. The Unit #1 generator should be rewound as soon as possible. We suggest this should be performed no later than the Spring of 2013, but ideally it should be performed sooner. The condition of this unit's stator winding insulation indicates that there is a high risk of an in-service failure. If an opportunity arises to rewind this generator before 2013 it should be taken.

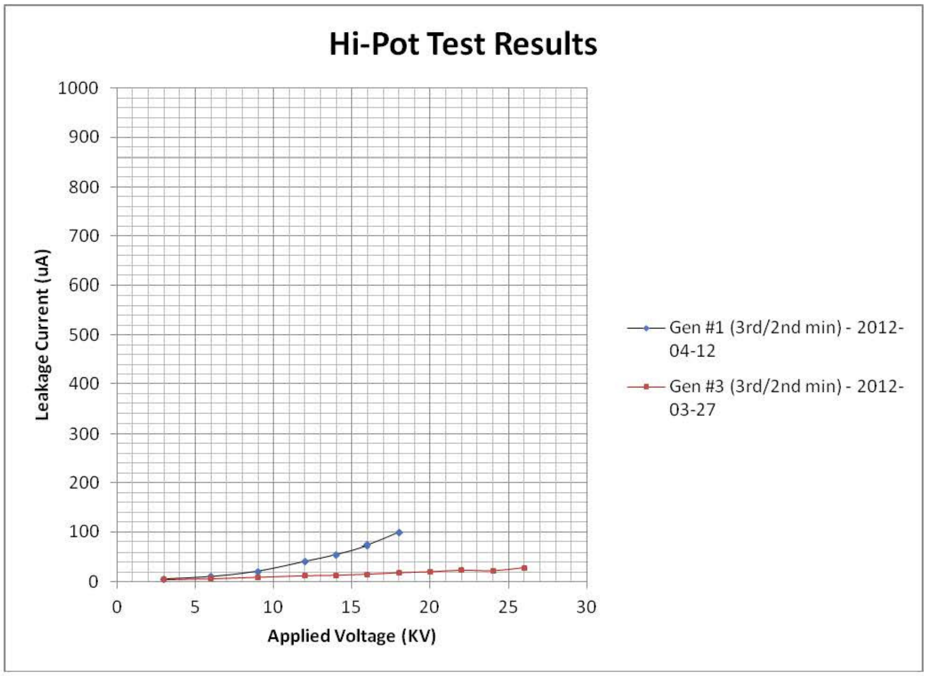
4.2. The Unit #3 generator stator insulation is in a deteriorated condition but the danger of an in-service failure is not as great as that of Unit #1. The Unit #3 rewind should therefore be planned to be completed after Unit #1 has been rewound. We suggest that this should occur no later than Spring or Summer of 2014. The condition of this unit should continue to be tested at yearly intervals until it is rewound. If an opportunity arises to rewind this generator before 2014 it should be taken.

4.3. The Unit #4 rewind consumed the only available spare stator winding coil. These coils are long-lead items and not having a spare available would result in a lengthy outage in the event of a failure in service. We recommend that, at a minimum, one complete rewind set (coil, wedges, accessories, etc.) be ordered as soon as possible. Ordering a second set would allow Unit #3 to be promptly rewound as well.

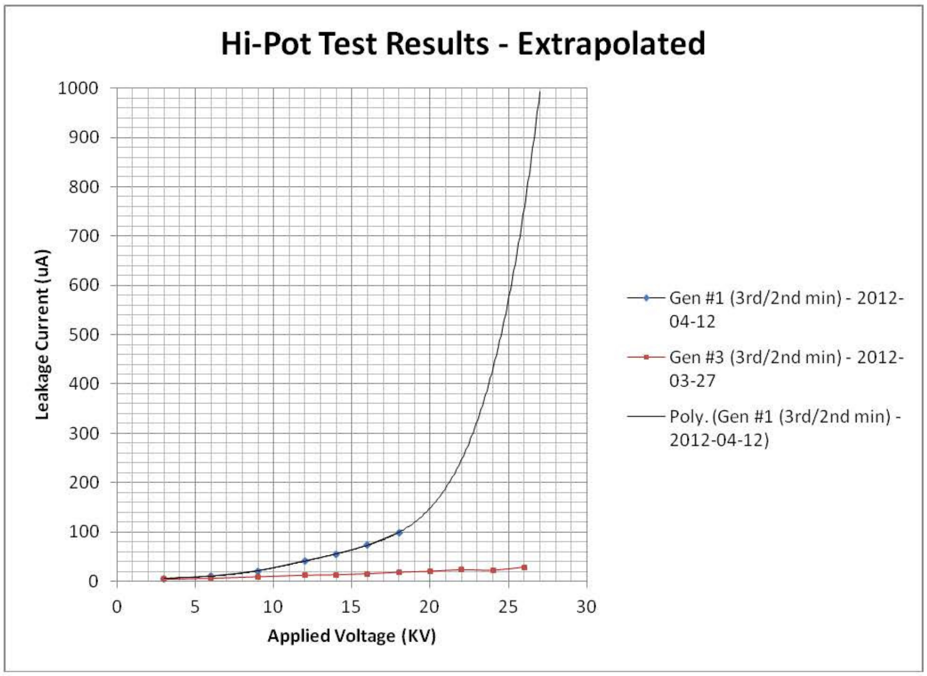
4.4. The Bay D'Espoir generating station auxiliary station services are provided by Unit #1 and Unit #3. During the rewind of the generator of either Unit #1 or Unit #3, there will be no redundancy for the station services for the Plant. It would be worthwhile to consider an alternate power source to restore the redundancy in these power supplies during the outages. One common practise is to back feed the unit step-up transformer with proper protection modifications (including 13.8kV bus ground faults) during the rewind outage of Unit #1 or Unit #3.



Graph #1 – Polarization Index Test Results – Unit #1 and Unit #3 Generators



Graph #2 – DC Step Test Results (HiPot) Test Results – Unit #1 and Unit #3 Generators



Graph #3 – DC Step Test Results (HiPot) Test Results (Extrapolated) – Unit #1 and Unit #3 Generators

BAY D'ESPOIR GENERATING STATION

POWERHOUSE NO.1

UNIT GENERATORS #1 AND #3

CONDITION ASSESSMENT FOLLOW-UP REPORT

Newfoundland and Labrador Hydro

Prepared for:

Newfoundland and Labrador Hydro

Prepared by:

AMEC Americas Limited
P.O. Box 9600
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REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
ANDREW DUPLESSIS
A.B. Duplessis
SIGNATURE
May 24/12
DATE
NEWFOUNDLAND & LABRADOR

Date: May 24, 2012 Rev 1

AMEC Ref No.: 168688

Reference: Unit Generators #1, #3 and #4 Condition Assessment Report No. 168688 Rev 1. Sept 1st, prepared by AMEC for Newfoundland and Labrador Hydro.

1. General

As recommended in the above report, diagnostic testing on these generators is to be performed annually to reassess their condition until they have been rewound. The report states that due to their deteriorated condition, they should be rewound as soon as possible. Yearly testing will not provide information that would support a decision to delay this work, but rather might give information that would give reason to accelerate the work.

A complete rewind of Unit #4 was performed this year (2012), leaving Units #1 and #3 to be rewound.

Bay D'Espoir generating station staff performed tests on the Unit #3 generator on March 17, 2012 and the Unit #1 generator on April 12, 2012. The tests performed were the Megger and Polarization Index (PI) 10 minute Test and the DC Controlled Voltage Step Test. These tests were carried out shortly after unit shutdown but before cleaning to minimize the effect of moisture penetration in the winding insulation.

AMEC has reviewed these test results and the analysis is included in Section 2 below.

2. AMEC Review of Test Results

2.1. Unit #1 Generator

2.1.1 Megger and PI 10 minute test at 2500 VDC

The results of the Megger and PI tests were plotted on the attached Graph #1. The polarization index is 2.9, which is typical when using asphalt mica insulation.

2.1.2 DC Controlled Voltage Step Test

The normal DC controlled voltage step test maximum limit commonly used by utilities when testing 13.8kV Generator stator insulation is 30 kVDC. When the insulation system is in good condition the leakage current is linearly proportional to applied voltage up to 30 kVDC.

The DC controlled voltage step test was carried out at 3kV/3minutes for the first 4 steps to 12kV then at 2kV/2 minutes steps from 12kV to 18kV. The results of this test are included on Graph #2. The leakage current measured at the 18kV step was so high that the technician stopped the test to avoid damaging the machine. The curve fit extrapolation shown in Graph #3 shows that a failure under test is likely if the test were to be continued up to 26kVDC.

The insulation of a 13.8kV generator winding in good condition will be linearly proportional to the applied voltage up to 30kVDC, while a winding on the verge of failure will only be linearly proportional up to 15kVDC. Most utilities will not energize a generator that has test results of 15kV or below. The results of the test described above (last successful test at 18kV) indicate that this unit's insulation level is severely degraded and there is a high risk of an in-service failure.

2.2. Unit #3 Generator

2.2.1 Megger and PI 10 minute test at 2500 kVDC

The test results plotted on the attached Graph #1 indicate that the generator winding insulation resistance is worse than the Unit #1 in insulation resistance after 10 minutes. This is possibly affected by the surface tracking of the windings (i.e. windings contaminated with dirt), therefore the PI is only 2.60. The IEEE STD 43 minimum recommended value of PI is 2, but the typical acceptable range for machines with asphalt mica insulation is 2.5 – 3.5.

2.2.2 DC Controlled Voltage Step Test

The DC controlled voltage step test was carried out at 3kV/3minutes for the first 4 steps to 12kV then in 2kV/2 minutes steps from 12kV to 26kV. The curve shows that the slope starts to increase during the last step from 24 to 26kV. The leakage current would be expected to be much higher if the step 26 – 28kVDC were to be carried out. This shows that the insulation is weakened but it would likely survive another year of operation.

3. Review of Past Results

3.1 Unit #1

Based on the results of these tests, the Unit #1 generator winding insulation has deteriorated to the same condition that the Unit #4 generator was in last year. To avoid a failure in operation this unit requires a rewind as soon as possible.

3.2 Unit #3

Besides the surface contamination seen by Megger and PI test, the DC controlled voltage test results are comparable to those of the previous test in 2009. It shows a slight increase in leakage current at 24 – 26kV step. In our experience, we expect that this generator can remain online for another year without a high risk of winding failure. Ideally it would be rewound as soon as possible, but to suit operational requirements it could be rewound in the spring or summer of 2014.

4. Conclusion

Normal utility practise requires that generator major outages for rewinds be planned ahead of time (regardless of duration) so energy replacement can be arranged in advance at a reasonable cost. Any unplanned long outage will result in costly power replacement. This is even more important to the Newfoundland and Labrador Hydro system because it is an independent grid without the ability to import power.

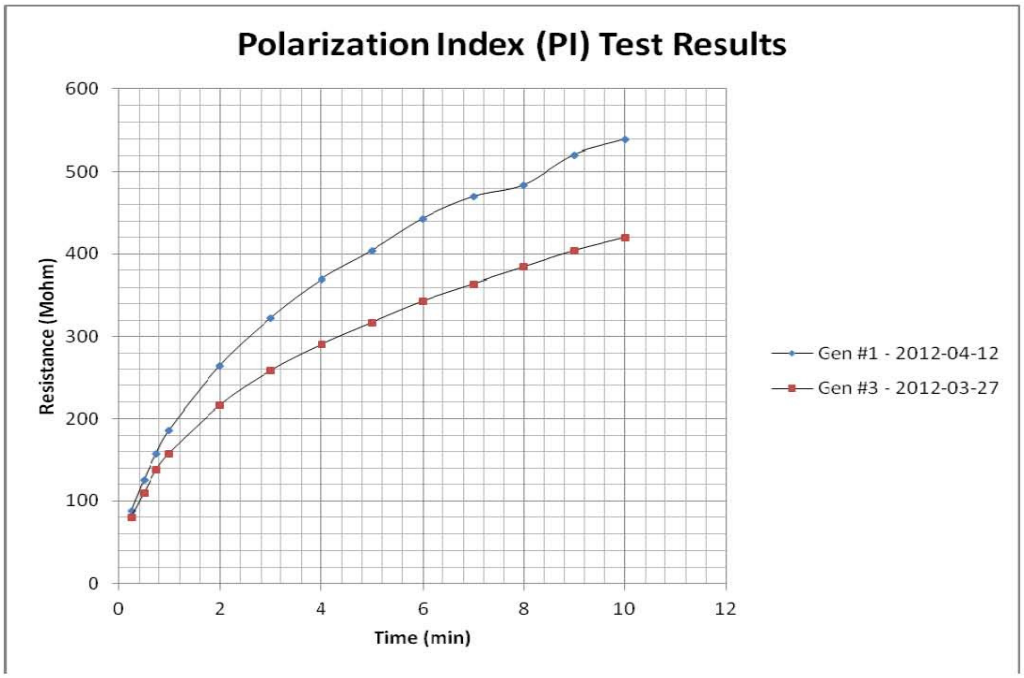
We strongly recommend the following actions:

4.1. The Unit #1 generator be rewound as soon as possible. We suggest this be performed no later than the Spring of 2013, but ideally it would be performed sooner. The condition of this unit's stator winding insulation indicates that there is a high risk of an in-service failure. If an opportunity arises to rewind this generator before 2013 we recommend it be taken.

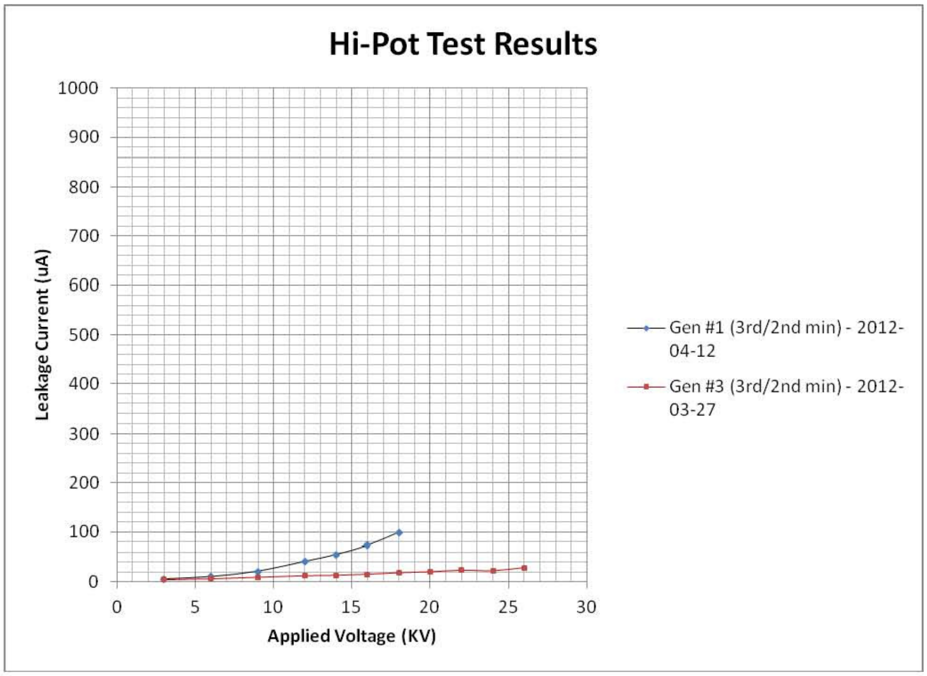
4.2. The Unit #3 generator stator insulation is in a deteriorated condition but the danger of an in-service failure is not as great as that of Unit #1. The Unit #3 rewind should therefore be planned to be completed after Unit #1 has been rewound. We suggest that this occur no later than Spring or Summer of 2014. The condition of this unit must continue to be tested at yearly intervals until it is rewound. If an opportunity arises to rewind this generator before 2014 we recommend it be taken.

4.3. The Unit #4 rewind consumed the only available spare stator winding coil. These coils are long-lead items and not having a spare available would result in a lengthy outage in the event of a failure in service. We recommend that, at a minimum, one complete rewind set (coil, wedges, accessories, etc.) be ordered as soon as possible. Ordering a second set would allow Unit #3 to be promptly rewound as well.

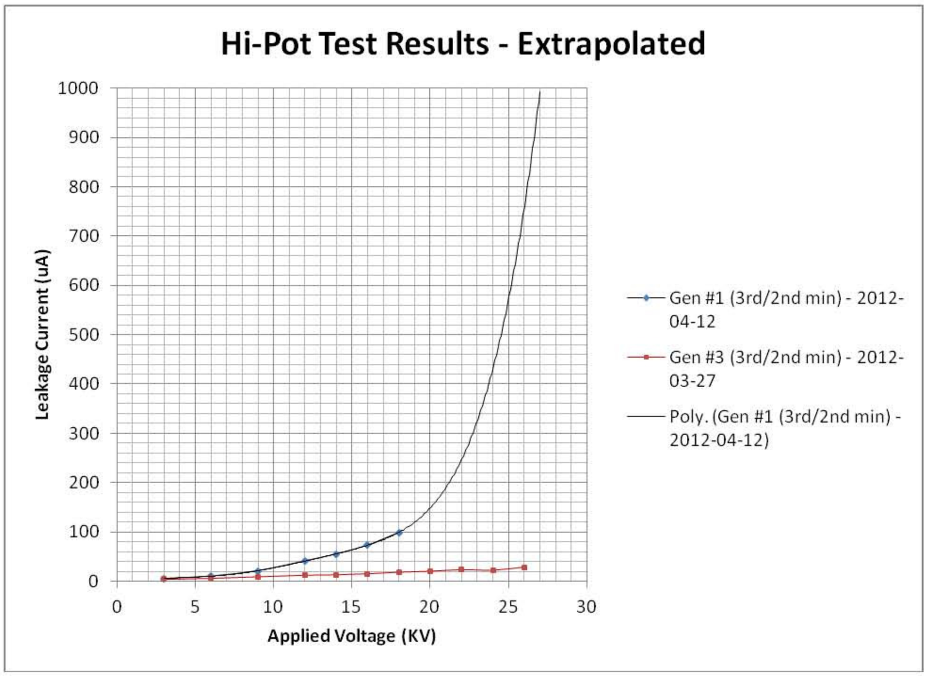
4.4. The Bay D'Espoir generating station auxiliary station services are provided by Unit #1 and Unit #3. During the rewind of the generator of either Unit #1 or Unit #3, there will be no redundancy for the station services for the Plant. It would be worthwhile to consider an alternate power source to restore the redundancy in these power supplies during the outages. One common practise is to back feed the unit step-up transformer with proper protection modifications (including 13.8kV bus ground faults) during the rewind outage of Unit #1 or Unit #3.



Graph #1 – Polarization Index Test Results – Unit #1 and Unit #3 Generators



Graph #2 – DC Step Test Results (HiPot) Test Results – Unit #1 and Unit #3 Generators



Graph #3 – DC Step Test Results (HiPot) Test Results (Extrapolated) – Unit #1 and Unit #3 Generators

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER G. E. POOLE G.E. Poole SIGNATURE July 26/13 PROVINCE OF NEWFOUNDLAND	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Surge Tank 3 Refurbishment

Bay d'Espoir

March 2013

newfoundland labrador hydro

a nalcor energy company

SUMMARY

In 2012, Hydro engaged the engineering firm Hatch to perform a condition assessment of Surge Tank 3 at the Bay d'Espoir Hydroelectric Generating Station. A report (see Appendix A) was prepared with recommendations to extend the service life of the surge tank coating system along with budget cost estimates to implement the recommendations. The cost estimate for coating the exterior of the surge tank and structural supports includes provision for containment and capture of all material removed during surface preparation.

This project provides for a complete refurbishment of all exterior surfaces of the surge tank including surface preparation and coating of the surge tank exterior and structural supports. Additionally, it includes refurbishment of the compression ring, turnbuckles, rod braces and foundation anchor bolts. Also, included is an engineering assessment of the roof anchor point system and replacement with certified anchor points as required, installation of a gate at the ladder access point to the lower balcony, replacement of roof ladder and painters post, refurbishment of damaged insulation on the hot water heating system piping, replacement of obstruction lighting on top of the tank and conduit from the electrical building to the obstruction lighting and installation of wear plates between the cross braces at each intersection to reduce wear.

Hydro is proposing this project to ensure the continued uninterrupted operation of this structure, which is 43 years old, and avoid a potentially significant increase in rehabilitation cost from accelerating degradation rates.

TABLE OF CONTENTS

1 INTRODUCTION

The Bay d'Espoir Development includes three hydroelectric generating stations, six reservoirs, and associated dykes, dams, canals and hydraulic structures. The headwaters of the Bay d'Espoir Development begin at the Victoria Lake reservoir at an approximate elevation of 320 meters. The water travels through the Granite Canal Hydroelectric Generating Station (Granite Canal), Upper Salmon Hydroelectric Generating Station (Upper Salmon) and finally through the Bay d'Espoir Hydroelectric Generating Station (Bay d'Espoir) where it discharges at sea level.

The generating stations comprising the Bay d'Espoir Development were built over a number of years with the Bay d'Espoir station being the oldest dating back to 1967 and Granite Canal Development being the newest, coming online in 2003. Some of the oldest hydraulic structures within the Bay d'Espoir Development were constructed in 1967. There are four remote hydraulic structures associated with Bay d'Espoir. They are Ebbegunbaeg Control Structure, Salmon River Spillway Structure, Victoria Control Structure and Burnt Dam Spillway Structure. During construction of the Bay d'Espoir Development Stage I, Surge Tanks 1 and 2 were built. Surge tank 3 followed these in 1970 as part of the Bay d'Espoir Development Stage II and comprises part of the third penstock which provides water to generating Units 5 and 6 at the Bay d'Espoir Powerhouse. See Figure 1.

Figure 1: Bay d'Espoir Surge Tanks

This project is being proposed as a result of the findings of a condition assessment conducted by an engineering consultant in 2012. Based on the findings and recommendations in the report, Surge Tank 3 is in need of refurbishment to protect the steel components from corrosion and to ensure its continued operation. This surge tank is in the worst condition of the three tanks because it has not been coated since 1985. The other two tanks were recoated in the early 1990s.

Items pertaining to legislative requirements or environmental performance have no impact on the project.

Alternatives were not considered because the tank is in need of a recoat with a compatible system to extend the life of the coating system. The new coating system proposed will last in excess of 15 years.

2 PROJECT DESCRIPTION

This project involves refurbishment of Surge Tank 3 at the Bay d'Espoir Hydroelectric Generating Station. In particular, the coating on the surge tank is in a deteriorated condition. There has been a complete coating failure on the roof of the tank which has left the roof exposed to the elements, leading to corrosion. Additionally, there is coating breakdown on the tank shell, ladder, access platforms and the entire structural support system. Following this refurbishment, Surge Tank 3 should not require additional coating for at least 15 years.

The scope of this project involves refurbishment and upgrade of the following components of the surge tank:

- Refurbish all exterior surfaces including surface preparation and coating of the surge tank exterior and structural supports including containment of material removed during surface preparation;
- Refurbish the compression ring and part of the top balcony;
- Refurbish the turnbuckles, rod bracing and leg foundation anchor bolts;
- Assess the roof anchor point system and replace with certified anchor points as required;
- Installing a gate at the ladder access point to the lower balcony;
- Replace the roof ladder including the painters post with a fixed ladder;
- Refurbish the damaged insulation on the hot water heating system piping and re-flashing at the top of the insulation at the inlet to the surge tank;
- Replace the obstruction lighting on top of the tank; and
- Install wear plates at the intersection of the cross braces.

The budget estimate for this project is $2.265 million. Engineering is scheduled to start in February 2014 with construction being undertaken from July to September 2014. This work is required to ensure the continued safe and reliable operation of Surge Tank 3 and generating Units 5 and 6 at the Bay d'Espoir Hydroelectric Generating Station.

3 JUSTIFICATION

Surge Tank 3 is in the worst condition of the three surge tanks. The existing coating system was applied in 1985 whereas the other two tanks were recoated in the early 1990's. This project is justified on the requirement to replace failing or deteriorated infrastructure in order for Hydro to provide safe and reliable operation of Surge Tank 3 and generating Units 5 and 6 at the Bay d'Espoir Hydroelectric Generating Station. A condition assessment study performed by a professional engineering firm, Hatch, in 2012 identified significant deterioration of the surge tank and made a number of recommendations for repair and refurbishment.

It has been more than 25 years since any coating has been applied to this structure. Coating systems do not typically last this long and coating failure on the surge tank has been observed and documented in the attached Hatch report. Failure of a coatings system leaves the steel that it is designed to protect vulnerable and exposed to the elements. This environmental attack can lead to corrosion of the steel which could cause leaks in the tank or in a worst case scenario, if the corrosion is severe enough, it can lead to structural failure. This could create an unsafe situation for Hydro's employees and the general public. It also has the potential to cause simultaneous outages to generating Units 5 and 6 with a combined capability of 150 MW, which could have an impact on Hydro's ability to meet the electrical demand on the Island.

The coating system that was applied in 1985 is well beyond its useful life of 15 years and as a result damage to the surge tank has been observed. In order to maintain the life of this valuable asset a new coating system needs to be applied and it needs to be done now.

3.1 Existing System

The main powerhouse at Bay d'Espoir contains six generating units. There are three pressure conduits that transport water to these six units. Each pressure conduit has a surge tank installed to protect the system against a load rejection. Surge Tank 3 is located on the third pressure conduit which supplies water to generating Units 5 and 6 in the powerhouse.

Each of the surge tanks are in excess of 110m above the ground. They are supported by strongly braced legs designed to resist hurricane force winds and earthquakes. The diameter of each tank is 7.6m and each tank contains approximately 1,300 tons of steel. The surge tanks and risers are insulated to a point above the static water level and are electrically heated in winter to prevent icing.

Surge Tank 3 was completed in 1970 as part of the Bay d'Espoir Development – Stage II. The surge tank was recoated in 1985, more than 25 years ago. The other two surge tanks were recoated in 1990. Structural modifications were undertaken on all three surge tanks in 2006 as a result of an overloading deficiency identified as part of an engineering structural review. Horizontal steel beam struts at mid-height of the tank were reinforced by welding plates on each side of the beam flange to create a closed "box" section.

3.2 Operating Experience

The surge tanks have operated without incident during their time in service. As outlined above, there is over 1,300 tons of steel in each of these surge tanks. This steel needs continuous protection and is starting to corrode as indicated in the Hatch report. There has been a complete coating failure of the roof of the surge tank, leaving the steel exposed to the elements. The extent of coating failure over the remainder of the surge tank is not as severe but will certainly become more severe if recoating is not done promptly. This tank is 43 years old and to continue with reliable, uninterrupted operation it needs to be refurbished. Failure to undertake this work could lead to deterioration of the steel components which could eventually lead to a failure.

3.2.1 Reliability Performance

There are currently no reliability issues but if the work is not done there is the potential for outages on Units 5 and 6 which could impact Hydro's ability to meet the electrical demand on the Island Interconnected System. By undertaking the work now, system reliability can be maintained.

3.2.1.1 Outage Statistics

There is no outage statistics associated with this structure.

3.2.2 Legislative or Regulatory Requirements

Legislative or regulatory requirements do not impact this project.

3.2.3 Safety Performance

If metal corrosion were to lead to a leak in this tank or even to a structural failure there is the potential to create safety issues for Hydro personnel working in the area.

3.2.4 Environmental Performance

Environmental performance does not impact this project.

3.2.5 Industry Experience

Coatings used in industry today to protect steel structures from corrosion typically have different service lives depending on the type of surface preparation done and the type and thickness of coatings applied. There will be on-going maintenance with any coating systems and recoats will be required but with the surface preparation method and coating system being proposed this system should last for more than 15 years without maintenance.

3.2.6 Vendor Recommendations

There are no vendor recommendations associated with this project.

3.2.7 Maintenance or Support Arrangements

Routine corrective maintenance has been performed over the years by Hydro personnel and external contractors. This has involved touch-up painting as required and minor structural modifications.

3.2.8 Maintenance History

The total overall corrective maintenance cost for Surge Tank 3 has been approximately $175,000. None of this cost has been associated with work on the surge tank coating.

The five-year maintenance history for Surge Tank 3 is shown in Table 1 below;

Table 1: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2012	0.0	50.7	50.7
2011	0.0	0.2	0.2
2010	0.0	1.8	1.8
2009	0.0	2.5	2.5
2008	0.0	0.0	0.0

3.2.9 Historical Information

There has been no similar work of this nature done on the surge tanks in the past five years.

3.2.10 Anticipated Useful Life

The new coating system is anticipated to last for more than 15 years.

3.3 Forecast Customer Growth

Forecast customer growth does not impact this project.

3.4 Development of Alternatives

There are no viable alternatives for refurbishment of Surge Tank #3.

3.5 Evaluation of Alternatives

As there are no viable alternatives an evaluation is not required.

3.5.1 Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to this project.

3.5.2 Economic Analysis

As there are no viable alternatives an economic analysis is not applicable.

4 CONCLUSION

The surge tanks at the Bay d'Espoir Hydroelectric Generating Station are critical to Hydro's ability to meet the province's energy demands. If this surge tank had to be taken out of service as a result of significant leakage or structural issues, Hydro would lose the ability to generate power from Units 5 and 6 at the Bay d'Espoir Hydroelectric Generating Station, resulting in a loss of 150 MW from Hydro's generating capacity.

4.1 Budget Estimate

The budget estimate for this project is provided in Table 2. This cost summary table includes estimates prepared by Hatch and included in the attached report as well as internal engineering costs associated with managing the work plus a contingency of 20%.

Table 2: Project Budget Estimate

Project Cost:*($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	87.0	0.0	0.0	87.0
Consultant	66.0	0.0	0.0	66.0
Contract Work	1,610.0	0.0	0.0	1,610.0
Other Direct Costs	30.5	0.0	0.0	30.5
Interest and Escalation	112.8	0.0	0.0	112.8
Contingency	358.7	0.0	0.0	358.7
TOTAL	**2,265.0**	**0.0**	**0.0**	**2,265.0**

4.2 Project Schedule

The anticipated schedule for this project is provided in Table 3.

Table 3: Project Schedule

Activity		**Start Date**	**End Date**
Planning	Open project. Develop detailed schedule	February 2014	March 2014
Design	Coatings system	March 2014	April 2014
Procurement	Prepare tender, advertise, review and award	March 2014	May 2014
Construction	Surge tank refurbishment	July 2014	September 2014
Closeout	Closeout, lessons learned and documentation	October 2014	November 2014

APPENDIX A

Bay d'Espoir Surge Tank No. 3

Condition Assessment Final Report

HATCH™

Newfoundland and Labrador Hydro

Bay d'Espoir Surge Tank No. 3 Condition Assessment Final Report

H341684-0000-50-124-0001
Rev. 0
December 14, 2012

Newfoundland and Labrador Hydro

Bay d'Espoir Surge Tank No. 3
Condition Assessment
Final Report

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HATCH™

Newfoundland and Labrador Hydro
Bay d'Espoir Surge Tank No. 3 Condition Assessment

Final Report

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Table of Contents

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List of Tables

List of Figures

Executive Summary

In July 2012, Hatch was engaged by Newfoundland and Labrador Hydro (NL Hydro) to perform a condition assessment of Surge Tank #3 at the Bay d'Espoir (BDE) hydroelectric generating station. Hatch engaged Remote Access Technology (RAT) to perform the inspection.

RAT expressed concern over the existing fall protection system and roof anchors. Neither was used by RAT during the inspection.

The external inspection revealed complete coating breakdown on the tank roof. There was also significant coating breakdown on the tank shell above the cladding, ladder, access platforms and entire structural support system. With the exception of the coating breakdown, the tank, ladder, access platforms and structural support system appeared to be in good condition. The walkway from the ladder to the lower balcony does not have a gate or chain at the ladder access point. Some wear was present on the diagonal cross bracing intersections.

The internal inspection revealed that the coating system on the interior of the tank roof, shell, bowl and riser is in good condition with some minor localized breakdown.

The cathodic protection (CP) system is intended to be a secondary corrosion protection to the coating system. A functional analysis of the CP system was not performed during the site inspection. Based on the RAT inspection report, the anodes, cabling, etc. have become intertwined. It is our opinion the CP system is not functional and poses a hazard to the turbine runner and other components. Exterior components such as the junction boxes located at the base of the surge tank are in relatively good condition, but the conduit straps on the 2 inch rigid PVC conduit from the electrical shed to the CP junction boxes on the surge tank riser are broken. Consequently, at the time of inspection the conduit was unsupported.

The hot water heating system piping insulation appears to be in good condition with the exception of a few areas. A visual inspection of the electrical heat trace system inside the surge tank electrical shed indicated that the system was in good condition.

The existing electrical distribution at the surge tank electrical shed does not meet current standards. It appears that over the lifetime of the surge tank there have been many modifications to the electrical distribution.

The only grounding system evident for Surge Tank #3 was located in the area close to the electrical shed. The existing grounding system at Surge Tank #3 electrical shed does not meet current standards and codes.

The existing aviation obstruction lighting was still in operation at the time of the site inspection. There is substantial corrosion to the rigid steel conduit which houses the electrical cables providing power to the two beacon lights.

Based on the condition assessment, the following are recommended.

1. Refurbish all exterior surfaces (not covered in insulation and cladding) in accordance with SSPC-SP 10 and apply a new coating system.
2. Complete a detailed assessment of the tank interior coating system with a certified NACE inspector. Implement a program whereby a detailed inspection of the tank interior coating system is performed every four to six years, coordinated with planned unit outages. Refurbish localized areas of coating breakdown on the interior of the tank shell, bowl and riser and apply a compatible coating system.
3. The existing roof anchors should be taken out of service immediately and an analysis of the anchor design be completed. If the design is found to be adequate, all welds should undergo non destructive examination such as magnetic particle inspection to determine their condition.
4. Complete a structural assessment of existing vertical ladder to confirm its suitability for use with the new fall arrest system.
5. Install a gate or chain at the ladder access point to the lower balcony to ensure the handrail is continuous.
6. Replace the roof ladder including the painters post with a fixed ladder.
7. Remove the existing CP system and all associated components and supporting system.
8. Repair the damaged insulation on the hot water heating system piping on the horizontal run from the electrical shed to the west leg, and re-flash at the top of the insulation at the inlet to the surge tank.
9. During the execution of future interior work, take additional UT readings around the entire circumference of the bottom two shell courses to determine or confirm the actual shell plate thickness. If the actual shell plate thickness deviates from the reference drawings, complete an analysis to verify the stress in the bottom two shell courses and compare to the allowable stress given in AWWA D100.
10. Replace the obstruction lighting on the tank top and conduit from electrical building to the obstruction lights.
11. Conduct testing of the electrical ground system to determine if the concrete structure is adequate to be used as a grounding electrode. If not, proper ground electrodes should be installed and tested as per current standards.
12. Upgrade the electrical distribution equipment in order to provide adequate over-current protection and disconnecting means of connected devices. The existing 600-120/208 volt transformer and transformer disconnect are reaching the end of their life. Replacement of these two items should be considered within in the next 5 years.
13. Install proper bonding and grounding to electrical equipment to meet current standards.

Preliminary (+30/-20%) cost estimates were prepared for these recommendations. All cost estimates exclude owners cost.

Cost estimates for painting the exterior of the surge tank and structural supports were obtained from two companies. The estimated cost of painting of the exterior of the tank (Recommendation #1), is $575,000 excluding containment during surface preparation and $1,375,000 including containment during surface preparation.

The estimated cost to perform a detailed assessment of the tank interior coating system with a certified NACE inspector (Recommendation #2) is estimated to be $81,250.

The cost estimates for all other recommendations total:

- Desktop studies/design reviews (Recommendations #3 & #4), $25,000
- Structural/ mechanical upgrades (Recommendations #5 - #9), $147,200
- Electrical upgrades (Recommendations #10 - #13), $133,600.

1. Introduction

In July 2012, Hatch was engaged by Newfoundland and Labrador Hydro (NL Hydro) to perform a condition assessment of Surge Tank #3 at the Bay d'Espoir (BDE) hydroelectric generating station. The BDE hydroelectric generating station main powerhouse consists of six generating units fed from three penstocks. Each penstock has a surge tank, numbered #1, 2 and 3. Surge Tank #3 is connected to generating Units #5 and 6 penstock.

The objectives of the study, as identified in an email from Nelson Seymour of NL Hydro to Greg Saunders of Hatch dated March 15, 2012, are as follows.

1. Perform an internal inspection of the tank and riser with focus on plate thickness, welds, coatings, internal structural members, and cathodic protection system. Particular attention should be given to the bowl (bottom dished head), its leg support connection points, and the riser expansion joint.
2. Perform an external inspection of the tank and riser including the structural support system, thermal insulation system, hot water heating system, tank cap, rotating ladder, foundations, and electrical grounding.
3. Develop recommendations with Class 3 cost estimates to carry out each of the recommendations.

Hatch engaged Remote Access Technology (RAT) to perform the inspection. See Appendix A for RAT's inspection report. Site inspections were conducted from August 20 to 23, 2012, by James Calanan, Jeremy Crummey and Wolfgang Holtzmann of RAT.
Kerry Savoury and Renard Froude of Hatch were on site during the inspection. Albert Hunt of NL Hydro was the confined space attendant during the inspection. The inspection was mostly visual with some ultrasonic thickness (UT) readings taken on the tank top, tank shell at the top balcony, and the expansion joint. Attempts were made to take UT readings on the bowl but were unsuccessful due to a heavy protective coating build-up which created an uneven surface prohibiting the acquisition of readings without removing the coating. RAT's inspection report, in conjunction with the photos taken while on site was used to develop the condition assessment final report.

In addition to the site inspections, Hatch undertook the following activities in performing the condition assessment.

- Review of existing drawings as provided by NL Hydro. The drawings were primarily used in developing a familiarity with the surge tank for the site visits.
- Review of previous inspection and condition assessment documents along with operation and maintenance manuals. These documents were made available for review following the site inspections at NL Hydro's BDE office. Relevant sections were copied.

2. History of Surge Tank #3

The following chronological list was developed based on the reference documents provided by NL Hydro:

- Built in 1969 to 1970.
- During the original construction, the outside of tanks were sand-blasted, primed with epoxy-red-lead primer and finish painted with two coats of aluminum paint at 3 mils. The interior of the tanks, riser and 50 ft of the pressure conduit were blasted and painted with 3 coats of Crown tar epoxy with total thickness of 10 mils.[1]
- 1985 – The exterior of Surge Tank #3 was repainted.[2]
- April 20, 1990 – Surge Tank #3 was said to be in good condition.[2]
- June 7, 1990 – Inspection of Surge Tank #3 riser interior conducted. All structural welds found to be in acceptable condition and were said to require only minimal repairs in the following year. Surface deposits approximately ½" (12.4 mm) thick cover 90 to 95 percent of the first two cans and nodules with continual decreasing quantities end after can no. 10 (starting from the bottom). Pit depth on the upper 6-7 cans range from 1/32" (0.8 mm) to 1/8" (3.2 mm).[3]
- June 10-11, 1990 – Diagonal cross bracing and horizontal riser stays tightened on Surge Tank #3.[4]
- April 27, 2001 - A visual inspection from the ground revealed that Surge Tank #3 appeared to be in the worst condition of the three. The cross bracing was worn and beginning to show signs of corrosion but less wear was observed on Surge Tank #3 cross bracing than the other two surge tanks. Most significant wear was on 2nd tier cross members. Some horizontal stays appeared twisted.[6]
- August 20, 2002 – Inspection of Surge Tank #3 by RAT revealed the following:[7]
  - Checker pattern portion of tank exterior was found to have 20 to 30 percent full coating system failure. Average thickness measurements where coating was still intact was found to be 19 mils, with minimum and maximum thicknesses of 14 and 32 mils respectively.
  - Top of the tank showed the most significant corrosion and it was recommended that the surface be refurbished in accordance to SSPC 11 and re-apply 3 coat system.
  - A brief inspection of the internal portion of the tank showed significant signs of corrosion and it was recommended that UT measurements be conducted on the tank plates.
  - The tank legs coating system was found to have a 25 to 30 percent failure of the top coat. Average dry film thickness (DFT) measurements showed thicknesses of 8 mils

as opposed to the original 16 mils. It was recommended to perform surface preparation in accordance to SSPC 3 and re-apply top coat.

- Horizontal steel beams were found to be in good condition.
- All cross bracing showed some signs of friction wear. One particular brace showed an estimated 20 percent loss of metal.
- Most corrosion on the balconies was said to be caused by water pooling and complete coating failures were found in these areas. It was recommended that more drain holes be added closer to the railing, where pooling was more prevalent. One area on the top balcony showed severe corrosion and it was suggested that a patch plate be welded in this location.
- No significant sag or corrosion was found in the horizontal braces.

- May 2, 2007 – A review of the exterior of Surge Tank #3 concluded the following:[8]
  - Several areas on the surge tank showed signs of weathering with two areas of coating loss near the ladder where the exposed metal surface shows signs of metal corrosion. Coating failure accounted for less than 0.5 percent of the total area.
  - The tank top had corrosion in one area only, for an area of less than 10 percent of the total. Mechanical cleaning permitted per SP-11 in this area.
  - There was very little indication of corrosion on the four support legs. The only area noted was at the 1 to 2 meter level of support leg on which the access ladder is affixed, which accounted for less than 0.5 percent of the total area. The aluminum topcoat showed signs of weathering in areas, with the primer coat exposed.
  - The struts between the support legs showed corrosion on the edges and on the inside surface adjacent to web/flange. The total area of corrosion on these beams was approximately 5 to 10 percent of the total.
  - A number of ASTM D 3359 adhesion tests were performed on existing coating system:
    - Painted Surge Tank – 12 tests – all adhesion tests were acceptable
    - Support Legs – 3 tests – all adhesion tests were acceptable
  - Surfaces to be recoated were:
    - Surge tank exterior surfaces
    - Support legs
    - Horizontal I beams and other cross structures between support legs

- Recoating over the existing coating system with a compatible coating system, the life expectancy of the coating on the structure may be extended by 10 to 12 years.

- August 20 to 23, 2012 – RAT Inspection

3. Internal Inspection

3.1 Tank Top

The tank top as shown in Figure 3-1 Figure 3-1is constructed with a series of stiffener ribs covered with lap jointed plates. The original drawings show a 1" (25 mm) lap between the roof plates, welded on the outside only. It was observed that the inside lap has opened up. It is unknown if this occurred during construction or if this occurred over time due to plate sagging.

The coating system on the tank top interior appears to be in good condition with some minor localized coating breakdown.

Figure 3-1: Tank Top Interior

3.2 Shell

From the top of the shell to roughly the mid-height as shown in Figure 3-2Figure 3-2, the coating system appears to be intact with some minor localized breakdown.

At roughly the mid-height, there are two sets of inlet ports for the hot water heating system, one above the other as shown in Figure 3-3. The bottom ports, installed during the original construction of the surge tank are plugged and no longer operational. The top ports are operational. They were installed when the dams were raised around the head pond, which raised the operating level of the surge tank above the bottom ports.

There was coating breakdown and corrosion along the weld seams with water staining and rust bleeding from the ports. The inlet piping to the bottom ports was disconnected on the outside of the tank.

Around the manhole at the bottom of the tank shell, as shown in Figure 3-4Figure 3-4, there appears to be some significant coating breakdown and corrosion.

It is recommended that all localized areas of coating breakdown on the tank shell interior be refurbished in accordance with SSPC-SP 11 and a coating system be applied.

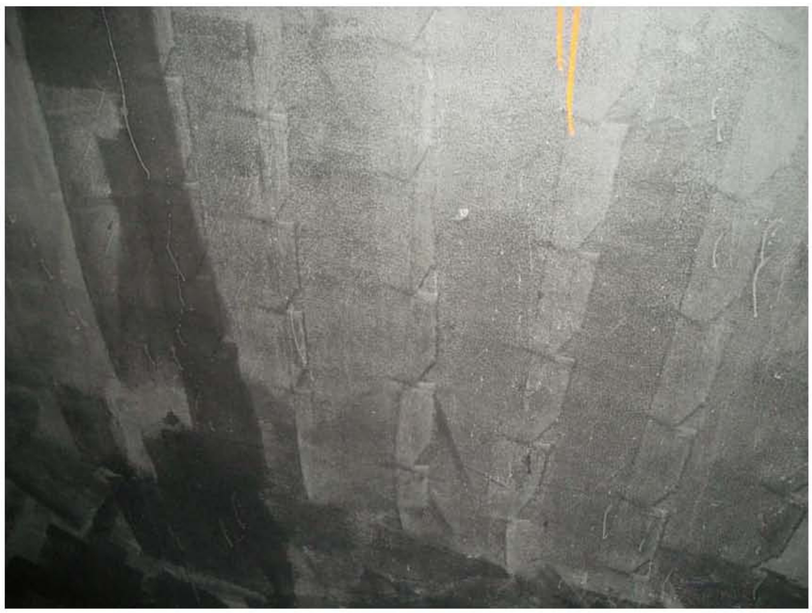

Figure 3-2: Tank Shell Interior Above Hot Water Heating System Inlets

Figure 3-3: Tank Shell Interior at Mid-height Near Hot Water Heating System Inlets

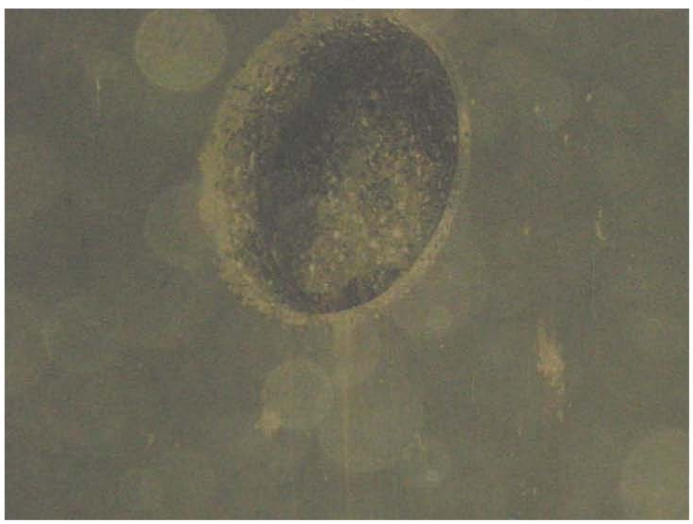

Figure 3-4: Tank Shell Interior at Bottom Showing Manhole

3.3 Tank Bowl

As shown in Figure 3-5Figure 3-5 and Figure 3-6Figure 3-6 below (photos taken during the inspection), it appears that the tank bowl is coated similar to the riser. Also, NL Hydro's documentation (Newfoundland and Labrador Power Commission, Operating and Maintenance Instructions, Volume 1 prepared by ShawMont Newfoundland Ltd.) states that the interior of the tanks, riser and 50 ft of the pressure conduit were originally blasted and painted with three coats of tar epoxy with total thickness of 10 mils.[1]

Figure 3-6Figure 3-6 shows couplant at attempted UT reading locations. Lighter area underneath couplant is from scrapping with wire brush.

The existing coating appears to be in good condition with some localized coating breakdown. It is recommended that these localized areas be refurbished in accordance with SSPC-SP 11 and a coating system be applied.

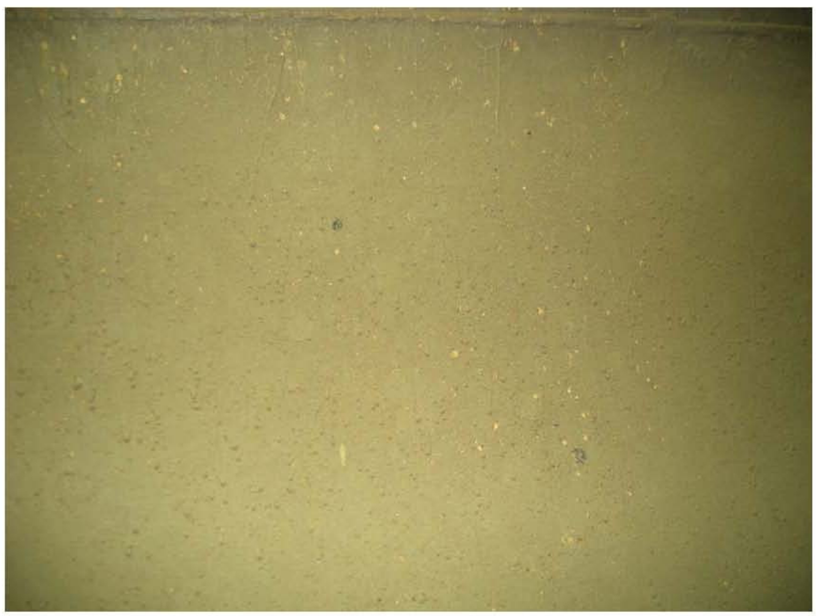

Figure 3-5: Interior of Tank Bowl

Figure 3-6: Interior of Tank Bowl with UT Couplant

3.4 Riser

The riser appears to have experienced some corrosion prior to the application of the most recent coating system as shown in Figure 3-7Figure 3-7 and Figure 3-8Figure 3-8. The steel surface beneath the coating system is not smooth. This coating system appears to be in good condition.

Figure 3-7: Interior of Riser

Figure 3-8: Interior of Riser with Support Channel

4. External Inspection

4.1 Roof

The exterior of the tank top has near complete coating breakdown as seen in Figure 4-1. It was recommended in 2002 by RAT that the surface be refurbished in accordance to SSPC-SP 11 and re-apply 3 coat system.[7] It appears that this recommendation was not acted on. It is recommended that the tank top be refurbished in accordance with SSPC-SP 10 and a coating system be applied.

UT readings were taken on the tank top (see Section 4.1 of the RAT report). The reference drawings did not indicate the thickness of the roof top plate. The UT readings were consistent and suggest 3/8" (9.5 mm) plate.

RAT expressed concern over the existing roof anchors which appears to be welded to the tank top plate only and not to any structural sections. It is recommended that detailed design check be performed on the existing roof anchors to determine if the design is adequate. If the roof anchors are deemed suitable from the design check, it is recommended that all attachment welds undergo non destruction examination (NDE). The roof anchors should be taken out of service until this is completed.

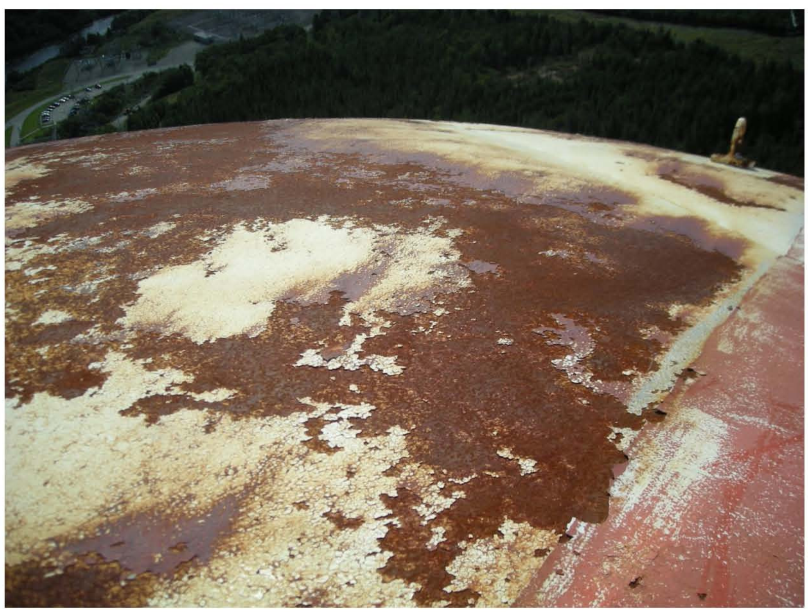

Figure 4-1: Tank Top Showing Significant Coating Breakdown

4.2 Shell

The surge tank shell above the external insulation system has significant coating breakdown as shown in Figure 4-2Figure 4-2. The coating system on Surge Tank #3 was in the worst condition of all three surge tanks. It is recommended that the areas of localized coating breakdown and corrosion be refurbished in accordance with SSPC-SP 10 and a compatible coating system be applied to the entire surge tank shell above the external insulation system.

Cladding and insulation was removed adjacent to the west leg on the upper balcony to expose the exterior of the surge tank shell bottom course and leg attachment as seen in Figure 4-3. There were no visible signs of corrosion in this area.

UT readings in a four by four grid pattern were taken in this area (see Section 4.2 of the RAT report). Readings 1a, 1b, 1c and 1d were taken on the 3/4" (19.1 mm) thick column plate. The results are consistent with the reference drawings and show little to no corrosion.

The remaining twelve UT readings were taken on the shell plate (bottom course) adjacent to the column plate. The readings are consistent and suggest a bottom plate that is 3/8" (9.5 mm) thick. The reference drawings indicate the bottom course of the surge tank is 9/16" (14.3 mm) thick, the second course up is 13/32" (10.3mm) thick and the remaining courses are 3/8" (9.5 mm) thick. This discrepancy in the UT readings and the reference drawings can be explained by any number of factors including, but not limited to:

1. Inaccurate UT readings.

   Although possible, forty other readings were taken at different locations and all were consistent and as expected per the reference drawings.

2. Severe loss of material due to corrosion.

   In considering this, there is absolutely no indication of corrosion on the outside of the surge tank shell. The coating system on the inside of the surge tank is also intact with little indication of corrosion, certainly not to the extent needed to corrode almost half the original wall thickness.

3. Constructed with thinner plate.

   The surge tank could have been constructed with 3/8" thick plate for its entire height, including the bottom two courses, deviating from the construction drawings.

   It was not possible to attain UT readings on the interior of the surge tank shell while suspended on a rope near the center of the surge tank. It is therefore recommended that during the execution of future interior work, additional UT readings be taken around the entire circumference of the bottom two courses to determine the actual shell plate thickness. If the actual shell plate thickness deviates from the reference drawings, a detailed structural analysis of the surge tank is recommended.

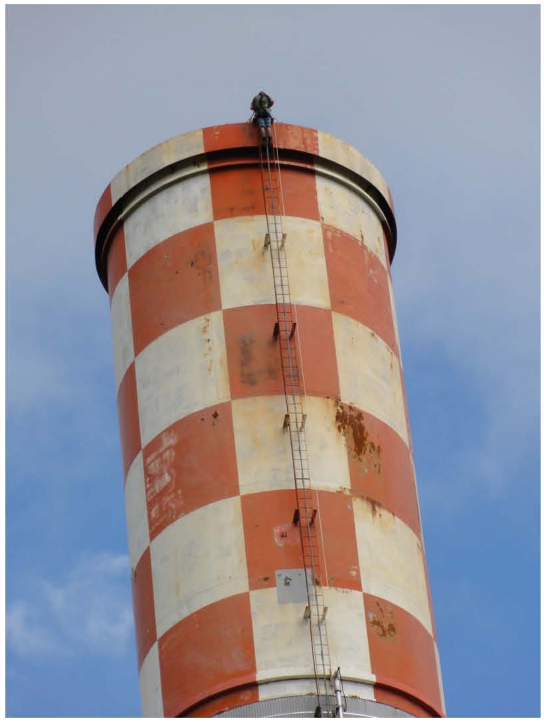

Figure 4-2: Surge Tank Shell Above External Insulation

Figure 4-3: Cladding Removed Adjacent to Leg

4.3 External cladding

Overall, the external cladding was intact as shown in Figure 4-4 and Figure 4-5. There was some water staining present on both the surge tank shell and the riser. The water staining appears to be originating from the hot water heating system ring header piping on the surge tank shell and from the four attachment points of the horizontal rod bracing to the riser.

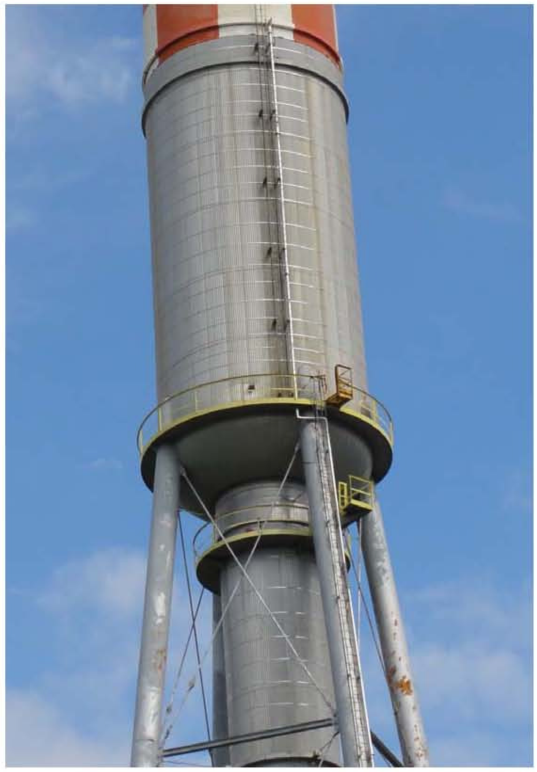

Figure 4-4: Surge Tank Shell and Top of Riser External Insulation

Figure 4-5: Riser and Structural Support

4.4 Compression Ring / Upper Balcony

The compression ring is a critical structural element located at the attachment of the legs to the surge tank shell, which also functions as the upper balcony. As shown in Figure 4-6, there was significant coating breakdown on the compression ring which has resulted in corrosion caused by pooled water. This was also reported as an issue in 2002. It was recommended in 2002 that more drain holes be added closer to the railing, where pooling was more prevalent. One area on the top balcony showed severe corrosion and it was suggested that a patch plate be welded in this location. [7]

From a comparison of Figure K-3 in the 2002 RAT report with Figure below, it is unclear if the recommendations reported in 2002 were acted on, but it is clear that the compression ring is in worse condition now than in 2002. It is recommended that the compression ring be refurbished per the RAT 2002 report and in accordance with SSPC-SP 10 and a coating system applied.

Figure 4-6: Compression Ring / Upper Balcony

4.5 Expansion Joint

External cladding and insulation was removed on the lower balcony exposing the expansion joint as shown in Figure 4-7.

UT readings were taken in this area (see section 4.3 of the RAT inspection report). A series of 16 readings were taken in a 4x4 grid. Readings 1a, 2a, 3a and 4a (taken above the weld seam) were taken on 1/2" (12.7 mm) thick plate. The remaining readings were taken on 3/8" (9.5 mm) thick plate (below the weld seam). The results are consistent and show little to no corrosion in this area.

Figure 4-7: Cladding Removed Showing Expansion Joint at Lower Balcony

4.6 Lower Balcony

The lower balcony appears to be in good condition with some localized coating breakdown and corrosion, likely resulting from water build-up, as shown in Figure 4-8. It was in better condition than the upper balcony. The walkway from the ladder to the lower balcony shown in Figure 4-9 does not have a gate or chain at the ladder access point, which is a safety issue that should be corrected.

RAT expressed concern that the turnbuckles and rod bracing as shown in Figure 4-10Figure 4-10 are bent and show signs of heavy corrosion. From the reference drawings, these braces are noted as erection rods which were to be loosened after erection.

It is recommended that the lower balcony be refurbished in accordance with SSPC-SP 10 and a coating system applied.

Figure 4-8: Lower Balcony

Figure 4-9: Walkway from Ladder to Lower Balcony

Figure 4-10: Erection Rods on Lower Balcony

4.7 Lower Rest Platform (Crow's Nest)

Lower rest platform (referred to as the crow's nest by NL Hydro personnel) had some minor surface corrosion as shown in Figure 4-11. The grating hatch was functional.

Figure 4-11: Lower Rest Platform (Crow's Nest)

4.8 Structural Support

4.8.1 Legs and Struts

The legs and struts had some coating breakdown as shown in Figure 4-12Figure 4-12. It appears that the coating system was touched up in the past.

It is recommended that the areas of coating breaking be refurbished in accordance with SSPC-SP 10 and a compatible coating system be applied to the entire structure.

Figure 4-12: Structural Support Showing Coating Breakdown

4.8.2 Diagonal bracing

All diagonal bracing showed some signs of wear. Most appears to be in good condition with very little wear as shown in Figure 4-13. There are a few diagonal braces however with some excessive wear as shown in Figure 4-14. Wear of the diagonal bracing was also reported in 2002.[7]

To reduce the wear and extend the life of the diagonal bracing, it is recommended that a wear plate be installed at between the braces at each intersection and a compatible coating system be applied. The wear plate shall be attached to one brace only.

Figure 4-13: Typical Cross Member with Very Little Wear Present

Figure 4-14: Cross Member Showing Signs of Wear

4.8.3 Connections

The connections appear to be in good condition with some minor coating breakdown as shown in Figure 4-15.

Figure 4-15: Typical Structural Support Connection

4.8.4 Foundations (Above Grade)

The inspection of the riser and leg foundations was limited to a visual inspection of the portion above grade. No excavation was performed to inspect below grade and no destructive testing (i.e., cores for compression testing) was carried out.

As shown in Figure 4-16 and Figure 4-17, the concrete appears to be in generally good condition with some cracking that in most cases has been filled with a sealant. It was reported that crack sealing was carried out on a regular basis during routine maintenance. The sealant prevents water infiltration and further deterioration; however, it also prevents inspection of the cracks to determine width and depth. No reports were provided indicating when the cracks developed or probable cause of the cracking (e.g., Alkali Aggregate Reaction, freeze/thaw cycles, etc.). There were some cracks in the legs foundation that were not filled with sealant suggesting they either developed recently or were not considered large enough to warrant sealing. Cracks should be monitored to determine if they are getting larger or more numerous.

There was some minor efflorescence noted in a few areas with a larger area of efflorescence in one area on the downstream face of the riser foundation. There are no visible signs of overstressing or areas where the concrete has deteriorated to a point where portions of concrete have spalled off except for some minor surface deterioration in a few areas where water may not drain properly. It was noted that the foundations for Surge Tank 3 were more deteriorated in comparison to foundations for the other surge tanks.

Overall the visible foundation concrete appears to be in satisfactory condition.

Figure 4-16: Riser Foundation

Figure 4-17: Leg Foundation and Anchor Bolt Arrangement

4.8.5 Anchor Bolts

Most anchor bolts appear to be in good condition with some minor coating breakdown, with the exception of one anchor bolt on the north leg foundation and one anchor bolt on the west leg foundation. As shown in Figure 4-18 and Figure 4-19, there was significant coating breakdown corrosion at both the base of the anchor bolts and the anchor chairs. It is recommended that these anchor bolts be refurbished in accordance with SSPC-SP 10 and a coating system applied.

Figure 4-18: Corroded Anchor Bolt on North Leg Foundation

Figure 4-19: Corroded Anchor Bolt on West Leg Foundation

4.9 Ladder

The ladder appears to be in good condition with some minor coating breakdown as shown in Figure 4-20. The painters post for tank top ladder was functional but has complete loss of coating as shown in Figure 4-21.

Prior to ascending the surge tank, RAT personnel expressed concern over the transitioning between the fixed vertical ladder and the rotating tank top ladder. It was noted that during the inspection of Surge Tank #1 in 2011, the rotating ladder on the tank top had rotated 180 degrees from the fixed ladder, which wasn't discovered until RAT personnel had ascended the surge tank. For this inspection, the tank top ladder was in the correct position and was secured to the fixed ladder prior to climbing.

It is recommended that the existing roof ladder including the painters post be replaced with a fixed ladder.

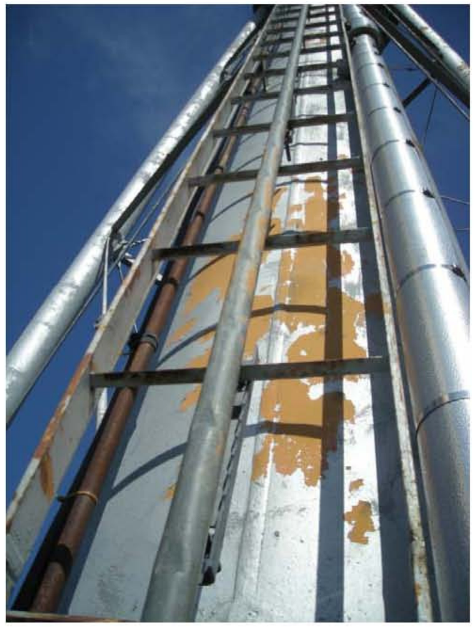

Figure 4-20: Access Ladder on West Leg

Figure 4-21: Painters Post for Ladder on Tank Top

4.10 Fall Arrest System

The existing fall arrest system was not used by RAT during the site inspection. A visual inspection from the ground revealed that the vertical rail was bent and twisted. It was noted on site that, during the previous inspection on Surge Tank #1 in 2011, RAT personnel experienced operational issues with the fall arrest system, mainly the inability of the fall arrester to slide freely up the vertical rail. As a result, they decided to rig their own fall arrest line.

During the development of this report, NL Hydro tendered the replacement of the existing fall arrest system on Surge Tank #3. Consequently, no further assessment of the existing fall arrest system was conducted.

The scope of this condition assessment did not include a structural assessment of existing ladder to confirm its suitability for use with the new fall arrest system. It is recommended this be completed.

5. Ancillary Items

5.1 Cathodic Protection

The cathodic protection (CP) system is intended to be a secondary corrosion protection to the coating system. The coating system on the interior of the tank and riser appears to have performed well and is still in good condition, with some minor localized coating breakdown.

A functional analysis of the CP system was not performed during the site inspection. Based on the RAT inspection report and as shown in Figure 5-1, the anodes, cabling, etc. have become intertwined. As we understand from our discussions with Mr. Trevor Arbuckle (NL Hydro), this is common each time the surge tank is dewatered. In addition, we understand the float support system never worked properly. It is our opinion the CP system is not functional and poses a hazard to the turbine runner and other components.

Exterior components such as the junction boxes located at the base of the surge tank are still in relatively good condition as shown in Figure 5-2. As shown in Figure 5-3, the conduit straps on the 2 inch rigid PVC conduit from the electrical shed to the CP junction boxes on the surge tank riser are broken; consequently, at the time of inspection the conduit was unsupported. A SWOP card was filled out and this issue was brought to the attention of Jakiul Hassan while on site.

The following is recommended:

- Remove the existing CP system and all associated components and supporting system.
- During removal, complete a detailed assessment of the tank interior coating system with a certified NACE inspector. Surface prepares localized areas of coating breakdown in accordance with SSPC-SP 11 and applies a compatible coating system.
- Implement a program whereby a detailed inspection of the tank interior coating system is performed every four to six years. During the inspection, surface prepares localized areas of coating breakdown in accordance to SSPC-SP 11 and applies a compatible coating system.

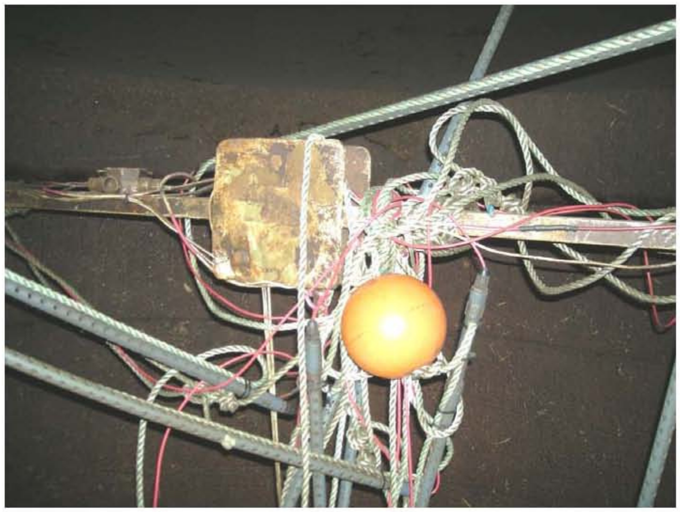

Figure 5-1: Tangled Cathodic Protection System at Top of Riser

Figure 5-2: Cathodic Protection System on Tank Riser

Figure 5-3: Cathodic Protection System Conduit at Electrical Shed

5.2 Hot Water Heating System

The hot water heating system piping insulation appears to be in good condition with the exception of a few areas as shown in Figure 5-4 and Figure 5-5.

The top of the piping insulation at the tie-in to the surge tank is improperly flashed as shown in Figure 5-6.

It is recommended that the areas of damaged insulation and improper flashing be repaired.

Figure 5-4: Damaged Insulation on the Hot Water Heating System Piping

Figure 5-5: Damaged Insulation on the Hot Water Heating System Piping

Figure 5-6: Top of Hot Water Heating System Piping Insulation

5.3 Heat Trace System

The electrical heat trace cable is used to provide freeze protection along the hot water heating system piping.

A visual inspection of the electrical heat trace system inside the surge tank electrical shed indicated that the system was in good condition. The Pyrotenax heat tracing controller, conductors and heat trace power pack all appear to be relatively new and in good condition.

5.4 Electrical Distribution

The existing electrical distribution at the surge tank electrical shed does not meet current standards. It appears that over the lifetime of the surge tank there have been many modifications to the electrical distribution to incorporate such additions as the hot water heating system and electrical heat trace. There are two existing exterior 600 volt receptacles which are in poor condition and do not appear to be in service at this time.

The control panel for the hot water heating system is fed from a disconnect which is connected directly into the main service disconnect. Also tied into this main service disconnect is the feed to the old exterior receptacles and the feed to the 600 – 120/208 volt transformer disconnect. This installation does not meet current standards as it is against the Canadian Electrical Code to have multiple feeds coming from the main service disconnect. This existing arrangement does not provide adequate overcurrent protection for all devices downstream of the main service disconnect. The proper design for this type of configuration would be to use a splitter trough with fused-disconnects.

The existing 600-120/208 volt transformer and transformer disconnect appear to be original to the building and are reaching the end of their life. Replacement of these two items should be considered within in the next 5 years.

A new 120/208V, 100 amp main breaker, distribution panel was recently installed. This panel has a lifespan of 20-25 years from the installation date.

5.5 Electrical Grounding

The only grounding system which was evident at Surge Tank #3 was located in the area close to the electrical shed as shown in Figure 5-7, Figure 5-8 and Figure 5-9. The existing grounding system at Surge Tank #3 electrical shed does not meet current day standards and codes. Without previous drawings to provide insight into how the original grounding system was installed it is impossible to know exactly what was done. Based only on visual inspection it appears that a bare, stranded, copper conductor was embedded in the concrete at the time of construction. This conductor runs through the concrete structure and is bonded with clamp style fittings to the structure steel skids of the electrical shed. It appears that the concrete foundation which supports the electrical shed is being used as the 'ground' reference electrode. Proper resistance to ground testing would have to be conducted in order to confirm if this installation satisfies the grounding requirements of current standards.

Clamped to this main copper conductor are two smaller, stranded copper conductors. Both conductors are insulated but one of the two is covered with black insulation, then covered again with green electrical tape while the other has green insulation. The green insulated copper conductor runs back to the Positron telephone system box inside the electrical shed. The black insulated ground conductor runs back to the hot water heating system control panel.

The above mentioned bonding conductors were the only two that were visible at Surge Tank #3 electrical shed. Without opening up panels, disconnects, etc. it was not possible to determine exactly what pieces of equipment were bonded. There was no visible indication the main service disconnect is connected to ground as required under current standards. The main service disconnect should be directly connected to the ground bar or ground electrodes, which in this case would be the main grounding conductor embedded in the concrete. It is recommended the grounding system be upgraded to meet current standards to ensure safety and adequate protection of the electrical system. These modifications and upgrades would most likely be completed at the same time any modifications or upgrades were made to the electrical distribution equipment discussed in the previous section. As per current standards, once any existing equipment has been modified it must also be upgraded to meet the governing rules and regulations at the time the work is being conducted.

Figure 5-7: Electrical Grounding at the Electrical Shed

Figure 5-8: Electrical Grounding Connection

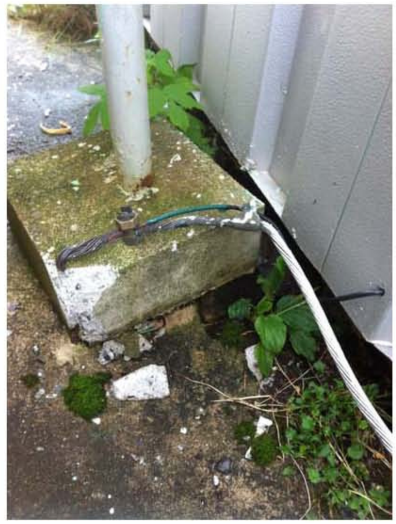

Figure 5-9: Electrical Grounding Connection

5.6 Obstruction Lighting

The existing aviation obstruction lighting as shown in Figure 5-10 was still in operation at the time of the site inspection. There is substantial corrosion to the rigid steel conduit which houses the electrical cables providing power to the two beacon lights as shown in Figure 5-11 and Figure 5-12. If there are plans to complete any work on this area of the surge tank, it is recommended that the conduit and obstruction lights be replaced at the same time to reduce labour costs. Consideration should be given to epoxy coated rigid galvanized steel conduit when replacing the existing conduit system as it provides additional corrosion resistance. When it is decided to install new obstruction lights, it should be noted that these lights are to be installed as per Canadian Aviation Regulations (CARs) Standard 621.

.

Figure 5-10: Tank Top Obstruction Lighting

Figure 5-11: Tank Top Obstruction Lighting Conduit

Figure 5-12: Tank Top Obstruction Lighting Conduit

6. Summary of Recommendations

Based on the condition assessment, the following are recommended.

1. Refurbish all exterior surfaces (not covered in insulation and cladding) in accordance with SSPC-SP 10 and apply a new coating system.
2. Complete a detailed assessment of the tank interior coating system with a certified NACE inspector. Implement a program whereby a detailed inspection of the tank interior coating system is performed every four to six years, coordinated with planned unit outages. Refurbish localized areas of coating breakdown on the interior of the tank shell, bowl and riser and apply a compatible coating system.
3. The existing roof anchors should be taken out of service immediately and an analysis of the anchor design be completed. If the design is found to be adequate, all welds should undergo non destructive examination such as magnetic particle inspection to determine their condition.
4. Complete a structural assessment of existing vertical ladder to confirm its suitability for use with the new fall arrest system.
5. Install a gate or chain at the ladder access point to the lower balcony to ensure the handrail is continuous.
6. Replace the roof ladder including the painters post with a fixed ladder.
7. Remove the existing CP system and all associated components and supporting system.
8. Repair the damaged insulation on the hot water heating system piping on the horizontal run from the electrical shed to the west leg, and re-flash at the top of the insulation at the inlet to the surge tank.
9. During the execution of future interior work, take additional UT readings around the entire circumference of the bottom two shell courses to determine or confirm the actual shell plate thickness. If the actual shell plate thickness deviates from the reference drawings, complete an analysis to verify the stress in the bottom two shell courses and compare to the allowable stress given in AWWA D100.
10. Replace the obstruction lighting on the tank top and conduit from electrical building to the obstruction lights.
11. Conduct testing of the electrical ground system to determine if the concrete structure is adequate to be used as a grounding electrode. If not, proper ground electrodes should be installed and tested as per current standards.
12. Upgrade the electrical distribution equipment in order to provide adequate over-current protection and disconnecting means of connected devices. The existing 600-120/208 volt

transformer and transformer disconnect are reaching the end of their life. Replacement of these two items should be considered within in the next 5 years.

13. Install proper bonding and grounding to electrical equipment to meet current standards.

7. Cost Estimates

Preliminary (+30/-20%) cost estimates were prepared for the recommendations outlined in Section 6. A 25% contingency is included. All cost estimates exclude owners cost, such as procurement and construction management.

Cost estimates for painting the exterior of the surge tank and structural supports (Recommendation #1) were obtained from two companies. One company provided a cost estimate that excluded containment of the grit and old paint/ rust particles during surface preparation. The second company provided a cost estimate that included containment. The two cost estimates are presented in Table 7-1. It is assumed that painting will be completed under a standalone contract.

The estimated cost to perform a detailed assessment of the tank interior coating system with a certified NACE inspector (Recommendation #2) is also presented in Table 7-1.

The cost estimates for the desktop studies/design reviews (Recommendations #3 & #4) are presented in Table 7-2. The cost estimates for desktop studies/design reviews excludes any cost associated with the findings of these studies/reviews, i.e. replacement/upgrade cost.

The cost estimates for the structural/ mechanical upgrades (Recommendations #5 - #9) are presented in Table 7-3. The cost estimates for the electrical upgrades (Recommendations #10 to #13) are presented in Table 7-4.

It is assumed the structural/ mechanical upgrades and electrical upgrades will be executed under separate contracts with one mobilization and demobilization for each. Weather will be a major cost and schedule risk during the execution of this work. This estimate assumes no weather related issues or delays.

Table 7-1: Coating and Coating Inspection Cost

	Direct Cost	Contingency (25%)	Total Cost
Surface preparation and painting, excluding containment	$460,000	$115,000	$575,000
Surface preparation and painting, including containment	$1,100,000	$275,000	$1,375,000
Interior coating assessment	$65,000	$16,250	$81,250

Table 7-2: Desktop Study / Design Review Cost

	Direct Cost	Contingency (25%)	Total Cost
Design assessment of existing roof anchor	$8,000	$2,000	$10,000
Design review of existing tank ladder	$12,000	$3,000	$15,000
		Total	**$25,000**

Table 7-3: Structural / Mechanical Upgrades Cost

Description	Total
Construction Costs	
Mobilization/ Demobilization	$10,000
New gate on lower balcony	$4,100
Replace existing roof ladder	$41,000
Repair damaged insulation on piping	$11,300
Remove CP system	$28,800
NDE on existing roof anchors	$3,600
UT readings on the bottom two shell courses	$3,600
Sub-Total	**$102,400**
Contingency (25%)	$25,600
Sub-Total	**$128,000**
Engineering & Construction Supervision (15%)	$19,200
Total Estimated Construction Cost	**$147,200**

Table 7-4: Electrical Upgrades Cost

Description	Total
Construction Costs	
Mobilization/ Demobilization	$10,000
Grounding Test	$500
Replace obstruction lighting and conduit	$50,000
Upgrade Electrical Distribution Equipment	$25,000
Sub-Total	**$85,500**
Contingency (25%)	$21,375
Sub-Total	**$106,875**
Engineering & Construction Supervision (25%)	$26,725
Total Estimated Construction Cost	**$133,600**

References

1. *Newfoundland and Labrador Power Commission - Operating and Maintenance Instructions,* Volume 1 (ShawMont Newfoundland Ltd.).
2. Arbuckle, Trevor, *The Report on the Surge Tanks at Bay d'Espoir*, Fax Memo, (Newfoundland and Labrador Hydro, April 20, 1990).
3. Arbuckle, Trevor, *Inspection of Surge Tank Riser #3*, Interoffice Memorandum, File #101.80.36/3 (Newfoundland and Labrador Hydro, July 6, 1990).
4. Arbuckle, Trevor, *Tightening of Horizontal and Diagonal Cross Bracing #3 Surge Tank*, Interoffice Memorandum, File #101.80.36/3 (Newfoundland and Labrador Hydro, July 19, 1990).
5. Arbuckle, Trevor, *Summary Report - Surge Tank Repairs - 1990*, Interoffice Memorandum, File #101.80.36/1.2.3 (Newfoundland and Labrador Hydro, November 19, 1990).
6. Kearley, Leveson, *Condition Assessment, Bay d'Espoir Surge Tanks #1, 2, & 3.* (Newfoundland and Labrador Hydro, October 24th, 2001).
7. Del Rizzo, J.B. and Stacey, Tony, *Bay d'Espoir Surge Tank Inspection Final Report* (Remote Access Technology (Newfoundland) Inc., August 20, 2002).
8. Bantleman, Anthony, *Evaluation of Condition of Coating on Exterior of Surge Tank #3,* (Bantleman Consulting Service Inc, June 2007).

Appendix A

Surge Tank Inspection Report (RAT)

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Remote Access Technology

Surge Tank #3 Inspection Report

Bay D'Espoir Hydroelectric Power Station

www.RATintl.com

Table of Contents

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1.0 Introduction

Remote Access Technology was mobilized to the Bay D'Espoir hydroelectric power station from August 20th – 23rd, 2012 to perform a visual inspection on the internal & external condition of the tank as well as ultrasonic inspection at various locations on surge tank #3.

1.1 Inspection Summary

The external visual inspection was performed on surge tank #3, concentrating on the checkered portion of the tank shell, tank riser, tank top, thermal insulation system, ladder system including the rotating ladder at the tank top, hot water heating system, legs, cross braces and structural connections.

The internal inspection of the tank included the tank top, bowl, internal structural members, cathodic protection system, and riser.

Ultrasonic inspection was carried out on the tank top, expansion joint on the lower balcony and on the surge tank on the upper balcony. In order to perform the UT on the balconies the cladding and insulation was removed and reinstated afterwards. Ultrasonic thickness measurements are not available on the bowl of the tank as the coatings have created a rough surface thus prohibiting the acquisition of readings without removing the coating. It appears as if there are two different coatings inside the tank. The vertical section of the tank appears to be coated with a grey coating and the bowl is a yellow coloured coating. The transition between the two systems is at the interface between the bowl and the vertical sections of the tank. Photos of the bowl are located in section 3.1 of this report.

A general inspection was performed on the ladder system and hot water heating system. Overall the ladder system is in good condition, coating breakdown and minor corrosion is present. The transition point between the rigid rail of the vertical section to the swivel ladder on the roof was of some concern as it involved transitioning from one rail to another. Also of note, the lower walkway around the tank has no gate/chain at the ladder access point. This creates an area of concern as the handrails are not continuous around the entire tank. A few areas on the insulation of the hot water heating system indicated potential areas of water ingress. The insulation on the hot water heating system piping that runs from the utility shed to the West leg shows signs of damage as well.

The tank top had coating break-down and corrosion. The aviation lights, swivel ladder and hatch opening for the tank were all operational. On the inside of the

1

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tank top were pad eyes, however they are welded directly to the tank top with no apparent structural stiffening.

The interior of the tank riser has generalized pitting throughout. The interior inspection of the surge tank shell and the bowl showed that the coating was still present with only a few areas of coating breakdown on the tank shell observed.

All anodes appeared to be present, however they were heavily tangled. It was decided that it was too dangerous to attempt to untangle them while on ropes.

Cross members inside the tank were found to be in good condition.

The Exterior of the Surge Tank has coating breakdown and shows signs of corrosion. The riser was found to be in good condition with exception of some water staining. The rest area, upper and lower balconies have coating breakdown and show signs of corrosion. The bottom balcony braces all showed signs of warping and corrosion. The Tank legs, horizontal steel beams were found to be in good structural condition all showed coating breakdown, all cross bracing showed signs of friction at the intersections.

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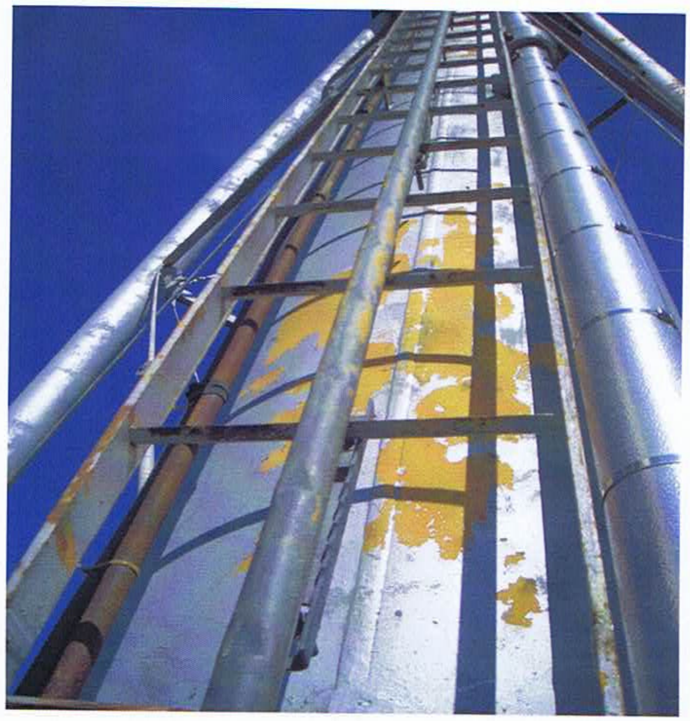
2.0 External Inspection Results

2.1 Ladder System



Location: Ladder

Description: General photo. Typical areas of coating break-down and corrosion.

3

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Location: Ladder

Description: General photo. Ladder bolted connection showing typical corrosion.

Location: Ladder

Description: General photo. Ladder bolted connection showing typical corrosion.

4

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2.2 Hot Water Heating System

Location: Tank exterior

Description: General condition of insulated piping.

Location: Hot water heating system piping and heat trace (entering surge tank)

Description: Cladding cap missing, possible/potential area for water ingress.

5

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Location: Hot water heating system piping (entering surge tank)

Description: Cladding torn, possible water ingress.

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2.3 Rest Area and Balconies

Location: Rest Area

Description: General Coating breakdown and corrosion on railings.

Location: Rest Area

Description: Coating breakdown and corrosion on grating.

7

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Location: Bottom Balcony

Description: Typical condition of handrails, minor coating breakdown.

Location: Lower Balcony

Description: Localized corrosion on the balcony floor.

8

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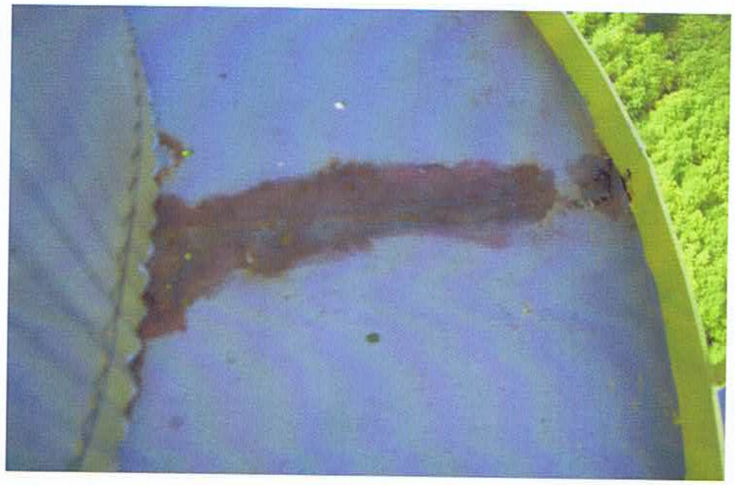

Location: Lower Balcony

Description: Localized corrosion on the balcony floor.

Location: Lower Balcony

Description: General photo. Rod braces are warped and have heavy corrosion

9

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Location: Upper Balcony

Description: General photo, Corrosion on handrails.

Location: Upper Balcony

Description: General photo, Corrosion of deck.

10

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Location: Upper Balcony

Description: Manhole penetration, possible/potential water ingress.

Location: Upper Balcony

Description: General photo. Tank leg penetration, possible/potential water ingress.

11

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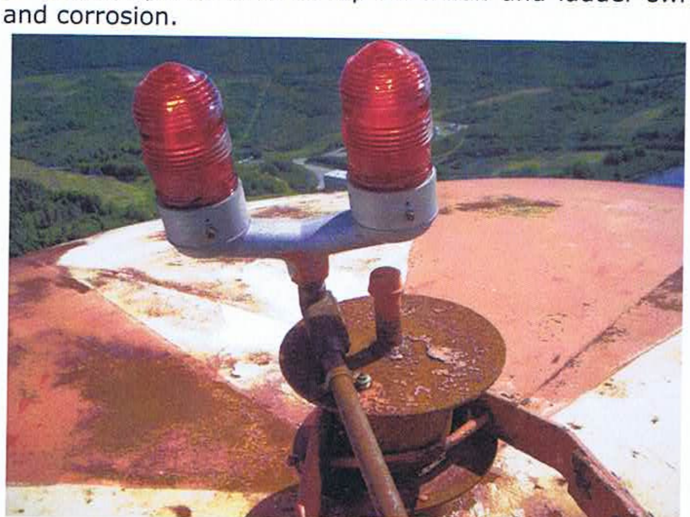
2.4 Tank Top

Location: Tank Top

Description: General photo of tank top condition and ladder swivel system, coating breakdown and corrosion.



Location: Tank Top

Description: Aviation lights are active.

12

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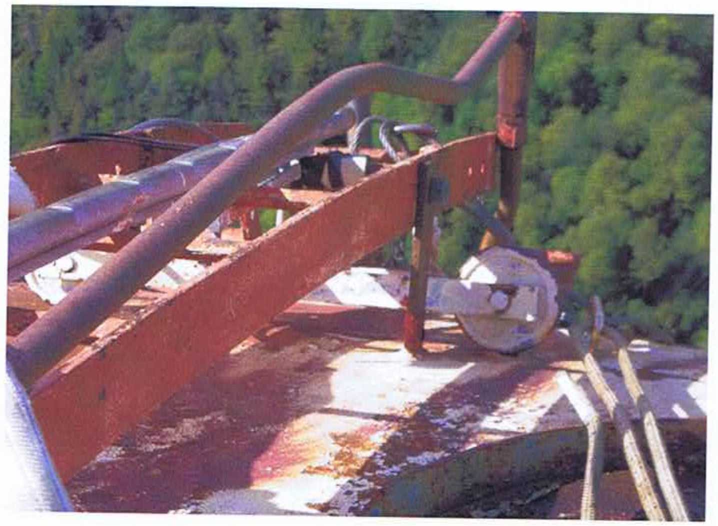

Location: Tank Top

Description: Swivel mechanism for ladder/fall arrest system functional.

Location: Tank Top

Description: Hatch way to tank.

13

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2.5 Surge tank, Riser & Cross Braces

Location: Surge Tank

Description: General Photo. Typical photo of coating break-down/corrosion.

Location: Riser

Description: General photo. Good condition some water staining present.

14

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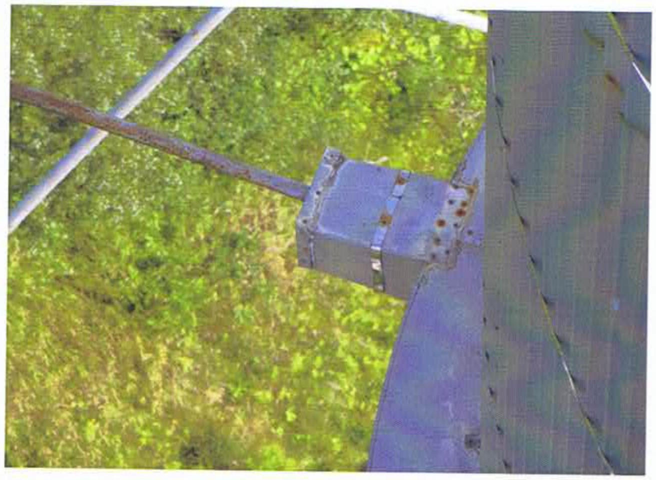

Location: Riser East Road Brace

Description: General Photo, showing overall condition of Rod Braces

Location: Horizontal Steel Beams (West-North leg)

Description: General Photo showing coating breakdown on horizontal beams.

15

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Location: West Leg

Description: General photo, connection point.

Location: Cross member (West-North)

Description: General photo, typical friction wear on the cross members on the tower.

16

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3.0 Internal Inspection Results

3.1 Tank Top

Location: Surge Tank (tank top looking west)

Description: Lap joint opening on tank top at manhole.

Location: Surge Tank (tank top looking east)

Description: Lap joint opening of tank top 2".

17

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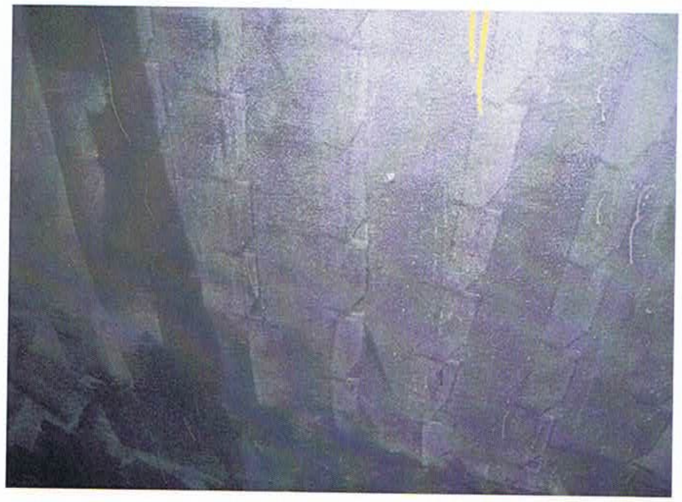
3.2 Tank Shell



Location: Surge Tank

Description: General photo. Typical coating system on tank shell.

Location: Surge Tank

Description: Localized coating breakdown on tank shell.

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Location: Surge tank

Description: Corrosion along the weld seam on tank shell.

19

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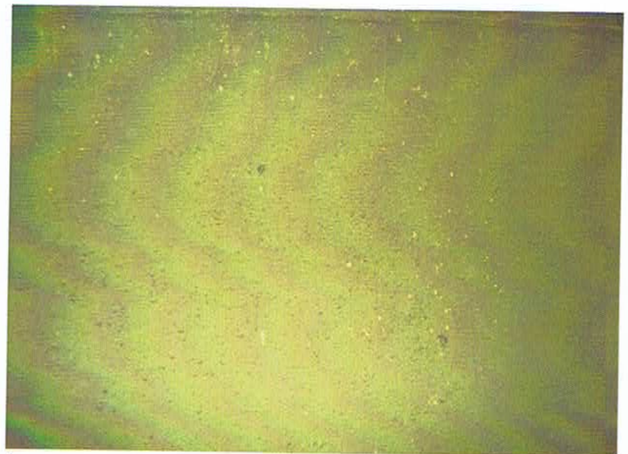
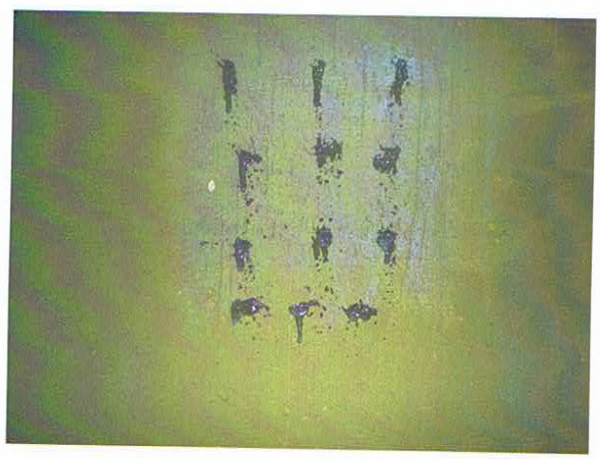
3.3 Tank Bowl



Location: Bowl

Description: It appears to be coated in drips from the coating applied to the sides of the tank. Recording ultrasonic thickness readings was not possible due to the condition of the surface.



Location: Bowl

Description: UT couplant was applied to the surface of the bowl, however the coating was not uniform, this preventing the acquisition of UT readings without removing the coating.

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Location: Bowl

Description: UT couplant was applied to the surface of the bowl, however the coating was not uniform, this preventing the acquisition of UT readings without removing the coating.

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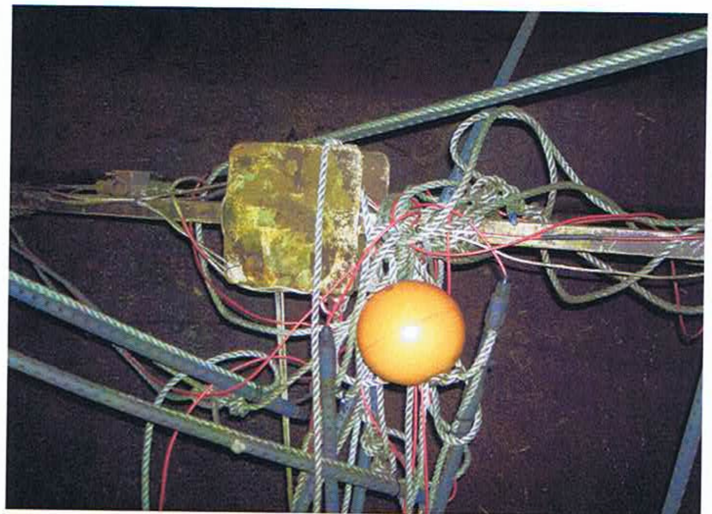
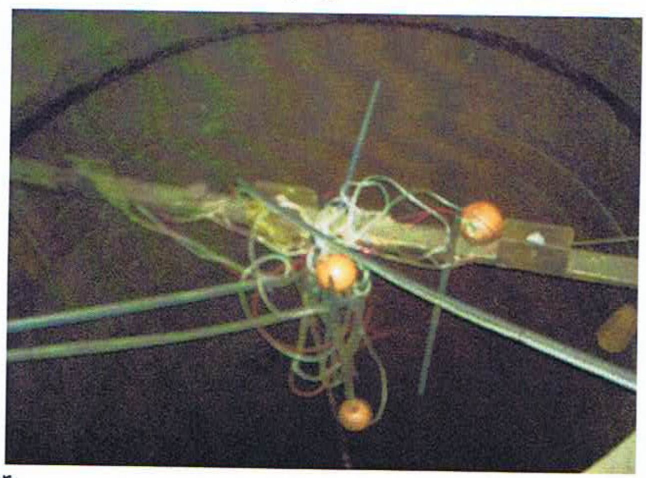
3.4 Riser & Anodes



Location: Riser

Description: Tangled anodes, no warping in cross member



Location: Riser

Description: Tangled anodes, no warping in cross member

22

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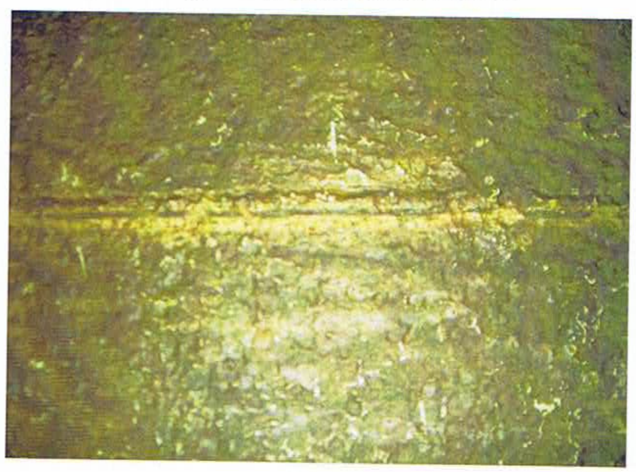
Location: Riser

Description: General photo. Typical pitting on riser shell.



Location: Riser

Description: General photo. Typical pitting on riser shell.

23

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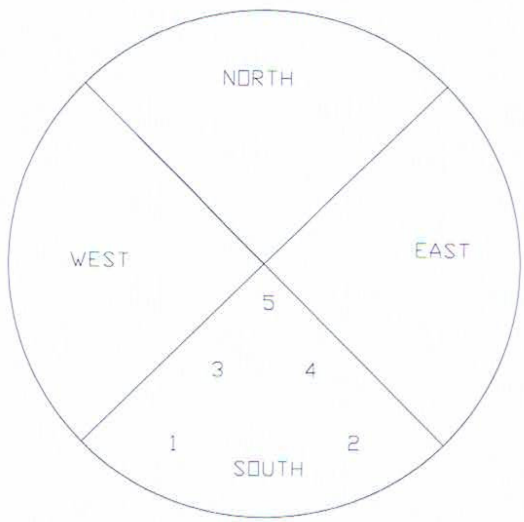
4.0 Ultrasonic Thickness Gauging

Calibration Block CS: SN/09-1266
Probe: fh2e SN/01tmjo
Ultrasonic Machine: krautkramer dms2 SN/01tx0r
Calibrated: 19mar12-19mar13 SN/12544

4.1 Tank Top

Readings were recorded in the four quadrants of the tank top. The readings were taken in the following pattern shown below.



Location	North	East	South	West
1	8.4mm	8.2mm	9.6mm	8.7mm
2	6.7mm	8.4mm	10.1mm	8.9mm
3	8.5mm	8.3mm	9.7mm	7.9mm
4	8.7mm	8.5mm	9.9mm	8.4mm
5	8.9mm	7mm	9.8mm	8.6mm

24

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4.2 Surge Tank (exterior)

Readings were taking on the exterior of the surge tank at the upper balcony level. Some cladding was removed to gain access to the area. The following images show the removed cladding and the repair.

Location: Upper Balcony

Description: Cladding and Insulation removed for inspection.

1a	19.9mm	**2a**	7.3mm	**3a**	7.2mm
1b	19.8mm	**2b**	8.3mm	**3b**	7mm
1c	18.8mm	**2c**	8.1mm	**3c**	6.2mm
1d	20mm	**2d**	6.5mm	**3d**	8mm

25

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Location: Upper Balcony

Description: Reinstatement of insulation and cladding.

26

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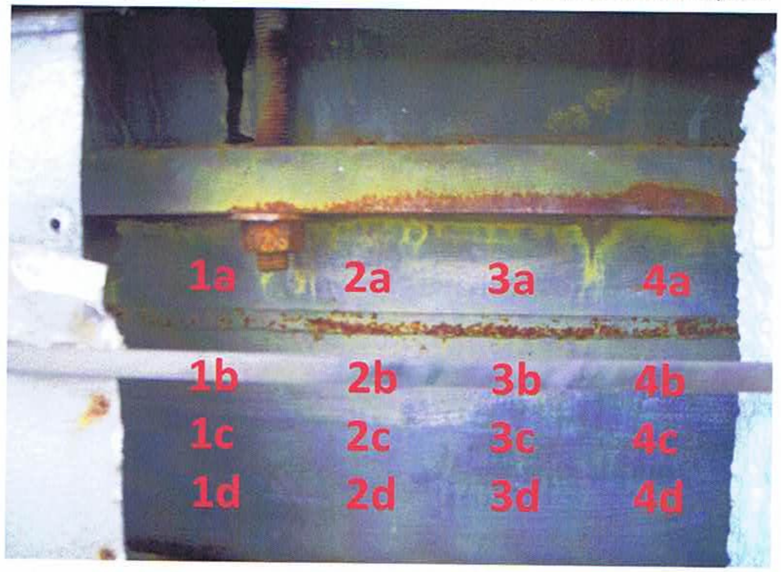
4.3 Expansion Joint (exterior)

Readings (above and below the weld) were taking on the exterior of the expansion joint at the lower balcony level. Some cladding was removed to gain access to the area. The following images show the removed cladding and the repair.



Location: Expansion Joint Lower Balcony

Description: Cladding and Insulation removed for inspection.

1a	14.3mm	**2a**	12.5	**3a**	13.5mm	**4a**	13.0mm
1b	9.7mm	**2b**	9.6mm	**3b**	9.9mm	**4b**	9.7mm
1c	9.8mm	**2c**	10.3mm	**3c**	9.5mm	**4c**	9.8mm
1d	9.8mm	**2d**	9.5mm	**3d**	10.4mm	**4d**	9.7mm

27

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Location: Expansion Joint Lower Balcony

Description: Reinstatement of insulation and cladding.

28

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St. John's, Newfoundland, Canada A1A 3W8
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A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER T. ARBUCKLE SIGNATURE PROVINCE OF NEWFOUNDLAND	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Upgrade Burnt Dam Spillway Structure

Burnt Dam

March 2013

newfoundland labrador hydro
a nalcor energy company

SUMMARY

This project involves an upgrade of assets at Burnt Dam Spillway during the final two years of a five year program to extend the service life of the structure by 25 years. The project involves upgrading the diesel power supplies and emergency hydraulic system at Burnt Dam Spillway as recommended by Hydro's internal engineering and technical personnel. The project is being proposed to ensure a reliable source of power for operation of the two gates at Burnt Dam Spillway. Upgrades to Burnt Dam Spillway during the first three years of the program will be completed in 2013 from recommendations that were identified in an engineering study completed by Hatch in 2008 – 2009.

TABLE OF CONTENTS

1 INTRODUCTION

The Bay d'Espoir Development includes three hydroelectric generating stations, six reservoirs, and associated dykes, dams, canals and hydraulic structures. The headwaters of the Bay d'Espoir Development begin at the Victoria Lake reservoir at an approximate elevation of 320 meters. The water travels through the Granite Canal Hydroelectric Generating Station (Granite Canal), Upper Salmon Hydroelectric Generating Station (Upper Salmon) and finally through the Bay d'Espoir Hydroelectric Generating Station (Bay d'Espoir) where it discharges at sea level. Additional water is collected, stored and diverted from drainage areas between Victoria Lake and the Long Pond reservoir which is the fore bay for Bay d'Espoir.

The generating stations comprising the Bay d'Espoir Development were built over a number of years with the Bay d'Espoir station being the oldest dating back to 1967 and Granite Canal Development being the newest, coming online in 2003. Some of the oldest hydraulic structures within the Bay d'Espoir Development were constructed in 1967. There are four remote hydraulic structures associated with Bay d'Espoir. They are Ebbegunbaeg Control Structure, Salmon River Spillway Structure, Victoria Control Structure and Burnt Dam Spillway Structure (Burnt Spillway).

Burnt Spillway, shown in Figure 1 and on the map in Figure 2, is a critical hydraulic structure in the Bay d'Espoir Development. It allows water from the Burnt Pond Reservoir, a small uncontrolled reservoir south of the Victoria Lake Reservoir, to be released in a controlled, non-destructive manner when needed for flood control. Water discharged from Burnt Spillway is lost from the Bay d'Espoir Reservoir System, and not available for production of electrical energy at Granite Canal, Upper Salmon and Bay d'Espoir generating stations. The spillway consists of two seven-meter wide steel gates which can release a combined 1,144 cubic meters per second of water at the maximum flood level. During the 45 year period up to 2012, one or both gates have been opened and then closed for flood control 33 times.

Figure 1: Burnt Dam Spillway Structure

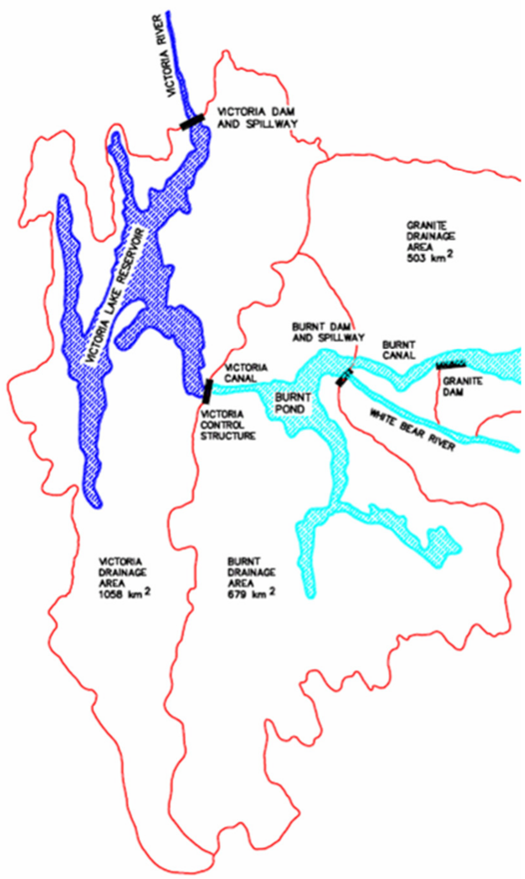

Figure 2: Victoria Lake and Burnt Pond Reservoirs

To provide further spilling in extreme floods (a 1 in 10,000 years occurrence), a fuse plug has been constructed in the north end of the Burnt Canal. In the event that the Burnt Spillway is unable to handle flood flows, a fuse plug, which acts like a pressure relief valve, will rupture and allow further flood waters to discharge from the reservoir. The fuse plug is a section of the dam that is designed to fail once the water reaches a critical elevation. This allows water to spill in a more controlled manner than what would occur if the dam was breached. The fuse plug is designed to operate at a water elevation of 315.2 meters, whereas spilling at the Burnt Spillway normally commences at 313.9 meters. The water level in the Burnt Pond Reservoir can rise quickly in a flood situation. A delay in gate opening of 24 hours during a high run-off period could result in fuse plug operation.

2 PROJECT DESCRIPTION

This project is the final two years of a five year program to upgrade the Burnt Spillway. Equipment at the spillway is at or near the end of its useful life and/or is in a deteriorated condition. After this upgrade is completed, the Burnt Dam Spillway will be in a condition to operate safely and reliably for another 25 years.

This project involves replacement, refurbishment and upgrade of various components at the Burnt Dam Spillway. The scope of work for this phase includes the following;

- Permanently install the existing portable emergency hydraulic drive shown in Figure 3 in a new enclosure and install permanent piping to the drives of each gate hoist.
- Replace the existing 25 kW and 75 kW diesel generating sets shown in Figures 4 and 5 and associated switchgear.
- Replace the DC disconnect switches in the diesel building with non-fusible disconnects fitted with viewing windows.
- Replace the cables from the diesel building to the spillway gates control building and raise and seal the cable penetrations through the exterior walls shown in Figure 6.
- Replace the existing diesel generator exhaust pipes shown in Figure 6.
- Modify the diesel building's intake/exhaust vents as shown in Figure 6.

The budget estimate for this project is $1,312,100. Engineering is scheduled to start in September, 2014 with construction taking place from July to October 2015.

Figure 3: Portable Emergency Hydraulic Drive

Figure 4: 75 kW Diesel Generator Set

Figure 5: 25 kW Diesel Generator Set

Figure 6: Cable Penetrations, Exhaust Stacks and Intake/Exhaust Vents

3 JUSTIFICATION

This project is justified on the requirement to upgrade equipment in order for Hydro to provide safe, reliable flood management for the Victoria Lake and Burnt Pond Reservoirs as well as fisheries compensation flow into the White Bear River. A condition assessment study performed by a professional engineering firm, Hatch, in 2008 (see Appendix A) identified Burnt Spillway as having the lowest overall Health Index when compared to four other hydraulic structures of similar vintage within the Bay d'Espoir Development. Hydro's ability to continue to manage flood waters and meet its fisheries compensation commitments is contingent upon the successful upgrade of Burnt Spillway. Most of work to be completed during this project will address deficiencies with the power supply systems that were outside the scope of Hatch's mandate but are necessary to achieve the overall reliable operation of Burnt Spillway as assessed by Hatch. When the upgrade program for Burnt Spillway is complete, it is anticipated that this hydraulic structure will be in a condition to operate safely and reliably for at least another 25 years.

Critical component failure in a major piece of drive equipment would result in the inability to open or close a gate. If the reservoir water elevations are rising and a gate is unable to be opened, it will diminish spill capacity and increase the potential of a fuse plug operation. However, if reservoir elevations are decreasing and a spillway gate is stuck in the open position, it results in a potential spill of up to 575 cubic meters of water per second. Spilled water is lost and cannot be used for power generation anywhere on the system. Operation of the fuse plug would have a significant consequence including lost reservoir water, fuse plug reconstruction cost, and disruption of effective water management for the Bay d'Espoir reservoir System while the fuse plug was being constructed. Reconstruction of the fuse plug is estimated to cost approximately one million dollars and would take between six and ten months to complete, depending upon the time of year of the failure.

The reliable operation and availability of the diesel generator sets is critical for both heating and operation of the spillway gates and for supplying power to the accommodations that are occupied on a year round basis. In 2009, the 40 kW diesel generator was replaced and uprated to 60 kW. The 25 kW diesel generator is 45 years old and is at the end of its service life. In 2012 the 75 kW diesel generator was very unreliable with five breakdowns due to failure of various components. In addition to the diesel generators, the emergency hydraulic drive system is also critical to the reliable operation of the spillway gates. It is used as a backup system and is designed to open the gates if all the diesel generators were unavailable during a flood situation. Permanent installation of this unit will reduce the response time and address safety concerns during an emergency situation. Due to their design the DC disconnect switches no longer meet safe isolation requirements for worker protection. The power cables are over 40 years old and been exposed to extreme weather conditions. The exhaust pipes need to be replaced by proper stacks for acceptable dispersion of exhaust emissions to address environmental and safety requirements and the building's exhaust vents and intakes require modifications to address problems from snow blockage during winter operation.

As discussed earlier, there is a fuse plug installed in the north end of Burnt Canal which serves as an emergency relief to control extreme flooding. If the fuse plug ruptured, Burnt Pond Reservoir would drain to the bottom elevation of the fuse plug resulting in loss of storage from the Burnt Pond Reservoir. While awaiting reconstruction, there would be loss of the full potential use of the Victoria Lake Reservoir, which could be up to 550 GWh of additional stored energy. It is estimated that to replace that amount of energy with thermal generation from Holyrood would be greater than $100 million at today's oil prices (based on $110.72 per barrel). Water that would normally be released from the Victoria Lake Reservoir into the Burnt Pond Reservoir, and which would subsequently flow through the Burnt Canal to the remainder of the Bay d'Espoir Reservoir System, would instead be spilled through the Burnt Dam Spillway, and/or the failed fuse plug, and lost for hydraulic generation.

3.1 Existing System

The Burnt Dam Spillway is a two gate structure that is required to discharge water in a controlled manner from the Burnt Pond Reservoir in the event of flood conditions. It is also used in the summer time to discharge water downstream into the White Bear River for fish habitat when inflows are low.

The spillway structure was placed in service in 1967, it is now approximately 45 years old, and has never undergone a major overhaul. It is a manned remote diesel powered site that can be accessed by truck over a dirt road for six to seven months of the year and by helicopter other times of the year when the road is not kept open. However, due to remoteness and poor road conditions bi-weekly crew changes are completed by a helicopter on a year round basis.

Since 2011, work has been under way to overhaul Burnt Dam Spillway including:

- Replacement of the stop log hoist, storage enclosure and stop log storage system;
- Condition assessment and refurbishment of each gate's mechanical components; and
- Replacement of all deteriorated electrical and control equipment.

Burnt Dam is equipped with three diesel generator sets and a portable hydraulic unit. A 25 kW unit supplies power to the facility from May through October and a 60 kW unit supplies power during the colder period of the year from November through April when the gate heaters are in service. A 75 kW unit provides backup for the 60 kW unit. The portable diesel-driven emergency hydraulic unit is required as a last resort alternative to open the gates if the diesel generator sets are unavailable.

Major work that has been planned and completed at for Burnt Dam is shown in Table 1.

Table 1: Planned Major Work and Upgrades

Year	Major Work/Upgrade	Comments
2011-2013	Replacement of stop log hoist enclosure and electrical equipment	Originally scheduled for 2011 but has been delayed and will now be completed in 2013.
2012 -2013	Refurbishment of gate hoists drives and screws and refurbishment of stop logs; detailed inspection of the embedded parts and mechanical components; replacement of electrical components	Refurbishment of one gate was competed in 2012 and the second will be completed in 2013; to be completed in the second half of 2013.
2012- 2013	Fabrication and installation of a stop log storage system	Originally scheduled for 2012, will now be completed in 2013
2012 - 2014	Refurbishment and Replacement of the gates embedded parts and mechanical components; replacement and upgrading of two diesel generator sets and permanent installation of the emergency hydraulic drive.	Originally scheduled for 2012 but now scheduled for completion during the second half of 2013; to be completed in 2014-2015 pending project approval by the Board.

3.2 Operating Experience

In 2006 there was an incident whereby the gates at Burnt Spillway failed to operate when required. A crew was dispatched from Bay d'Espoir to perform emergency work on both gates but could not get either of the gates open to the position requested by Hydro's Energy Control Centre (ECC) in order to lower the reservoir water level. This is a serious situation during times of high reservoir levels as there is a potential to cause a fuse plug operation. The incident in 2006 did not cause the fuse plug to operate however it did cause the loss of a significant amount of reservoir water when both gates could not be closed for approximately two days. It was estimated that the cost to replace the value of the lost hydro generation with thermal generation in 2006 from the Holyrood station was $2.6 million (based on $50 per barrel at the time).

During the incident, when neither gate would rise to the required open position, the dispatched crew was successful in raising the gates enough to prevent failure of the fuse plug. However, once the reservoir levels where reduced to an acceptable level the crew had difficulty closing the gates. This resulted in three days of additional work but more importantly the loss of a significant amount of stored energy in the form of lost water through the spillway. After this incident the gate screws at both Burnt and Salmon River Spillways were cleaned and recoated with lubricant.

3.2.1 Reliability Performance

Due to the high potential for flash flooding of Burnt Pond, the opening of the Burnt Dam gates must be 100 percent reliable. When it was first commissioned in the 1960s it was an unmanned remotely controlled structure but due to frequent failures of the control system, and the need to guarantee operational reliability, in the early seventies it was converted to a manual operation. There now is concern for the reliability of the gate operations due to component deterioration which could cause a similar incident as happened in 2006. In 2012, there were five failures to components of the 75 kW generator set used to heat and raise the gate including oil seals, starter, fuel pump, over crank and base pan.

3.2.1.1 Outage Statistics

Outage statistics for the Burnt Spillway are not formally recorded. A review of work order history indicates that there have been at least four occasions when a gate could not be opened or closed due to cold temperatures, ice accumulation, or hardening of the grease for the gate hoist screw stems. An outage of a gate at Burnt Dam Spillway does not directly impact production at any of the three downstream generating stations. Outages on Burnt Dam Spillway are normally planned and only taken for maintenance purposes, usually on an annual basis during a time when the threat of spilling is very low. Only one gate is taken out of service at any one time leaving the other gate available for spilling or fisheries compensation.

3.2.2 Legislative or Regulatory Requirements

In 1966, an agreement was made between the Newfoundland and Labrador Power Commission (now Hydro) and the Department of Fisheries of Canada (now Fisheries and Oceans Canada) titled *Release of Water to Protect Fish Populations in Grey River and White Bear River.* The agreement took effect February 1966 and was varied by letters dated September 8, 1977 and July 11, 1996 (see Appendix B). The agreement established measures to be taken by the Power Commission for the conservation of stocks of anadromous fishes to be affected by the Bay d'Espoir Development, under the provisions of the Fisheries Act, R.S.C. 1952, c.119; as amended by 1960-61, c.23. Under this agreement, Hydro is required to provide fisheries compensation flow into the White Bear River to maintain a flow of 7.08 cubic meters per second at the mouth of the White Bear River from June 1 to September 30 each year. This is achieved by releasing up to 4.25 cubic meters per second through one of the gates at the Burnt Spillway during this period. Hydro's ability to meet its fisheries compensation commitment is contingent upon the successful upgrade of the Burnt Spillway to ensure reliable gate operation.

3.2.3 Safety Performance

Burnt Dam Spillway is a remote location and a reliable source of power for accommodations and operation of the control structure equipment is critical especially during the winter months. Due to the location of the gate hoists on top of an open structure with the only access is by a fixed ladder, hookup of the portable emergency hydraulic drive unit during a flood situation by the two person crew at site has a number of safety issues including exposure, rescue and medical treatment if someone was injured especially if the work has to be executed during severe weather conditions. Where the exhaust stacks for the diesel generator sets have a horizontal discharge at the wall level of the diesel building there is potential for the exhaust fumes to contaminate the air inside the diesel building.

In addition the DC disconnect switches do not have viewing windows for safe isolation and worker protection.

3.2.4 Environmental Performance

The gates at Burnt Spillway are required to provide fisheries compensation flow into the White Bear River to protect fish populations. In accordance with an agreement between Hydro and the Federal Department of Fisheries (see Appendix B), a flow of 7.08 cubic meters per second must be maintained at the mouth of the White Bear River from June 1 to September 30 each year. This is achieved by releasing up to 4.25 cubic meters per second through Burnt Spillway during this period, opening one gate approximately 8.5 centimeters. Hydro relies on Environment Canada flow data for White Bear River to schedule compensation flows through Burnt Spillway. During the 45 year period up to 2012, the gates were operated for fisheries compensation flow every year except for one.

Also, if the gates were unable to open during flood conditions a breach of the fuse plug and potential overtopping of the dam would cause environmental damage by flooding and eroding land downstream of the structures.

3.2.5 Industry Experience

Churchill Falls (Labrador) Corporation is involved in a rehabilitation program on the control and spillway structures in their system. These structures are approximately 40 years old. The Menihek Generating Station in Labrador was commissioned in 1954 and has gates similar to the ones used at Burnt Dam and is also undergoing a rehabilitation program of the spillway structure.

3.2.6 Vendor Recommendations

The vendor recommends replacement if they can no longer support the equipment due to the age and availability of spare parts.

3.2.7 Maintenance or Support Arrangements

Routine preventive and corrective maintenance is performed by Hydro personnel. Replacement of the diesel generator sets and the other work has also normally been completed in the past by internal labor forces.

3.2.8 Maintenance History

A summary of the five-year maintenance history for the 75 kW and 25 kW diesel generator units at Burnt Dam Spillway is provided in Table 2. In addition, where the Burnt Spillway Structure is very remote there are additional helicopter costs at a rate of $1,500/hr for transporting maintenance personnel. Annual helicopter costs to complete preventive and corrective maintenance range from $40,000 to $60,000.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2012	1.5	19.6	21.1
2011	2.1	0.5	2.6
2010	2.0	12.9	14.9
2009	0.8	19.8	20.6
2008	2.5	5.4	7.9

3.2.9 Historical Information

In 2009, the existing 60 kW diesel generator was installed, replacing a 25 year old 40 kW unit at a cost of $260,000. The existing 75 kW diesel was installed in 1987 and is now over 25 years old. The existing 25 kW diesel generator was relocated from Ebbegunbaeg control structure in the late 1970s and is now over 45 years old. The portable emergency hydraulic drive was purchased in 1989. In the past, prior to 2009 the 40 kW and the 25kw would have to be synchronized together in order to heat and open the gates if required during winter operation. There have been times due to maintenance or breakdowns where only one of the larger units is available. There have also been isolated occasions when the site has been without power due to equipment failures and opening of the gate would be dependent on the emergency hydraulic drive unit.

3.2.10 Anticipated Useful Life

Most of the equipment being replaced is over 40 years old and is at the end of its anticipated service life. The 75 kW diesel generator is over 25 years old and is unreliable. It is anticipated that the service life of Burnt Spillway will be extended by at least 25 years when the refurbishment program is complete. The new diesel generator sets will meet this extended service life.

3.3 Forecast Customer Growth

Forecast customer growth does not impact this project.

3.4 Development of Alternatives

There are no viable alternatives to upgrading Burnt Spillway. If the gates fail to open during a flood situation the consequences could be catastrophic. The 25 kW diesel generator is at the end of its service life and a new 25 kW is required. The 75 kW diesel generator is unreliable and breaks down when it is used as the prime power source. A permanent set up of the emergency hydraulic drive is required for both response time and safety of personnel. New DC disconnect switches are required to meet the mandatory safety standards for worker protection. The power cables are at the end of their service life and their present entry into the building results in flooding. The diesel engine exhaust pipes do not achieve acceptable dispersion of exhaust emissions and are a health and safety issue. The building intake/exhaust vents are a winter operational problem due to snow blockage.

3.5 Evaluation of Alternatives

As there are no viable alternatives an evaluation is not required.

3.5.1 Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to this project.

4 CONCLUSION

Burnt Dam Spillway is critical to Hydro's Bay d'Espoir reservoir system for flood control and fisheries compensation and must be maintained for reliability. This project provides for work to be completed in the final two years of a five year program that involves upgrading the diesel power supply and the gates' emergency hydraulic drive to help ensure operational reliability.

4.1 Budget Estimate

A budget estimate for this project is provided in Table 3.

Table 3: Project Budget Estimate

Project Cost:*($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	226.0	0.0	226.0
Labour	45.0	370.6	0.0	415.6
Consultant	35.0	13.6	0.0	48.6
Contract Work	0.0	148.0	0.0	148.0
Other Direct Costs	24.5	142.5	0.0	167.0
Interest and Escalation	5.7	100.2	0.0	105.9
Contingency	0.0	201.0	0.0	201.0
TOTAL	**110.2**	**1,201.9**	**0.0**	**1,312.1**

4.2 Project Schedule

The anticipated schedule for this project is provided in Table 4.

Table 4: Project Schedule

Activity		Start Date	End Date
Planning	Open project. Develop detailed schedule	September 2014	October 2014
Design	Stack dispersion modeling and design, emergency hydraulic piping design, switch gear design and exhaust vent design	October 2014	Dec.2014
Procurement	Procurement of design consultant, piping contractor and design consultant, all equipment and materials	October 2014	June 2015
Construction	Installation/construction of new diesel generators and switchgear, emergency hydraulic piping and building, exhaust stacks and vents and new cables	July 2015	October 2015
Commissioning	Commissioning of new diesel generators/switchgear and emergency hydraulic drive system	August 2015	October 2015
Closeout	Closeout , lessons learned and documentation, disposal of old equipment and materials	November 2015	November 2015

APPENDIX A

Hydraulic Structure Life Expectancy Study – Final Report (Hatch)

(excerpts applicable to the Burnt Dam Spillway Structure)

Newfoundland and Labrador Hydro

Hydraulic Structure Life Expectancy Study

Final Report

H330777
Rev. 0
May 22, 2009

HATCH™

Newfoundland and Labrador Hydro
Hydraulic Structure Life Expectancy Study

Final Report

Prepared by: Rick Hibbs, P.Eng. — May 22, 2009 (Date)

Approvals

Hatch

Approved by: Gregory Saunders, P.Eng. — May 22, 2009 (Date)

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L. G. MANN
SIGNATURE
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DATE
NEWFOUNDLAND & LABRADOR

PROVINCE OF NEWFOUNDLAND
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To practice Professional Engineering in Newfoundland and Labrador Permit No. as issued by PEG-NL N0130 which is valid for the year 2009

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Table of Contents

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Appendices:

Executive Summary

Hatch conducted a Life Expectancy Study of five hydraulic structures in the Bay d'Espoir Development: the Bay d'Espoir Intake, Burnt Spillway, Salmon River Spillway, Ebbegunbaeg Control Structure, and Victoria Control Structure. The study included: a review of drawings, operation and maintenance manuals, work order history and preventative maintenance routines; site visits, component inspections and functional testing of equipment; discussions with Hydro personnel; determination of a Health Index for each site; and a HydroVantage analysis which uses a risk-based failure cost to determine the least-cost course of action.

The findings of the Life Expectancy Study are summarized as follows.

Bay d'Espoir Intake

- Health Index 73.
- Short term recommendations focus on upgrading electrical components of the structures and continued implementation of PLC controls to Gates 1-3 similar to Gate 4. The estimated total cost of the short term recommendations is $227,000.

Burnt Spillway

- Health Index 66.
- Short Term Recommendations focus on reducing risk of operational failure of the gates. Complete rehabilitation of gate mechanical and electrical and upgrades to communications are recommended in the short term to improve reliability. The stoplog monorail hoist is a safety concern and should be replaced. The estimated total cost of the short term recommendations is $370,000.

Ebbegunbaeg Control Structure

- Health Index 80.
- Short Term Recommendations focus on enhancing reliability by replacing gain heating systems, rehabilitating gate roller assemblies, and improving communications. The screw stem hoists can remain in service but should be rehabilitated within seven years. The estimated total cost of the short term recommendations is $245,000.

Salmon River Spillway

- Health Index 71.
- Short Term Recommendations focus on reducing risk of operational failure through complete mechanical and electrical rehabilitation to improve reliability. The estimated total cost of the short term recommendations is $245,000.

Victoria Control Structure

- Health Index 68.
- Short Term Recommendations focus on upgrading electrical components that are at end of life, revamping the preventative maintenance routines, and performing a civil inspection. The estimated total cost of short term recommendations is $145,000.

1. Introduction

Newfoundland and Labrador Hydro (Hydro) contracted Hatch to perform a Hydraulic Life Expectancy Study for some of the water control structures in the Bay d'Espoir Development. The study will provide Hydro with the remaining useful life of the equipment at the structures and the necessary repairs or replacements to increase life by 25 years. This report documents the investigations, observations and analyses conducted, and lists recommendations to achieve Hydro's objectives.

1.1 Background

Hydro is a utility which owns and operates facilities for the generation, transmission and distribution of electricity to utility, industrial and residential customers in the Province of Newfoundland and Labrador. On the island, Hydro has nine hydroelectric generating plants with a total installed capacity of 980 MW and five thermal generating plants with a total installed capacity of 626 MW, interconnected by an electric power grid.

The Bay d'Espoir Development includes three generating stations and a series of dykes, dams, canals, control structures, spillways and reservoirs. The headwaters of the Bay d'Espoir Development begin at Victoria Lake at an approximate elevation of 320 m. The water travels through Granite Canal Generating Station, Upper Salmon Generating Station and finally through the Bay d'Espoir Generating Station where it discharges at sea level. Additional water is collected, stored and diverted from a number of drainage areas between Victoria Lake and Long Pond, which is the forebay for the Bay d'Espoir Generating Station. The generating stations were built over a period of time with Bay d'Espoir being the oldest dating from 1968 and Granite Canal being the newest, coming online in 2003.

Some of the oldest water control structures on the Bay d'Espoir Development are the four intake structures to the Bay d'Espoir Generating Station (1968-1977), the Burnt Spillway (1967), the Ebbegunbaeg Control Structure (1967), the Salmon River Spillway (1967), and the Victoria Control Structure (1967). Hydro has selected these structures for study to determine the condition of mechanical, electrical and protective equipment.

1.2 Objectives

The objectives of the study, as identified in Request for Proposal 2008-39101, are as follows.

1. Determine the condition of the hydraulic structures.
2. Make recommendations for immediate and long-term repair, upgrade and replacement of equipment such that the useful life of the structures will be extended to year 2035. Recommendations are to be itemized by location, discipline and priority.
3. Prepare budgetary estimates of required materials, labour and engineering for all recommendations.

In addition, other concerns were identified during the site visit meeting at the Bay d'Espoir Generating Station on October 15, 2008. Although these issues were not in the original scope of work of the Hatch Proposal dated August 11, 2008, some are addressed in this report. The list of issues is as follows.

- Inspection requirement and frequency of inspection for gate rollers.
- Requirements for interior gate heating versus up-lifters.
- Detailed PM Inspections missing from existing program for gates 40+ years.
- 100% heated gates/gains vs. a single gate.
- Continuous vs. intermittent gate/gain heating.
- Type of lubricant recommended for gate screw stems.
- Frequency required for cleaning screw stems.
- Protective covers for screw stems – Telescopic vs. Flex Material.
- Water leakage into gearboxes.
- Heating requirement for lube oil in gear boxes.
- Frequency for changing oil in gear boxes.
- Advantage of enclosing structures – benefits.
- Replacement vs. rewinds on spillway gate hoist motor.
- Spare parts recommendations.
- Condition assessment/inspection of gate stem gearboxes.
- Condition of master logs.
- Alignment checks for gates/gains.
- Condition of monorail hoist system and recommendations for improvement.
- Condition of monorail bus bars and recommendations for most durable type.
- Evaluation of gate electrical system.
- Evaluation of gate emergency lift system.
- Evaluation of gate electrical protection system.
- Adequacy of gearbox/motor size for gearbox and motor at Victoria Control.
- Comment on gate heating deficiencies at Victoria Control.
- Benefits/disadvantage of gate hoist control system on Ebbegunbaeg Gate 2.
- Benefits/disadvantage of screw stem hoist system at Ebbegunbaeg.

- Recommended inspections for intake gates.
- Other points.

1.3 Approach

Hatch undertook the following activities in preparation of the recommendations.

- Reviewed drawings and operation and maintenance manuals.
- Reviewed preventative maintenance program and work order history.
- Conducted site visits including visual inspections, condition assessment of structures and functional tests where possible.
- Held meetings and discussions with Hydro personnel.
- Analysed observations and findings using Condition Index (CI) and Health Index (HI) methodology.
- Performed a HydroVantage Analysis of selected components.
- Co-ordinated effort to match results of condition assessment with the HydroVantage results.
- Itemized recommendations in order of priority of critical and non-critical components at each hydraulic structure.
- Prepared a budget cost estimate for labour, materials and engineering for the recommendations.

1.4 Report Organization

Section 2 of this report describes the methodology used to perform the assessments, conduct the analyses, and make the recommendations. Sections 3-7 provide detailed findings, analysis results and recommendations for each structure. More detail can be found in the appendices. Electrical site inspection checklists, mechanical site inspection checklists, HydroVantage analysis results and selected photographs of the structures are found in Appendices A, B, C and D, respectively. Section 8 of the report summarizes the recommendations and includes cost estimates.

2. Methodology

The project was completed in primarily two phases: Data Collection and Analysis. The Data Collection Phase consisted of gathering all sources of information and processing the information such that it could be analyzed. The original scope of work at the time of award provided for analysis of life expectancy and the preventative maintenance program of selected structures. Following the site visit, Hydro extended the scope of work to include the optional HydroVantage analysis as proposed by Hatch. Work conducted in the Data Collection and Analysis phases facilitated drawing conclusions and preparing the recommendations.

2.1 Data Sources

The following sources of information were included in this study.

2.1.1 Drawings

Hydro provided several electrical, mechanical and structural drawings for the structures. The drawings were primarily used in developing a familiarity with the structures and in preparing check sheets for the site visits.

2.1.2 Operation and Maintenance Manuals

The operation and maintenance manuals for each structure were reviewed at Hydro's offices and relevant sections were copied. The manuals differ greatly because equipment came from different suppliers. The manuals were used in preparation of check sheets and maintenance reviews.

2.1.3 Interviews

Rather than conduct formal interviews, the Hatch engineers engaged Hydro staff during the site inspections and functional tests. This approach allowed Hydro staff to demonstrate and illustrate their concerns and quickly recall maintenance and repair history. Valuable information was provided by the staff and that information fed directly into the Life Expectancy Analysis.

2.1.4 Preventative Maintenance Program

Hydro provided the mechanical and electrical preventative maintenance check sheets and schedule for the structures.

2.1.5 Maintenance History

Hydro provided five years of maintenance work order history from their JD Edwards maintenance program for each of the structures. The work orders were compiled and compared to identify recurring maintenance concerns.

2.1.6 *Site Inspections*

Site inspections were conducted October 15 to 18, 2008 by Kishen Bhan, Lewis Hann and Rick Hibbs of Hatch, and Paul Hancock, Hubert Fudge, Rodney Willcott, and Walter Organ of Hydro. In preparation for the site visits, Hatch prepared check sheets for recording the condition of various components. The site inspections were mostly visual; however, simple tests were also conducted such as determining if rollers were seized and measuring starting/normal currents drawn by the hoist motors and gate and gain heaters. Where possible, access was made to the gate leaves, the hoist structure and inside gates to permit closer inspections. Hydro maintenance staff also removed covers of gearboxes and electrical panels to permit internal inspections.

2.1.7 *Functional Tests*

Functional tests were performed on Burnt Spillway Gate 2 and Salmon River Spillway Gate 1 while the upstream stoplogs were in place. Ebbegunbaeg Gates 1 and 2 were operated under flowing conditions. The four Victoria Control gates were operated under both flowing and dry conditions. The Bay d'Espoir intake gates could not be tested due to plant loading. Functional tests involved lifting and lowering the gates under normal power supply; the emergency hydraulic hoists were started but not used.

2.2 Analysis

2.2.1 *Electrical General*

Performing a condition assessment for low voltage power equipment and its components requires a review of maintenance records, spare parts availability, and analyzing the condition against the required functionality and safety considerations. Age is only one of many factors that should be considered in assessing the condition of electrical equipment. The rate and severity of degradation depend on operational duties of the equipment and environmental factors.

Overall equipment condition assessment includes consideration of the following:

- Physical condition;
- Functional requirements and performance;
- Frequency of emergency/preventative maintenance;
- Spare parts availability; and
- Fire and safety implications.

Outdoor components experience the following types of degradation:

- Wiring insulation deterioration;
- Mechanical (supports and mounting);
- Corrosion; and
- Moisture ingress.

Corrosion and moisture ingress, or combinations of these, represent the most critical degradation processes in outdoor electrical equipment. Age alone is not a good indicator of equipment condition, as the effects of the operating environment generally have a significant impact.

Indoor components experience the following types of degradation:

- Wiring insulation deterioration;
- Poor electrical connections due to corrosion, vibration or other physical problems;
- Corrosion (unheated space).

Wiring insulation degradation can lead ultimately to failures and equipment unavailability. Assessment of the insulation integrity of low voltage equipment is performed by visual inspection and testing using a mega-ohm meter, often referred to as Megger Testing.

Moisture and high humidity in electrical equipment enclosures and electrical rooms promote corrosion and should be avoided. When ambient temperatures fall below the dew point, condensation can occur. In the event water enters equipment enclosures and electrical rooms through roof or other leaks, it can affect performance and aggravate long-term corrosion. Routine inspections and maintenance can detect and mitigate corrosion, but providing proper environmental conditions or installing equipment designed for humid environments can prevent corrosion significantly.

Generally, visual inspections offer the best form of condition assessment for low voltage distribution panels and control panels. Visual inspections are an important part of any maintenance program but need to be accompanied by routine functional checks and tests that will clearly identify problems that require mitigation.

Normally, it may not be practical to test the electrical functionality of low voltage fuses and breakers during routine inspections, but it is important that this equipment is maintained in good service condition. Alarms and supervisory systems can sometimes be utilized to identify power system and equipment failures.

Wiring insulation may degrade from fraying and brittleness. Older power distribution and control cables are insulated with rubber-based insulation that tends to deteriorate over time. In many cases, this deteriorated insulation falls away when touched, exposing conductors. Modern PVC insulated cables do not tend to have this problem except when exposed to severe overheating.

Replacement of low voltage electrical distribution equipment, control panels and associated wiring that is at or near the end of service life is a cost effective risk management strategy.

2.2.2 Mechanical General

The mechanical condition assessment of the hydraulic structures includes both structural steel components and strictly mechanical components.

The structural steel components include the gate leaf components such as skinplate, girders, stiffeners and end trucks; stoplog steel components and hoist structure. For these steel components, the main indicators of serviceability are corrosion, distortion and signs of excessive stress in connections such as weld cracks or bolt looseness. After review of the work order history and discussion with Hydro personnel at the kick-off meeting, it was concluded that there was no preliminary evidence of excessive corrosion or over-stressing and thus no Non-Destructive Examination (NDE) of the steel work was considered warranted.

The mechanical components investigated include the gate roller assemblies and gains, the gate seals and sealing surfaces, and the hoisting equipment.

The ideal method to inspect the roller assemblies is to disassemble the rollers and inspect the bushings, pins and thrust washers. It is likewise desirable to measure the straightness and plumbness of the gains. This was not possible in the limited time available for inspections. The rollers were visually observed while the gates were in motion and accessible rollers were rotated by hand, where possible. Rollers which rotated were considered effective, while those that did not were suspect. However, by this simple method, it cannot be concluded that a roller assembly has failed (seized). Similarly, side rollers which maintained contact and rotated were considered effective. Close access to the gains was not possible; visual examination from the deck for scrape marks, galling, and corrosion was used to determine condition.

In most cases, it is not possible to visually inspect the gate seals unless the gate is removed from the structure. The condition of the seals was evaluated based on their ability to retain water while in service.

Both wire rope and screw stem hoists are used in the Bay d'Espoir Development Structures. The weakest component in a wire rope hoist is typically the rope itself. This will normally require replacement before the drum, fan brake or gear box. Confirmation of wire rope strength is normally done via a pull test; however this is impractical for ropes in service which instead are inspected for corrosion, fraying, kinks and distortion. Wear and material loss is the main indicator of condition for the remaining components on wire rope hoists and the components of screw stem hoists. Gears, drums and screws should have patterns of equal wear; broken teeth and gouges are signs of localized overstressing. The effects of unequal and excessive wear can often be heard when the hoist is operating.

2.2.3 *Life Expectancy*

Hatch pioneered the Health Indexing System to quantify the condition of the equipment relative to long term degradation factors that signify cumulative problems leading to end-of-life (EOL).

The following condition ratings provide the basis for formulating an overall Health Index for the relevant equipment/system:

3 Good condition, only minor deterioration or defects are evident.

2 Fair condition, moderate deterioration, function is adequate.

1 Poor condition, serious deterioration of at least some parts. Function is inadequate.

0 Unacceptable conditions, extensive deterioration, barely functional, may be unsafe to operate.

To calculate the Health Index for each component, weighting is given to each of the subcomponents based on its relative importance: 8 for a dominant subcomponent whose failure or end-of-life determines that for the whole component, 4 for high importance subcomponents, 2 or 3 for medium importance subcomponents and 1 for low importance subcomponents. For each individual subcomponent, the weighting is then multiplied by 3, 2, 1 or 0 corresponding to the condition rating as shown on the Condition Assessment form. The overall Health Index is then derived from the sum of these products for all subcomponents. The standard procedure is to normalise this sum to give a final result based on a scale of 0 to 100. Health Index is the actual sum of products divided by the maximum possible sum of products and then multiplied by 100. The maximum possible sum of products is obtained by setting the condition rating at 3 for all subcomponents. Thus, a component in perfect condition would have a Health Index of 100.

One Health Index has been prepared per structure, reflecting the mechanical and electrical condition of all gates and hoists. Table 2-1 ranks the Health Index score against overall condition and intervention required.

Table 2-1: Health Index Scale for Head Gate Hoist

Health Index	Condition	Description	Requirements
85-100	Excellent	No noticeable defects or deterioration.	Normal maintenance
70-84	Very Good	Generally only minor defects or deterioration apparent; or significant deterioration in very few subcomponents but no noticeable defects or deterioration in remainder.	Normal maintenance Consider replacement or rehab for deteriorated items.
55-69	Good	Some deterioration or defects are apparent, but function is not significantly affected.	Increased inspection or testing. Consider replacement or rehab for deteriorated items.
40-54	Fair	Moderate deterioration or presence of defects. Function is still adequate.	
25-39	Poor	Serious deterioration or defects in several subcomponents, function is not adequate.	Plan a rehab or replacement in near future. Safety evaluation required.
10-24	Very Poor	Extensive serious deterioration and defects, barely functional.	
0-9	Failed	No longer functions. General failure of a major subcomponent.	Not to be operated.

2.2.4 *Maintenance Records and Preventative Maintenance Program*

The maintenance records were reviewed and grouped so that recurring maintenance issues could be identified. The findings were discussed with Hydro prior to the site visit to confirm if any special tests or examinations were warranted. Two issues recurred most frequently: replacement of up-lifters and trouble with the new wire rope hoist in Ebbegunbaeg. The first issue was not a concern to Hydro; the up-lifters are generally working quite well for Hydro and these sealed units are fairly inexpensive so spares are kept in inventory and units replaced when necessary. The new wire rope hoist in Ebbegunbaeg had some initial problems when placed into service but these were rectified and the hoist has been reliable since.

The preventative maintenance program check sheets were compared amongst the structures and reviewed for completeness.

2.2.5 *HydroVantage*

The HydroVantage Analysis uses a risk-based failure analysis to identify the least long-term cost of operation that will optimize the reliability of the structures. The analysis takes into consideration the failure curves of components, the effective age of the components, maintenance costs, rehabilitation and/or replacement costs, unplanned repair costs, and forced outage costs. HydroVantage uses this information to determine the course of action which produces the least net present value (NPV). Courses of action include interventions such as replacement and rehabilitation (and the timing of such) versus run-to-failure. The list of components is presented in Table 2-2.

Table 2-2: HydroVantage List of Components

Structure	Component	Description
Bay d'Espoir Intake	motor starter	
	distribution panel	
	wire rope hoist	
	wire rope	
	roller assembly	all 8 rollers
Burnt Spillway	motor TEFC type	
	gate/gain heater	
	screw stem hoist	not including gearbox
	screw stem gearbox	same curve as hoist
	roller assembly	all 8 rollers
Salmon River Spillway	motor starter	
	gate/gain heater	
	screw stem hoist	
	sluice gate assembly	gate "as a whole"
Victoria Control Structure	motor Limitorque type	
	distribution panel	
	screw stem hoist	powered (like others)
	screw stem hoist manual	simpler than powered
Ebbegunbaeg Control Structure	motor starter	
	gate/gain heater	
	screw stem hoist	
	roller assembly	all 8 rollers

To prepare the HydroVantage model, the following was considered.

1. Rollers. It is assumed that operation of the gate will be affected when two rollers fail. It is further assumed that the first roller failure will go unnoticed.
2. Intake Gates. The intake gates are normally open and closed once a year during maintenance. It is assumed that there is a very low probability (and hence risk) of an intake gate or hoist failure causing the gate to close while a connected turbine is in operation. Failure to close during a maintenance inspection carries no outage cost. Failure to open following a planned maintenance will result in some outage cost. It is further assumed that the first week (seven days) of an unplanned intake gate outage will not result in lost generation; other units can be dispatched. However, an outage longer than one-week is expected to result in lost generation and hence consequence costs.
3. Control Gates. All the control structures reviewed have more than one gate and thus have inherent redundancy. Failure of a control gate to open on demand has little consequence unless all gates are required to be fully open. However, failure of a control gate to close can carry the

4. Burnt Dam Spillway

4.1 Site Description

The Burnt Dam Spillway consists of two 7 m (22 ft) wide fixed wheel gates that operate under a maximum head of 8 m (26 ft) and are equipped with screw-stem hoists. Both gates are equipped with provision for gain heating, but only one gate is double-sided and heated. Submersible up-lifters are used to keep ice away from the face of the gate. The spillway discharges water out of the Bay d'Espoir Hydroelectric system that would otherwise be used by three generating stations: Granite Canal, Upper Salmon, and Bay d'Espoir. The watershed can flood quickly and the spillway is used annually. The site is manned and there is a hydraulic emergency hoist if there is a power supply or motor failure.

4.2 Site Visit and Functional Testing

4.2.1 Electrical

4.2.1.1 Power Distribution

Power for Burnt Dam Spillway is supplied from an onsite diesel generator plant that runs continuously to supply the gate structure as well as the living quarters. An additional diesel is started when the gate hoists are to be operated. Assessment of the diesel power supply was not in the scope of this study.

The power center at the base of the gate structure is supplied with 600 V 3-phase power from a 40 A breaker in the diesel building. The power center 600 V distribution utilizes a 600 V splitter and disconnects to feed the gate hoist motors, gain heaters, gate heaters and blowers, monorail hoist and a single phase120/240 V step-down transformer. The splitter panel and disconnects appear to be original equipment, are corroded and weathered and are at the end of their service life. The 120/240 V distribution panel supplies the siren, lighting, motor heaters, receptacles and a baseboard heater power center. The 25 kVA, 120/240 V step-down transformer appears to be original equipment and at the end of its service life.

An electrical enclosure at the top of the gate structure originally housed the motor and heater control equipment. This enclosure now serves primarily as junction box as the electrical equipment has been relocated to the power center at the base of the structure. When the cables are replaced and re-routed, this panel will be redundant.

4.2.1.2 Motors and Controls

Each of the two gates has an 11 kW (15 hp) motorized stem screw gate hoist. Starters and controls for the gate hoist have been relocated to the power center at the base of the structure but were not updated at that time. Two new Allen-Bradley size 4 combination starters have been purchased to replace the existing units. One starter has been installed on Gate 1 and the other is being stored in the power center. These starters are significantly oversized for the hoist motors and precautions need to taken to ensure properly sized fuses and overloads are installed.

The motor nameplate data indicates the rated voltage is 550 V. The motors are original equipment and have been exposed to high humidity and temperature variations for in excess of 40 years and should be replaced.

The monorail hoist was not accessible for a close-up inspection but serious maintenance issues exist with this piece of equipment. The power track supplying the hoist motor is out of service and a temporary cabtire power supply has been installed. This is hazardous and unreliable. The electrical junction box on the hoist is severely corroded and likely no longer watertight. The power track should be replaced by a heated power track bus system in order to prevent ice buildup along the power track during winter season.

Functional tests on Spillway Gate 2 were carried out with the stoplogs in place. Voltage drop, as measured during the raise test, was less than 1% at the motor starter. Voltage unbalance was approximately 1%. Current unbalance was in excess of 10% and the motor load approached the full load rating. Considering the test was performed under very favourable conditions, no ice and stoplogs in place, this could be indicative of other problems and may be an issue during heavier loading conditions. Increased motor loads will likely push the hoist load beyond its capacity and prevent operation of the gate. The higher than expected motor currents are likely the result of higher than design lifting loads due to mechanical binding or misalignment and should be resolved.

4.2.1.3 Gate and Gain Heaters

Gate 1 is the only heated gate at the Burnt Spillway structure.

Gate heating for Spillway Gate 1 consists of two gate heaters rated at three by 12 kW, 600 V, 3-phase and two blower motors rated at 0.75 kW (1 hp), 3-phase, 600 V. Both the gate heaters and blower motors are installed within the gate steel enclosure fed through power cables from the 575 V power distribution panel. The blower motors are required to maintain a constant temperature in the various areas of the gate by circulating hot air. Each of the gate heaters and blower motors has been provided with individual controls through switching panel boxes with indications displayed locally over the gain heater panels.

Gain heating for Spillway Gate 1 consists of two sets of gain heaters rated at 6 kW, 600 V, 1-phase, one each installed on the east and west side gains of the spillway gate. In addition, a sill heater rated at 12 kW, 600 V, 1-phase is provided and installed in the gate bottom sill.

The gate and gain heating equipment appears to be original; it is highly corroded with no provision for thermostatic control including high and low current operation during winter and summer months. It was also reported that the blower motor in Spillway Gate 1 fails almost every year and has to be rehabilitated or replaced. Further, there is no provision for remote alarm and indication of gate and gain heaters. Thermostatic control and multi-modes of gate and gain heater operation offer advantages in terms of increased operating efficiencies as well as reduced operation and maintenance costs. The heaters also have a longer life since their operation is mainly controlled by preset temperatures in at least two operating modes. Replacement of gate and gain heating controls including provision for local and remote indication and alarm sensing is therefore required at Gate 1.

Gate 2 has provision for installation of gain heaters in its respective gains; the gate is not insulated and does not have a downstream facing plate. Utilities have started using marine de-icers with success, but have not made the move to discontinue internal gate heating. Not only does internal heating keep ice off the face of the gate and rollers, it also prevents condensation and corrosion inside the gates.

An internally heated gate with upstream de-icers will be more reliable than a non-heated gate. However, operating history for Burnt Spillway does not justify the cost of operating a second heating system and maintaining the equipment in good working order. Overtopping of the dams has not occurred, despite having only one heated gate at each structure with unreliable heating systems. Therefore the risk has been manageable. However, it may be more economical to install, operate and maintain a second gate heating system than managing the risk: overtime, ploughing roads, helicopter travel, etc necessary when a gate does not lift on command. Determination of the cost of managing the risk was beyond the scope of this study.

Burnt Spillway is an ideal test subject for heated/unheated gate question since there are two identical gates and both can have functional gain heaters. Could an un-heated gate perform adequately with well-maintained sill and gain heaters and marine de-icers? Since Burnt Spillway gates are used regularly, this can be monitored and an empirical conclusion reached over time.

Electrical inspection and functional testing were carried out on the gate and gain heating system at Gate 1 during the site visit. The heaters and blower motors were switched on, and currents and voltages of each component were recorded. The heaters and blower motors were found to operate satisfactorily.

4.2.1.4 Instrumentation Control and Communication

Presently, head pond measurements are performed manually from a water level measuring device and a staff gauge installed permanently in a heated gauging pit at the upstream west side wall of the spillway gate. The water level measuring device has provision for remote water level indication and telemetry through the supervisory terminal box installed in the diesel generator building. It was however reported that head pond level was manually transmitted by the operating staff stationed 24/7 at Burnt Dam to the system control centre at St. John's.

Gate position sensing was originally performed through a combination of 5-position selector switching and a set of vane actuated switches with provision for remote indications through a set of individual relays at each set position. Any changes to the above mentioned design after installation of the new motor starter panel for Spillway Gate 1 could not be verified during the site inspection.

Lower and upper limit cut-off switches provide over-travel protection to the spillway hoist and hoist motors.

Controls and communication between Gates 1 and 2 and the system control centre at St. John's are performed with a low baud internet connection using VoiP communication protocol and a VHF radio link to Granite Canal Generating Station located 25 kms from the spillway. All spillway controls are performed by local operators. No telephones are provided at the spillway gate enclosure; however, telephones are available in the residential building for operators.

The following data was reported to be sent manually from the spillway gates and control dam to the remote station at Granite Canal GS and control centre in St. John's:

- Pond water level.
- Pond water temperature.
- Metrological station data.

No remote camera is installed at the spillway gate locations to provide real time security in the spillway and the dam area and surroundings.

Functional tests on Spillway Gate 2 were carried out and included verification of the upper and lower limit switches. Although the gate was lifted to 9 m (indicated on the staff height gauge), the upper limit switch did not operate.

Functional tests on gate instrumentation were performed on Spillway Gate 2; however tests such as simulation of alarms and remote control were not performed.

4.2.2 Mechanical

4.2.2.1 Gates

The downstream sides of both gates were visible during the site visit. The stoplogs were in place so that Gate 2 could be dewatered and lifted.

The gate leaves were generally in fair condition. The gates will require painting soon and the bolts holding together the skinplate sections on Gate 2 showed signs of corrosion. There was some loose insulation on Gate 1.

4.2.2.2 Rollers

The rollers were inspected on Gate 2 as it was lifted and lowered and they were observed to be in good overall condition. The rollers moved as the gate was lifted and a sample of rollers could be rotated by hand.

4.2.2.3 Seals and Guides

The side seals are brass rods and are generally in good shape. There was some small leakage on the sides. The bottom seals were not visible but it was noted that Gate 1 sealed well on the bottom.

The guides for Gate 2 appeared to be in good condition.

As Gate 2 was lifted, the brass seal rods produced a fair amount of vibration noise and the gate rubbed against the upper guides near the top of its range of motion. The brass seal rods are a free-moving bar held in place by water pressure. Since the gate was lifted behind stoplogs, the hydrostatic head on the gate quickly dissipated and there was no load on the rods to prevent them from vibrating. The gate rubbing on the upper guides may be just excessive paint buildup, but the motor current readings during lift were high and further investigation is warranted.

4.2.2.4 Hoists

The screw stem hoists are original to the structure. Generally the hoists are in fair condition but are showing signs of wear. The reducing gear box has water-contaminated oil in Gate 2 and water infiltration into the screw hoists is also a concern. The screw stems appear to be in good condition but need to be cleaned of excessive grease. Although the emergency hydraulic hoist provides back-up in event of power supply failure or motor failure, it cannot move a gate if there are problems with the gearbox, screw stems or screw hoists and it does take some time to set up so operation of the gate is delayed.

Refurbishment of the hoists is required as follows.

- Gear Box: Disassemble, inspect and repair gears as necessary, replace bushings, replace heater, replace seals.
- Shafts, couplings and bushings: Disassemble, Liquid Penetrant Inspection, replace bushings
- Hoists: Disassemble and clean, inspect and repair gears as necessary, replace bushings, inspect bronze lift nut, inspect thrust bearing, replace seals, check/repair/replace grease lines. (Be equipped to replace lift nut and thrust bearing.)
- Screw Stems: Clean, inspect and local repairs to threads as necessary. (Replace if not straight or elongation observed.)
- Limit Switches: Test, repair or replace. Replace weather covers.

There was a program of greasing the screw stems which has now created the situation of excessive buildup of hardened grease in the screw hoists. Grease is used for both screw-stem protection and smooth operation of the hoist. A major hoist manufacturer, Armtec recommends Shell SRS 2000 for screw stem lubrication and inspection every six months: if lubricant is dirty or feels gritty, completely remove grease and apply new grease. The recommended methodology is to open the gate and remove grease from the stem (above the hoist) while running the gate. Apply new grease to the stem above the hoist while closing the gate, thereby cleaning the lift nut with new grease. Remove excess grease from top (clean) and bottom (dirty) of hoist.

A well-fitted telescopic stem cover may help keep the grease clean, but may also cause other problems such as condensation and corrosion. Alternatively, changing the grease as per the above procedure every two years, during the dewatering PM, may work better.

4.2.2.5 Stoplogs and Hoist

The stoplogs were in place for isolation of Gate 2 and could not be directly observed. Leakage between logs was evident.

Hydro staff identified that there was a safety concern with the masterlog; the stoplogs must rotate 90° from the stored to in-service position. The stoplog monorail hoist was in poor condition and poses a safety hazard. It was not operated during the site visit, but it was reported that there are recurring problems with the bus bars and it was evident that hoist trolley does not travel fully on the monorail beam near Gate 1.

4.3 Maintenance Records Review

There were four work orders issued since 2005 that dealt with a gate failing to operate. Three of these work orders originated in either November or January months, and are thus assumed to be related to spill events.

There are annual and bi-annual preventative maintenance routines for the gates. The routines are fairly thorough and include dewatering a gate every two years.

4.4 Health Index

The Heath Index score for the Burnt Spillway Gates is 66, which corresponds to a condition of Good.

Components	Weight	Condition Rating	Weighted Score
Gate	8	2	16
Roller Assemblies	4	3	12
Seals & Guides	2	3	6
Gate Hoist	4	2	8
Stoplogs and Hoist	1	1	1
Cubicles, Enclosures & Buildings	1	2	2
600V Splitter Panel	3	1	3
Branch Panel	2	2	4
Transformer	3	1	3
Cables	3	2	6
Total of Observed Components	31		61
Maximum Possible Score	31	3	93
Health Index	(61/93)*100		66

4.5 HydroVantage Analysis Results

Five components were studied with HydroVantage: the motors, the gate/gain heaters, the screw stem hoist (less gearbox), the hoist reducer gearbox, and the roller assemblies.

For analysis purposes, it is assumed that a forced outage will only produce consequence costs if the failure causes delay in closing a gate and hence release of too much water during a spill event. It is assumed that, since there are two gates, the likelihood of needing both gates open or being able to open neither gate is remote.

The results of the analysis using the 2007 average fuel cost are as follows:

- Replace the motors now.
- Replace the entire gate and gain heating system now.
- Rehabilitate the hoists now.
- Replace the hoist reducer gearbox now.
- Rehabilitate the roller assemblies now.

The results of the analysis cannot be more definitive; Burnt Spillway has such a high risk cost that intervention can be justified at even a very low fuel cost.

The consequence cost of a failure at the Burnt Spillway is exceptionally high at $2.6 million per day using the 2007 average fuel cost. The high consequence cost combined with the frequent use of the spillway and frequent failure (as per the work order history) results in very high risk. Thus any action to reduce risk can be easily justified. A high-level study was performed to determine if the high risk and high operating costs of the spillway structure could justify complete replacement of the spillway gates with an overflow spillway. An overflow spillway would require no electrical, no manpower and little maintenance. An overflow spillway sized to replace both gates is estimated to cost $11 million and one sized to replace one gate is estimated to be half as much. Although the risk cost of the spillway gates is very high, it can be reduced by rehabilitation of components (less than $0.5 million) and thus rehabilitation is a cheaper alternative than complete replacement. However, building an overflow spillway sized to handle most floods (say 1:10 or 1:20 year floods) could allow operation of the structure without permanent attendance and would significantly reduce operating cost and risk. This alternative should be investigated further but should not delay immediate actions to reduce risk such as gate rehabilitation.

4.6 Recommendations, Burnt Spillway

4.6.1 Short Term (0-2 Years)

18. Refurbish the electrical/mechanical components of the structure including: gate painting, inspection of embedded parts, roller assembly rehabilitation, hoist refurbishment, motor replacement, and heating system replacement including controls with provision for dual operating modes and thermostatic temperature controls.
19. Upgrade existing water level measuring instrumentation with capability to transfer water level data to remote centre.
20. Calibrate and re-test the upper and lower cut-off limit switches for proper functionality and safety.

21. Upgrade the communication system to a broadband system by radio or satellite for automatic transfer of gate control and water level data, and other parameters for alarm, indication including video signals and reporting to remote control centre.
22. Replace all 600 V distribution equipment in the power center (splitter panel, disconnects, step-down transformer.)
23. Replace the 120/240 V distribution panel.
24. Replace and re-route all power and control cables, making the electrical panel at the top of the structure redundant and eliminating unnecessary terminations that are a source of potential problems.
25. Replace stoplog monorail hoist. Replace existing power track with a heated power track bus system.

4.6.2 *Medium Term (2-7 Years)*

26. Investigate requirement for remote operation of the two spillway gates by installing PLC based controls and data acquisition equipment for transfer of data and control.
27. Investigate replacement or upgrade of gate positioning devices at Spillway Gates 1 and 2 by digital encoders or infrared position devices.
28. Investigate full or partial replacement of gated spillway structure with overflow structure.

4.6.3 *Long Term (Beyond 7 Years)*

29. Investigate requirement of gate and gain heating for Spillway Gate 2, in view of high risk costs.
30. Install video camera fitted with defrosting visor for real time surveillance and security against illegal intrusions.

Burnt Spillway

Short Term Recommendations (0-2 Years)			Medium Term Recommendations (2-7 Years)			Long Term Recommendations (Beyond 7 Years)		
No.	**Brief Description**	**Budget Cost**	**No.**	**Brief Description**	**Budget Cost**	**No.**	**Brief Description**	**Budget Cost**
18	Mech/Elec Refurbishment	140,000	26	Investigate Remote Operation	10,000	29	Heating Gate 2	10,000
19	Water Level Measurement	25,000	27	Investigate Gate Positioning	5,000	30	Video Camera	50,000
20	Calibrate limit switches	0	28	Investigate Overflow Spillway	50,000			
21	Broad Band Communications	100,000						
22	600V Distribution Equipment	15,000						
23	120/240V Distribution Panel	5,000						
24	Power and Control Cables	10,000						
25	Stoplog Monorail Hoist	75,000						
		370,000			65,000			60,000
				Total for Burnt Spillway			$495,000	

APPENDIX B

Release of Water to Protect Fish Populations in Grey River and White Bear River

Category:	**Environmental Agreements with Government Agencies** **Agreement for Release of Water to Protect Fish Populations in Grey River and White Bear River, 1996**
TITLE:	**Agreement between Newfoundland and Labrador Hydro and the Department of Fisheries and Oceans Regarding Release of Water to Protect Fish Populations in Grey River and White Bear River dated February 1966, and Varied by Letter from Mr. R. J. Wiseman, Section Head, Department of Fisheries and Oceans and Mr. Gerald Marks, System Operation Engineer, Newfoundland and Labrador Hydro dated September 8, 1977, and Further Varied for White Bear River by Letter from Ms. Michelle Gosse, Habitat Evaluation Engineer, Department of Fisheries and Oceans and Mr. L. LeDrew, Ecologist, Newfoundland and Labrador Hydro dated July 11, 1996.**
Related Documents:	

AGREEMENT TITLE	RELEASE OF WATER TO PROTECT FISH POPULATIONS IN GREY RIVER AND WHITE BEAR RIVER
EFFECTIVE DATE	FEBRUARY 1966, VARIED BY LETTER DATED SEPTEMBER 8, 1977, AND FURTHER VARIED FOR WHITE BEAR RIVER BY LETTER DATED JULY 11, 1996
SIGNATORIES	NEWFOUNDLAND AND LABRADOR HYDRO AND DEPARTMENT OF FISHERIES AND OCEANS

Schedule

An enumeration of requirements discussed between officials of the Department of Fisheries of Canada and of the Newfoundland and Labrador Power commission at a meeting held in the Commission’s offices on 21 January 1966 of measures to be undertaken by the Power Commission for the conservation of stocks of anadromous fishes to be affected by the Bay D’Espoir Power Development. These measures are required of the Power commission under the provisions of the Fisheries Act, R.S.C. 1952, c.119; as amended by 1960-61, c.23.

1. Salmon River, East Bay, Fish Populations: Fishways or other fish protective devices o measures are not required at Power Commission works to be installed on this river (see Ministerial approval dated August 6, 1965, and correspondence from Department’s Area Office to Power commission dated August 26, 1965).

2. <u>North West Brook Fish Populations:</u> Fishways or other fish protective devices or measures are not required to be installed to protect indigenous fish populations of this stream. This does not preclude requirement for fish protective devices or measures which may arise after the development has become operative as described in No. 5 below.
3. <u>White Bear River Fish Populations:</u> Fisheries problems that may arise when the watershed of this river is incorporated into the Bay D'Espoir Power Development are not herein considered. These will be evaluated separately when and if the decision to proceed with this stage of the power development has been made.
4. <u>Grey River Fish Populations:</u>
   i) The Power Commission will install at Pudop's Dam, Grey River, a 4 foot, 6 inch diameter release pipe and facilities adequate to ensure that flow in the lower river, measured at an agreed gauging station below the confluence of Grey River and Salmon Brook, does not fall below 600 cfs. Except as noted in 4(vii).
   ii) The water release facilities referred to in 4 (I shall be maintained and operated by the Power Commission.
   iii) It is understood that release of water as described in 4 (I will normally be required only during the period June 1 – October 31 of any year. This, however, does not preclude requirement for water release if necessary for fish conservation purposes at other times in any year.
   iv) The supply and installation of gauging equipment (of a recording type) required at the gauging station referred to in 4 (I shall be the responsibility of the Power Commission. However, because of difficulties that may be encountered by the Commission in fulfilling this responsibility, the Department will provide such reasonable assistance in this regard as may be requested of it by the Power Commission.
   v) An officer of the Department shall be responsible for "reading" the aforementioned gauge and shall, when flow falls to the 600 cfs. Level or below, immediately advise the designated officer of the Power Commission. Upon receipt of such notice, the Power Commission shall initiate measures to release amounts of water required to maintain flow at, or bring it up to the 600 cfs. Level, and shall continue to release such amounts as will maintain flow at or above such level until natural runoff conditions below the dam are adequate to maintain flow at 600 cfs.
   vi) On receipt of notice from the designated officer of the Department that water release is required, the Power Commission shall take all necessary steps to initiate same at the earliest moment; it being understood that, excepting conditions beyond the control of the Power Commission, water release will be initiated within 24 hours after receipt of notice from the Department officer>
   vii) It is understood that flow as described in 4(v) will be provided except that when the water level of Pudop's reservoir is below that required to provide necessary volume of flow through the release facilities, the Power Commission shall not be liable to

release water in excess of that which reservoir level will enable release facilities to deliver below Pudop's Dam.

viii) Until such time as more efficient means of communication may become utilizable, notice of required water release to the Power Commission shall be by radio-telephone. To this end, the Power Commission will supply adequate R/T sets at Grey River and at Bay D'Espoir Control Room.

5. Conne River Fish Populations: Because it is impossible to predict the effect of the Bay D'Espoir Power Development on anadromous fish runs to Conne River in advance of the power development becoming operative and, particularly, since these runs may be affected by greatly increased flow from the powerhouse at North West Brook, this problem, if it arises, shall be the subject of separate discussion, the solution to which is in no way prejudiced by the foregoing.
6. Other matters affecting the fishery interest that may arise, and which cannot reasonably be foreseen at this time, shall be the subject of separate discussion when and if these arise.
7. Meeting with Nfld. & Labrador Hydro on White Bear and Grey River Agreement: On Friday, June 25, 1976, at 1000 hours, a meeting was held in B.R. Bauld's office with two officials of N&LH (G. Marks and J. Long). Also attending, addition to the undersigned, was L.W. Rowe of C&P District Office, Grand Falls. Generally speaking, the following water release agreements were arranged in principle.

   White Bear River: As in the 1971 agreement, N&LH agreed to release 150 cfs from their Great Burnt Dam during the months June, July, August and September in order to make up the required 250 cfs at the mouth. In addition, it was agreed that a radio should be set up at the guardian's cable on White Bear so that he could water the flow and request additional release if needed. Ultimately, the Corporation would like to get into a situation whereby they would only release at Great Burnt during June-September when the flow at the mouth fell below 250 cfs. Specifically, they do not want to release 150 cfs continually unless it is needed.

   Grey River: After several years of our review of flows and flow requirements on Grey River, the Service indicated it would be satisfied with a guaranteed 400 cfs.

This Agreement has been varied by two letters attached:

1. Letter from R. J. Wiseman, Section Head, Department of Fisheries and Oceans to Mr. Gerald Marks, System Operations Engineer, Newfoundland and Labrador Hydro dated September 8, 1977 (see letter below) and,

2. Letter from Michelle Gosse, Habitat Evaluation Engineer, Department of Fisheries and Oceans and Mr. L. LeDrew, Ecologist, Newfoundland and Labrador Hydro dated July 11, 1996 (see letter below).

Environment Canada / Environnement Canada
Fisheries and Marine / Pêches et Mer

101.40.40
101.40.47

September 8, 1977

Your file / Votre référence
Our file / Notre référence 5460-1-5

Mr. Gerald G. Marks
System Operations Engineer
Nfld. & Labrador Hydro
St. John's, Newfoundland
A1A 2X8

Dear Gerry:

This is in response to your letter of September 1, 1977 seeking clarification of agreements between this Service and Hydro regarding the release of compensation water for the Grey and White Bear Rivers.

First of all we would agree with your assumption that adequate flows were maintained this year as a consequence of abnormally high precipitation. Our records from the automatic recorder/transmitter on the Grey River indicate that with few exceptions sufficient flows were maintained. We have no such data on the White Bear, but from a lack of complaints by the local fishery officer we must assume that a combination of high precipitation and releases from Great Burnt Dam were responsible.

A reiteration of the agreement reached during a meeting on June 29, 1976 is as follows:

Grey River

A flow of not less than 400 c.f.s. must be maintained at the guaging station located at the Grey River - Salmon Brook confluence. From printouts produced by the automatic recorder/transmitter at the guaging station this Service will monitor discharges and call on Hydro for releases from Pudops Dam when the flow falls below 400 c.f.s.

White Bear River

As agreed in 1971, a flow of 250 c.f.s. must be maintained at the mouth of the river during the period June 1 to September 30. A release of 150 c.f.s. from your Great Burnt Dam on a continuing basis during this period would ensure a flow of at least 250 c.f.s. We are aware of your concerns and efforts to conserve water at Great Burnt but with no way to monitor and call for water from right on the spot the only guarantee we have for sufficient water is a continual release of 150 c.f.s. from Great Burnt during the period under consideration.

/2

P.O. Box 5667
St. John's, Newfoundland

Boîte postale 5667
Saint-Jean (Terre-Neuve)

081-7-7000 (03/76)

Mr. Gerald Marks - 2 - September 9, 1977

In summary then, for Grey River this Service will call for water when the flow at the guaging station drops below 400 c.f.s.; at White Bear River, Hydro should release 150 c.f.s. on a continual basis during June to September unless you are otherwise sure that 250 c.f.s. is discharging at the mouth.

Yours very truly,

Bob Wiseman

R. J. Wiseman
Section Head
Inland Fisheries & Habitat Protection
Freshwater & Anadromous Fisheries Management
Research and Resource Services
Newfoundland Region

cc. D. A. Rowe
:th

91/05/08
Note Drawings B-120-C-1
-C-2
-C-4
-C-5
For details Re: Grey River Salmon Release Structure
GLR.

101-40-47

Fisheries and Oceans | Pêches et Océans

P. O. Box 5667
St. John's NF A1C 5X1

Your file Votre référence

Our file Notre référence

July 11, 1996

Mr. L. LeDrew
Ecologist - Assessments and Research
Environmental Services and Properties Department
Newfoundland & Labrador Hydro
P. O. Box 12400
St. John's NF A1B 4K7

Dear ~~Mr. LeDrew~~ Larry:

Re: White Bear River Gauging Station

Further to your letter of June 27, 1996 and the July 5, 1996 telephone conversation with Marvin Barnes and I, please be advised that flow information obtained from the installation of the gauge station, as proposed, with appropriate calibration and consideration of the hydrologic regime/conditions in the area, can be utilized to ensure provision/maintenance of flows in White Bear River. However, as indicated on July 5, 1996, this does not preclude any future reviews/discussion or requirements on this issue with regard to the magnitude of flows and appropriate releases in White Bear River to protect fish and fish habitat.

As previously indicated, the flow regime information obtained from the gauge should be reviewed with DFO. With regard to the installation of the gauge, Mr. Randy Blundon, Area Habitat Coordinator - Southern should be contacted at 709-832-0010 regarding works or undertaking that may affect fish or fish habitat.

If you have any questions on the above, please do not hesitate to call me at 772-6157.

Yours truly,

Michelle Gosse

Michelle Gosse, P. Eng.
Habitat Evaluation Engineer
Marine Environment and Habitat Management

cc: M. A. Barnes
R. Blundon
D. A. Scruton

Canada

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER G. E. POOLE G.E. Poole SIGNATURE July 26/13 PROVINCE OF NEWFOUNDLAND	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Upgrade Shoreline Protection

Cat Arm

May 2013

newfoundland labrador
hydro
a nalcor energy company

SUMMARY

Hydro has been visually monitoring road embankment erosion along a section of the Cat Arm Access Road since it was originally built, as well as rehabilitating portions of this particular section of the access road. This area is a harsh environment directly open to the Atlantic Ocean and subject to sizeable wave action. This road provides access to the Cat Arm Powerhouse and a significant rehabilitation of a section of this road was undertaken in 2005 using heavy armour stone and is shown in Figure 1 below. Armour stone is typically stones of different sizes and irregular shapes which are used in hydraulic protection. In this particular instance, the armour stone is used to protect the base of the road embankment section by dissipating the wave energy.

Figure 1: Rehabilitated Section of Cat Arm Access Road

A portion of this rehabilitated section has eroded to the point that action is now required to offset more extensive work that might be needed later. An 80m section of heavy armour stone, placed near the water's edge during the 2005 rehabilitation has now been washed out into the ocean. This loss of armour stone has led to the degradation of smaller material placed to

stabilize the road embankment. Without the armour stone, there is no protection to support the finer rock fill and filter materials which are now easily eroded by wind and wave action (see Figure 2).

Figure 2: Eroded Section of Road Embankment

This proposal is for a two-year project to upgrade the shoreline protection along a portion of the access road embankment to the Cat Arm Powerhouse, which provides for an engineering investigation and design in the first year with construction to take place in the second year. Completion of this project will ensure continued uninterrupted use of the Cat Arm access road which is used by Hydro's operational and maintenance staff on a regular basis. The scope of the project includes design and implementation of an upgraded shoreline protection barrier to stabilize this eroded section of the Cat Arm access road.

TABLE OF CONTENTS

1 INTRODUCTION

The Cat Arm Development, on the Northern Peninsula, includes two reservoirs, ten dams and dykes, two overflow spillways, one fore bay tunnel, one intake structure and one powerhouse, located at sea level. Access to the powerhouse is via a 25 km long gravel road off route 420 near Jackson's Arm. An 80m section of the road embankment near the powerhouse at Devil's Cove is seriously deteriorated and requires rehabilitation.

This access road and the Cat Arm Development were completed in the early 1980's. There have been continual erosion problems with the road over the years stemming from loss of foundation material at sea level as a result of wind and wave attack from the ocean. The first rehabilitation work was done in 1993 with the installation of binwalls to shore up the road embankment. Similar work was done in 2012 due to the same problems. Guide rail has been moved in from the shoulder of the road, narrowing the driving surface as a result of embankment erosion and a larger project was undertaken in 2005 to stabilize a portion of the access road embankment near the powerhouse, by constructing a shoreline protection barrier. Severe environmental conditions have caused new damage to this shoreline protection barrier resulting in road embankment damage and it needs to be addressed before damage escalates exponentially.

The Cat Arm Development is critical to Hydro to ensure Island Interconnected System power demands are reliably met. The Cat Arm Hydroelectric Generating Station has a net output of 127 MW with an average annual energy production of 740 GWh. This plant produces approximately 14 percent of Hydro's hydroelectric power capacity and comprises 16 percent of the Island Interconnected System's hydroelectric energy capability. It is imperative that access to this facility be maintained to allow operations and maintenance activities to be carried out.

2 PROJECT DESCRIPTION

This project is required to rehabilitate an 80 m section of road embankment near the Cat Arm powerhouse at Devil’s Cove that is seriously deteriorated and needs attention.

The work involves upgrading of an armour stone wave barrier at the waterline edge for wave protection, and the placement of rock fill material to re-establish a stable road embankment.

The project will require approvals from the Provincial Department of Environment and Conservation, Provincial Department of Natural resources and the Federal Department of Fisheries and Oceans.

3 JUSTIFICATION

The Cat Arm Hydroelectric Generating Station access road is the only access available to the powerhouse. The road is used on a daily basis by Hydro's operating staff and at regular intervals by the maintenance personnel. Vehicles transporting personnel and maintenance material must travel this access road.

Wind and wave action on this coast continues to cause significant erosion along various sections of this road. One of these areas is at an armour stone shoreline protection barrier constructed in 2005. Extreme environmental conditions in the area have damaged the shoreline protection barrier along an 80m section. These conditions and this type of damage were unforeseen during original construction. This shoreline protection barrier provides protection for the blast rock and filter material in the upgraded road embankment section. With the protection material removed, the remaining blast rock and filter material is left unprotected and erodes easily into the ocean.

A review of the shoreline protection barrier by Hydro staff and a geotechnical consultant, AMEC Earth and Environmental (AMEC) in 2010 (See Appendix A) concluded that on-going erosion is anticipated during periods of high waves combined with storm surges or higher tides and the road embankment should be repaired to prevent further erosion. It is otherwise likely to progress to the point where the re-built road section will degrade such that the road driving surface will be reduced to a single lane. If that were to happen, a restriction limiting transportation of heavy equipment to the plant may have to be put in place.

Failure to carry out the recommended upgrade will result in continued road embankment erosion likely leading to an increase in rate of failure and increased cost to repair. This potential slope failure could lead to possible road embankment collapse, to a point where the road will be impassible or unsafe. This will result in a loss of access to the powerhouse for operational and maintenance work and would have an impact on plant reliability and power supply to Hydro's customers.

A permanent and safe access road is required for the long term reliable operation of Cat Arm.

3.1 Existing System

The Cat Arm Hydroelectric Generating Station contains two generating units, each rated at 67.5 MW, with a maximum production output of 63.5 MW when running simultaneously. It is situated on the east side of the Northern Peninsula and was completed in 1984. Access to the plant is via a 25 km long gravel road off route 420 near Jackson's Arm. An 80m section of this road near the powerhouse at Devil's cove requires rehabilitation.

As part of other road work undertaken in 2012, Hydro submitted an application for Permission to Occupy to Crown Lands in 2012. Hydro subsequently applied for a Crown Easement to the road lands. (This application is pending approval). This easement form of title has been determined to be appropriate for Hydro's needs as Hydro does not need to exclude others from using the road. Hydro does require the legal right to have secure access in order to make improvements to the road and to build and maintain structures such as guide rails, bridges and culverts. This is the form of title upon which Hydro holds a significant amount of its distribution and transmission plant.

Cat Arm is a critical component of Hydro's hydraulic resources and is in continuous operation. The access road was originally completed in 1984 and is now 29 years old.

Major work and upgrades completed on the Cat Arm access road since original construction consists of road repairs and slope stabilization measures as detailed in Table 1.

Table 1: Major Work or Upgrades

Year	Major Work/Upgrade	Cost
2012	Slope stabilization (install binwalls)	$235,000
2005	Construction of armour stone embankment	$1,358,300
1993	Binwall installation	$50,000

3.2 Operating Experience

Approximately one kilometer of the Cat Arm access road leading to the powerhouse was constructed on an exposed sea cliff, which has experienced erosion since the road's completion in 1984. The armour stone shoreline protection barrier that was completed in 2005 has eroded over a portion of its length. It is worsening annually and the armour stone over an 80m length of the constructed embankment has washed away into the ocean. (See Figures 3, 4, 5 and 6 below.) The loss of this armour stone has left the remaining rockfill and filter material exposed to the elements. This smaller material is easily eroded and the wave action is eroding the embankment towards the road driving surface above it. Eventually, the road driving surface will be impacted by the loss of foundation support.

Figure 3: 2008

Figure 4: 2009

Figure 5: 2011

Figure 6: 2012

3.2.1 Reliability Performance

There is no reliability performance issues associated with this project.

3.2.2 Safety Performance

The loss of embankment material will progress to the point where the road is impacted posing a safety risk to those who utilize the road on a regular basis. Vehicles will not be able to pass in both directions simultaneously.

3.2.3 Legislative of Regulatory Requirements

There are no legislative requirements associated with this project. The road was built to the required standard based on its determined usage but now this section of the road's driving surface could be reduced making it substandard.

3.2.4 Environmental Performance

There are no environmental performance requirements associated with this project.

3.2.5 Industry Experience

There is no known industry experience for this work due to the unique nature of the site and environmental conditions.

3.2.6 Vendor Recommendations

There are no vendor recommendations associated with this project.

3.2.7 Maintenance or Support Arrangements

Routine maintenance of the Cat Arm access road is performed by Hydro personnel. Snow clearing and road rehabilitation are performed by external contractors with access to equipment suitable for work of this nature.

3.2.8 Maintenance History

A summary of the maintenance expenditure history for the Cat Arm Hydroelectric Generating Plant Access Road is shown in Table 2 below.

Independent geotechnical assessments of the roadway embankment were completed in 2008 and 2010 and the findings and recommendations for rehabilitation are included in Appendix A.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2012	0.0	0.0	0.0
2011	36.1	0.0	36.1
2010	0.0	1.5	1.5
2009	0.0	0.2	0.2
2008	18.0	0.0	18.0

3.2.9 Historical Information

Concerns over the loss of embankment material along the section re-constructed in 2005 were first identified in 2008. As a result, Hydro acquired the services of AMEC Earth and Environmental (AMEC) to investigate the hazards associated with the erosion of this embankment material. AMEC recommended that a survey be completed to determine the quantity of lost material and to continue to monitor the situation. Surveys were completed in 2008 and 2009. The loss of material in 2008 was determined to be 1,650 cubic meters and in 2009 the loss had increased to 1,950 cubic meters. As a result of this continued loss of material AMEC were again consulted in 2010 to conduct further investigation. Hydro requested that the AMEC reassess the access road embankment and recommend alternatives with cost estimates to rehabilitate the failing slope. The slope erosion investigation report contained in Appendix A forms the basis of the estimate for this project. An additional survey completed in 2011 found that the material loss had increased to 5,900 cubic meters.

3.2.10 Anticipated Useful Life

The access road is depreciated over 57 years.

3.3 Forecast Customer Growth

Customer load growth does not affect this project.

3.4 Development of Alternatives

Due to the geographic features of this area, there are no viable alternatives to upgrading the road. Boat or helicopter use on an ongoing basis would be logistically challenging and is unacceptable.

4 CONCLUSION

An 80 m section of the Cat Arm access road embankment has deteriorated to the point that there is a risk of partial loss of the road driving surface if rehabilitation measures to stabilize this erosion are not undertaken. This could result in rapidly increasing deterioration and increased costs. The road provides the only feasible access to the plant and is travelled daily by plant operating staff and on a regular basis by plant maintenance personnel. The proposed embankment stabilization must be completed to ensure that safe reliable access is maintained to the plant.

4.1 Budget Estimate

The budget estimate for the project is shown in Table 3.

Table 3: Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	19.0	48.8	0.0	67.8
Consultant	16.0	68.0	0.0	84.0
Contract Work	0.0	400.0	0.0	400.0
Other Direct Costs	16.8	14.0	0.0	30.8
Interest and Escalation	3.5	60.8	0.0	64.3
Contingency	0.0	116.5	0.0	116.5
TOTAL	**55.3**	**708.1**	**0.0**	**763.4**

4.2 Project Schedule

The anticipated project schedule for this project is presented in Table 4

Table 4: Project Schedule

Activity		**Start Date**	**End Date**
Planning	Project planning and coordination with Operations	June 2014	June 2014
Design	Conduct field Investigation	July 2014	July 2014
Design	Develop solution and complete design	August 2014	September 2014
Design	Prepare tender package, tender, evaluate and award	March 2015	May 2015
Construction	Embankment stabilization works	June 2015	August 2015
Closeout	Contract closeout	September 2015	October 2015

APPENDIX A

Geotechnical Services for Slope Erosion Investigation

Cat Arm, Newfoundland

Report by AMEC

Report on

Geotechnical Services
for
Slope Erosion Investigation
Cat Arm, Newfoundland

Prepared for

Newfoundland and Labrador Hydro,
A Nalcor Energy Company
500 Columbus Drive
St. John's, NL A1B 0C9

Prepared by:

AMEC Earth & Environmental
A Division of AMEC Americas Limited
133 Crosbie Road
P.O. Box 13216
St. John's, NL A1B 4A5

TF1010479

May 2010

TABLE OF CONTENTS

LIST OF APPENDICES

1.0 INTRODUCTION

The report herein presents the results of a slope erosion investigation carried out by AMEC Earth & Environmental, a division of AMEC Americas Limited (AMEC), at the site of the previously (2005) reconstructed shoreline embankment on the road to the Cat Arm powerhouse. The purpose of this investigation was to investigate the rate of ongoing erosion at the damaged area identified in 2008 and to provide comment on remedial options, including scheduling and cost estimate.

2.0 INVESTIGATION PROCEDURES

AMEC's work included a visual site investigation in conjunction with Nalcor personnel. Calvin Miles, P. Geo, of AMEC, performed the field work for this investigation on March 10, 2010. This fieldwork involved the visual observation of the erosion areas, including taking a series of photographs to be used for comparison with prior photographs. This visual inspection was performed via helicopter and on foot along the shoreline.

3.0 RESULTS

Please see Drawing 1 in Appendix A for a plan of the erosion areas.

Visual observation show that Areas 1 and 2 identified during the 2009 investigation (see report "Slope Erosion Investigation, Cat Arm, Newfoundland, March 2009"), has eroded to the extent that they have become one. A visual estimate of the material lost is approximately 200 m^3. Visual observation of this area showed that the lower slope armor, filters, and some of the core materials had eroded away. In addition, the upper slope, in areas, was somewhat undermined. Most of the material, including the large armour stone had been washed away and only the larger units could be seen deposited embedded in the beach or near the shore in shallow water.

The new shoreline during the investigation had a slope of approximately 20 degrees and was littered with various sizes of stones from armour stone to coarse gravel. Many of these stones were deposited during construction. When placed, these stones were angular but had subsequently become sub-angular due to wave action. The previous sandy beach (prior to construction) was not observed during this investigation.

A review of previous AMEC reports show this area was once a crevice or wave washed notch in the bedrock coastline in an area of a probable bedrock fault or shear zone. Air photographs show this area to be backfilled during the original Cat Arm access road construction.

Photographs taken prior to re-construction of the road embankment in 2005, show a sandy beach in the area of the lower slope. adjacent to the shoreline. A review of construction records, show that the outer armour in this area was placed in approximately 3 m deep water, and approximately 15 m or more out from the previous shoreline.

It was observed that waves would deflect from the partially submerged rock ridge and run up the beach two to three metres more than in other adjacent areas.

Area 3 in the 2009 report showed no visual erosion or realignment of the armour units.

4.0 DISCUSSION AND RECOMMENDATIONS

It appears that the damage to the embankment was not the result of a slide but due to erosion and subsequent undermining. Possible mechanisms include:

- Increased localized wave energy due to confinement and run-up along the bedrock outcrop on the north side of the area. This could be responsible for eroding the inner core material and smaller filter (as observed by the sub-rounded edges of the stones observed on the beach). Erosion of this inner material would result in the collapse of the outer armour protection;

- The increased localized wave energy along with the generally smooth, seaward sloping, bedrock outcrop, and the erosion of the inner material, may be responsible for the removal of some of the large armour from the shoreline and its final deposition into deeper water, away from any effects of wave action;

- The possible deep deposits of uncontrolled fill during the initial road construction (1980's) and the subsequent development of a sandy shoreline, may have observed some settlement due to the increase loading from the construction of the 2005 embankment. This settlement, if encountered, is not believed to be substantial, but may in combination with other mechanisms, result in movement of the outer armour stones; and,

- Pack ice and freezing ocean spray (and its associated pressures) may be responsible for slight movement of the outer armour stones, which in combination with other mechanisms and/or repetitive occurrences, resulted in the slope erosion.

Although, there appears to be no immediate threat to the stability of the existing roadway or to traffic using this roadway, the area of the erosion should be monitored, particularly following storm events. Ongoing erosion is anticipated during periods of high waves combined with storm surges or higher tides and should be repaired as soon as possible to prevent the further erosion of the embankment. Repair of the slope would involve reopening the quarry used in the original construction.

It is not expected that the existing armour from this area can be utilized in its repair, since many of the stones have been deposited into deeper water. Reconstruction to the original specification in this area may not be effective in preventing future erosion. As an additional protective measure it is recommended that a layer of geogrid or geotextile fabric be installed between the inner filter and inner core, to further reduce any washing out of the inner core. It is also recommended that the armour along the shoreline between the bedrock outcrop on the north side of this area and the bedrock shoreline on the south side of the 2005 embankment be secured together by cables and rock anchors to the nearby armour stones and to the bedrock at the north and south ends.

The majority of the slope repair cost will be mobilization and production of the larger armour. Core material will be the waste rock produced in obtaining the armour and its cost will be minimal (predominately the trucking costs). Since minimal further lost of armour is anticipated and the continued erosion would be of the blast rock core material, Nalcor may consider postponing the repair work until receiving capital expenditure approval.

In order to further understand the wave action with the geometrical shape of the shoreline and adjacent waters, we recommend that detailed topographical and hydrographical surveys be performed in the area.

5.0 COSTS

A preliminary cost estimate to conduct the reconstruction is in the order of **$366,000**.

The contractor cost is estimated to be **$300,000**, and assumes that work will be conducted within an 80 metre section and involves changing the slope angle in this area from 1 vertical to 2 horizontal (1V:2H) to 1V:3H. and replacing the eroded material with graded armour stone, filters and core materials . Table 5.0A below summarizes the cost estimate with further details and cost break down presented in Appendix C.

In order to conduct this work a tender document and construction drawings will be required. In addition, construction supervision and contract closure will also be required. It is recommended that further study be conducted to investigate the probable mechanism responsible for the slope failure. A cost estimate to conduct this work is **$ 66,000**. A preliminary cost estimate is presented in Table 5.0B with further details and cost break down presented in Appendix C.

Table 5.0A – Construction Cost Estimate

Item	Est Rate	Amount	Units	Total Cost
Armor Stone	$ 40.00	3500	m^3	$ 140,000.00
Filter	$ 30.00	2000	m^3	$ 60,000.00
Blast Rock Fill	$ 30.00	1500	m^3	$ 45,000.00
Anchoring and dowels	$ 40,000.00	1	est	$ 40,000.00
Mob/demob	$ 15,000.00	1	est	$ 15,000.00
			TOTAL	**$ 300,000.00**

Table 5.0B – Contract Preparation, Supervision, and Closure Cost Estimate

Item	Fees	Expenses	Total Cost
Site Investigation	$ 6,628.00	$ 1,820.00	$ 8,448.00
Design Brief	$ 6,351.00	$ 400.00	$ 6,751.00
Tender & Specification	$ 2,986.00	$ 400.00	$ 3,386.00
Tender & Contract Award	$ 4,964.00	$1,420.00	$ 6,384.00
Construction Supervision	$ 25,731.00	$ 7,200.00	$ 32,931.00
Completion Report & As Built Drawings	$ 3,543.00	$ 400.00	$ 3,943.00
Administrative Expenses	$ 3,012.00	$ 1,164.00	$ 15,000.00
		TOTAL	**$ 66,019.00**

6.0 CLOSURE

This report has been prepared for the exclusive use of Nalcor. The proposed scope of work and cost estimates were conducted using standard assessment practices and in accordance with verbal and written requests from the client. No further warranty, expressed or implied, is made as to the professional services provided under the terms of our contract and included in this report. The results presented herein are based solely upon the scope of services and time and budgetary limitations described in our contract. Any use which a third party makes of this report, or any reliance on or decisions to be made based on it, are the responsibility of such third parties. AMEC Earth & Environmental accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions based on this report. The limitations of this report are attached in the Appendix D.

Respectfully Submitted,

AMEC Earth & Environmental
A division of AMEC Americas Limited

Reviewed by,

REGISTERED PROFESSIONAL GEOSCIENTIST
CALVIN MILES
SIGNATURE
DATE
PROVINCE OF NEWFOUNDLAND

Kevin Penney, P Eng
Geotechnical Engineer

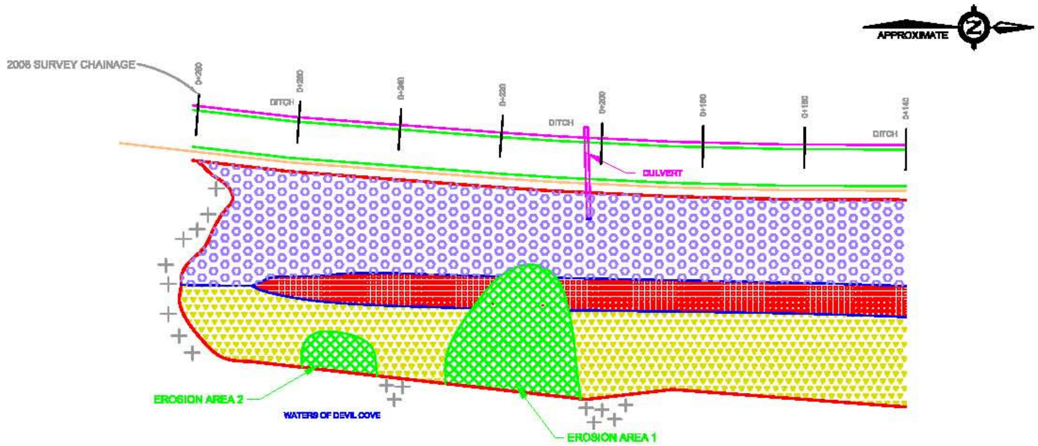
Calvin Miles, P Geo
Senior Associate

PROVINCE OF NEWFOUNDLAND AND LABRADOR
PEG Newfoundland and Labrador PROFESSIONAL ENGINEERS AND GEOSCIENTISTS
PERMIT HOLDER
This Permit Allows
AMEC AMERICAS LIMITED
To practice Professional Geoscience in Newfoundland and Labrador.
Permit No. as issued by PEG ______
which is valid for the year ______

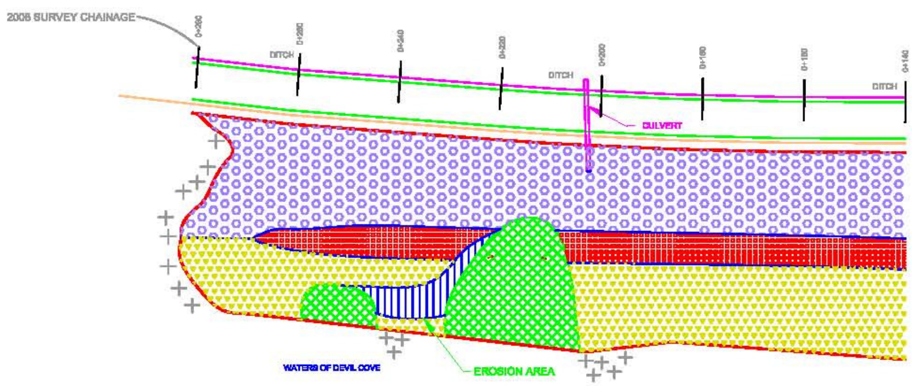
Page 4

APPENDIX A

DRAWING



PLAN VIEW OF EMBANKMENT SHOWING 2008 EROSION AREAS



PLAN VIEW OF EMBANKMENT SHOWING 2010 EROSION AREAS

NOTES:

1. ALL DIMENSIONS ARE IN METRES.
2. DO NOT SCALE FROM DRAWING.
3. THIS DRAWING IS INTENDED TO SHOW RELATIVE LOCATIONS AND CONFIGURATION OF THE STUDY AREA IN SUPPORT OF THIS REPORT.
4. ALL LOCATIONS, DIMENSIONS, AND ORIENTATIONS ARE APPROXIMATE.
5. THIS DRAWING CONTAINS INTELLECTUAL PROPERTY OF NALCOR ENERGY AND MAY NOT BE REPRODUCED OR COPIED WITHOUT THEIR WRITTEN CONSENT.

Legend

- Upper Section of Slope
- Lower Section of Slope
- Bench Area
- 2008 Erosion Areas
- 2010 Erosion Area
- Bedrock Outcrop

amec	Date: May 2010	Project: GEOTECHNICAL SERVICES FOR SLOPE EROSION INVESTIGATION CAT ARM, NL		
nalcor energy	Drawn by: A. Hollett	Title: LOCATION PLAN		
	Approved by: K. Penney	Scale: NTS	Project No.: TF1010479	Drawing No.: 1

APPENDIX B

PHOTOGRAPHS

Erosion area March 10, 2010 with larger armour stone remaining at the shoreline.

Run-up of waves was noticeably higher near the rock ledge.

Some armour and filter stones remain in eroded area.

Eroded area with smaller rounded soil on the wave run up area to the left half of the photo.

APPENDIX C

COST ESTIMATES

Nalcor - Cat Arm Hydro Development
TF1010479

Table 1 - Contractor Costs

Item	Est Rate	Amount	Units	Total Cost		2005 Rate	2005 Cost	
Armour Stone	$ 40.00	3500	m3	$ 140,000.00		$ 31.00	$ 108,500.00	
Filter	$ 30.00	2000	m3	$ 60,000.00	$ 245,000.00	$ 27.50	$ 55,000.00	$ 198,000.00
Blast Rock Fill	$ 30.00	1500	m3	$ 45,000.00		$ 23.00	$ 34,500.00	
Anchoring and dowels	$ 40,000.00	1	est	$ 40,000.00				
Mob/demob	$ 15,000.00	1	est	$ 15,000.00				
		TOTAL		**$ 300,000.00**				

Work involves reducing the slope for a 80 m section of shoreline from 2H:1V to 3H:1V
Volumes include the addition 4000 m3 to flatten slope and 3000 m3 to replace eroded material.
Allowance is provided for reinforcing armour with anchors and dowels.

Nalcor - Cat Arm Hydro Development
TF1010479

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Allowance is provided for reinforcing armour with anchors and dowels.

Nalcor - Cat Arm Hydro Development
TF1010479

Table 2 - Contract Preparation, Supervision, and Closure Costs

Position	Proposed Personnel	Hours	Rate	Fees	Duties	Expense Item	Units	Cost	Expenses
Site Investigation	Investigate the slope and quarry. Conduct a sounding along the shoreline to determine the near shore profile.								
Geotechnical Engineer	Kevin Penney	30	$ 117.00	$ 3,510.00	Site Visit & Reporting	Flight + expenses	2	$ 600.00	$ 1,200.00
Sr. Review	Calvin Miles	5	$ 158.00	$ 790.00	Sr review	Boat and Equipment rental	1	$ 400.00	$ 400.00
Technician	-	30	$ 65.00	$ 1,950.00	Site visit & drafting	Daily Expenses (meals)	2	$ 50.00	$ 100.00
Clerical	-	2	$ 53.00	$ 106.00		Daily Pickup + Fuel	1	$ 120.00	$ 120.00
H&S	-	4	$ 68.00	$ 272.00					
			TOTAL	**$ 6,628.00**				**TOTAL**	**$ 1,820.00**
Design Brief	Prepare a design brief outlining the various remedial options and costs. Remodel the wave height (energy) using the new near shore profile.								
Civil Engineer	Cliff Smith/Janet Williams	5	$ 117.00	$ 585.00	Reporting	Misc expenses	1	$ 400.00	$ 400.00
Geotechnical Engineer	Kevin Penney	10	$ 117.00	$ 1,170.00	Reporting				$ -
Sr. Review	Calvin Miles	5	$ 158.00	$ 790.00	Sr review				
Technician	-	20	$ 65.00	$ 1,300.00	Drafting etc			**TOTAL**	**$ 400.00**
Clerical	-	2	$ 53.00	$ 106.00					
Oceanographer/Modeler	Sebastien Donnet	20	$ 90.00	$ 1,800.00	Shoreline/wave modeling				
Sr. Oceanographer	Patrick Roussel	5	$ 120.00	$ 600.00	Sr review				
			TOTAL	**$ 6,351.00**					
Tender & Spec Preparation	Prepare technical specifications and construction drawings.								
Civil Engineer	Cliff Smith/Janet Williams	10	$ 117.00	$ 1,170.00	Reporting	Misc expenses	1	$ 400.00	$ 400.00
Geotechnical Engineer	Kevin Penney	5	$ 117.00	$ 585.00	Reporting				$ -
Sr. Review	Calvin Miles	2	$ 158.00	$ 316.00	Sr review				
Technician	-	10	$ 65.00	$ 650.00	Drafting etc			**TOTAL**	**$ 400.00**
Clerical	-	5	$ 53.00	$ 265.00					
			TOTAL	**$ 2,986.00**					
Tender & Contract Award	Assist Nalcor with tendering and contract award. Includes site visit prior to tender closing.								
EIT/Sr Tech	to be determined	15	$ 90.00	$ 1,350.00	prep + site visit	Flight + expenses	2	$ 600.00	$ 1,200.00
Geotechnical Engineer	Kevin Penney	15	$ 117.00	$ 1,755.00	Meetings, Management, Site Visit	Daily Expenses (meals)	2	$ 50.00	$ 100.00
Sr. Review	Calvin Miles	5	$ 158.00	$ 790.00	Planning, Review, Meeting	Daily Pickup + Fuel	1	$ 120.00	$ 120.00
Civil Engineer	Cliff Smith/Janet Williams	5	$ 117.00	$ 585.00	Meetings, Management				
H&S	-	4	$ 68.00	$ 272.00	Review contractors HASP			**TOTAL**	**$ 1,420.00**
Clerical	-	4	$ 53.00	$ 212.00					
			TOTAL	**$ 4,964.00**					
Construction Supervision (Assume 3 weeks field work)	Supervise construction activities.								
EIT/Sr Tech	to be determined	220	$ 90.00	$ 19,800.00	assume 60 hr week + prep + travel	Flight + expenses	3	$ 600.00	$ 1,800.00
Geotechnical Engineer	Kevin Penney	20	$ 117.00	$ 2,340.00	Meetings, Management, Site Visit	Daily Expenses (Hotel + meals)	20	$ 150.00	$ 3,000.00
Sr. Review	Calvin Miles	20	$ 158.00	$ 3,160.00	Planning, Review, Site Visit	Daily Pickup + Fuel	20	$ 120.00	$ 2,400.00
H&S	-	4	$ 68.00	$ 272.00	Review contractors HASP				
Clerical	-	3	$ 53.00	$ 159.00				**TOTAL**	**$ 7,200.00**
			TOTAL	**$ 25,731.00**					
Completion Report / As Builts	Prepare completion report and as-builts of the construction activities.								
EIT/Sr Tech	to be determined	15	$ 90.00	$ 1,350.00	Reporting	Misc expenses	1	$ 400.00	$ 400.00
Geotechnical Engineer	Kevin Penney	5	$ 117.00	$ 585.00	Reporting				$ -
Sr. Review	Calvin Miles	3	$ 158.00	$ 474.00	Sr review				
Technician	-	15	$ 65.00	$ 975.00	Drafting etc			**TOTAL**	**$ 400.00**
Clerical	-	3	$ 53.00	$ 159.00					
			TOTAL	**$ 3,543.00**					
		TOTAL FEES		$ 50,203.00	plus 6% of fees **$ 53,215.18**	3,012.18			
		TOTAL EXPENSES		$ 11,640.00	plus 10% of expenses **$ 12,804.00**	1,164.00			
		TOTAL COST			**$ 66,019.18**				

APPENDIX D

LIMITATIONS

LIMITATIONS

The conclusions and recommendations given in this report are based on information determined at the test locations. The information contained herein in no way reflects on the environmental aspects of the project, unless otherwise stated. Subsurface and groundwater conditions between and beyond the test locations may differ from those encountered at the test locations, and conditions may become apparent during construction, which could not be detected or anticipated at the time of the site investigation. It is recommended practice that the Geotechnical Consultant be retained during construction to confirm that the subsurface conditions throughout the site do not deviate materially from those encountered at the test locations. Any elevations used in this report are primarily to establish relative elevation differences between the test locations and should not be used for other purposes, such as grading, excavating, planning development, etc.

The design recommendations given in this report are applicable only to the project described in the text and then only if constructed substantially in accordance with the details stated in this report. Since all details of the design may not be known, we recommend that we be retained during the final stage to verify that the design is consistent with our recommendations, and that assumptions made in our analysis are valid.

Any comments made in this report on potential construction problems and possible methods are intended only for guidance of the designer. The number of test locations may not be sufficient to determine all the factors that may affect construction methods and costs. For example, the thickness of surfical fill and organic layers may vary markedly and unpredictably. The contractors bidding on this project or undertaking the construction should, therefore, make their own interpretation of the factual information presented and draw their own conclusions as to how the subsurface conditions may affect their work. This work has been undertaken in accordance with normally accepted geotechnical engineering and geophysical practices. No other warranty is expressed or implied.

The data collected and interpretation outlined in this report were based upon data collected at specific locations on the site. Our opinion cannot be extended to portions of the site for which no data were collected.

The objective of this report was to assess the ground geoelectrical conditions at the site, given the context of our contract.

The conclusions of this report are based in part on the information provided by others. The possibility remains that unexpected geoelectrical conditions may be encountered at the site in locations not specifically investigated. Should such an event occur, AMEC Earth & Environmental Limited must be notified in order that we may determine if modifications to our conclusions are necessary.

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador Matthew W. Leonard SIGNATURE JULY 29/2013 DATE NEWFOUNDLAND & LABRADOR	Electrical N/A
	Mechanical N/A
	Civil
	Protection & Control N/A
	Transmission & Distribution N/A
	Telecontrol N/A
	System Planning N/A

Upgrade North Cut-Off Dam Access Road

Bay d'Espoir

March 2013

newfoundland labrador hydro
a nalcor energy company

SUMMARY

The North Cut-Off Dam Access Road is approximately eight kilometers long and runs from Bay d'Espoir Powerhouse 1 to the North Cut-Off Dam structure. Constructed in the mid-1960s, the road has not undergone any major work or upgrades since its original construction.

Routine maintenance has been completed to keep the road open and passable, however, it is now deteriorated and in need of an upgrade to normal standards to prevent accelerated erosion and damage and ensure safe access to Hydro's structures. Over the course of the past 50 years of service, the road topping has deteriorated to the point in which the subgrade material is exposed, creating a very rough, uneven driving surface with exposed rocks. This rugged terrain takes a toll on the personnel and vehicles which are required to travel the road on a regular basis. Drainage ditch systems have become plugged and culverts have collapsed from corrosion.

The proposed upgrades include improvements to the storm drainage system, the supply placement and compaction of Granular B subgrade material, and the supply, placement and compaction of Granular A road topping.

The proposed upgrades are essential to ensuring the continued reliability of the access road at least cost and will serve to extend the road's service life an additional 50 years.

TABLE OF CONTENTS

1 INTRODUCTION

The Bay d'Espoir Development includes three hydroelectric generating stations, six reservoir systems, and associated dykes, dams, canals and hydraulic structures. The headwaters of the Bay d'Espoir Development begin at Victoria Lake at an approximate elevation of 320 meters. The water travels through the Granite Canal Hydroelectric Generating Station, Upper Salmon Hydroelectric Generating Station and finally through the Bay d'Espoir Hydroelectric Generating Station (Bay d'Espoir) where it discharges at sea level. Additional water is collected, stored in, and diverted from a number of drainage areas between Victoria Lake and Long Pond, the forebay for Bay d'Espoir.

The majority of the hydraulic structures within the Bay d'Espoir Development are accessible via access roads - these roads are maintained and operated by Hydro. To ensure that these roads are of an acceptable standard upgrades are required. Work under this proposal consists of upgrades to the eight kilometer North Cut-Off Dam access road which runs from the Bay d'Espoir Powerhouse to the North Cut-Off Dam (see Figure 1).

Figure 1: Access Road to be Upgraded

2 PROJECT DESCRIPTION

This project involves the completion of upgrades to North Cut-Off Dam access road. The work will consist of:

- supply and installation of eight storm culverts;
- supply and installation of rip rap headwall/tail wall[1];
- supply, placement and compaction of Granular B subgrade material; and,
- supply, placement and compaction of Granular A road topping material.

[1] Rip Rap Head/Tail walls are a form of erosion control installed at the inlet and outlet of storm culverts respectively. Consisting of strategically placed rip rap material, these walls help to ensure that the flow of water through the storm culverts is not impeded by the accumulation of eroded material from the ditch emabnkments.

3 JUSTIFICATION

The access road was constructed during Stage 1 of the Bay d'Espoir Hydroelectric Development in the mid-1960s. No major upgrades or work have been completed on the roadway since its original construction. Routine maintenance has been carried out to keep the road open and passable, however, it is degraded and in need of an upgrade to normal standards to prevent accelerated deterioration, increased refurbishment cost and to ensure continued reliable access to Hydro's structures.

Over the past 50 years, the road topping has deteriorated to the point that the sub-grade material is exposed. This creates a very uneven, rough driving surface which is difficult to drive over and tough on both Hydro personnel and vehicles (see Figure 2).

Figure 2: Representative Section of North Cut-Off Dam Access Road

Furthermore, inadequate drainage has resulted in annual washouts of the roadway during the spring runoff - the drainage issues stem from collapsed culverts and inadequate drainage ditches. The resulting washouts make the road impassable and necessitate repairs in order to permit vehicular access to the destination structure (see Figure 3).

Figure 3: Inadequate Drainage

The road is travelled regularly for the completion of routine operation and maintenance procedures. To restore the road to an acceptable condition the proposed upgrades must be completed.

3.1 Existing System

The North Cut-Off Dam access road was constructed in the mid-1960s, as part of the Stage 1 Bay d'Espoir Development work. There has been no major work or upgrades completed on the road since its original construction. The road is owned by Hydro, and maintained by Hydro personnel using standard road grading and maintenance techniques. Over the past 50 years the road topping has deteriorated to the point in which the subgrade material is exposed. This has created a very rough, uneven driving surface.

3.2 Operating Experience

The access road permits vehicular access to critical hydraulic structures. These structures require regular visits for the completion of by-weekly inspection and maintenance tasks - the road is utilized year round.

The condition of the roadway has deteriorated greatly since its original construction. Water pooling, exposed culverts, ground stakes and several large depressions in the roadway create hazardous driving conditions. To facilitate reliable access to the North Cut-Off Dam, the road must be repaired.

3.2.1 Safety Performance

The access road provides a rough, uneven driving surface. While Hydro personnel use safe driving habits to account for these conditions, the potential for mechanical damage to vehicles is significantly higher than that presented during a typical driving situation. The ruts and exposed rocks cause steering wheels to twist suddenly and vehicles to lurch.

When attempting to conduct repairs on damaged components of the vehicle, employees are often placed in situations in which there is an increased risk for injury. The nature of the typical repair presents a risk of injury by way of heavy lifting, crushing, burns, and abrasions.

3.2.2 Industry Experience

Industry practice is to maintain regularly travelled roadways in a safe and passable condition.

3.2.3 Maintenance or Support Arrangements

The access roads are maintained by Hydro Operations personnel through the application of standard road grading and maintenance techniques.

3.2.4 Maintenance History

The five-year maintenance history for the North Cut-Off Dam Access Road is shown in Table 2.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2012	0.2	6.8	7.0
2011	0.0	0.2	0.2
2010	0.0	0.5	0.5
2008	0.8	0.2	1.0

3.2.5 Historical Information

Historical information for recent road upgrade projects is contained in Table 3.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Comments
2012	348.7	323.5	Star Lake Access Road, Phase 1
2011	998.4	1,095.3	Upgrade Burnt Dam Access Road, Phase 2
2007	309.2	288.5	Upgrade Burnt Dam Access Road, Phase 1
2007	674.5	649.7	Upper Salmon Access Road Improvements

3.2.6 Anticipated Useful Life

The anticipated useful life of the access road is 50 years.

3.3 Development of Alternatives

The North Cut-Off Dam Access Road is required to provide access to the North Cut-Off Dam. Failure to complete the proposed upgrades will result in the continued deterioration of the roadway, eventually making it impassable. Given the current condition of the road there are no viable alternatives outside of completing the proposed upgrades.

4 CONCLUSION

The North Cut-Off Dam access road provides essential access to the North Cut-Off Dam. It is utilized by Hydro personnel year round for the completion of routine maintenance and dyke inspection. The upgrades are required to ensure the continued availability of the road to provide a safe, reliable means of access to the North Cut-Off Dam.

Failure to complete the recommended upgrades will result in the continued deterioration of the roadway.

4.1 Budget Estimate

The budget estimate for this project is shown in Table 4.

Table 4: Project Budget Estimate

Project Cost:*($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	47.6	0.0	0.0	47.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	449.9	0.0	0.0	449.9
Other Direct Costs	4.5	0.0	0.0	4.5
Interest and Escalation	29.3	0.0	0.0	29.3
Contingency	100.4	0.0	0.0	100.4
TOTAL	**631.7**	**0.0**	**0.0**	**631.7**

4.2 Project Schedule

The anticipated project schedule is shown in Table 5.

Table 5: Project Schedule

Activity		**Start Date**	**End Date**
Planning	Project planning and coordination with Operations	March 2014	March 2014
Design	Preparation of tender package/contract award	March 2014	May 2014
Construction	Complete North Cut-Off Dam Access Road upgrades	June 2014	July 2014
Commissioning	Final inspection	-	July 2014
Closeout	Contract closeout	-	September 2014

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER T. ARBUCKLE SIGNATURE PROVINCE OF NEWFOUNDLAND	
	Telecontrol
	System Planning

Automate Generator Deluge Systems

Bay d'Espoir

April 2013

newfoundland labrador
hydro
a nalcor energy company

SUMMARY

This project is the second year of a four year program to replace the existing generator deluge systems on the seven hydroelectric generating units in Powerhouse 1 and 2 at Bay d'Espoir Hydroelectric Generating Station (Bay d'Espoir). Under this project two units will be upgraded. A deluge system is a fire suppression method that will spray water onto the generator in the event of a fire. At present, these systems must be activated manually by plant personnel opening a deluge valve that is located next to the generator. This procedure has been identified by Hydro's insurance provider, FM Global, as a significant risk and they have recommended automating these systems to improve response time and ensure a response is made if human access is not possible. An automatic system will also provide a safer fire protection system for plant personnel to operate. In addition, the National Fire Protection Association recommends providing automated systems for generator fire protection.

TABLE OF CONTENTS

1 INTRODUCTION

Hydro's largest hydroelectric generating station in the Island Interconnected System is located at Bay d'Espoir. The Bay d'Espoir Hydroelectric Generating Station (Bay d'Espoir) consists of seven generating units producing a total capacity of 604 MW which is approximately 39 percent of the Island Interconnected System's installed capacity. The company's insurer, FM Global, visits hydro generating stations annually and makes recommendations for improvements that will reduce the risk of asset damage, increased costs, and power interruption. This report addresses a condition identified by FM Global. At present, the fire protection systems serving the generating units at Bay d'Espoir are all manually activated. This project will replace these systems on two generating units with automatically activated systems as recommended by FM Global and the National Fire Protection Association (NFPA).

2 PROJECT DESCRIPTION

The scope of work for this project is to replace the existing manually operated generator deluge system on generating Units 3 and 6 with a modern fully automatic deluge system. A new deluge control cabinet will be installed along with a new deluge valve; the sprinkler distribution ring will be reused. The distribution ring is a system of pipes that surround the generator and deliver water to spray nozzles in the event of a fire. When the system is activated, water flows immediately through all nozzles at once. The budget estimate to complete this project is $611,500 and the work is scheduled to be performed in 2014. An outage on each generating unit will be required to complete the new installations. The outages will take place during the annual maintenance period and will be two to four weeks in duration depending on the unit outage schedule.

3 JUSTIFICATION

This project is justified on the need for Hydro to upgrade the existing equipment to reduce exposure to harm to operations personnel and reduce the potential for damage to equipment in the event of a fire on a generator.

The FM Global Risk Report for Bay d'Espoir (see Appendix A, Section 07-11-002) indicates the hazard associated with a manual system is the ability of a generator fire to spread rapidly during the time it takes an operator to respond to the initial alarm. The longer it takes to respond to a fire, more extensive damage to the equipment and increased cost of repairs will occur. A large fire could also prevent access to the manual valves altogether, leading to greater damage with potential loss of 450 MW of generating capacity to the Island Interconnected System for a period of time ranging in duration from several months to over a year.

Hydro has not experienced a fire on any of its seven generating units at Bay d'Espoir however, the existing manual systems pose a significant risk if there is a fire since its components are located near the generator, requiring personnel to don protective equipment and move towards the fire. It is required that the deluge systems for each generating unit be upgraded to a fully automatic system to limit employee exposure to harm, improve response time and reduce potential equipment damage in the event of a fire.

3.1 Existing System

Each generator at Bay d'Espoir is equipped with a manually operated deluge system that can be used to extinguish a fire that may occur in the vicinity of the upper and lower stator windings. There have been no major upgrades of the deluge system since the original installation.

The existing generator fire protection systems consist of an upper and lower sprinkler ring connected to the main firewater header through a series of piping and valves. In the event of a fire, an alarm sounds in the control room. An operations person is then fitted with a self-contained breathing apparatus (SCBA) and proceeds to the appropriate generating unit to determine if a fire exists. If a fire is present and the unit is still rotating, the operator must stop the unit, open the main disconnect and place the main ground switch to the “On” position to ensure the unit is de-energized. Once the unit has stopped rotating and has been de-energized, the operator proceeds to the proper generator manual deluge station and opens the main fire water valve to release water onto the fire (See Figure 1).

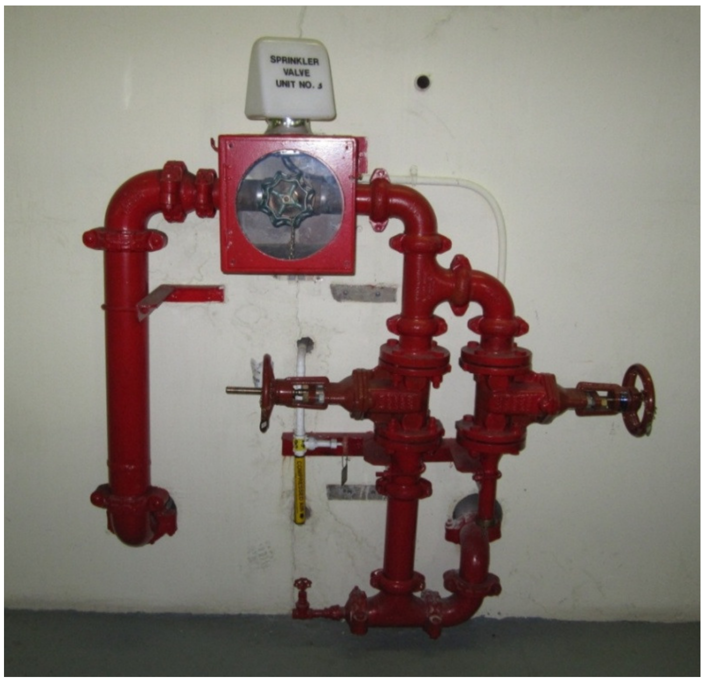


Figure 1: Typical Deluge Valve Arrangement on Units 1 – 6

FM Global indicates that a generator fire could occur if there is a short circuit, which could ignite the insulation on the generator. The initial fire would be small, however once established, the fire could spread rapidly - within two to three minutes. The estimated response time of Operations personnel, from the time they receive the alarm to when the unit deluge system is activated, is approximately six to eight minutes. By this time, there could be significant damage done to the generator and access to the manual deluge valve may be impeded, as the approximate distance from the valve to the generating unit is 16 feet (Figure 2).

Figure 2: Deluge Valve (left) with respect to Generating Unit (right)

The proposed new system will be activated automatically such that when a fire is detected by a sensor located in the generator area, the generating unit will be shut down and de-energized, the ventilation fans shut down and exhaust louvers closed, and then water will be applied to the fire. Shutting down the ventilation system helps to control the fire by reducing the supply of oxygen. The operators remain safe in the control room during automatic activation.

FM Global updated their risk report for Powerhouse 1 and 2 in Bay d'Espoir in 2012 and identified the lack of an automatic deluge system on generating Units 1, 3, 4 and 7 as a hazard that needs to be corrected (See Appendix A). This recommendation was based on the units that still had asphalt windings (Units 1, 3, and 4) or a unit in a different powerhouse (Unit 7). As noted in the FM Global report, Hydro indicated that all the generating units from one to seven will be converted to automatic systems. Hydro is taking this approach as this would correct the operations safety hazard and give better protection to all the units, and would also comply with NFPA.

3.2 Operating Experience

In the time taken for an operator to respond to a fire alarm on a generating unit, a potentially small fire could turn into something much larger thus leading to more equipment damage and increased replacement costs. An automatic system is more effective because there is no delay in responding to an alarm, thereby ensuring a greater potential for extinguishing a fire before major equipment damage occurs.

3.2.1 Reliability Performance

In 2010 during the rewind of Unit 2, it was noted that the sprinkler ring in the deluge system did not have the proper holes drilled in the pipe ring to discharge water. This was noticed because the rings had to be removed during the project. The rings were properly drilled and put back into place. It appears this deficiency in the fire protection system had existed since the time of original construction because there had been no upgrades or major work on the system since that time. There is a concern that this condition may exist in other units, and to inspect this sprinkler ring the generating unit will be required to be partially dismantled.

3.2.2 Legislative or Regulatory Requirements

The NFPA maintains a recommended practice referred to as “NFPA851: Recommended Practice for Fire Protection for Hydroelectric Generating Plants”. Within this document the NFPA recommends that the protection of generator windings be provided by an automatically actuated fire suppression system. Currently, Hydro meets this recommended practice at all of its hydroelectric generating stations with the exceptions of Powerhouse 1 and 2 at Bay d’Espoir. The applicable section of NFPA 851 is provided in Appendix B.

3.2.3 Safety Performance

In the event of a fire a plant operator must be equipped with SCBA before entering the generator hall. The operator comes in close proximity to a generating unit that may be on fire to access manual control valves (as seen in Figure 2). The operator first verifies that there is a fire before proceeding to follow a series of steps to ensure the unit is stopped and de-energized before the deluge valve is manually opened to release water. This current practice exposes the operator to unnecessary risk and increases the likelihood of personal harm and extensive equipment damage.

Currently, operations personnel review on a monthly basis the instructions or set procedures required to be followed in the event of a generator fire. In addition, all operations personnel have refresher courses on the use and operation of personal protective equipment (i.e. the self-contained breathing apparatus packs), and have firefighting training on site in Bay d'Espoir. As well, in 2012, a Plant Emergency Organization (PEO) team was developed. This team had a kick-off meeting and has identified ways to mitigate the risk to operational personnel while the new systems are waiting to be installed. On the team recommendation, Hydro has purchased new personal protective clothing and is in the process of getting formal training for members of the team. When formal training is complete, fire drills will be scheduled on a regular basis to ensure everyone is familiar with the systems and duties in case of a fire.

3.2.5 Industry Experience

The Centre for Energy Advancement through Technological Innovation (CEATI), an international utilities interest group in which Hydro participates, released a technology review in 2006 titled "Fire Protection and Suppression in Hydroelectric Plants" that outlines the current design standard used by BC Hydro (see Appendix C). For generator housings, BC Hydro ensures that each generator incorporates an automatic water spray type fire protection system, similar to that being proposed for Bay d'Espoir. Hydro also meets this standard at all of its other hydraulic generating stations, as does Churchill Falls (Labrador) Corporation.

3.2.6 Maintenance or Support Arrangements

Maintenance of the current generator deluge systems in Bay d'Espoir has been completed by Hydro's personnel.

3.2.7 Maintenance History

There is no maintenance history specifically for the generator deluge system. However, the five year history for the Fire Protection and Detection System is provided in Table 1.

Table 1: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2012	0.8	6.3	7.1
2011	1.4	0.9	2.3
2010	0.4	9.1	9.5
2009	0.0	6.0	6.0
2008	0.6	3.9	4.5

3.2.8 Historical Information

Hydro received approval under Board Order No. P.U. 4 (2013) to automate the generator deluge systems on two units at Bay d'Espoir in 2013 at a cost of $532,000.

3.2.9 Anticipated Useful Life

The anticipated useful life for firefighting equipment is 45 years. The existing systems are between 36 (Unit 7) and 46 (Unit 3) years of age.

3.4 Development of Alternatives

The status quo is not acceptable and there are no viable alternatives to this style of automated generator deluge system.

4 CONCLUSION

The current manual generator deluge system on Units 3 and 6 in Bay d'Espoir needs to be upgraded to fully automatic control. A fully automated system will reduce the safety risk to plant operators and also will have the potential to significantly reduce equipment damage in the event of a fire. An automated deluge system will align Hydro with FM Global recommendations, other Hydro generation plant installations, the standard put forth by the NFPA Recommended Practice, as well as the industry standard currently adopted by CEATI. All other Hydro Generating Plants have an automatic generator deluge system. The status quo is not acceptable and there is no viable alternative to this project.

4.1 Budget Estimate

A budget estimate for this project is provided in Table 2.

Table 2: Project Budget Estimate

Project Cost:*($ x1,000)*	**2014**	**2015**	**Beyond**	**Total**
Material Supply	35.4	0.0	0.0	35.4
Labour	99.8	0.0	0.0	99.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	334.0	0.0	0.0	334.0
Other Direct Costs	8.6	0.0	0.0	8.6
Interest and Escalation	38.8	0.0	0.0	38.8
Contingency	95.5	0.0	0.0	95.5
TOTAL	**612.0**	**0.0**	**0.0**	**612.0**

4.2 Project Schedule

The anticipated schedule for this project is provided in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Open Job; review scope; site visit	February 2014	March 2014
Design	Technical specifications for the design, Tender documentation	March 2014	April 2014
Procurement	Issue and award tender and track materials	April 2014	June 2014
Construction	Materials on site, construction begins, construction complete	June 2014	July 2014
Commissioning	Commissioning of both units	June 2014	July 2014
Closeout	Closeout package	September 2014	October 2014

APPENDIX A

FM Global Risk Report

FM Global Risk Report

Location Findings
Nalcor Energy

Baie D'Espoir Generating Station
Route 361
Baie D'Espoir, Newfoundland and Labrador A0H 1R0
Canada

All in One
Interim Risk Evaluation

Visit by:	Guy Labonté and Stéphane Joubert
Visit date:	01 June 2012
Conference with:	Mr. Sam Rose, Manager Hydro Generation

Index: 000009.80-01 / **Account:** 1-74568 / **Order ID:** 676517-52

Principal Site Activity

Baie D'Espoir Generating Station is a constantly attended hydroelectric generating station. The seven generating units at this facility have a combined generating capacity of approximately 604 MW.

Understanding the Risk at this Facility

This crown corporation is dedicated to supply a cost efficient, reliable and dependable source of electricity to the industrial, utility and residential customers in Newfoundland. A sustained power production is critical to the island and a prolonged outage could become a safety issue during peak periods. This well-maintained hydroelectric generating station feeds 50% of the island's power demand during the winter and no other power supply could compensate the sudden unplanned outage of a generator. Thus, it becomes even more important to maintain and overhaul the critical systems of this power plant to avoid unexpected failures.

The intent of the FM Global visit is to transfer the knowledge and experience that FM Global has gained, often through losses sustained, to this facility so as to add to the established programs and projects. In this, the equipment hazard exposures are as follows.

The first three generators have been in service for over 45 years. Industry experience suggests that they have reached their normal, trouble-free, life expectancy. Generator Nos. 1 and 3 have failed their recent dc hi-pot test and should promptly be rewound.

The proper condition of station service batteries is critical for ensuring that breakers and other safety systems will operate as designed if needed. In the event of a cable, generator or transformer fault, the failure of a battery bank to provide sufficient tripping power to a circuit breaker could increase the damage sustained by the equipment sharing the circuit. Stator iron or transformer winding damage usually requires a costly and extended outage to conduct repairs. Therefore, enhancements to the maintenance program are recommended.

No infrared survey of the internal electrical production and distribution equipment has been performed such as for the switchyard equipment. Thermographic imaging is a common and useful tool used on a multitude of electrical equipment, owing to its ability to easily and effectively discover damaged and overheating components. Such problems can arise from corrosion, loose contacts and defective parts, and can result in unscheduled outages. Severe problems can even result in fire and prolonged downtime.

This facility is provided with the least reliable water supply for fire protection out of all five hydro stations on the island. Power House No. 1, which is occupied by six generators, is only provided with a water supply coming from the two penstocks through pressure reducing valves. These valves have proven to be unreliable over the years. The insured is working on installing the suggested proper testing apparatus and hopes to have it operational for 2013. The key factor is the

Understanding the Risk at this Facility continued

installation of a proper water flow testing apparatus; without it, it is understood that the suggested preventive maintenance program for Power House No. 1 CAN NOT be implemented.

Target Recommendations are those that the Account Engineer has selected as part of the account risk improvement priorities.

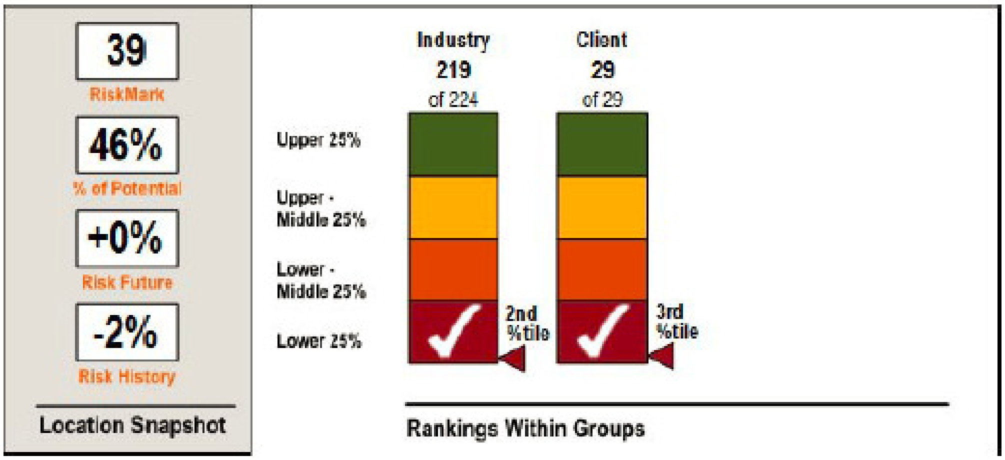
Location Overview

The following display(s) show Risk*Mark* information for this location. Note that the Risk*Mark* scores and displays are different than in the past. Risk*Mark* was recalibrated and enhanced to now include Equipment Hazards and an emphasis on Human Element programs. Risk*Mark* will now provide additional points for risk improvement in these and other areas. Your contacts at FM Global can help you to see the advantages of this more comprehensive benchmarking tool.

Location Overview continued

Risk*Mark* Snapshot

This display provides a snapshot of the risk quality of this location, including a summary of the current Risk*Mark* score, the percentage of the potential score, the history of risk improvement, the projected risk improvement in the future, as well as risk quality rankings within various groups of locations.



The Industry used in the above chart is Hydro Power Plant.

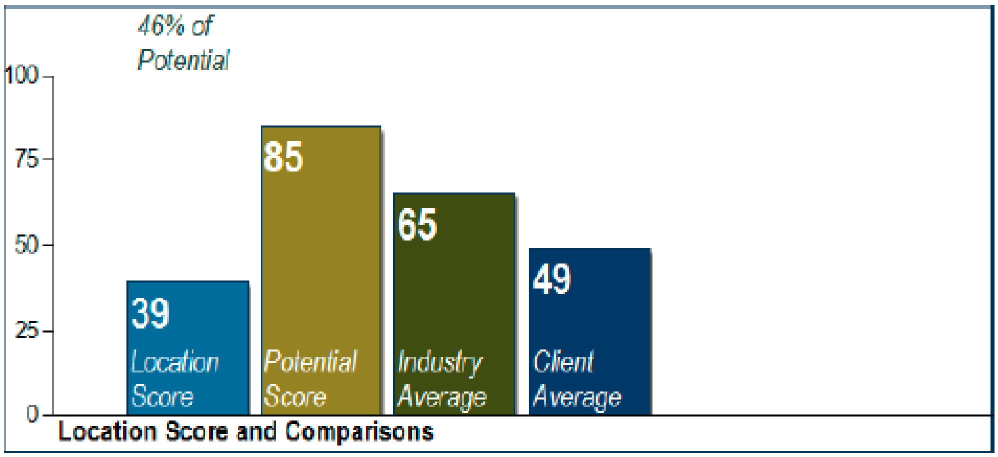
The Risk Future number is the per year improvement in your percentage of potential score, projected to 01 July 2014. The Risk History number is the per year improvement in your percentage of potential score, since 01 July 2009.

FM Global Risk Report — Nalcor Energy

Location Overview continued

Risk*Mark* Comparisons

This display shows a comparison of your Risk*Mark* to the average scores of other groups as noted in the display. Note that your potential score and percent of potential scores are also included.



The Industry used in the above chart is Hydro Power Plant.

Management of Exposures

Certain potential hazards and conditions were evaluated at this facility. Completion of the following items will help lower both the frequency and severity of losses and minimize the possibility of costly interruptions to your business.

Target Recommendations

Experience shows that the majority of all losses in this type of facility can be prevented or minimized by addressing the Target Recommendations, which are flagged below.

04-07-001 continued

The Hazard	To be effective during a fire, the fire protection systems at Power House No. 1 require a constant supply of water at a pre-determined pressure. The pressure reducing valves are used to reduce the 265-psig water pressure in the penstock to a pressure within the physical limits of the sprinkler system piping and equipment, set at 140 psi. The pressure reducing valves are supposed to open up gradually as the water demand increases while maintaining the same pressure on its discharge side. If either of the two valves fails to open, the water supply is not increased as required to feed the sprinkler systems and will allow the growing fire to spread uncontrolled. Without proper flow testing apparatus, the existing water supply is unknown.
Risk*Mark* Points	Completion of <u>only</u> this recommendation will result in a Risk*Mark* score increase of less than one point. Completing this recommendation along with other risk improvement efforts can result in more significant improvements to the Risk*Mark* score.
Status	The insured has implemented the suggested improvement at Power House No. 2 but is still working on installing the flow test header at Power House No. 1.

07-11-002

Convert the manual fire protection system for Generator Nos. 1, 3, 4 and 7 to automatic mode.

The water spray protection for all generators should be made automatic, interlocked with a unit trip, and shut down of all air handling equipment associated with the generator.

07-11-002 continued

The Hazard	The generators are provided with manual deluge protection. Fires on the generator could occur if there is a short circuit which could ignite insulation. The fire typically will start small; however, once established, it can spread rapidly within two to three minutes. Emergency services will respond, assess the situation and open the deluge valves, but this can typically take six to eight minutes. By that time, there could be significant damage to the generator. In the early stages of the fire, automatic protection is more effective as there is no delay in response. Automatic protection is always ready to fight a fire and will reduce the damage from a fire.

Generator Deluge Valving

Part A. Target

Convert the manual generator deluge system on Unit No. 1 to automatic.

An FM Approved alarm system should be provided in combination with an FM Approved deluge valve assembly.

Risk*Mark* Points	To significantly increase the location Risk*Mark* score, multiple recommendations must be completed.
Status	The insured indicated that the long term plan is to convert all seven generators' fire protection from manual to automatic.

Part C. Target

Convert the manual generator deluge system on Unit No. 3 to automatic.

An FM Approved alarm system should be provided in combination with an FM Approved deluge valve assembly.

Risk*Mark* Points	To significantly increase the location Risk*Mark* score, multiple recommendations must be completed.
Status	The insured indicated that the long term plan is to convert all seven generators' fire protection from manual to automatic.

07-11-002 continued

Part D. Target — **Convert the manual generator deluge system on Unit No. 4 to automatic.**

An FM Approved alarm system should be provided in combination with an FM Approved deluge valve assembly.

Risk*Mark* Points	To significantly increase the location Risk*Mark* score, multiple recommendations must be completed.
Status	The insured indicated that the long term plan is to convert all seven generators' fire protection from manual to automatic.

Part G. Target — **Convert the manual generator deluge system on Unit No. 7 to automatic.**

An FM Approved alarm system should be provided in combination with an FM Approved deluge valve assembly.

Risk*Mark* Points	To significantly increase the location Risk*Mark* score, multiple recommendations must be completed.
Status	The insured indicated that the long term plan is to convert all seven generators' fire protection from manual to automatic.

11-06-004

Conduct a flushing investigation on all sprinkler systems at a frequency of five years.

Conduct a flushing investigation on all sprinkler systems at a maximum frequency of every 5 years.

The Hazard	The facility's water supply for fire protection is coming from an open body of water. From this, debris in the water can be pushed to the automatic sprinkler systems and can create obstruction and restrictions in the piping. If water cannot reach the fused sprinkler heads at a predetermined flow and pressure, the fire could spread uncontrolled inside the facility, leading to significant property damage not expected if the systems work as designed.
Risk*Mark* Points	To significantly increase the location Risk*Mark* score, multiple recommendations must be completed.
Status	The insured understands the hazard and indicated that Mr. Boyd, project engineer, has been assigned to this task. No formal dates were committed to during the visit.

11-06-003

Reinstall missing spray nozzles for the outside step-up transformer's deluge fire protection.

Part A. — **Reinstall the missing nozzle for the Transformer No. 1 deluge system.**

Reinstall the missing spray nozzle for the Transformer No. 1 deluge sprinkler system. The missing nozzle is located under the east side radiator.

APPENDIX B

NFPA 851

response. The fire signaling panel should be located at the entry to the plant.

4-9.6 An emergency lighting system for critical operating areas that depends on batteries or fuel supplies should be manually operated from a switch at the entry to the plant. The emergency lighting can be permitted to consist either of fixed units or of portable lights. *(See 3-6.2.)*

4-9.7 It is important that the responding fire brigade or public fire-fighting forces be familiar with access, plant fire protection systems, emergency lighting, specific hazards, and methods of fire control. This should be reflected in the plant fire emergency plan. *(See Section 2-4.4.)*

4-9.8 The air supply and exhaust systems for the plant should be automatically shut down in the event of a fire. Manual override should be located at the entry to the plant so that emergency responders can activate these controls upon arrival.

Chapter 5 Identification and Protection of Hazards

5-1 General. The identification and selection of fire protection systems should be based on the fire risk evaluation. This chapter identifies fire and explosion hazards in hydroelectric generating stations and specifies the recommended protection criteria unless the fire risk evaluation indicates otherwise.

5-2 Turbine-Generator Hydraulic Control and Lubricating Oil Systems.

5-2.1 Hydraulic Control Systems.

5-2.1.1 Hydraulic control systems should use a listed fire-resistant fluid.

5-2.1.2 Determination of the need for fire-resistant fluid should be based on the quantity of fluid involved in the system, whether or not equipment that utilizes this fluid will operate hot or be exposed to external sources of ignition, and whether exposure problems are created for adjacent equipment by the use of non–fire resistant fluid.

5-2.1.3 If a listed fire-resistant fluid is not used, hydraulic control equipment should be protected. Fire extinguishing systems, where installed for hydraulic control equipment, should include protection for reservoirs, other equipment, valves, and associated piping.

5-2.2 Wherever possible, oil piping should be welded and flanged to minimize the possibility of an oil leak due to severe vibration.

5-2.3 Oil piping should be routed away, or be shielded from, electrical equipment or other sources of ignition.

5-2.4* Fixed fire protection for this equipment, where provided, should be as follows:

(a) Automatic wet pipe sprinkler systems utilizing a design density of 0.25 gpm/ft^2(10.2 mm/min) for the entire hazard area *(see 3-6.3)*.

(b) Automatic foam-water sprinkler systems providing a density of 0.16 gpm/ft^2 (6.5 mm/min).

(c) Gaseous extinguishing systems of either the local application or total flooding types. Safety considerations associated with these extinguishing agents should be evaluated prior to the selection of gas-type protection systems.

5-2.5 Consideration for protection of horizontal and vertical turbine bearings should be made based on the fire risk evaluation.

5-2.6 Curbs [minimum 6 in. (0.15 m) high] or drains or both should be provided for the oil storage and oil purification areas in accordance with Chapter 3.

5-2.7 Fire extinguishing systems, where installed for lube oil systems employing combustible-type oil, should include protection for the reservoirs, pumps, and all oil lines, especially where unions exist on piping and beneath any shielded area where flowing oil can collect. Facilities not provided with curbs or drains should extend coverage for a distance of 20 ft (6 m) from the oil lines, when measured from the outermost oil line.

5-2.8 Clean or dirty oil storage areas should be protected based on the fire risk evaluation. This area generally represents the largest concentrated oil storage in the plant. The designer should consider, as a minimum, the installation of fixed automatic fire protection systems and the ventilation and drainage requirements in Chapter 3.

5-3 Generator Pit and Windings.

5-3.1 Protection of generator windings consisting of thermoplastic materials should be provided by automatically actuated gaseous extinguishing systems, waterspray rings, or both.

5-3.2 Protection of generator pits containing auxiliary circuits such as protection current transformers (CTs), neutral transformers, and grounding resistors that are associated with generator protection should be provided by an automatically actuated gaseous extinguishing system or water spray system.

5-3.3 Gaseous suppression systems should be actuated by protective relays or fire detection systems or both.

5-3.4 Operation of waterspray rings should be interlocked so that the unit will trip before the system activates.

CAUTION

Immediately after the generator has been sprayed with a water-based system, it should be mechanically run (electrically isolated and without excitation) for at least 24 hours to avoid creating stator ground faults on both types of winding materials.

5-4 Control, Computer, and Communication Rooms.

5-4.1 Control, computer, and telecommunication rooms should meet applicable requirements of NFPA 75, *Standard for the Protection of Electronic Computer/Data Processing Equipment.*

5-4.2 A smoke detection system should be installed throughout these rooms, including walk-in-type consoles, above suspended ceilings where combustibles are installed and below raised floors. Where the only combustibles above the false ceiling are cables in conduit and the space is not used as a return air plenum, smoke detectors can be permitted to be omitted from this area.

5-4.3 A preaction sprinkler system for the computer or telecommunications rooms should be considered during the fire risk evaluation. In addition, gaseous extinguishing systems should be considered for areas beneath raised floors that contain cables or for areas or enclosures containing equipment that is of high value or is critical to power generation. Individ-

APPENDIX C

BC Hydro Standard

turbine, generator, and main floors.

Exhaust fans shall continue to run or start in the event of a fire. The automatic control of the fans shall be initiated by the area or the duct detector systems. Manual control of the fans shall be provided at the Fire Control and Annunciator panels.

The "pre-action" valve actuation shall be on the basis of–thermal cross zoned smoke, air sampling or thermal detection. The initial Smoke detection zone or alarm stage shall provide a pre-alarm to sound an early alarm for a fire situation.

Pull stations shall be provided at all exit points from the general floor areas on each floor.

Self-extinguishing waste receptacles shall be provided at each unit on each floor.

(b) Justification

Sprinklers are required by the BCBC for the stories more than one floor below grade, however, because of the high fuel load from the cables and the potential for a fire to adversely affect plant output it is considered to be advantageous to sprinkler the generator floor.

Control of the exhaust fans will help minimize smoke damage and aid in fire fighting and clean-up.

The requirement for a pre-action sprinkler system over the sensitive electric panels is based on the recommendations of the Fire Risk Reduction Program (FRRP) sub-committee set up to determine levels of fire protection around electrical equipment. The sub-committee recommendations were based on G.M. Shrum Generating Station where plant layout dictated that 3 pre-action systems would be required; one for Units 1-5, one for the service bay, and one for Units 6-10.

The requirement to "charge" the pre-action system on the basis of thermal detection was another recommendation of the FRRP sub-committee.

The placement of fire extinguishers, pull stations, waste receptacles, exits and exit sign lights meets the intent of the NFC and BCBC.

2.4.2 Generators and Enclosure

For large size conventional units the generator will be within an enclosure (possibly extending above the generator floor), and provided with access doors and ventilating louvres.

The main fire hazards are generator winding insulation, thrust bearing lube oil and dust. The main sources of ignition will be heat or a spark from the equipment or an electrical arc from a fault. The type of stator insulation used should be investigated and analyzed to determine combustibility. However, in the presence of sustained electrical arcing there is very little that will not burn.

(a) Intent of Standard

The generator enclosure material shall be non-combustible. The generator enclosure shall be considered as a fire separation and shall be 2-hour fire separated. All openings for cables, conduits, ducts, pipes, etc. shall be fire stopped.

Each generator shall incorporate an automatic water spray type fire protection system in accordance with NFPA standards.

The system shall be designed to provide a spray of water directly onto the insulated portions of the upper and lower winding structures (including the stator windings, stator terminals, circuit rings, winding endheads, field windings and damper windings) at a minimum of 0.6 L/s per square metre with an end head pressure at the most remote nozzle of 210 kPa minimum (plus an allowance for windage).

A water spray ring shall be mounted at the top and bottom of the generator windings, with spray nozzles on double elbow connections to the rings. The size of the rings and other piping shall be based on hydraulic calculations per NFPA 15. The nozzles shall be spaced approximately 500 mm (20 in) apart with a spray angle of approximately 80 to 90 degrees, such that the spray coverage of each nozzle overlaps the adjacent nozzles. The rings shall incorporate a minimum of four mechanical type (Victaulic) couplings to allow for the removal of the piping during ovehauls. Mechanical type couplings shall be provided in the feed piping to the rings.

The generator water spray system shall discharge, and the generator shall trip, in the event of either of the following occurrences:

1. One or both thermal detectors in alarm, together with a generator fault.
2. Operation of the high pressure switch indicating that a water spray discharge is occurring.

The water spray discharge shall last for the period set on the fire control panel (3 - 10 minutes). If at the end of that period all thermal detectors have reset, then no further discharge will take place. If they have not reset, then a second period shall be initiated. The system shall recycle until all thermal detectors have reset.

The most important fire protection devices on a generator are the circuit breakers which disconnect it from the power system and open the field circuit. Once the circuit breakers have been opened there should be no reluctance to operate the deluge system provided the generator is equipped with a synthetic resin insulation system. It is believed that the water from deluge systems is better dispersed if rotation and consequently windage in the machine is still present.

The deluge system is considered to be only a last resort to prevent destruction of the unit.

To assure personnel safety from potential electrocution, extra care must be taken to confirm that the fire protection piping is adequately grounded. No. 4 copper grounds are recommended.

Sprinkler systems rather than CO_2 or Halon systems are recommended for generator fire protection because they are equally as effective and do not pose as an environmental or life safety hazard. Experience within B.C. Hydro has shown that the water damage resulting from deluging a unit with epoxy based insulation is minimal.

The 35 kPa setting on the pressure switch downstream of the deluge valve is low enough to indicate when the deluge valve is open or when leakage by the deluge valve is about to enter the generator enclosure. This action will prevent water damage that could result from deluging a "hot" unit or from leakage.

The pressure switch shall also provide a "system activated" signal to the control and annunciator panels.

The smoke detectors should provide a pre-alarm to permit manual response to a fire situation before it can develop into a major fire.

The test valve at the unit will permit annual testing of the complete deluge system.

Fire separating the unit enclosures will help ensure that a fire inside or outside the unit enclosure will not spread.

2.4.3 Turbine Pits

For conventional fixed blade units the turbines are located in concrete enclosures. The combustible material in these areas will consist of the main guide bearing lube oil and the governor oil supplied to the servomotors. The main sources of ignition would be due to human error or possible heat sources due to bearing failures.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER J. W. VINCENT J.W. Vincent SIGNATURE 2013-JULY-30 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Overhaul Steam Turbine Generator – Unit 2

Holyrood

June 2013

newfoundland labrador
hydro
a nalcor energy company

SUMMARY

This project for Unit 2 at Holyrood Thermal Generating Station is to perform a major overhaul of the turbine, generator and auxiliary systems. The purpose is to return the turbine, generator and auxiliary systems back to design specifications, such that the equipment can operate safely, efficiently and reliably until the next scheduled overhaul. In addition, it will identify any unusual findings, internally and/or externally, that if not corrected or controlled could lead to premature failure of the equipment.

The major overhaul of Unit 2 would entail complete dismantling of all the turbine stages, removing the rotor from the generator and internal inspections of all systems and auxiliary equipment. The overhaul is to mainly be completed by contacted services, consisting of technical services, labour, materials and supervision. As required, plant personnel will provide assistance for application of work protection and services, parts procurement, removal of specific monitoring and control systems, overall contract management and technical liaison with Hydro’s management personnel.

TABLE OF CONTENTS

1 INTRODUCTION

The three major components of the thermal generating units are the power boiler, turbine and generator. Through combustion of No. 6 fuel oil, the power boiler provides high energy steam to the turbine. The turbine is directly coupled to the generator and provides the rotating energy necessary for the generator to produce rated output power. The Unit 2 turbine is a General Electric (GE) Lynn Model D3 made up of three stages, each designed to extract maximum energy from the high pressure steam and in turn to provide maximum rotational energy to the generator. Each turbine is constructed of three sections**:** a single flow high pressure section, a single flow intermediate section (both in one high pressure-high temperature casing) and a separate double flow low pressure section. The high, intermediate and low pressure sections of the turbine rotor are built on a single shaft with solid couplings to form what is known as a tandem compound, double flow, reheat turbine. Each stage is designed such that it extracts energy from the supplied steam as efficiently as possible converting it into rotational energy.

The electrical generator is coupled to the steam turbine and converts the rotating energy into electrical power. The generator itself is a General Electric (GE) 194 MVA two pole unit rotating at 3600 rpm to produce 3 phase, 0.9 power factor, 60 cycle, 16,000 volt power at its stator terminals. It is pressurized and cooled by hydrogen gas to provide maximum efficiency both in heat transfer and windage losses.

The generator has two basic components; a rotational excitation field and three stationary stator coils. The rotational field, through magnetic coupling, induces a high voltage into the stationary stator coils. The stator coils are connected via a step-up transformer to the main Holyrood Terminal Station and then to the Island Interconnected System. The turbine generator assembly is approximately 80 feet in length and 24 feet in diameter and is shown in the accompanying photos (Figures 1, 2, and 3) in both its assembled and disassembled states. The turbine is designed to operate using high energy steam at approximately 14,000 Kpa pressure and 500 C temperature. The generator operates at approximately 16,000 Volts and 7,000 Amps when providing full load (175 MW) to the island power grid.

Figure 1: Unit 2 Turbine Generator Assembled

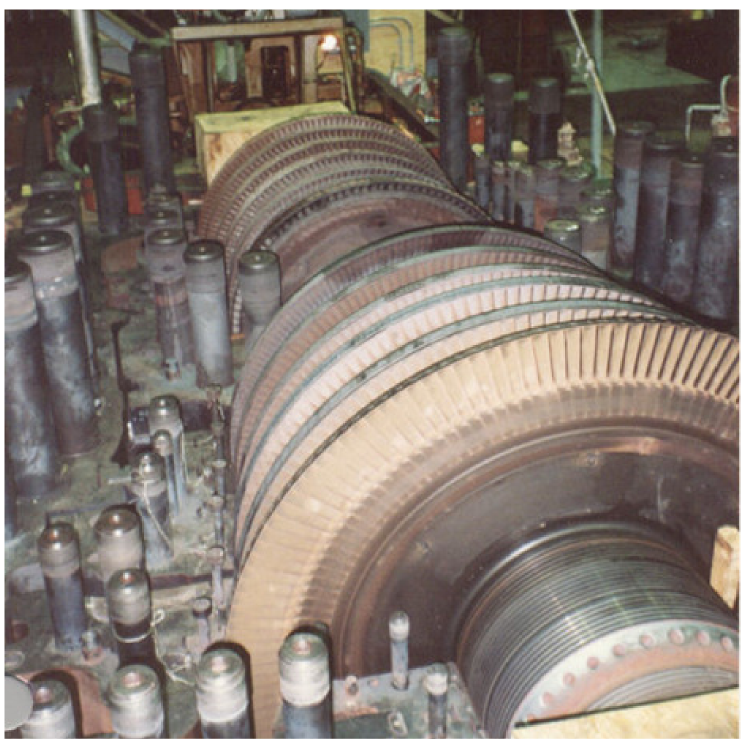


Figure 2: Unit 2 HP/IP Turbine Disassembled

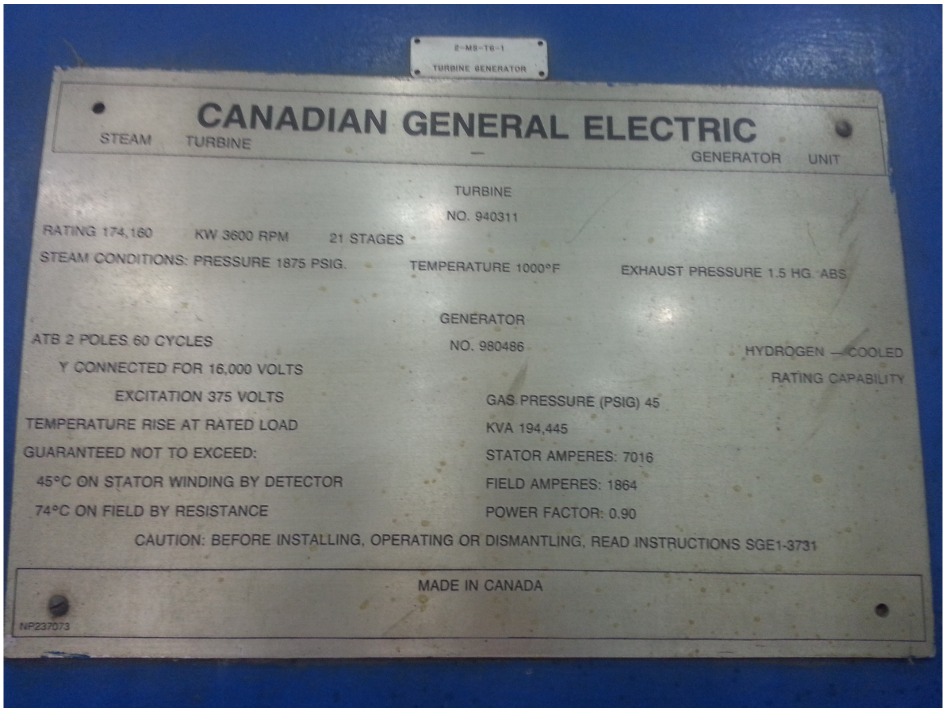


Figure 3: Unit 2 Turbine Generator Name Plate

2 PROJECT DESCRIPTION

This project is to perform a scheduled major overhaul of Unit 2 turbine, generator and auxiliary systems located at the Holyrood Thermal Generating Station. The turbine is constructed of special metal alloys to withstand the extreme temperatures and pressures and must conform to very close tolerances in order to convert the steam energy as efficiently as possible. The generator is subjected to electrical and magnetic stresses while providing megawatt and megavar power for the Island Interconnected System. The generator stator windings have increased forces and loading induced upon them during system faults. Unit 2 is no exception and encounters system faults and swings in load during system events. To ensure that these units operate at peak performance and provide maximum energy on demand, it is necessary that they undergo major overhauls on a scheduled basis to return the equipment to design specification. The last major overhaul took place in 2005 and was completed by General Electric. Overall the reliability of the unit is in question due to poor performance during the last Meggar and Polarization Index (PI) tests during the 2005 overhaul. The tests found the winding resistance to be low/unacceptable with a Meggar reading of 42 megaohms and a Polarization Index of 0.9. General Electric recommended that the stator be rewound in during the next major outage. (Appendix A) However, with the announcement of the Muskrat Falls project, Unit 1 and Unit 2 are scheduled to be decommissioned after 20/21, removing the need to rewind Unit 2. General Electric also noted that during startup, the turning gear drive clutch jaw teeth broke and recommended that non-destructive testing be performed on the teeth of the drive clutch and emergency governor stub shaft at every major inspection for crack development.

This major overhaul consists of a total dismantling of all turbine stages, removal of the generator rotor, and internal inspections of all systems including auxiliary equipment. The work will mainly be completed by contracted services with assistance from plant personnel when required. The contracted work consists of technical services, labour, materials and supervision. Plant support is required for work protection application and services, parts procurement, removal of specific monitoring and control systems, overall contract management, and technical liaison with Hydro's management personnel.

The work to be completed consists of three types: Routine *Standard Work* (Appendix B) that is defined by the equipment manufacturer, *Defined Work* which is extra to the standard work and identified prior to the overhaul, and *Unforeseen Work* which may result from examination of the equipment during the internal inspection. The contractor is responsible to schedule and complete the standard and defined work within the specified overhaul period. The unforeseen work and associated repair schedule is determined by the contractor in consultation with Hydro. The major overhaul requires approximately 12 weeks to complete, using crews working two shifts (Appendix B). Unforeseen work coupled with the transport of "out of province" repairs could alter the schedule and have an effect on the overall cost. The Turbine also undergoes a valve overhaul at a three year frequency to inspect control and stop valves and related auxiliary equipment. This overhaul work is included as part of the work schedule for the nine year major overhaul, utilizing the same outage, isolation and disassembly of the equipment to perform both overhauls.

In 2003, Holyrood undertook a similar initiative and contracted Hartford Steam Boiler Inspection and Insurance Company (HSB) to review Hydro's turbine generation operation using HSB's proprietary Turbine Outage Optimization Program (TOOP) to determine if Holyrood should extend its current overhaul program to a longer interval. All aspects of the turbine generator were reviewed; design, construction, historical experience, operation, maintenance, inspections and monitoring. HSB concluded that all three units could extend major overhaul frequency from six years to nine years provided some upgrading and repairs were completed and instrumentation installed to enhance the existing turbine monitoring program. (see Appendix C). Hydro completed an analysis of the reports and determined that the upgrades and improved monitoring required to extend the major overall frequency was warranted as a cost savings measure without jeopardizing the safe and reliable operation of either unit. The necessary upgrades were completed for all three units and the maintenance plan for major overhauls revised to the nine year frequency.

In January 2010, AMEC Americas Limited (AMEC) was contracted by Hydro to conduct a Phase 1 Condition Assessment and Life Extension Study of the Holyrood Generating facility. This was a non-intrusive assessment concentrating on historical data, maintenance reports, operations logs, existing maintenance and inspection plans and reviews with operations staff. The investigation took a year to complete with a final report delivered to Holyrood management in March 2011 (see Appendix D). The study agreed with the 2003 TOOP (HSB) report to extend the major overhaul schedule for the turbine to the nine year frequency but recommended that overhauls on the generators revert back to the six year interval. This specific recommendation will be further reviewed by Hydro before a final decision is made. The AMEC study also agreed with the 2003 GE recommendation to complete a more in depth inspection of Unit 2 generator during the next major overhaul with a follow-up plan to recondition both the rotor and stator if required.

The first major overhaul since the nine year extension decision is scheduled for Unit 2 in 2014. The last major overhaul of Unit 2 was completed in 2005. Over the past eight years (2005 – 2013), Unit 2 has seen 22,246 operating hours or 2.54 unit years, and approximately seven unit starts per year. Operating hours are low in comparison to industry normal for that period, typically 50,000 equipment operating hours between overhauls, but the number of starts would be considered high and is one of the governing factors in any major overhaul schedule. This overhaul is necessary to inspect the turbine components for wear, to inspect the generator for its electrical and mechanical condition, and to inspect all auxiliary equipment. This major overhaul is also the first under the extended maintenance plan and it will provide valuable data on the suitability of a longer operating period.

3 JUSTIFICATION

This project is justified on the requirement to maintain the generating equipment in its optimal operating condition for Hydro to provide safe, least-cost, reliable electrical service to its customers. The purpose of the major overhaul is to return the turbine, generator and auxiliary systems to design specifications such that they can perform safely, efficiently, and reliably to meet system demands until the next major overhaul. It will also identify any unusual findings (internally or externally) that if not corrected or controlled could lead to premature failure of the equipment. Since the installation of Unit 2 in 1969, major overhauls of the turbine, generator and auxiliaries have been performed on a scheduled basis that reflected industry standards. The manufacturer, GE in their 2003 report (FRS-No: 20350670) identified 50 recommendations to be completed during or immediately prior to the next major overhaul of this turbine generator unit (see Appendix A). Based on GE's conclusions and recommendations and Holyrood's implementation of their findings, the next major overhaul of Unit 2 is scheduled in 2014 (nine year interval). Holyrood supplies approximately 33 percent of the Island Interconnected System's capacity and is particularly important due to its location on the Avalon Peninsula close to the large customer base. A loss of Unit 2 generation during high load requirements could have a significant impact on the Island Interconnected System's ability to meet demand. Under the previous GAAP accounting guidelines, major unit overhauls were deemed an operating and maintenance cost and formed part of Holyrood's operating Budget. In 2012, Hydro implemented new accounting standards under which all major overhauls are to be completed using the Capital Budget process. Since its installation, Unit 2 major overhauls have been completed on a frequency consistent with industry standards and have been included in Holyrood's ten year plan of projected operating maintenance expenditures.

3.1 Existing System

Unit 2 is designed for continuous operation with varying loads. It is typically operated as a seasonally base-loaded unit (November to March) to meet system requirements. It, together with the other two generating units, typically provides about 33 percent of the Island Interconnected System load during the crucial winter peak period. Maintenance outages are taken during the summer months when its capacity is not required. Unit 2 has been operating in this mode, within design capability, since it was commissioned in 1969. The anticipated operational schedule for Unit 2 during the period 2013 to 2041 is shown in Table 1.

Table 1: Holyrood Generating Station Anticipated Mode of Operation 2014 and Beyond

2014 through 2017 - Generation: Capacity factor between 50 percent and 100 percent; Availability of 95percent.
2018 through 2020 - Generation Standby: Capacity factor between 30 percent and 75 percent; Availability of 90 percent to 95 percent.
2020 Onward - Offline

Unit 2 turbine generator will continue with the current operating regime until after 2018.

Table 2 shows the upgrades on Unit 2 since installation.

Table 2: Unit 2 Turbine Generator - Major Upgrades

Year	Major Work
2008	Stator winding ground fault protection improved.
2008	Hydrogen dryer and purity meter replaced;
2007	New nozzle block installed;
2005	Full replacement of the stator slot wedges with top ripple springs; Slot couplers re-installed; Stator end-winding support system cleaned and re-tightened; Resistance Temperature Detectors (RTD's) checked; Damaged epoxy dowels of fiber inner end-shields – repaired with oversized dowels; Rotor dried out and re-tested; Collector ring distributors corroded, removed, cleaned and put back; Bore seals pressure tested ; Realigned hydrogen seal housing; Hydrogen coolers cleaned and pressure tested ; Installed 4 new cold gas RTD's in stator; Digital multi-functional generator protection relay installed, (for improved winding ground protection, alarms connected, and sequence of events monitoring). Electro-mechanical protection relays retained; and Hydrogen seal rings lapped and clearances re-set to lower limits to minimize future oil leaks.
1999	GE static exciter replaced;
1989/90	Up-rated from 174.160 MVA at 30 psi hydrogen pressure, to 194.445 MVA at 45 psi hydrogen pressure; Retaining rings polished and NDE inspected in situ.

3.2 Operating Experience

Unit 2 turbine generator was installed and commissioned in 1969. In 1990 its maximum continuous rating (MCR) output was increased from 150 MW to 175 MW. The Unit 2 operating hours to the end of March 2013 were 172,632. Assuming the generator operates for approximately 5,000 hours per year until 2014, it is expected to attain approximately 180,000 hours before the next major overhaul in 2014. Due mainly to system requirements, the unit has averaged about seven starts per year which when projected to 2014 will total about 65 for the nine year operating period.

3.2.1 Reliability Performance

Following the last major overhaul on Unit 2 in 2005, there has been one forced outage for the unit. On May 14, 2007, a large change on Unit 2's vibration was noted, followed by a control valve (CV) malfunction which caused a forced outage.

Table 3 shows Unit 2 and plant performance for a five year period (2008-2012).

Table 3: Holyrood Unit 2 and Plant Performance

Five Year Average 2008-2012	All Causes		
Unit	**Capability Factor (%)**	**DAFOR (%)**	**Failure Rate**
Holyrood Unit 2	77.57	3.82	23.65
Holyrood Plant	69.01	10.03	6.38
CEA (2007-2011)	74.13	9.84	7.52

Capability Factor is defined as unit available time. It is the ratio of the unit's available time to the total number of unit hours.

DAFOR is defined as Derated Adjusted Forced Outage Rate. It is the ratio of equivalent forced outage time to equivalent forced outage time plus the total equivalent operating time.

Failure Rate is defined as the rate at which the generating unit encounters a forced outage. It is calculated by dividing the number of transitions from an Operating state to a forced outage by the total operating time.

3.2.2 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements that would make this capital budget proposal necessary.

3.2.3 Safety Performance

Unit 2 turbine operates at very high steam flows (1,050,000 Lbs/hour) which, combined with high pressures (1,900 PSI G) and temperatures (1005 F), contribute to the wear and tear of internal components. The combined turbine generator weight is approximately 60 tons, 80 feet in length and rotates at 3,600 rpm requiring specific speed governing and tripping mechanisms to eliminate any possibility of over-speed. The generator itself operates at high voltages and uses hydrogen gas as a coolant both requiring special containment mechanisms to prevent exposure to personnel and the environment. Maintenance of these systems is vital to ensure the unit's safety performance and as such forms part of the major overhaul scope. There are, however, no specific safety performance regulations or codes requiring compliance.

3.2.4 Industry Experience

Traditionally, the North American standard for turbine and generator major overhauls was based on a six year cycle. This frequency was in agreement with the original equipment manufacturer's guidelines and was acceptable to the utility industry in general. In an effort to reduce operating costs, utilities began to scrutinize the turbine generator major overhauls, in particular the six year schedules, to determine the viability of increasing the major overhaul frequency. Following comprehensive reviews internally as well as through external expertise many utilities endorsed this recommendation and the standard frequency for major overhauls for many North American utilities was changed from the traditional six years to nine years.

3.2.5 Vendor Recommendations

In 2003, Holyrood contracted Hartford Steam Boiler (HSB) to investigate the possibility of extending the traditional overhaul interval of six years to a nine year frequency. Holyrood accepted the recommendation and revised all major overhauls to the extended frequency. The Original Equipment Manufacturer (OEM), General Electric verbally indicated that they did not endorse the six year overhaul frequency. In 2011, AMEC's Condition Assessment and Life Extension study agreed with the 2003 TOOP (HSB) report to extend the major overhaul schedule for the turbine to the nine year frequency but recommended that overhauls on the generator revert back to the six year interval.

3.2.6 Maintenance or Support Arrangements

All major turbine generator overhauls have been performed by an OEM. Prior to 2011, General Electric had been contracted by Hydro under a maintenance services agreement to perform all major and minor overhauls on the Holyrood turbine generator units. In 2011, Hydro retendered its requirement for another three year period. Plant personnel assist the OEM when required, overs the work protection application and provide overall management and liaison for the overhaul work.

3.2.7 Maintenance History

The only maintenance cost specifically identified for Holyrood Unit 2 turbine generator in the last five years is for the valve overhaul at a cost of $1,003,000.

3.2.8 Historical Information

As noted previously, since 1969, major overhauls of Unit 2 turbine, generator and auxiliaries have been performed on a frequency that matched industry standards ranging from a one year frequency in 1969 to a six year frequency prior to 2003. Valve overhauls have taken place on a three year frequency, one of which is typically included in the six year major overhaul schedule. Table 4 details costs incurred for major overhauls on all units since 1992. Note that the $ 3,297,000 cost of Unit 3 in 2007 was escalated due to extra repairs noted by General Electric in their 2001 overhaul report. The primary cause was exfoliation carry-over from the power boiler.

Table 4: Maintenance History All Units

Year	Unit	Type of Overhaul	Costs ($000)
2007	3	Major	3,297
2005	2	Major	2,609
2003	1	Major	2,404
2001	3	Major	2,381
1999	2	Major	1,849
1997	1	Major	1,600
1994	3	Major	1,262
1993	2	Major	1,287
1992	1	Major	559

A major overhaul on Unit 1 was approved by Order No. P.U.5(2012) as part of the 2012 Capital Budget for $4.2 million. The total amount spent was $4.0 million. The estimate for Unit 2 is greater than $5 million due to a 20 percent contingency and an increase in contract costs.

3.2.9 Anticipated Useful Life

In the 2010 Holyrood Condition Assessment, AMEC concluded that Unit 2 turbine has a reliable remaining life in the order of twenty years (to 2030), provided that sufficient inspection and testing is performed during the 2014 major overhaul. AMEC also concluded that Unit 2 generator has a reliable remaining life in the order of five years (to 2015) due to the condition of the stator windings. In addition during the Unit 1 Overhaul in 2012, Alstom performed Re-current Surge Oscillograph (RSO) testing of the Unit 1 and Unit 2 generator field windings with favourable test results. For Unit 2, the measurements recorded showed no indications of any inter turn faults in the windings. Replacement of the stator windings will be required to extend the generator life beyond that date. The Life cycle curves for Unit 2 turbine and generator (as presented in the AMEC report) are illustrated in figures 5 and 6 below. These curves have a plot of current and projected operating hours on the Y-axis and calendar years on the X-axis. The vertical lines represent different nominal age limits for various components and the horizontal lines represent a range of practical operating-hour life limits based on historical information and expert opinions. The risk boxes provide an indication of potential issues either from an age or operating-hour perspective. The two early risk areas for the turbine are the high pressure and intermediate pressure valves beyond 2010 and the low pressure turbine beyond 2015. The two risk areas for the generator are the stator winding beyond 2015 and the rotor winding and cores beyond 2020. The major overhaul scheduled for 2014 will extend the turbine remaining life to the desired 2020 end of life (EOL) date.

3.3 Forecast Customer Growth

This project is being completed strictly to maintain Unit one turbine generator in optimal condition to provide safe, least-cost, reliable electrical service to Hydro's existing customers. Forecast customer growth is not a consideration for this project.

3.4 Development of Alternatives

There are no alternatives to this project other than to delay the major overhaul which based on the manufacturers' (GE) reports, independent expert reviews, and operations experience would not be acceptable.

3.5 Evaluation of Alternatives

As there are no alternative to this project, no evaluation is required. A net present value calculation was not performed as there are no viable alternatives to performing an overhaul. As this project does not involve new generation sources, a levelized cost of energy analysis is not applicable.

3.5.1 Energy Efficiency Benefits

This project will not provide any energy efficiency benefits other than to restore the turbine generator its optimal performance condition.

3.5.2 Economic Analysis

A cost benefit analysis is not required for this project. There are no alternatives to this project other than to delay the major overhaul which based on the manufacturers' (GE) reports, independent expert reviews, and operations experience would not be acceptable.

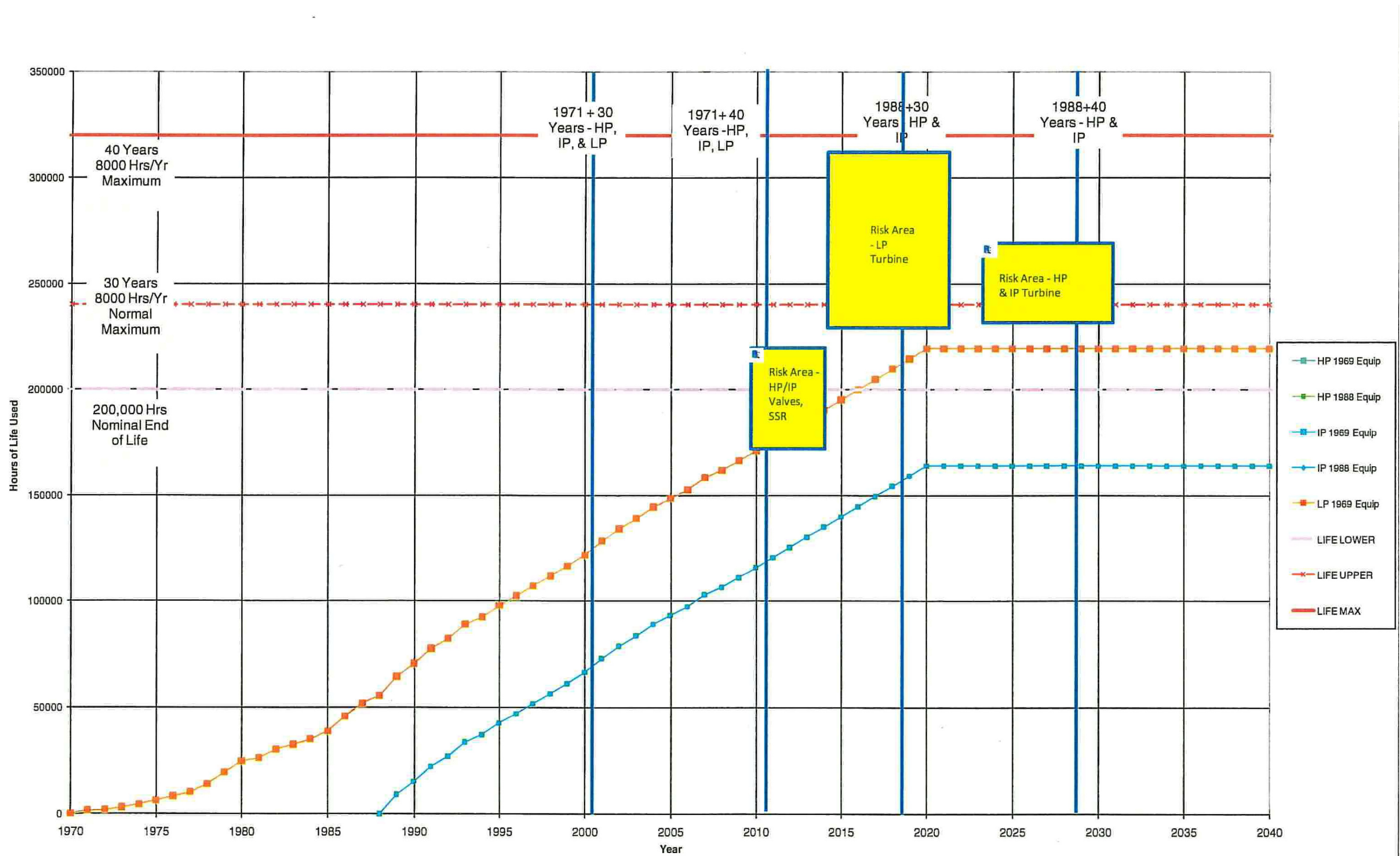


Figure 5: Unit 2 Turbine Life Cycle Curves

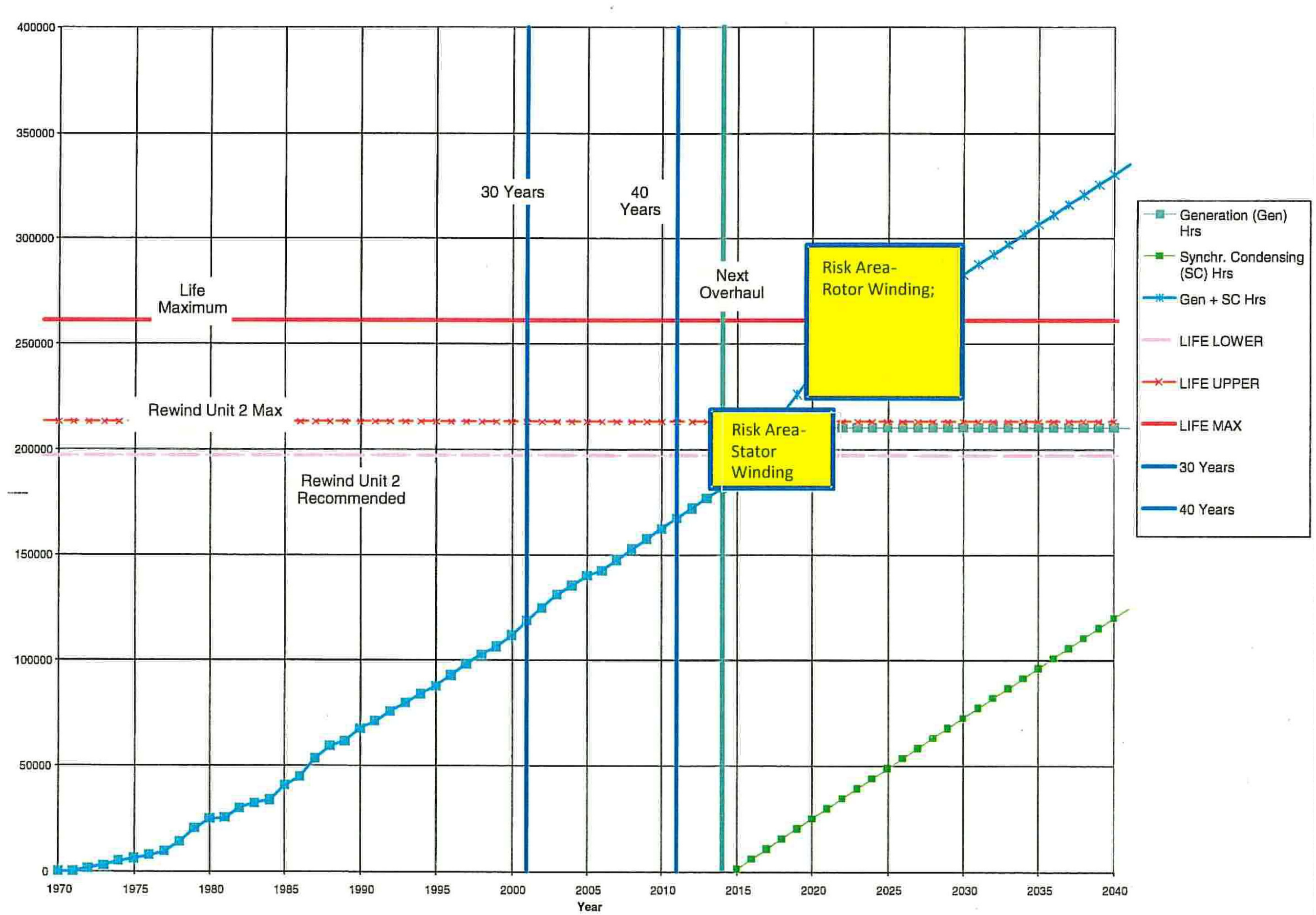


Figure 6: Unit 2 Generator Life Cycle Curve

4 CONCLUSION

This project is justified on the requirement to maintain the generating equipment in its optimal operating condition for Hydro to provide safe, least-cost, reliable electrical service to its customers. The purpose of the major overhaul is to return the turbine, generator and auxiliary systems to design specifications such that they can perform safely, efficiently, and reliably to meet system demands until the next major overhaul. It will also identify any unusual findings (internally or externally) that if not corrected or controlled could lead to premature failure of the equipment.

There is a significant risk involved if the turbine, generator or any of the auxiliary systems should fail during periods when its generation is required.

4.1 Budget Estimate

The budget estimate for the project is $5,147.0 million. The budget estimate is shown in Table 5.

Table 5: Budget Estimate

Project Cost: ($ x1,000)	**2014**		**Beyond**	**Total**
Material Supply	475.0	0.0	0.0	475.0
Labour	350.0	0.0	0.0	350.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	3,250.0	0.0	0.0	3,250.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	257.0	0.0	0.0	257.0
Contingency	815.0	0.0	0.0	815.0
TOTAL	**5,147.0**	**0.0**	**0.0**	**5,147.0**

4.2 Project Schedule

The anticipated project schedule is shown in Table 6.

Table 6: Project Schedule

Activity	Milestone
Pre-shutdown checks	May 2014
Mobilize	June 2014
Dismantle turbine, generator, valves, and auxiliary equipment	June/July 2014
Equipment inspection	June/July 2014
Equipment repairs	July/August 2014
Assemble turbine, generator, valves and auxiliary equipment	August 2014
Operational checks	August 2014
Demobilize	September 2014

APPENDIX A

General Electric Major Overhaul Report
FRS Number 20350952
Unit 2 Steam Turbine Inspection Report
May – September 2005

JOB SUMMARY

This report covers a major inspection of steam turbine 940311 and generator 980486. The inspection was conducted over 12 weeks on a two shift basis working 10 hours per day, 5 days per week. There were some exceptions to this where nightshift was discontinued for 3 weeks and some work was performed on weekends. The equipment overhauled included: High Pressure, Reheat and Low Pressure turbine sections, Generator inspection with rewedge, Main Stop Valve (1), Upper and Lower Turbine Control Valves (6), Combined Reheat Valves (2), Extraction Non-Return Valves (7), Emergency Blowdown Valve (1), Steam Seal Regulator (1), Various lube and seal oil pumps.

General Electric provided project management and technical direction for the inspection. GE Service Center technicians performed all diaphragm repairs and generator wedging services on site. Craft Labour was provided by GETSCO. Machine shop services were provided by TRT Services for on site and local service and by GE for specialty service and parts. Blast Cleaning service was provided by ARCO Enterprises. NDT services were supplied by Aitec through Newfoundland & Labrador Hydro.

RECOMMENDATIONS

SHOULD BE DONE ON A REGULAR MAINTENANCE SCHEDULE...

1. Piping, Oil; Piping;

It took 4 additional days to flush the hydrogen seal oil supply that it did to flush the bearing oil supply. The seal oil supply lines should be flushed on more frequently, such as at valve outages which occur every three years.

RECOMMENDATIONS

SHOULD BE DONE AT THE NEXT OUTAGE...

1. Valve, Main Stop; Assembly; cover,PSH

It is recommended to have a valve cover 196C7431P0001 in stock for the next outage. The peening lips have been exhausted.

2. Valve, Combined Reheat; Assembly; cover,psh,stem

The reheat stop valve caps have had the peening lips exhausted and should be replaced at the next outage. Cap Part # 100A478P0001 quantity 2.

3. Turning Gear; Clutch; 2shaft,2shaft2,chain

At startup the turning gear drive clutch jaw teeth broke. The teeth on both the drive clutch and emergency governor stub shaft should be NDT'd at every major inspection for crack development.

4. Valve, Extr Non-Return; Body; 102

Inspect valve body BSV115 for cracks at the next inspection.

JOB SUMMARY

During this outage stator was found to be in bad shape. There was lots of oil in the winding. Wedges, ties, bars and connection ring hardware was found to be greasing. Generator field was found to have a low insulation resistance and PI was less than 1. Stator was rewedged with piggy back top ripple spring wedges. All existing slot couplers on the machine were saved during wedge removal. They were put back in their original locations during new wedge installation. Loose ties and hardware was repaired / tightened. Generator field was dried out by using a DC welder and injecting about 300 amps of current in the rotor winding. Distribution ring bolts and washers were found to be badly eroded and were removed for replacement. A bore pressure test at 80 psi was carried out and it passed.

RECOMMENDATIONS

SHOULD BE DONE IMMEDIATELY...

1. Field; Winding;

Rotor should be kept warm when ever the unit is shut down and hydrogen is removed from generator by putting heaters inside the stator.

GENERATOR FIELD

Field

Collector Distribution Rings:
Distribution ring hardware including bolts and lock plates were found to be badly corroded. They were cleaned.

Field

Winding:
A megger & polarization index (PI) test was performed to measure winding resistance over a period of ten minutes. Results showed an unacceptable PI index calculation. A PI of 0.9 was found. Megger readings were found to be in the range of 42 megohms that is considered to be low. A 400 amps DC welder was used to dry out the stator winding. Winding dry out process was started on July 19th. About 300 amps was used to dry out the winding. On July 21st a check of the winding insulation resistance was made and it showed winding insulation resistance improved but PI was still 1.05. On July 22nd insulation resistance and PI of the rotor winding was found to be in acceptable condition.

Rotor should be kept warm when ever the unit is shut down and hydrogen is removed from generator by putting heaters inside the stator.

GE Energy Services

RECOMMENDATIONS

SHOULD BE DONE AT THE NEXT OUTAGE...

1. Stator; Winding;

GE recommended AC hipot test voltage for this machine is 24 KV. In case customer decides to perform a DC hipot test then the recommended voltage for this machine is 40.8 KV. These values are based on suitability to service voltage for a reliable operation. A DC hipot test at 34 KV was carried out. Testing at this voltage does not give the level of confidence for reliable operation of the unit for long time. It is therefore recommended that a full AC hipot test at 24 KV AC be performed.

2. Stator; Winding;

Based on units past maintenance history it is quite immanent that condition of the winding and support hardware has deteriorated. Any maintenance that is being performed is to slow the further degradation process in short run. In the long run reliability of the unit is in question. It is therefore recommended that stator be rewound in near future.

3. Instrumentation; Rtd;

Hot and cold gas RTD's needs to be replaced.

APPENDIX B

Unit 2 Major Overhaul
Turbine Generator Standard Overhaul Work

Turbine Generator Major Overhaul

Standard Outage Work:

A. Generator

1.	Pre-shutdown Checks	(5 Days)
2.	Mobilize	(4 Days)
3.	Remove Lagging	(3 Days)
4.	Disassemble Generator	(15 Days)
5.	Inspection	(10 Days)
6.	Electrical Tests (Stator & Rotor)	(5 Days)
7.	Visual Inspection	(2 Days)
8.	Assemble Generator	(25 Days)
9.	Excitation Inspection	(3 Days)
10.	Assemble Lagging	(4 Days)
11.	Pre-start and Operational Checks	(5 Days)
12.	Demobilize	(5 Days)

B. Steam Turbine

1.	Pre-shutdown Checks	(5 Days)
2.	Mobilize	(6 Days)
3.	Remove Lagging	(5 Days)
3.	Disassemble Turbine (HP/IP/LP)	(20 Days)
4.	Disassemble Valves (Main Stop/Control, Reheat Stops/Intercepts & Non-Return Valves)	(20 Days)
5.	Bearing Inspection including Thrust	(5 Days)

B. Steam Turbine (cont'd)

6.	Turbine Controls (Actuators, Hydraulics)	(7 Days)
7.	Lube Oil System	(10 Days)
8.	Turning Gear	(6 Days)
9.	Steam Seal System	(5 Days)
10.	Turbine Supervisory Instrumentation	(6 Days)
11.	Assemble Turbine	(25 Days)
12.	Assemble Valves	(20 Days)
13.	Install Lagging	(6 Days)
14.	Pre-Start and Operational Checks	(5 Days)
15.	Demobilize	(6 Days)

APPENDIX C

Hartford Steam Boiler (HSB)
Turbine Outage Optimization Program (TOOP)

Newfoundland & Labrador Hydro Holyrood Station
Turbine Generator Unit 2

Executive Summary

Turbine Outage Optimization Program (TOOP) analyses were conducted on Newfoundland & Labrador Hydro's Holyrood Station Unit 2 turbine generator to determine the optimum interval of conducting major outages on this 1970 vintage General Electric, 175 MW unit. The unit was last overhauled in July-November 1999. Since that time, the unit has accumulated approximately 26,341 total equivalent operating hours (EOH). The TOOP analysis results have indicated the following:

- ***High Pressure (HP) Turbine*** - This turbine is average or median in risk when compared to other industry HP turbines analyzed by TOOP. Currently, the primary risk drivers are: erosion of diaphragms, impulse wheel, and blade foils, shrouds, and tenons; foreign object damage (FOD) to diaphragms, impulse wheel, blade foils and shrouds; rubbing/distortion of tenons; and fatigue cracking of disc steeples and discs. Based on the operating profile for the unit, this turbine would be expected to run to **48,038 EOH** or approximately **8.8 years** between outages. However, given the past FOD/erosion damage to stages in the HP and IP turbines, problems with control valve wear and alignment, and the nozzle block austenitic ring problems found with Unit 1 at last overhaul, the currently planned overhaul of the HP in 2005 should be conducted. After review/repair of residual flowpath damage, the 8.8 years would apply to subsequent overhauls.
- ***Intermediate Pressure (IP) Turbine*** - This turbine is average in risk when compared to other industry IP turbines analyzed by TOOP. The primary risk drivers are: erosion of diaphragms, shroulds, and tenons; FOD damage to blade foils and tenons; rubbing/distortion to blade shrouds and tenons; and fatigue cracks to disk steeples and blade roots. Based on the operating profile for the unit, it would be expected this turbine would be expected to run to **49,565 EOH** or approximately **9.1 years** between outages. As discussed for the HP turbine, the next outage for the IP turbine should be in 2005 as currently planned and any residual damage assessed and repaired. Subsequent overhauls would be at the 9.1 years interval.
- ***Low Pressure (LP) Turbine*** - The turbine is considered to be average to low in risk when compared to all other LP turbines analyzed by TOOP as well as by OEM and by size class. The primary risk drivers are: stress corrosion cracking (SCC) of discs, disc steeples, rotor; and FOD and erosion damage to blade foils and shrouds. Based on the operating profile for the unit, it is expected that the LP turbine can be run to **40,472 EOH** or approximately **7.4 years** between outages. If continuous Cation conductivity monitoring is added to the main steam inlet to the turbine, the LP turbine can be run to **52,619 EOH** or approximately **9.7 years** between outages. This interval would apply after review/repair of residual damage in the LP turbine at the currently planned 2005 outage.
- ***Generator*** - The generator is considered to be very low in risk when compared to all other generators analyzed by TOOP as well as by OEM and by size class. The primary risk drivers are: electrical breakdown of rotor and stator windings; fretting of retaining rings, the rotor, and rotor core/teeth; and overload of the retaining rings. Based on the operating profile, it is expected that the generator can be run to **53,006 EOH** or approximately **9.7 years** between outages. As with the turbine sections, there are areas that need to be addressed at the 2005 outage including wedge looseness, hydrogen seal leakage, and stator greasing.

In summary, if past problems in this unit are corrected at the 2005 outage, the failure mechanisms acting on the various sections of this unit should be slow acting with no accelerating wear or damage that would preclude running the unit longer between outages (i.e., going from 6 years today to 9 years for subsequent outages). This increase in major outage interval is also the result of the investment the plant has made in updated controls, operating procedures, and monitoring. To provide continued assurance of achieving this interval, there are several refinements which should be implemented with regards to inspection, operation, and monitoring to enhance the ability to detect changes in the health of the machine for preventing or minimizing any machine damage. These items are discussed in the Recommendations Section of this report.

APPENDIX D

AMEC
Condition Assessment
and
Life Assessment Study

13. Replace the Stage 2 diesel generator in or about 2014.
14. Replace the Stage 1 air compressors that are near their end of life in 2014 and 2015.

15.4 Unit 1

1. Undertake a generator stator rewind as part of the 2012 generator overhaul. Initiate planning early in 2011. Undertake the generator actions list in 2010 and 2011.
2. Address issues and action with steam turbine, including wok on main and intercept valve issues, stud bolt issues, and turning gear issues as per sections 8, 9, and 10 of this report.
3. Refurbish stack breeching per current plans.

Where economically feasible, assess and implement those efficiency improvement options for the facility which have short term economic benefits, e.g.:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency.

b) Repair of previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs.

15.5 Unit 2

1. Undertake a generator stator rewind as part of 2014 generator overhaul. Initiate pre-work early in 2013. Undertake early generator actions list in 2011.
2. Address issues and actions with steam turbine, including work on main and intercept valve issues, stud bolt issues, and turning gear issues.
3. Refurbish stack breeching per current plans.

Where economically feasible, assess and implement those efficiency improvement options for the facility which have short term economic benefits, e.g.:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency.

b) Repair of previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs.

15.6 Unit 3

1. Undertake a generator rotor rewind at the next generator overhaul in 2016 or, with some additional reliability risk, between 2020 and 2022 subject to the findings of the 2016 inspection.
2. Address issues and actions with the steam turbine, including work on main and intercept valve issues, and stud bolt issues.
3. Assess the cost-benefit of replacing the existing steam turbine mechanical governor system in 2011 for implementation during the 2013 minor valve outage.
4. Refurbish stack breeching per current plans.

14 CONCLUSIONS

The following major conclusions are based on the review of the condition assessment documentation in Sections 8 to 12 of this report. They are intended to highlight the key issues at a summary level.

14.1 Overall and Station Wide

1. Holyrood's overall condition is very good. Units 1, 2, and 3 are approximately 41, 40, and 31 years of age respectively. The units' operational ages for the majority of equipment and systems are actually 20, 19, and 16 years respectively, or even less when the typical operating load range of between 70 and 140 MW is considered.

2. Holyrood can, with modest additional refurbishment/investment, be expected to continue to provide reliable electricity generation service to the generation end dates of either 2015 or 2020.

3. Holyrood can, when its units are converted to synchronous condensing operation in or about 2014/2015, with additional life extension investment in the electrical portion of the facility, be expected to make an end date for synchronous condensing of 2041.

4. The Level 2 condition assessments identified in Chapters 8 to 11 and summarized in Chapter 12 are necessary to more accurately assess the ability of the identified systems to meet their respective remaining life requirements. The identified priorities may be useful in assigning funding.

5. The steam turbines are generally considered to be in good condition, with some specific issues identified in Chapters 8 to 10. Their condition supports an inspection/overhaul interval of 9 years supplemented with minor 3 year valve outages, subject to any unexpected changes in conditions found at each outage and in particular their next inspection/overhaul.

6. The generators are generally considered to be in moderately poor condition, particularly Units 1 and 2. Their specifics and suggested actions are identified in Chapters 8 to 10. The condition of all three generators, as well as industry experience and their importance for synchronous condensing to 2041, are not conducive with a nine year generator inspection interval. A six year cycle is more representative of their current condition.

7. The generator operating and monitoring conditions identified in Chapters 8 to 10, particularly those associated with hydrogen conditions and generator monitoring require review and action.

8. Detailed condition assessments of high pressure and temperature feedwater and steam lines, primarily main steam and hot reheat steam lines, on all units have not been carried out for some time and should be considered a very high priority safety and reliability due diligence task.

9. Some of Holyrood's large high pressure and temperature pipe hangers have not been checked and adjusted in some time. The hanger monitoring program appears to have been largely inactive in the last few years.

10. Steam side components of Holyrood's boilers are considered to have considerable remaining life, beyond that required to meet a 2020 end of generation service. A Level 2 condition assessment is necessary for the highest temperature and pressure headers identified in Chapters 8 to 10, as well as those parts not having the necessary inspection and condition assessment data to confirm their remaining life.

12. The diesel fire water pump is at end of life and requires replacement. The capacity requirement of the new fire protection system is higher than in the past due to recent expansion. The new pump, and possibly a new electric pump, needs to be capable of handling the additional requirement.

13. The Stage 2 diesel is original equipment at the end of life and needs to be replaced.

14. The Stage 1 air compressors are near end of life and need to be replaced in the next few years.

14.4 Unit 1

1. The generator stator winding is in poor condition. Its next overhaul is in 2012. It has a significant likelihood of encountering issues prior to 2021 when its next overhaul would currently be scheduled. Given an end date of 2041, a rewind in 2012 is recommended. A later date is likely to result in reliability degradation and higher potential for failure.

2. The steam turbine is in generally good condition and is expected to make the 2020 generation end date. It continues to have main and intercept valve issues, stud bolt issues, and turning gear issues. These should be examined further and/or addressed at the next 2012 major overhaul.

3. The boiler is generally in good shape, especially with the change in fuels. Some legacy effects of history of high sulphur, high vanadium oil use is likely to continue – tube leaks and thinness. Others such as economizer plugging, air preheater corrosion and plugging are expected to continue to diminish.

4. The stack breeching requires an upgrade. The steel casing and support structure has localized corrosion and the internal insulating liner has significant deterioration.

There are also options for improving the efficiency of the facility in the short term such as:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency; and

b) Repairing previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs

14.5 Unit 2

1. The generator stator winding is in poor condition. Its next overhaul is in 2014. It has a significant likelihood of encountering issues prior to 2023 when its next overhaul would currently be scheduled. Given an end date of 2041, a stator rewind in 2014 is recommended, subject to findings in 2012 on Unit 1.

2. The steam turbine is in generally good condition and is expected to make the 2020 generation end date. It continues to have main and intercept valve issues, stud bolt issues, and turning gear issues. These should be examined further and/or addressed at the next 2014 major overhaul.

3. The boiler is generally in good shape, especially with the change in fuels. Some legacy effects of history of high sulphur, high vanadium oil use is likely to continue – tube leaks and thinness. Others such as economizer plugging, air preheater corrosion and plugging are expected to continue to diminish.

4. The stack breeching requires an upgrade or replacement. The steel casing and support structure has localized corrosion and the internal insulating liner has significant deterioration.

There are also options for improving the efficiency of the facility in the short term such as:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency; and

b) Repairing previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs

14.6 Unit 3

1. The generator is in reasonable condition. Its next overhaul is in 2016. Nevertheless, it has a significant likelihood of encountering rotor winding issues prior to its next currently scheduled outage in 2025. Given an end date of 2041, a rotor rewind may be warranted in 2016 or earlier than 2025.

2. The steam turbine is in generally good condition and is expected to make the 2020 generation end date. It continues to have main and intercept valve issues, as well as stud bolt issues. Its mechanical governor system also experiences some control issues. These should be examined further and/or addressed at the next 2016 major overhaul.

3. The boiler is generally in good shape, especially with the change in fuels. Some legacy effects of history of high sulphur, high vanadium oil use is likely to continue – tube leaks and thinness. Others such as economizer plugging, air preheater corrosion and plugging are expected to continue to diminish.

4. The stack breeching requires an upgrade or replacement. The steel casing and support structure has localized corrosion and the internal insulating liner has significant deterioration.

5. The Unit 3 control room relay panels cannot accommodate the current and required wiring and need to be replaced for safety reasons.

6. When decoupled from the turbine, Unit 3 generator has no thrust bearing to address lateral movement during synchronous condensing operation and requires modification to reduce long term vibration and damage.

7. Unit 3 Exciter is considered at end of life and the entire system should be replaced.

14.7 Black Start Gas Turbine

1. The black start gas turbine is 42 years old, but with few operating hours and several thousand starts and stops.

2. The unit is experiencing significant reliability (starts/stops, operation) and safety problems.

3. The gearbox has been a source of oil leaks and fires, likely a seal issue that has existed for some time. As a result, recent fires have limited the unit's use.

4. The power turbine, gas turbine, gearbox, and generator are overdue for a major inspection/overhaul, based on recent boroscope and on-site power turbine inspections and industry practice.

5. The stack is badly corroded and appears to be leaking water into the back end of the gas turbine.

15 RECOMMENDATIONS

15.1 Overall and Station Wide

1. Implement the recommended Level 1 and 2 condition assessment tasks identified in Chapters 8 to 11 and summarized in Chapter 12, including augmented steam turbine and generator overhauls at their next normal overhaul date to the extent economically practical.

2. Retain the 9 year major inspection/overhaul interval and minor 3 year valve outage timing for the steam turbines, subject to any unexpected changes in conditions found at their inspection/overhauls and, in particular, at their next inspection/overhaul. Undertake the steam turbine pre-outage actions identified in Chapters 8 to 10.

3. Modify the generator inspection and overhaul interval back to every six years. Address the specific actions identified in Chapters 8 to 10, in particular those permitting better performance baselining in the balance of 2010 and 2011.

4. Perform in 2011 limited generator testing, with rotor in and on all units but particularly on Unit 1, to the extent safe and economically practical to obtain baseline data. Undertake work needed to scope out the details of the inspection/testing and stator rewind during the 2012 Unit 1 outage.

5. In 2011 and 2012, carry out a detailed condition assessment of high pressure and temperature feedwater and steam lines on all units as a very high priority safety and reliability due diligence task. Plan and implement an extensive high pressure and temperature pipe hanger inspection program as part of the plant's PM, safety, and reliability due diligence programs.

6. Carry out Level 2 inspections and testing in 2012, 2013, and 2014 for Units 1, 2, and 3 respectively on boiler components identified in Chapters 8 to 10.

7. Carry out Level 2 inspections and testing in 2012, 2013, and 2014 for Units 1, 2, and 3 respectively on high pressure heater components identified in Chapters 8 to 10.

8. Carry out Level 2 inspections and testing in 2012, 2013, and 2014 for Units 1, 2, and 3 respectively on deaerator components identified in Chapters 8 to 10.

9. Carry out Level 2 inspections and testing on low pressure heaters in 2011 for Units 1, 2, and 3.

10. Maintain existing programs for major equipment, pumps, and motor inspection scheduling and overall PM process.

11. Procure one spare 4 kV motor for each of the boiler feedwater pumps, the forced draft fans, condensate extraction pumps, and the cooling water pumps – primarily designed for Units 1 and 2, but with plans on how to use them with Unit 3 as necessary.

12. Develop and implement an optimized plan for station switchgear (all units, common facilities), primarily breakers and motor control centres, addressing a combination of extensive replacement and sparing to maintain station reliability without interrupting normal unit operation.

13. Inspect all condensate polishers in 2011. Replace Units 1 and 2 remaining enunciator panels (Unit 3 enunciator panel was replaced in 2007). Assess the cost-benefit of replacing polisher control panels on all units considered obsolete in light of generation end of service timeline.