AN APPLICATION TO THE
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2013 CAPITAL BUDGET APPLICATION

VOLUME I

August 2012

newfoundland labrador hydro
a nalcor energy company

newfoundland labrador hydro
a nalcor energy company

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August 8, 2012

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 – 2013 Capital Budget Application

Please find enclosed ten copies of Hydro's 2013 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 $66.1 million in capital expenditures. Also, Hydro is seeking approval of its 2011 rate base in the amount of $1,493,218,000.

Please note that this filing is complete, except for Appendix B of the Wood Pole Line Management Proposal that will be filed by the end of this month.

.../2

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

Todd Newhook,
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

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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 2013 capital budget pursuant to s.41(1) of the Act; (2) its 2013 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 2013 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 2011.

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 2013 Capital Budget in the amount of approximately $66.1 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 2013 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 2013 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 2013 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 2013 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 is a list of the multi-year projects that have expenditures in 2013.

8. Section G to this Application summarizes Hydro's proposed 2013 capital projects by definitions, by classification and by materiality as required by the Capital Budget Application Guidelines.

9. Section H contains no new leases proposed for 2013 in excess of $5,000 per year.

10. Section I to this Application is a Schedule of Hydro's Capital Expenditures for the period 2008 to 2017.

11. Section J to this Application is a report on the status of the 2012 capital expenditures including those approved by Orders No. P.U. 38 (2010), projects

under $50,000 not included in these Orders, and the 2011 capital expenditures carried forward to 2012.

12. Section K 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).

13. Section L to this Application shows Hydro's actual average rate base for 2011 of $1,493,218,000.

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

15. The proposed capital expenditures for 2013 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.

16. The Applicant has estimated the total of contributions in aid of construction for 2013 to be approximately $400,000. The information contained in the 2012 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.

17. 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 2013 Capital Budget as set out in Section A hereto, pursuant to section 41 (1) of the Act;

(2) Approving 2013 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 2013 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 2011 in the amount of $1,493,218,000 pursuant to section 78 of the Act.

DATED at St. John's, Newfoundland, this 8 day of August, 2012.

NEWFOUNDLAND AND LABRADOR HYDRO

Todd Newhook
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 2013 capital budget pursuant to s.41(1) of the Act; (2) its 2013 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 2013 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 2011.

AFFIDAVIT

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

1. I am Vice-President, Project Execution and Technical Services, on behalf of 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 8th day of August, 2012, before me:

Barrister – Newfoundland and Labrador

John MacIsaac

A Report to the

Board of Commissioners of Public Utilities

2013 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 renew, expand and modify 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: current planning for a sanction decision on Phase 1 of the Lower Churchill Project, the shift in load centers caused by such events as the closure of a paper mill, the expected startup of a nickel processing facility, and continued load growth on the Avalon Peninsula. This Overview will discuss the projects proposed for 2013. Discussion of the five year plan is contained in the section entitled "2013 Capital Plan".

2013 PLAN CONSIDERATIONS

Maintaining Hydro's systems in reliable operating condition is accomplished through a combination of planned maintenance, renewal and rehabilitation of existing assets, and replacement of assets which have reached the end of their useful lives and are worn beyond the point of economic repair. Assets may also be replaced by ones which will result in lower life cycle costs or improved operational characteristics (repair, renewal, and replacement within the long term Asset Management Strategy).

The majority of Hydro's installed assets are approximately 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 portion contained in this and previous capital budget applications appropriately linked the age and condition of Hydro's assets that are approaching full life cycle and require renewal or replacement. The quantity and value of these sustaining capital proposals can be expected to continue to be a major factor 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 efficient operation of assets.

During 2007, Hydro initiated an internal review of its major assets to develop a long term asset refurbishment and replacement plan. This process resulted in the production of a 20-Year Capital Plan which identifies the major capital expenditures which will be required to maintain the existing assets in safe, reliable operating condition to serve our customers. The plan takes into consideration the condition of assets, reliability criteria and system load growth. On an ongoing basis, Hydro has continued to strategically adjust the 20-Year Plan based on the updated inputs of condition assessments and system load requirements. The plan continues to be a living document which will be reviewed and revised annually as new information about the condition of Hydro's assets and the operating demands placed on them becomes available or as planning and operating criteria evolve over time.

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.

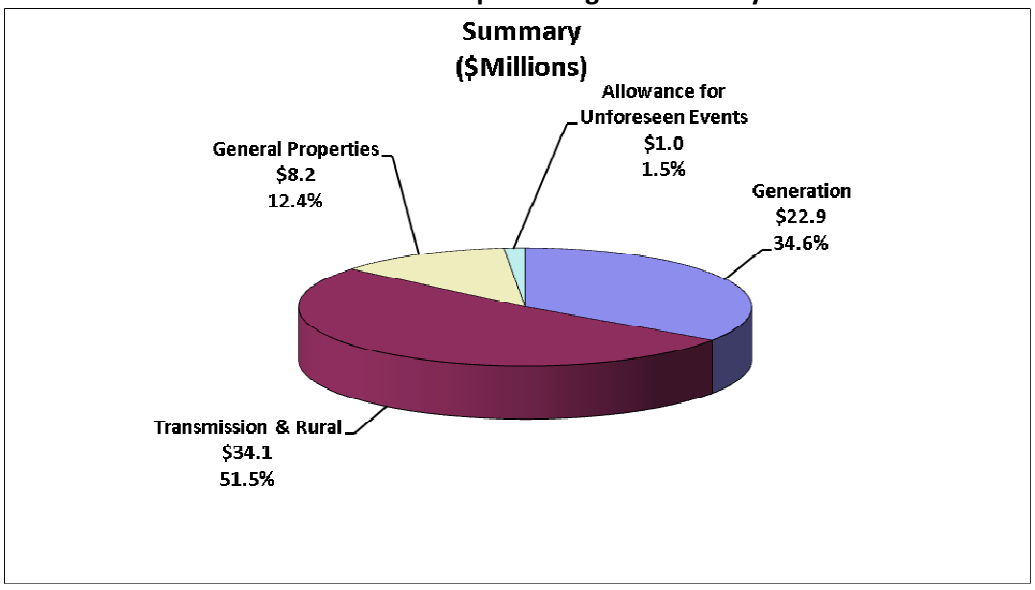
There are three broad categories of replacement criteria:

- 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.

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.

Chart 1 shows the breakdown of the 2013 Capital Budget by major classification. The classifications, other than the Allowance for Unforeseen Events, which represents approximately 1.5 percent of the 2013 budget, are then discussed further.

Chart 1: 2013 Capital Budget - Summary

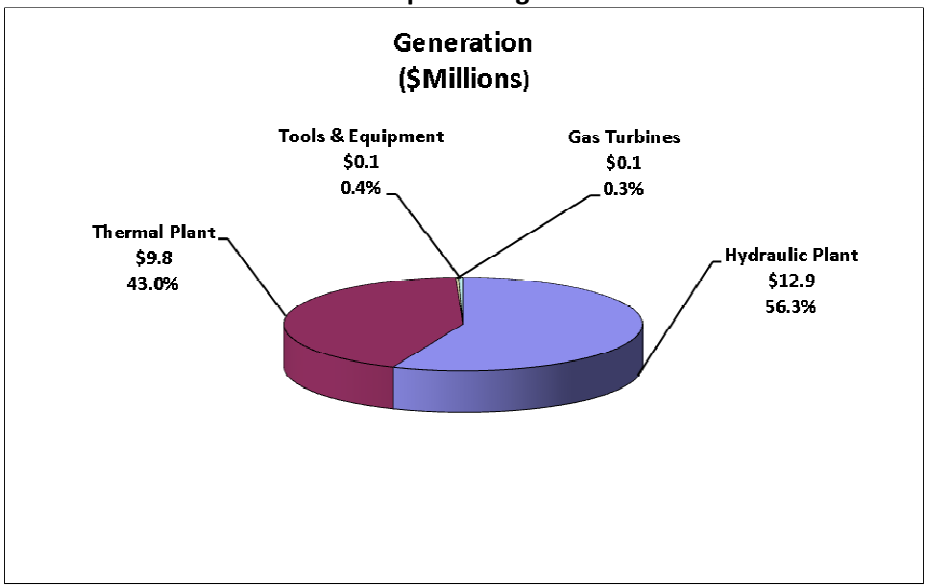


GENERATION ASSETS

On the Island Interconnected System, power and energy are provided by Hydro through a mix of hydroelectric and fossil-fired generation, as well as some 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 2011, the Island Interconnected production facilities consisted of 15 generating stations varying in size from 360 kW to 592 MW, with a total 1,517 MW of net capacity. Additionally, tools and equipment are required for the operating and maintenance of these generation assets.

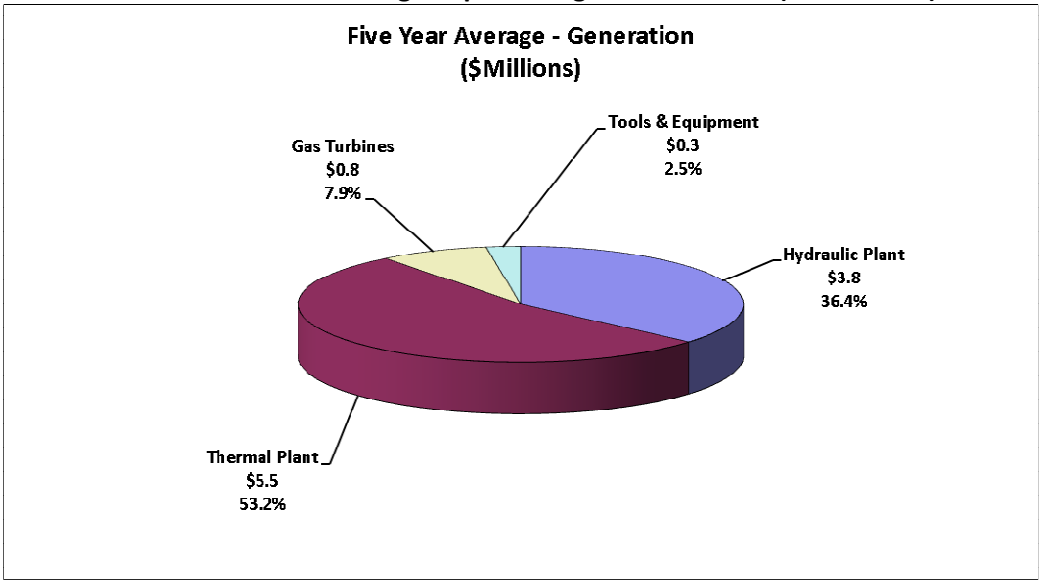
The division of the 2013 Capital Budget for Island Interconnected generation among Hydraulic Plant, Thermal Plant, Gas Turbines and Tools and Equipment expenditures is shown in Chart 2.

Chart 2: 2013 Capital Budget – Generation



The five-year (2007 to 2011) average capital expenditures are shown in Chart 3. For 2013, Thermal Plant represents 43.0 percent of the Island Interconnected generation capital budget, compared with an average of 53.2 percent over the past five years. Thermal plants continue to require major capital expenditures as the majority of the equipment and systems have reached the age of maturity and significant expenditures are required to ensure that these important generating assets can continue to operate reliably.

Chart 3: Five-Year Average Capital Budget - Generation (2007 - 2011)



Hydraulic Plant

Hydro's hydraulic generating plants range from nine years to forty-five years of age. Capital expenditures are required to ensure reliability and to maximize the potential useful operating lives of these assets, of which many components have reached or are coming to the end of their expected service lives. This application includes proposals for the rewind of the stator on Unit 1 at Bay d'Espoir and for the refurbishment of the Burnt Dam Spillway. Rewinds are a major expense and occur for generators typically at 30 to 40 year intervals depending on condition and basic design. When required, they typically result in significant increases in the capital expenditures plan for sustaining capital expense.

Thermal Plant

The three units of the Holyrood Thermal Generating Station have now reached or exceeded their generally expected service life of 30 years. Condition assessment and selective life extension will permit them to operate reliably until 2020. 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 proposed development of Muskrat Falls with a high voltage direct current transmission link to the Island. Should that project be determined to be the least cost option for consumers and be sanctioned, Holyrood will remain a critically important facility during construction. 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 as a synchronous condensing facility. Additionally, the plant will function as a standby facility during the early years of operation of the Muskrat Falls Generating Plant and the HVDC link between Labrador and Newfoundland, until 2020, when it will be 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 career until it reaches maturity and then the plant is operated as a peaking or standby facility in its final years, thus operating at a very low capacity factor, often less than 10 percent. This thermal plant has passed the age at which other utilities have performed condition assessment and life extension studies and have either retired their facilities or have initiated major life extension projects. However, until the Muskrat Falls Generating Plant is sanctioned and completed and power is brought to the Island Interconnected System via a HVDC link, the Holyrood plant must continue to operate at, or near, its historical average capacity factor of 40 percent to 50 percent annually and higher through the critical winter period. The closure of the pulp mills has reduced demand on Holyrood in the short term, however, demand is already climbing back to historical levels. When the nickel processing plant being constructed at Long Harbour begins operation in 2012, 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 replace 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.

The Holyrood Projects for 2013 are listed below and are further described in the section entitled “2013 Capital Plan”:

- Upgrade Governor Controls on Units 1 and 2
- Upgrade Vibration Monitoring Equipment Units 1, 2, and 3
- Upgrade Fuel Oil Day Tank
- Install Unit 3 Cold Reheat Condensate Drains and High Pressure Heater Trip Level
- Install Fire Protection Upgrades
- Replace Condensate Polisher Annunciator Panels Units 1 and 2
- Install Backup System for Raw Water Supply and Clarifier

- Install Variable Frequency Drives on Forced Draft Fans
- Complete Condition Assessment Phase 2 (Year 2)
- Overhaul Unit 2 Extraction Pump South
- Overhaul Unit 3 Turbine Valves
- Overhaul Unit 3 Boiler Feed Pump West

Gas Turbines

Hydro's gas turbine plants at Stephenville, Hardwoods and Holyrood 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 manufacturer of the gas generators (jet engines) at the Stephenville and Hardwoods plants has declared them obsolete and the supply of spare parts, 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. Gas turbines will continue to play an important role within Hydro's integrated generation plan in both isolated Island and Labrador Infeed scenarios. In late 2011, the Stephenville gas turbine alternator stator winding failed in service and a rewind has been proposed. In the process of performing the assessment of the Stephenville gas turbine, which is similar to the one at Hardwoods, insight was gained as to the likely condition of the Hardwoods components. This has informed Hydro as to the aspects and components which will require refurbishment in the next few years.

TRANSMISSION AND RURAL OPERATIONS ASSETS

Hydro owns and operates thermal generation with 39 MW of net capacity on the Labrador Interconnected system and owns and operates diesel generation assets with 31 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 53 high voltage terminal stations operating at voltages of 230, 138 and 69/66 kV. On the Labrador Interconnected system, Hydro owns and maintains 269 km 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 km 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 guidelines, 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 Labrador East and West, the highest customer growth areas in Hydro's distribution system.

The division of the 2013 Capital Budget for Transmission and Rural Operations is shown in Chart 4. These breakdowns are generally consistent with the five-year (2007-2011) average as shown in Chart 5 below. The Labrador City voltage conversion project is a very large multi year project involving the construction of new terminal stations and the reconfiguration of the entire Labrador City system, which has a significant effect on the historical pattern of expenditures during its implementation.

Chart 4: 2013 Capital Budget - Transmission and Rural Operations

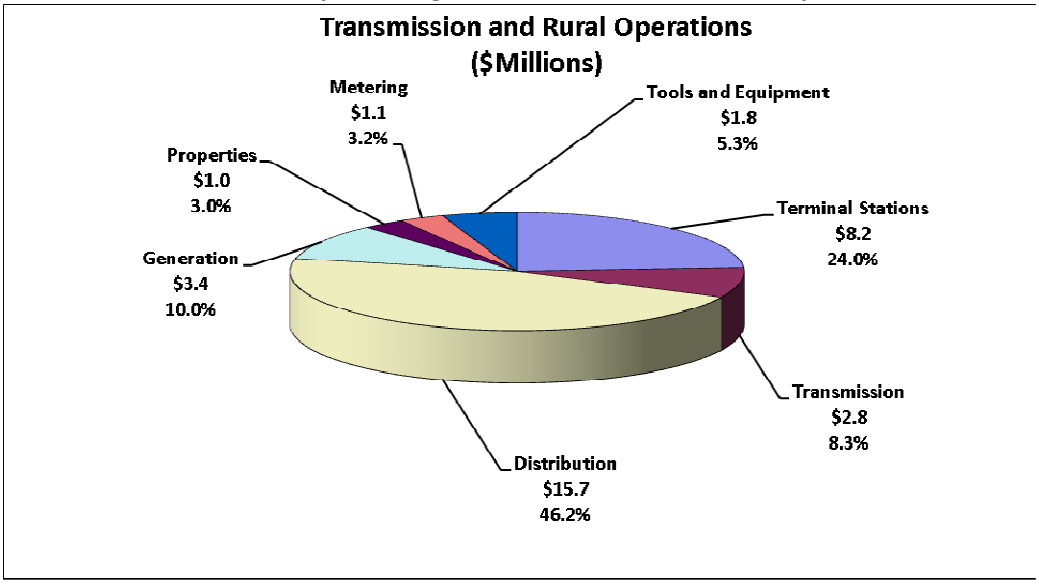
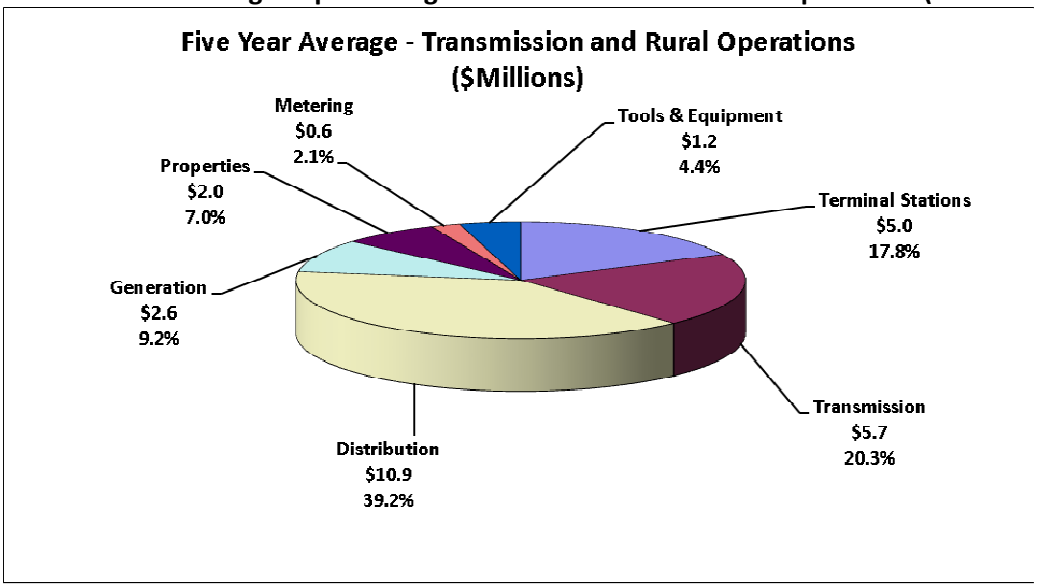


Chart 5: Five-Year Average Capital Budget – Transmission and Rural Operations (2007 - 2011)



Terminal Stations and Transmission

Many of Hydro's transmission lines 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.

The terminal station and transmission proposals for 2013 include:

- Upgrading power transformers;
- Replacing insulators at various sites;
- Replacing surge arrestors at various sites;
- Replacing instrument transformers;
- Upgrading circuit breakers;
- Replacing disconnect switches at various sites;
- Replace 230 kV breaker controls at various sites;
- Performing grounding upgrades;
- Replacing compressed air piping and installing a dew point monitor at various sites;
- Installing an Online Vibration Monitoring System at the Corner Brook Frequency Converter;
- Upgrading the terminal station at Wiltondale;
- Replacing Optimho relays on TL242 (Holyrood to Hardwoods); and

- Installing transformer fans at Conne River.

Distribution and Diesel Generation

The 21 remote electrical systems along the coasts of Labrador and the Island are served by diesel generation. Providing service to customers in these communities requires that the fuel storage, diesel generating units and distribution systems all be kept in safe, reliable and environmentally responsible working order. This application also includes projects specifically directed towards meeting load growth requirements, such as generation additions in Hopedale, L'Anse au Loup, and Nain.

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 lines. This application also includes projects to provide distribution upgrades and service extensions to new customers throughout Hydro's service area.

GENERAL PROPERTIES ASSETS

The General Properties category 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 2013 and the previous five year average, respectively.

Chart 6: 2013 Capital Budget - General Properties

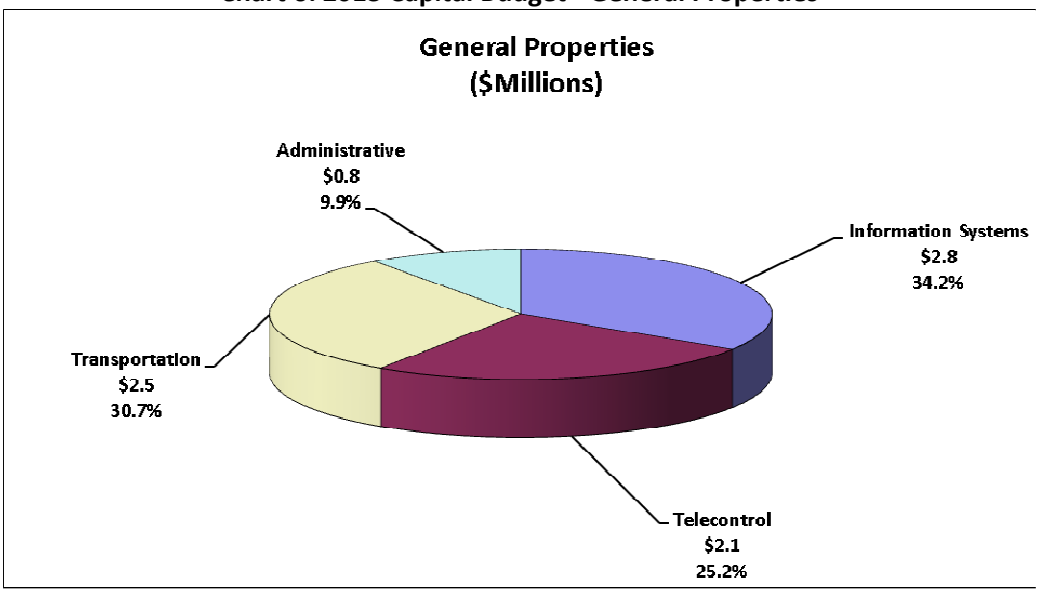
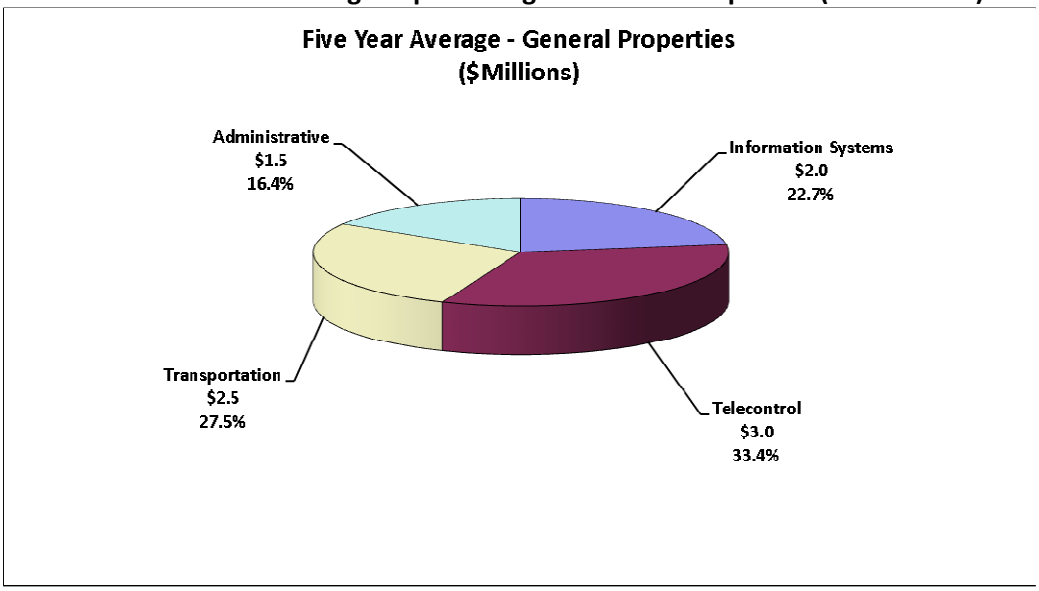


Chart 7: Five-Year Average Capital Budget - General Properties (2007 – 2011)



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 and among its employees, many of whom work in remote locations. The 2013 capital budget proposals in this category include infrastructure replacements and, in some cases, ongoing replacement or refurbishment programs, for such items as:

- Radomes;
- Network communications equipment; and
- Battery banks and battery chargers.

General

Project Prioritization and Ranking

An overall ranking of 2013 projects is attached as Appendix A.

Project Contingency

Within the cost estimates for the projects proposed, the estimated contingency has been set at 20%, where appropriate, in alignment with the class of estimate being delivered. This is consistent with the Association for Advancement of Cost Engineering (AACE) estimate classification system.

Project Front End Engineering Costs

Front End Engineering Costs - 2012

Ensuring that the preliminary engineering work is advanced during the capital budget preparation process enables more appropriate estimates and work plans. Many projects in Hydro's 2013 capital budget include costs that were incurred related to Phase 1 or front end engineering and design (FEED) work that were incurred in 2012 in advance of the capital budget submission.

Phase 1 engineering includes all of the engineering design for an engineering project. It starts from the project brief and works through to the visualization, conceptualization and definition stages. It involves translating the project into a conceptual design and then a basic design. In order to properly prepare capital budget information, engineers must begin the front end engineering and design (FEED) phase of the projects.

These costs are considered to be part of the initial costs associated with bringing an asset to its intended location and condition and can be capitalized under International Financial Reporting Standards IAS 16 Property, Plant and Equipment. While some high level of engineering work had been completed in the past prior to the filing of the capital budget submission, the Phase 1 engineering was often delayed until after the approval process by the Board. As a result, the necessary information for the preparation of a strong cost estimate for a project was received after the filing of the capital budget. This timing of the development of this information often resulted in revisions being made to the project plans and budget estimates.

Hydro has advanced the Phase 1 activities in 2012 to improve the quality of its 2013 capital budget submission. Therefore, Hydro's 2013 capital projects include its Phase 1 engineering costs incurred in 2012 in association with those 2013 capital projects and Hydro proposes that the inclusion of those costs be approved.

Costs associated with compiling and reporting the capital budget are not directly attributable to bringing an asset into operation and as such would be considered an operating expense. Hydro has included Phase 1 costs in its capital budget proposals only in those cases in which the Phase 1 costs exceed $1,000 in that project.

Of course, should the Board subsequently disallow or reject any of the capital projects for which these costs relate, the costs associated with the Phase 1 engineering work will be expensed to operating costs immediately.

A summary of the Phase 1 engineering costs incurred in 2012 but included in the 2013 capital budget submission is included in Table 1 below.

Front End Engineering Costs - 2013

The 2013 Capital budget includes a proposed project designated to capitalize the Front End Engineering and Design work that will be completed in 2013 for the 2014 capital budget. This work will be carried out between January and June of 2013 and is intended to provide a more appropriate level of engineering to prepare the budget estimates. As is the case with the proposal to include capital costs incurred in 2012 for the 2013 budget process, should any of the projects be disallowed or rejected by the Board, Hydro would expense the corresponding amounts immediately.

Table 1. Front End Engineering Design 2012 Costs

Front End Engineering Design Incurred in 2012 Pertaining to 2013 Capital Budget Proposals	
July 2012	
Project Description	**Costs ($000)**
Replace Battery Banks and Chargers - Various Sites	**3.7**
Replace MDR4000 Microwave Radio (West) - Various Sites	**3.0**
Replace Radomes - Various Sites	**2.6**
Replace Network Communications Equipment - Various Sites	**2.4**
Replace Telephone System - St. Anthony	**2.5**
Install Automated Fuel Monitoring System - Upper Salmon	**1.9**
Replace Stator Windings Unit 1 - Bay d'Espoir	**8.1**
Automate Generator Deluge Systems Units 5 and 6 - Bay d'Espoir	**3.3**
Upgrade By Pass Valves Units 3 and 4 - Bay d'Espoir	**1.9**
Upgrade Generator Bearings- Bay d'Espoir	**4.3**
Upgrade Burnt Dam Spillway - Bay d'Espoir	**13.2**
Purchase Low Pressure Screw Compressor Set - Bay d'Espoir	**2.6**
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir	**3.6**
Replace Fall Arrest System on Surge Tank 2 - Bay d'Espoir	**3.0**
Replace Cooling Water Pumps - Bay d'Espoir	**1.8**
Upgrade Water Flow Control Structure RR Pond - Granite Canal	**4.0**
Replace Microscada Computers - Granite Canal	**7.8**
Install Cold-Rehead Condensate Drains and High Pressure Heater Trip Level Unit 3 – Holyrood	**7.5**
Upgrade Governor Controls on Units 1 and 2 - Holyrood	**4.9**
Install Fire Protection Upgrades - Holyrood	**5.5**
Upgrade Fuel Oil Day Tank - Holyrood	**10.7**
Install Variable Frequency Drives on Forced Draft Fans - Holyrood	**11.0**
Upgrade Vibration Monitoring Equipment - Holyrood	**3.9**
Replace Condensate Polisher Annunicator Panels - Holyrood	**3.5**
Remove Safety Hazards - Various Sites	**2.9**
Upgrade Circuit Breakers - Various Sites	**9.9**
Replace Surge Arrestors - Various Sites	**1.7**
Replace Instrument Transformers - Various Sites	**6.4**
Upgrade Power Transformers - Various Sites	**7.1**
Replace Disconnects - Various Sites	**10.4**
Replace Compressed Air Systems - Sunnyside and Stoney Brook	**15.0**
Replace Insulators - Various Sites	**2.2**

Front End Engineering Design Incurred in 2012 Pertaining to 2013 Capital Budget Proposals	
July 2012	
Project Description	**Costs ($000)**
Replace Optimho Relays on TL242 - Holyrood to Hardwoods	**2.4**
Install Online Vibration Monitoring System - Corner Brook Frequency Converter	**6.5**
Replace Recloser Control Panels - Various Sites	**5.3**
Additions for Load Isolated Generation Stations - Various Sites	**26.0**
Upgrade Gas Turbine Controls - Happy Valley	**2.4**
Upgrade Terminal Station - Wiltondale	**9.2**
Install Backup System for Raw Water Supply and Clarifier - Holyrood	**1.7**
Complete Condition Assessment Phase 2 (Year 2) - Holyrood	**3.9**
Total:	**229.7**

APPENDIX A

2013 Project Prioritization

2013 Capital Budget Project Prioritization **Project Description**	**Cost ($000)**	**Rank**	**Cumulative Project Costs ($000)**
Multi-Year Projects (2013 is 2nd or 3rd year) (Non Prioritized)	11,626.4	N/A	11,626
Service Extensions and Upgrades (Non Prioritized)	7,796.0	N/A	19,422
Transportation (Non Prioritized)	2,195.6	N/A	21,618
Tools and Equipment (Non Prioritized)	953.6	N/A	22,572
Front End Engineering Design (Non Prioritized)	472.1	N/A	23,044
Upgrade Public Safety Around Dams and Waterways – Bay d'Espoir	298.1	1	23,342
Replace Emergency Diesel Fuel Tank – Paradise River	46.3	1	23,388
Replace PH 1 North End Equipment Door – Bay d'Espoir	265.5	1	23,654
Replace Condensate Polisher Annunciator Panels – Holyrood	123.5	1	23,777
Upgrade Fuel Oil Day Tank - Holyrood	584.2	1	24,361
Install Transformer Fans – Conne River	114.9	1	24,476
Additions for Load Distribution Systems – Various Sites	3,114.7	1	27,591
Additions for Load Isolated Generation Station – Various Sites	2,040.2	1	29,631
Install Fall Protection Equipment – Various Sites	196.6	1	29,828
Install Additional Washrooms – Various Sites	250.9	1	30,079
Purchase 10 Position Meter Calibration Test Console – Hydro Place	192.5	1	30,271
Remove Safety Hazards – Various Sites	250.5	1	30,522
Install Automated Metering – Various Sites	397.9	2	30,920
Replace Fall Arrest System on Surge Tank 2 – Bay d'Espoir	153.0	3	31,073
Complete Condition Assessment Phase 2 (Year 2) - Holyrood	1,170.2	4	32,243
Overhaul Diesel Units – Various Sites	977.8	5	33,221
Overhaul Turbine/Generator – Bay d'Espoir and Cat Arm	428.1	5	33,649
Overhaul Unit 2 Extraction Pump South – Holyrood	101.5	5	33,750
Overhaul Unit 3 Boiler Feed Pump West – Holyrood	178.5	5	33,929
Overhaul Unit 3 Turbine Valves –Holyrood	993.9	5	34,923
Replace Recloser Control Panels – Various Sites	209.7	6	35,132
Upgrade Power Transformers – Various Sites	1,621.1	7	36,753
Upgrade Circuit Breakers – Various Sites	2,785.3	8	39,539
Replace Instrument Transformers – Various Sites	593.2	9	40,132
Replace Insulators – Various Sites	187.1	10	40,319
Replace Surge Arrestors – Various Sites	121.3	11	40,440

2013 Capital Budget Project Prioritization **Project Description**	**Cost ($000)**	**Rank**	**Cumulative Project Costs ($000)**
Replace Disconnects – Various Sites	492.6	12	40,933
Legal Survey of Primary Distribution Line Right-of-Way – Various Sites	156.2	13	41,089
Upgrade Business Intelligence Software – Hydro Place	369.2	14	41,458
Upgrade Computer Room Air Conditioner – Hydro Place	83.2	15	41,541
Implement Helpdesk Service Manager Tool – Hydro Place	61.8	15	41,603
Perform Minor Application Enhancements – Hydro Place	81.1	16	41,684
Upgrade Energy Management System – Hydro Place	129.9	16	41,814
Upgrade Microsoft Products – Hydro Place	420.3	16	42,235
Replace Personal Computers – Various Sites	463.9	16	42,698
Replace Peripheral Infrastructure – Various Sites	309.9	16	43,008
Upgrade Enterprise Storage Capacity – Hydro Place	124.7	16	43,133
Upgrade Server Technology Program – Hydro Place	367.6	16	43,501
Replace Radomes – Various Sites	336.0	17	43,837
Replace Network Communications Equipment – Various Sites	182.4	17	44,019
Replace Battery Banks and Charges – Various Sites	782.0	17	44,801
Upgrade Site Facilities – Various Sites	49.8	17	44,851
Replace Telephone Systems – Various Sites	135.4	17	44,986
Install Backup System for Raw Water Supply and Clarifiers - Holyrood	955.6	18	45,942
Upgrade Burnt Dam Spillway – Bay d'Espoir	885.8	19	46,828
Install Fire Protection Upgrades - Holyrood	267.2	20	47,095
Replace MDR 4000 Microwave Radio (West) – Various Sites	539.0	21	47,634
Install Online Vibration Monitoring System – Corner Brook Frequency Converter	382.8	22	48,017
Replace Microscada Computers – Granite Canal	297.4	23	48,314
Automate Generator Deluge Systems Units 5 and 6 – Bay d'Espoir	532.0	24	48,846
Rewind Stator Windings Unit 1 – Bay d'Espoir	5,663.5	25	54,510
Replace Compressed Air System – Sunnyside and Stony Brook	303.0	26	54,813
Install Unit 3 CR Condensate Drains and HP Heater Trip Level - Holyrood	50.0	27	54,863
Replace Units 1-6 Autogreasing Systems Units 1 and 3 – Bay d'Espoir	260.1	28	55,123
Perform Wood Pole Line Maintenance Program – Various Sites	2,466.7	29	57,589
Upgrade Vibration Monitoring Equipment - Holyrood	519.9	30	58,109

2013 Capital Budget Project Prioritization **Project Description**	**Cost ($000)**	**Rank**	**Cumulative Project Costs ($000)**
Install Automatic Sprinkler System – Bay d'Espoir	429.9	31	58,539
Upgrade Governor Controls on Units 1 and 2 - Holyrood	1,455.5	32	59,995
Upgrade Distribution Systems – Various Sites	1,940.1	33	61,935
Upgrade By Pass Valves Units 3 and 4 – Bay d'Espoir	141.9	34	62,077
Install Automated Fuel Monitoring System – Upper Salmon	192.7	35	62,270
Upgrade Water Flow Control Structure RR Pond – Granite Canal	43.5	35	62,313
Upgrade Generator Bearings – Bay d'Espoir	480.9	36	62,794
Replace 230 kV Breaker Controls – Various Sites	68.9	37	62,863
Replace Optimo Relays on TL242 – Holyrood to Hardwoods	189.2	37	63,052
Upgrade Gas Turbine Controls – Happy Valley	61.4	38	63,113
Install Variable Frequency Drives on Forced Draft Fans - Holyrood	697.6	39	63,811
Install Waste Oil Storage Tank for PCB's – Bay d'Espoir	48.9	40	63,860
Upgrade Terminal Station Wiltondale	697.7	41	64,557
Replace Automatic Transfer Switches – Hinds Lake	314.7	42	64,872
Replace Cooling Water Pumps – Bay d'Espoir	175.5	43	65,048
Purchase Low Pressure Screw Compressor Set – Bay d'Espoir	97.3	44	65,145

PRIORITIZATION EXPLANATIONS

The following table shows the ranking of Hydro's 2013 capital projects. Rank 1 indicates the projects of the highest importance and, in 2013, no projects with a ranking of more than 44 were included. The total of the projects included is determined based on balancing unit load, overall budget, and logistical considerations. Projects that received the same score through the prioritization process have the same ranking. The 12 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 either multi-year projects or necessary programs.

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 … (maximum weight = 90)	No type Equipment Facility Production Customer delivery	5 40 50 70 90
12	Loss mitigation	Redundant unit	30

Criteria		Factors	Factor Weights
	(maximum weight = 90)	Backup option Nothing	60 90

A. Level 1

Immediate HIGH Priority Projects

- **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. Level 2

1. Work Classification

- **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. Continue Service to Customers

- **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. Number of Customers Impacted

- **<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. Loss Mitigation

- **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.

PROBABILITY

- **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

2013 Capital Plan

newfoundland labrador hydro
a nalcor energy company

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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 and twenty-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 determined through analysis of long term requirements to address future demands for power and energy, and transmission and distribution additions are also identified.

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. This rapid expansion means that many of the assets constructed 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.

Twenty Year Plan

Hydro's planning horizon for asset additions extends to twenty years in the future, depending on the asset, and these additions are ideally planned for construction on a just-in-time basis. This 20 Year Capital Plan does not include additional generation capacity to address future energy requirements of the interconnected electrical systems, nor does it include proposals for Conservation and Demand Management (CDM). The plan does contain some additional generation capacity for isolated diesel generation systems. CDM may include other capital plans intended to reduce demand and energy needs that, aside from reducing fuel requirements, may have some impact on generation additions. Asset replacements are planned based on condition assessments, maintenance and operating cost reviews, changing technology, expected service lives of equipment and knowledge of individual assets. The service lives of Hydro's assets are currently under review by the Public Utilities Board and Hydro has assumed within this application that those recommended service lives will be approved. Hydro previously depreciated its assets based on class, however, the lives are now based on unit of property so instead of eight main classes, there are now 136 units of property. Table 1 lists the units of property that have net depreciable costs greater than $20 million.

Table 1: Units of Property with Net Depreciable Costs greater than $20 Million

Unit of Property Description	Whole Service Life in Years
Dams, Dykes, Canals and Tunnels	100
Spillway Structures	100
Powerhouse	75
Penstock	70
Towers	65
Generators	60
Conductor	60
Transformers	55
Conductor - Distribution	55
Water Regulating Structures	55
Pole Structures - Wood	53
Roads	50
Poles Cribs and Pole Hardware	50
Buildings - Other	50
Turbines	50
Poles – Wood	37
Gas Turbine Systems	35
Insulators	30
Diesel Systems and Engines	25
Software	7

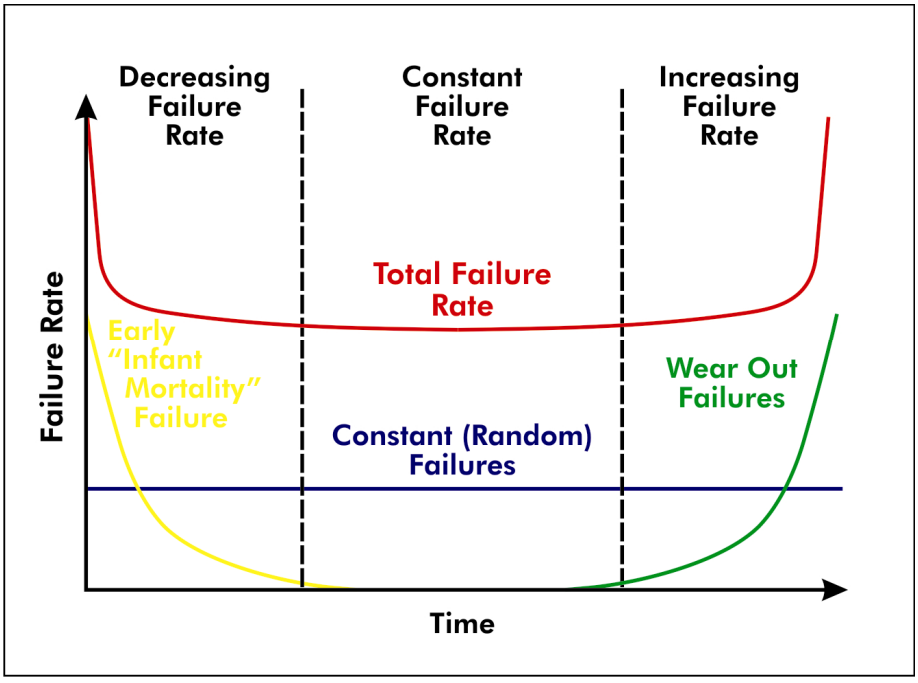
Table 2 indicates when some of Hydro's major assets were placed in service.

Table 2: Age of Selected Hydro Assets

Facility	Year Commissioned	Age
Bay d'Espoir Stage 1	1967	45
Bay d'Espoir Stage 2	1969	43
Bay d'Espoir Stage 3	1977	35
Holyrood Generating Station Stage 1	1971	41
Holyrood Generating Station Stage 2	1979	33
Stephenville Gas Turbine	1976	36
Hardwoods Gas Turbine	1977	35
Hinds Lake	1980	32
Upper Salmon	1983	29
Cat Arm	1985	27
Paradise River	1989	23
Granite Canal	2003	9
Transmission lines (numerous)	Beginning 1967	45
Terminal Stations (numerous)	Beginning 1967	45

The reliability of most equipment over its lifespan follows a generally accepted trend, known as the bathtub curve, as illustrated in the following chart:

Chart 1: Equipment Lifespan



Total Failure Rate, which in its graphic form is known as a "bathtub" curve because of its shape, is the sum of three individual types of failures:

1. Random failures, which are failures caused by a variety of reasons with unpredictable frequency.

2. Infant mortality failures, which occur during the first years of operation and are generally attributed to design, application, material or manufacturing defects or improper operation. These are "break in" failures.

3. Wear out failures, which, as the term implies, occur as the asset, or some of its components, reach the end of their service lives and break down.

The above tables and chart indicate that many of Hydro's major assets have reached, or are about to reach, maturity, at which time steps must be taken to ensure that reliable service is maintained. These steps can include refurbishment and partial or total replacement. In recent years, many projects have been implemented to refurbish or replace mature assets or asset components, and the number of these projects will continue to grow to ensure Hydro continues to provide a reliable supply of electricity to its customers. Hydro manages its assets to provide reliable least cost electricity to its customers.

The five and 20-year plans are living documents and will be revised on an ongoing basis as new information about the condition of Hydro's assets becomes available, as asset management strategies evolve, and as demands and priorities change within asset classes. During 2011, Hydro devoted significant effort into developing and refining the five and 20 year plans for the various systems. A key finding of this work is the general increase in required sustaining capital and to continue to provide safe, reliable, least cost power to Hydro's customers. Furthermore, the work highlighted additional capital activity that will be required to address load growth.

Hydro's parent company, Nalcor Energy is in the process of completing analysis required for a sanction decision on the proposed development of Phase 1 of the Lower Churchill Project in the Fall of 2012. Phase 1 would include the construction of the Muskrat Falls Generating Station and a High Voltage Direct Current (HVDC) transmission link from Muskrat Falls to Soldiers Pond on the Avalon Peninsula (Interconnected Island). In November 2010, Nalcor's analysis at Decision Gate Two, or Concept Selection determined that the Interconnected Island Scenario was the least cost option for consumers. The other alternative was an optimized scenario, the Isolated Island Scenario, which was primarily oil dependent and focused on using Holyrood, other thermal sources as well as smaller hydro

developments on the Island and wind generation. These generation expansion scenarios are not included in the 20 year Capital Plan; it addresses existing assets only with a few exceptions, such as terminal station and transmission line additions which will be required whether or not an HVDC infeed is constructed, and capacity additions at isolated diesel plants as well as distribution system expansion. Also included is some future funding for synchronous condenser conversion of Holyrood units 1 and 2.

Expenditures for new generation and transmission assets are not included in these estimates, with the exception of the addition of the upgrade of the transmission line corridor between Bay d'Espoir and Western Avalon (2014).

Strategic Spending Priorities

The strategic priorities 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

Five-Year Plan

The 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/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 new 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 2 and 4. The rewind of the remaining two units – 1 and 3 are included in the plan in 2013 and 2014 respectively. 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 2013 Capital Plan includes projects to replace the exciters at Upper Salmon and Hinds Lake, and to upgrade the Burnt Dam Spillway.

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. These are now being reviewed due to information obtained, and expected to be obtained, in the proposed work to refurbish the Stephenville gas turbine after a failure in service in late 2011. 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 2013 and 2015 to upgrade the programmable logic controller (PLC) and install a diesel automation and charger system, respectively.

Terminal Stations

Increasing load and maintaining reliability are the principal drivers for terminal station expenditures over the next five years. The largest single project continues to be the construction of two new terminal stations in Labrador City and the conversion of the distribution system from 4.16 kV to 25 kV. The distribution system is old and is loaded to capacity, requiring the construction of the two stations and the reconfiguration of the distribution system to maintain reliability and to ensure acceptable voltage levels in response to load growth. This work is contained in several capital projects which began in 2009 and will continue until late 2013.

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 replacing the compressed air piping at the Sunnyside and Stony Brook Terminal Stations. 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 eight 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 TL-241 (Plum Point to Peter's Barrens, 2014) and TL-221 (Hawkes Bay to Peter's Barrens, 2017) as well as sections of TL-215 (2014) along with other projects. A major project to upgrade the transmission line corridor between Bay d'Espoir and Western Avalon (2014) 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 largest distribution project for the next five years will be the reconfiguration of the Labrador City distribution system, which is now in progress. As was mentioned in the previous section of this document on Terminal Stations, the distribution system is aging and is loaded to capacity, requiring its reconfiguration to maintain reliability, ensure acceptable voltage levels and to respond to continued load growth. The principal feature of the reconfiguration will be the increase of the distribution system voltage from 4.16 kV to 25 kV, enabling more energy to be distributed while maintaining acceptable voltage levels. 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.

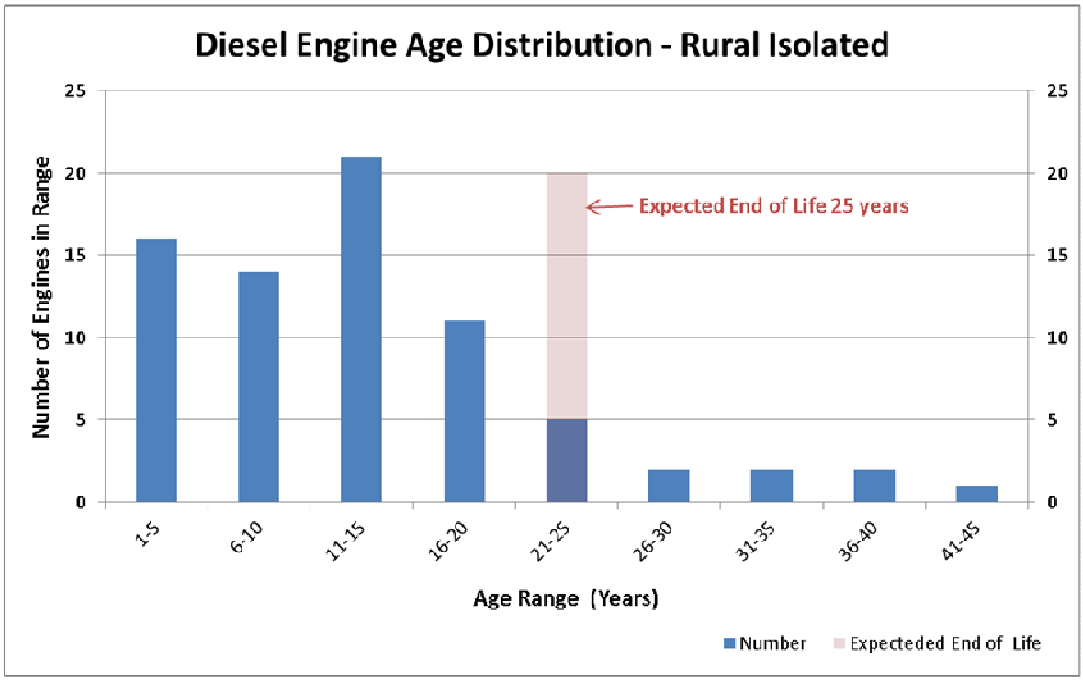
Rural Generation

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 2, below, 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 Nain, L'Anse au Loup, and Hopedale in 2013, Port Hope Simpson in 2014, and Paradise River and Postville in 2015. 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.

Given the prospect of spending several millions of dollars on two new diesel plants located approximately 100 kilometers apart and given that Port Hope Simpson is approximately 50 kilometers between Charlottetown and Mary's Harbour, the possibility of an interconnection among the three

systems may yet be viable to optimize generation needs for the area. Hydro will continue with studies for a long term solution to the electrical supply needs of the area. Hydro plans to submit a recommended solution by the end of March 2013.

Chart 2: 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 a complex business. Expenditures on these systems and personal computers will average $2.4 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 $3.2 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 and the replacement of fibre optic cable.

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 $2.5 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 $1.1 million annually on items such as office equipment and building infrastructure, during the next five years.

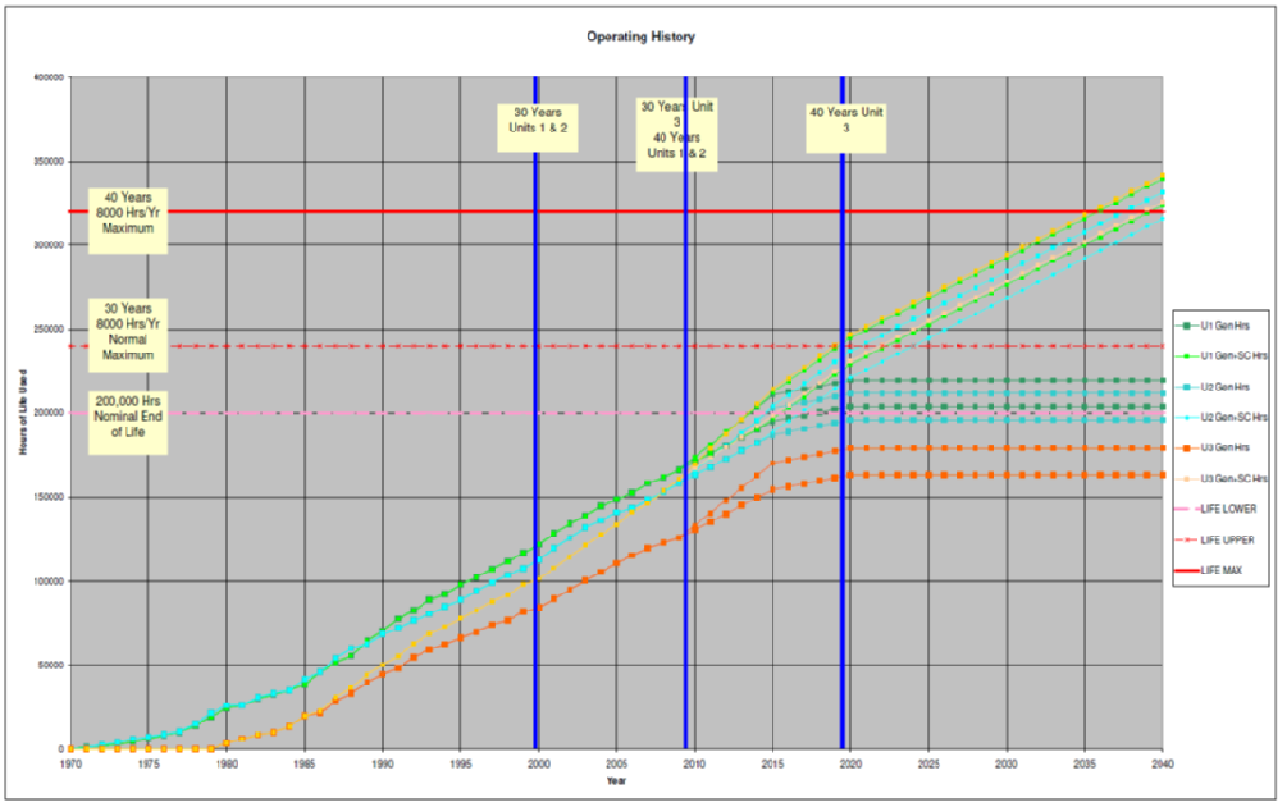
Holyrood

The Holyrood Generating Station (Holyrood) is among the largest generating plants on the Island Interconnected System, and, as a thermal plant, is by far the most complex. Stage I (Units 1 and 2) was commissioned in 1971 and has passed the normal 30-year design life for such a facility. Stage II (Unit 3) was commissioned in 1979 and has reached the end of its normal life. Units 1 and 2 were modified in the late 1980s to increase their capacity from 150 to 170 MW each. This was achieved by availing of the overcapacity inherently contained in equipment of that vintage and by modifying the plant's auxiliary systems. Across North America, similar age plants have either been retired or have been subjected to

life assessment and extension studies and have received large injections of capital to extend their useful lives. Some have been redeveloped into other configurations, such as combined cycle power plants. As can be seen from Chart 3, below, the Holyrood units have met and are exceeding typical expected operating hours and service life.

Hydro's long term role for Holyrood considers two potential scenarios. With the Interconnected Island Scenario, the current plan requires all three units to operate as synchronous condensers after the infeed is completed. In the Isolated Island Scenario, all three units will be required to operate as essential generating assets, as they do now in terms of capability, but will eventually see replacement or modification to provide similar capability. Depending on the scenario which is determined to be the least cost option for consumers and is progressed, some or all of the Holyrood Generating plant will be required for decades into the future. Hydro has completed Phase 1 of a condition assessment for the Holyrood Generating Station. The report was filed in May of 2011. When all phases of the study are completed, Hydro will have the necessary information to determine the capital expenditures required to maintain Holyrood in an efficient and reliable condition. The study is being performed in phases to ensure that the scope and progress of the work matches the progress of the Muskrat Falls Project and ultimate sanction decision so that only necessary expenditures are made.

Chart 3: Typical Thermal Plant Life Expectancy - Holyrood



Holyrood Thermal Generating Station Requirements 2012 to 2022

The Holyrood Generating Station (Holyrood), which was initially commissioned in late 1970 (over 40 years ago), has been and continues to be an essential generating plant in Hydro's Island Interconnected electrical system. This is largely due to the major load growth and lack of other major hydraulic resources on the Avalon Peninsula as well as on the Island. The plant's purpose is to supply power and energy as well as voltage support to the Avalon Peninsula due to transmission limitations to the eastern part of the grid where load growth exceeds that in other areas of the Island. Most of the hydroelectric generation on the island is located west of the Avalon Peninsula. Holyrood provides 466 MW of net capacity and could be required to deliver up to 3 TWh of energy per year to the Island Interconnected System. The steam aspect of the plant comprises two 170 MW units (1970) and one 150 MW unit (1979). Unit 3 has the capability to operate as a synchronous condenser and does so during summer months when power and energy output from Holyrood is not typically required and synchronous condenser operation allows more transfer of hydroelectric power to the east coast. The amount of time it operates in this mode depends on the loading needs, particularly on the Avalon Peninsula. Under the current planning scenario, following a HVDC infeed, it has been established that units 1 and 2 will also need to have that ability which will require modifications to the units to allow them to operate as synchronous condensers through the standby period and beyond.

Hydro's hydraulic energy supply capability is subject to inflow conditions that can vary substantially from year to year. While Hydro plans to secure energy supply for a repeat of the firm hydrological sequence (1958-1961), it also responds to annual variation of inflows in its regular operational planning process. Optimized generation dispatch is based on the latest available data and forecast information with respect to reservoir storages, expected snow melt, projected rainfall and forecast customer requirements.

Hydro's projected requirements for Holyrood are based on the load forecast for its utility and industrial customers, as well as Hydro's direct Island Interconnected distribution system customers and internal needs (losses, station services).

The Muskrat Falls Generating Station and interconnection via the Labrador Island HVDC Link will displace the current power and energy needs from Holyrood and change Newfoundland and Labrador's electricity system. In addition, the interconnection to Nova Scotia via the Maritime Link will potentially provide options for a short term supply through reserve available outside of the Province. For the

purposes of this capital budget submission first power was anticipated to be available in late 2016. However, sensitivity of the impact of a one year delay is provided regarding the demands on the existing plant. Any delay only serves to increase the importance of maintaining the Holyrood asset at full capability.

In the event there are short term delays in power delivery, Hydro has a responsibility to take a prudent approach to ensure that Holyrood is available and continues to be a safe and reliable generation source throughout the transition period and the capital budget proposals herein include these essential projects.

Prior to interconnection, the demands on Holyrood will increase to serve growing customer requirements. Over the past several years, industrial demand has declined from the closure of two paper mills and reduction at a third; however, there is substantial growth occurring particularly on the Avalon Peninsula from both utility and future industrial load, which is expected to cause demand to ultimately exceed historical levels.

Following the full commissioning of the HVDC interconnections, it is intended to maintain the Holyrood asset as generator ready for three to four years so that in the event of loss of supply from Labrador, it can be called upon to provide power and energy to the Island. Following that, the thermal aspect of the station will be decommissioned. At that time, under current planning assumptions, the units will continue to operate only as synchronous condensers. The final generation availability is currently projected to be in the 2020 timeframe.

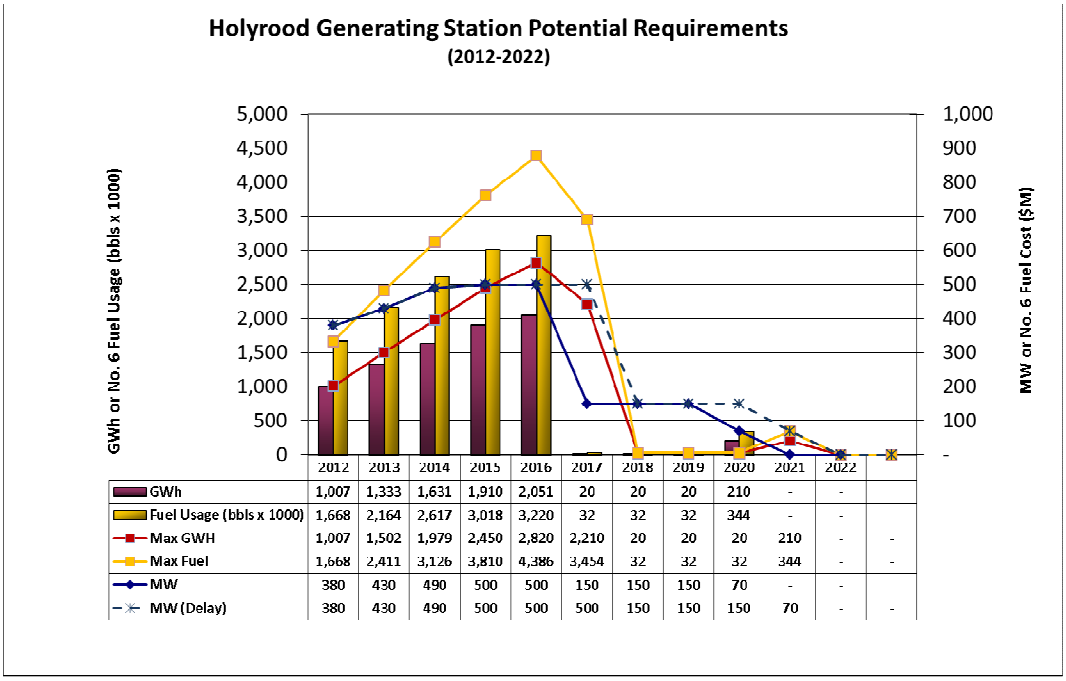
Hydro continues to plan for safe, reliable and least cost operation of the system as it moves towards and transitions to a potential new operating regime which will be established as a result of the HVDC infeed to the Island from Labrador and the interconnection by a second HVDC line to Nova Scotia. Accordingly, the Holyrood facility must continue to operate until final commissioning of the infeed and its conversion to a synchronous condenser plant. The plant will also be available for a period of time following interconnection for backup generation. For planning purposes, Hydro is using 2020 as the approximate year in which Holyrood will also be available for generation after which it will be available for synchronous condenser operation only. This will obviously be the subject of considerable discussion prior to decommissioning. Beyond 2020, considerable further capital reinvestment at Holyrood will be required if it were to continue as a dependable power generation source due to the age and condition of the asset.

The current base case is to operate Holyrood as needed through 2016 and as a backup with minimal operation for 2017 to 2020 (32,000 bbls of oil per year versus 3.2 million bbls during 2016). The plan is to operate each unit for a period of time to ensure they are fully operational, and to ensure that staff retains the skills required to keep the complex plant operational in case of any adverse events. The minimum assumption is that each unit would operate one week per year - two days at full load and five days at 100 MW to ensure availability. As well, consideration is being given to maintaining one unit in hot stand-by for the first winter season to ensure that unit is available within two hours.

In 2016, the Holyrood plant will have been in operation for 45 years which is beyond the life of many similar plants. This assumes that carbon and other emissions from the plant are still tolerated up to that time without financial penalty which, for this limited period, is a reasonable assumption. Beyond that time, releasing CO_2 at levels emitted at full production may not be acceptable under environmental regulations as it is anticipated that government regulations regarding greenhouse gas will change.

The expected base scenario and a maximum Holyrood production scenario are shown in Chart 4, below.

Chart 4: Forecast Holyrood Generation Requirements



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
GWh	1,007	1,333	1,631	1,910	2,051	20	20	20	210	-	-	
Fuel Usage (bbls x 1000)	1,668	2,164	2,617	3,018	3,220	32	32	32	344	-	-	
Max GWH	1,007	1,502	1,979	2,450	2,820	2,210	20	20	20	210	-	-
Max Fuel	1,668	2,411	3,126	3,810	4,386	3,454	32	32	32	344	-	-
MW	380	430	490	500	500	150	150	150	70	-	-	
MW (Delay)	380	430	490	500	500	500	150	150	150	70	-	-

The bar chart elements of the graph shown in Chart 4 assume a HVDC infeed to the island from Labrador and the availability of Labrador power to Hydro for use on the Island after 2016. This scenario, the base scenario, is based on average island hydraulic inflow conditions, which is standard operational planning

procedure, as well as the current load forecast and initial reservoir conditions. The bar chart indicates the energy output expected (burgundy), as well as the fuel consumed (yellow) by the Holyrood plant over this period in the base scenario. The solid blue line indicates the associated maximum Holyrood demand, or maximum gross MW output, required to meet forecast customer requirements. As indicated, the power and energy requirements from Holyrood will increase over the next five to six years due to increased industrial and utility demand as we approach the interconnection to Muskrat Falls. During 2016 production from Holyrood is estimated to be 2051 GWh, which is approximately two thirds of its maximum capability. The corresponding fuel consumption for this level of output is estimated to be 3.22 million barrels of oil.

It is important to note that during a poor inflow year, an annual increase in production from Holyrood of up to 900 GWh could occur. The plant must be ready to produce at this level in the event of such a hydraulic production shortfall, or it could lead to a curtailment of customer load.

During a repeat of the critical dry sequence, the annual required production from Holyrood, prior to an infeed, would be significant, up to 3 TWh per year. This maximum Holyrood production scenario is superimposed on Chart 4 line graphs as “Max GWh” (red) and “Max Fuel” (yellow). This sensitivity case also assumes a one year delay in the interconnection along with the low inflow or dry sequence conditions. The “Max GWH” line graph indicates the production requirement from Holyrood for this worst case. The “Max Fuel” line indicates the associated fuel consumption for this scenario. The reason 2017 is less than 2016 is that in the worst five year hydraulic cycle, year five is improved over the previous four years. The blue dashed line indicates the MW demand in the case of a one year delay and is simply shifted by one year.

Although there are numerous combinations that could be presented for various assumptions of inflow, in service date of the Labrador supply, and load forecast, the purpose of this chart is to illustrate the necessity of ensuring that the Holyrood plant is well maintained to serve the needs of Island customers.

To ensure continued security of supply, capital investment will be necessary throughout the period 2013 to 2020 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 obsolete equipment, refurbishment of fuel storage facilities, and general plant infrastructure work. As well, there will be some operational challenges with respect to ensuring that competent employees are attracted, retained and trained for

all aspects of operation and maintenance required for this complex plant, and that all systems are available and maintained to continue a reliable level of service.

The Holyrood Generating Station continues to be a critical asset that must be maintained in a reliable and cost effective state to meet customer demand and Hydro must have the skilled employees to operate and maintain the asset. With respect to human skills, Hydro has created an Employee Liaison Advisory Committee (union and management participation) whose role is to consider employee issues, retention, and retraining for permanent employees affected by this major repurposing of the facility.

In reviewing the capital needs of the plant, Hydro has considered the time lines discussed above and proposes to submit only those projects necessary for the safe, 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 and will be treated as all other capital needs of Hydro which reflect ongoing operational requirements.

Capital projects being proposed as part of this and upcoming 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.

Five-Year Plan for Holyrood

The five year plan for Holyrood assumes the Interconnected Island Scenario however there are projects that will change dependent on which alternative is ultimately progressed. For example, should the Muskrat Falls development not proceed, there are other projects that will be required to ensure future reliable supply to the island demand for power and energy such as the installation of emissions control equipment to address the emissions issues at the Holyrood Generating Station. Hydro identified the technical parameters, construction schedule, capital and operating costs for these projects in a study performed during 2008. As well, projects specifically related to the Interconnected Island Scenario such as the proposed expenditures to convert Holyrood to a synchronous condenser plant would no longer be required. However, additional condition assessments will be necessary if Holyrood is required for energy generation into the future. Some projects in the current plan would also no longer be required such as the review to determine details for condenser conversion ($1.4 million in 2014) and the

conversion of units 1 and 2 to synchronous condensers ($13.5 million in each of 2015 and 2016); however, other projects needed to sustain a thermal generation future would more than exceed the cost of these items.

2013 Projects

The projects planned and proposed to the Board for approval for 2013 follow and are considered necessary or justified regardless of the future operating mode of the station, as the primary focus is assuring safety, reliability and maintainability in the near term. Proposal 2 is included as it is a project that has payback over the expected generating life of the units under the infeed scenario that is more than adequate to cover the investment cost. Delays of the Labrador infeed only serve to make it more financially attractive. The projects included are:

1. Upgrade Vibration Monitoring Equipment on Units 1, 2 and 3
2. Install Variable Frequency Drives on Forced Draft Fans Units 1, 2, and 3
3. Install Fire Protection Upgrades
4. Install Unit 3 Cold Reheat Condensate Drains and High Pressure Heater Trip Level
5. Replace Condensate Polisher Annunciator Panels on Units 1 and 2
6. Upgrade Governor Controls on Units 1 and 2
7. Upgrade Fuel Oil Day Tank
8. Install Backup System for Raw Water Supply and Clarifier
9. Complete Condition Assessment Phase 2 (Year 2)
10. Overhaul Unit 2 Extraction Pump South
11. Overhaul Unit 3 Boiler Feed Pump West
12. Overhaul Unit 3 Turbine Valves

Following are explanations of why each of the above projects is required for the safe, reliable operation of the Holyrood Generating Station while allowing Hydro to meet its mandate for service at least cost.

1. Upgrade Vibration Monitoring Equipment, Units 1, 2 and 3

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 only. The modules that monitor the future synchronous condenser part of the plant and associated diagnostic software will be removed and replaced with the upgraded system. The removed modules will be used as spares for the existing system that monitors the steam turbines in anticipation they will last until the turbines are no longer required for generation. As well, the upgrade will utilize the existing probes. The primary driver for the upgrade is that the existing system technical support from the vendor is limited in that it provides for only repair or exchange of failed components, replacement parts are not available. Operating a 3600 rpm turbine and generator without reliable and accurate vibration monitoring for alarms and tripping is unacceptable for safety and reliability reasons.

2. Install Variable Frequency Drives on Forced Draft Fans

This proposal is a two-year project for the addition of six variable frequency drives (VFDs) on the forced draft (FD) fan motors in the Holyrood Generating Station. The proposal includes the cost to design, procure, install and commission all six VFDs. It also includes the structural steel platform design and installation to mount the six VFDs, the removal of the existing inlet vane and tuning to the control system for this new equipment. This proposal is justified on energy efficiencies with VFDs over the existing inlet vane arrangement to provide cost savings of $7.7M over a four year period.

3. Install Fire Protection Upgrades

The purpose of this project is to implement measures to reduce the likelihood that fuel originating from the No. 6 fuel oil system which in excess of 40 years old 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. 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*. Further, we have had fuel leak events that, if there had been a fire, would have been catastrophic for continued operation of the plant. Due to the large quantities of No. 6 fuel oil that is present inside the plant, FM Global has recommended a number of measures to reduce the likelihood that the fuel system will feed an existing fire. The measures that FM Global has proposed are to install concrete curbing, an automatic fuel shut-off valve, and fireproofing of the main fuel supply line pipe supports.

4. Install Unit 3 Cold Reheat Condensate Drains and High Pressure Heater Trip Level

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. Hydro's insurer (FM Global) has reported that the presence of water in cold reheat piping has been attributed to 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.

5. Replace Condensate Polisher Annunciator Panels - Units 1 and 2

This project is required to replace the annunciator for the condensate polisher system on both units 1 and 2 at the Holyrood Thermal Generating Station. The new annunciators will have the same capabilities and functionality as the existing ones. They will be installed at the present locations and will reuse the existing instrumentation wiring. A general alarm to the plant distributed control system (DCS) will be provided for each annunciator. The existing annunciators were installed in 1980 (32 years old), and are now obsolete and parts are generally unavailable. In the event of a failure, the condensate polisher system will have to be shut down. Due to the potentially harmful nature of the chemical treatments

involved, it is critical that the annunciator panels for both Unit 1 and Unit 2 condensate polishers be reliable. The purpose of the polishers is to treat the condensate which protects the boilers from corrosion and prevents boiler tube failures. With the age of the boilers it is prudent to undertake this project to ensure continued reliability of the boiler system.

6. Upgrade Governor Controls on Units 1 and 2

This project proposes to upgrade the existing General Electric (GE) Mark V turbine controller on Units 1 and 2 at Holyrood Thermal Generating Station (Holyrood) to the GE Mark VIe turbine controller. GE offers a migration of the Mark V controller to the Mark VIe controller bringing the older technology to today's standards. The migration allows for minimal downtime and site disruption with no impact to the field wiring, turbine devices or location of the existing Mark V cabinet. In 2014, the Mark V turbine controller will enter Phase 5, obsolete phase, of the life cycle plan. In this phase, General Electric states, "the product is no longer supported, and is not recommended for continued use in a machinery protection application." The turbine controller is used for the application of load, turbine over speed protection, thermal stress protection and automatic run-up and synchronizing capabilities. The turbine controller is critical for operation of the units and a failure of a component without the proper part or support would prevent the unit from operating.

7. Upgrade Fuel Oil Day Tank

The fuel oil day tank at Holyrood will be inspected and refurbished as required under this project. The American Petroleum Institute (API) recommends that tanks, such as the day tank at Holyrood, undergo an external inspection every five years and an internal inspection every ten years after its initial service date. The required inspection procedures are outlined in *API Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction*. The day tank at Holyrood has not been inspected since 1998. Therefore, it is recommended that the tank undergo a full inspection that is in compliance with the API 653 standard in 2013. This should be the last such inspection and refurbishment of this asset under the current future plan for the station.

8. Install Backup System for Raw Water Supply and Clarifier

This project will implement business continuity plans for two key processes at Holyrood, raw water supply and clarification. To achieve business continuity upon failure of Holyrood's underground raw water supply pipe from Quarry Brook (installed with the original plant), a secondary raw water supply

system will be supplied under this project. The new system will consist of a diesel-powered pump, piping, and an enclosure to house the new equipment. The system will be deployed upon loss of the plant's gravity-fed raw water supply pipe from Quarry Brook to ensure continued operability of the plant. As well a bypass line will be installed around the existing clarifier to allow the clarifier to be temporarily bypassed in the event of a loss of the system.

In 2007, Hydro engaged Aon Reed Stenhouse Inc., a risk management services company, to assist in evaluating systems at Holyrood that must remain operational to avoid exceeding the plant's Maximum Acceptable Down Time. The risk events below were identified as having the potential to cause the plant to exceed its Maximum Acceptable Down time.

1. Risk of Accident in the Transportation of Hydrogen affecting operation of facilities
2. Risk of Loss of Clarification Process due to Equipment Failure or Improper Maintenance affecting operation of facilities
3. Risk of Loss of Transportation (Lack of Hydrogen Supply Due to Supply Side Transportation Problems) affecting operation of facilities
4. Risk of Failure of Escalated Response from Support Fire Services affecting operation of facilities
5. Risk of Failure of Raw Water Supply Line affecting operation of facilities

Risk items 1, 3, and 4 have been or are being mitigated through the implementation of solutions. Items 2 and 5 will be addressed through this project.

9. Complete Condition Assessment Phase 2 (Year 2)

Hydro began a condition assessment and life extension program in 2009 as Phase I which was completed in 2011. This project is year two of the continuation of the program as Phase II which is planned to be completed in 2014. The scope of this project is to perform more detailed internal investigation on select equipment and systems as identified in 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 of the plant's current projected operating requirements. The first year of Phase 2 was approved in Board Order No. P.U. 5 (2012) for completion under Hydro's 2012 capital program with a project budget of $1.22 million. The 2012 proposal submission provided projected budget estimates for the years 2013

and 2014. This proposal has increased these annual budgets in light of higher than expected tenders for similar industrial type work received to date in 2012. In the 2012 application, $887.0 and $911.8 were proposed for 2013 and 2014 respectively. The current proposal requires $1,170.2 and $1,004.7, respectively. 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.

The remaining projects are the result of the move to IFRS which mandates major overhauls be considered capital. The following projects are projects that are completed at regular intervals during the course of the assets' lives.

10. Overhaul Unit 2 Extraction Pump South

The extraction pump is an important piece of equipment, the outage of which can cause unit shut down. A sudden failure of the pump during unit operation can cause a loss of power production to a maximum of 175 MW. This pump was last overhauled in 2001. In 2013, the pump will have been in service for 12 years since its last overhaul and an asset review has recommended the overhaul of this pump.

11. Overhaul Unit 3 Boiler Feed Pump West

Two pumps are required to carry 100 percent boiler load. Loss of one pump restricts the load to 70 MW. The Unit 3 Boiler Feed water pump west was last overhauled in the year 2000. There have been two major expenses in pump repair in 2005 and 2006 amounting to $90,415.82 for a cartridge replacement and $52,806 for a casing leak, respectively. By 2013, it will be 13 years since the pump was overhauled and in view of the two major repairs it is necessary to have the pump overhauled.

12. Overhaul Unit 3 Turbine Valves

The valves of a turbine control the load and hence the steam flow to the turbine. An improper functioning valve can cause an over speed of the turbine and result in damage to property and a risk to life. It is important for operation as well as safety to maintain the valves in proper condition. Hence the turbine valves need to be overhauled and the three year frequency is supported by industry practice. This was reviewed when the turbine overhaul schedule was moved to nine years from six and is reconfirmed at three year intervals.

Summary Guide to Holyrood Capital Expenditure Proposals for 2013

Following is a summary guide to the Holyrood capital expenditure proposals for 2013, indicating internal and external reports filed in support of each proposal and summarizing alternatives considered and recommendations made.

1. Upgrade Vibration Monitoring Equipment on Units 1, 2 and 3

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 components replaced will be used as spares for the non-synchronous condensing equipment. Upgraded equipment will remain in service beyond plant conversion to synchronous condenser operation.

Alternatives considered:

1. Full system upgrade to Bently Nevada 3500 Encore Series Machinery Protection System
2. Full system upgrade to Bently Nevada 3500 Standard Machinery Protection System
3. Upgrade to Bently Nevada Standard Machinery Protection System - Synchronous condenser equipment only

Alternative 3 is proposed, as it is the least cost option.

Reports appended:

- Manufacturer's proposals for alternatives considered
- Manufacturer's Product Life Cycle Support Notices

2. Install Variable Frequency Drives on Forced Draft Fans Units 1, 2, and 3

This is a two-year project for the addition of six variable frequency drives on the forced draft fan motors in the Holyrood Generating Station.

Alternatives considered:

1. Status quo
2. Install variable frequency drives on forced draft fan motors

Project is economically justified based on cumulative net present value analysis. Project payback is less than one year.

Reports appended: None

3. Install Fire Protection Upgrades

This project is to implement fire protection upgrades recommended by FM Global, Hydro's Insurer. Upgrades include concrete curbing around Units 1 and 3 fuel pumping skids, the installation of an automatic shut-off valve on the main fuel supply pipe, and fireproofing of the pipe supports on the main fuel supply line.

No other alternatives were considered to the recommended upgrades.

Report appended:

- FM Global Risk Report, Fire and Natural Hazards - Special Risk Evaluation, August 24, 2011
  Specific reference to recommendation: Target 08-10-001, p.6

4. Install Unit 3 Cold Reheat Condensate Drains and High Pressure Heater Trip Level

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. This work is recommended by Hydro's insurer, FM Global, to improve protection against steam turbine water induction.

No other alternatives were considered to the recommended actions to improve protection against steam turbine water induction.

Reports appended:

- FM Global Risk Report, Equipment Hazards Interim Risk Evaluation, Holyrood Thermal Plant, May 12, 2011

Specific reference to recommendation - Target 06-01-003 A and B, pp. 10–12.

- ASME Standard TDP-1-1998, Section 3.5

5. Replace Condensate Polisher Annunciator Panels on Units 1 and 2

The existing annunciators were installed in 1980 (32 years old), and are now obsolete. Equipment is being replaced due to obsolescence, therefore no other alternatives were considered.

Reports appended: None

6. Upgrade Governor Controls on Units 1 and 2

The scope of the work is to upgrade the existing General Electric (GE) Mark V turbine controller on Units 1 and 2 to the modern GE Mark VIe turbine controller. With the migration there is no

disruption to the field wiring, turbine devices or the existing cabinet location. The migration can be done with minimal disruption and downtime.

An alternative to this project would be to replace the Mark V turbine controller with a controller manufactured by another company. However, this would require more extensive engineering, testing, installation and outage duration to implement as it would involve the complete replacement of the existing Mark V turbine controller and field wiring. The benefits of using the existing field wiring, cabinet footprint and in-house experience with the GE turbine controller would not be applicable.

Report appended:

- Mark Vie Control: Migration from Mark V Control, GE, April 2012

7. Upgrade Fuel Oil Day Tank

This project is to inspect the fuel day tank as recommended by API 653 Standard. The standard recommends an internal inspection of tanks on a ten year interval. This tank was last inspected in 1998, 14 years ago.

As this is an inspection of existing equipment, no other alternatives were considered.

Reports appended: None

8. Install Backup System for Raw Water Supply and Clarifier

This project will implement business continuity plans for two key processes – raw water supply and raw water clarification.

Alternatives considered:

1. Install permanent underground 16” back up water pipe and install clarifier bypass
2. Supply back up pump and pipe and install clarifier bypass
3. Supply back up pump and install 8” back up pipe and install clarifier bypass

Alternative selected:

Alternative 2 was selected based on cumulative net present value analysis as the least cost option.

Report appended:

- Maximum Acceptable Downtime for Electric Power System Elements, Hydro System Operations, March 31, 2005

9. Complete Condition Assessment Phase 2 (Year 2)

This project is to perform year 2 of a Phase 2 condition assessment.

As this project involves condition assessment of existing equipment, no other alternatives were considered.

Reports appended:

- EPRI On-Line Boiler Condition Assessment Guideline
- Generation Planning Issues 2010 July Update, Hydro System Planning, July 2010

10. Overhaul Unit 2 Extraction Pump South

This project is a scheduled overhaul of Unit 2 south extraction pump.

As this project involves existing equipment maintenance, no other alternatives were considered.

Overhaul timing is recommended by pump expert, Flowserve.

Reports appended:

- Flowserve Review, May 24, 2011

11. Overhaul Unit 3 Boiler Feed Pump West

This project is a scheduled overhaul of Unit 3 west boiler feed pump.

As this project involves existing equipment maintenance, no alternatives were considered.

Overhaul timing is recommended by pump expert, Flowserve.

Report appended:

- Flowserve Review, May 24, 2011

12. Overhaul Unit 3 Turbine Valves

This project is a scheduled turbine valves overhaul of Unit 3 Turbine (three year interval).

As this project involves existing equipment maintenance, no alternatives were considered.

Reports appended:

- Unit 3 Valve Inspection Report, GE Infrastructure Energy, Issued September 22, 2010
- Hartford Steam Turbine Outage Optimization Program, Recommendations Excerpted
- HTGS Condition Assessment and Life Extension Study, AMEC Report No. 164200/RP/001 Unit 3 Steam Turbine Condition Assessment

Report Excerpt: 6.0 Condition Assessment (Used Life and Remaining Life)

APPENDIX A

Five-Year Capital Plan

	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
GENERATION	4,221.4	22,888.9	39,903.9	38,697.9	39,344.5	16,967.7	162,024.3
TRANSMISSION AND RURAL OPERATIONS	15,728.4	34,052.7	63,450.8	85,035.1	85,851.5	123,279.1	407,397.6
GENERAL PROPERTIES	1,898.8	8,203.2	7,327.6	10,491.2	9,904.3	9,926.0	47,751.1
ALLOWANCE FOR UNFORESEEN EVENTS		1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	5,000.0
TOTAL CAPITAL BUDGET	21,848.6	66,144.8	111,682.3	135,224.2	136,100.3	151,172.8	622,173.0

	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
GENERATION							
Hydraulic Plant	2,425.3	12,903.0	13,089.2	13,441.2	5,824.4	8,342.1	56,025.2
Thermal Plant	1,796.1	9,831.2	23,731.9	23,399.1	28,068.5	8,604.1	95,430.9
Gas Turbines	0.0	61.4	3,059.3	1,773.6	5,329.7	0.0	10,224.0
Tools and Equipment	0.0	93.3	23.5	84.0	121.9	21.5	344.2
TOTAL GENERATION	4,221.4	22,888.9	39,903.9	38,697.9	39,344.5	16,967.7	162,024.3
TRANSMISSION AND RURAL OPERATIONS							
Terminal Stations	673.6	8,164.4	12,005.4	15,225.1	10,474.9	15,483.1	62,026.5
Transmission	606.8	2,816.8	6,538.3	36,859.2	53,027.9	84,960.7	184,809.7
Distribution	12,776.1	15,737.1	26,631.0	20,380.9	12,633.9	13,470.4	101,629.4
Generation	809.8	3,409.0	14,289.2	10,858.9	6,901.4	6,101.6	42,369.9
Properties	0.0	1,033.6	1,060.0	463.1	1,166.2	2,434.3	6,157.2
Metering	379.6	1,077.6	971.3	498.3	199.1	199.0	3,324.9
Tools and Equipment	482.5	1,814.2	1,955.6	749.6	1,448.1	630.0	7,080.0
TOTAL TRANSMISSION AND RURAL OPERATIONS	15,728.4	34,052.7	63,450.8	85,035.1	85,851.5	123,279.1	407,397.6
GENERAL PROPERTIES							
Information Systems	187.4	2,799.4	2,126.8	3,263.0	1,401.8	2,545.5	12,323.9
Telecontrol	0.0	2,070.2	2,444.1	3,644.8	3,987.7	3,881.6	16,028.4
Transportation	1,711.4	2,521.1	2,433.5	2,751.0	2,497.4	2,114.0	14,028.4
Administrative	0.0	812.5	323.2	832.4	2,017.4	1,384.9	5,370.4
TOTAL GENERAL PROPERTIES	1,898.8	8,203.2	7,327.6	10,491.2	9,904.3	9,926.0	47,751.1
ALLOWANCE FOR UNFORESEEN EVENTS		1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	5,000.0
TOTAL CAPITAL BUDGET	21,848.6	66,144.8	111,682.3	135,224.2	136,100.3	151,172.8	622,173.0

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
HYDRAULIC PLANT							
Replace Stator Windings Units 1, 3 and 4 - Bay d'Espoir		5,663.5	5,821.1				11,484.6
Replace Static Excitation Systems - Upper Salmon, Hinds Lake and Holyrood	1,813.9	2,295.2					4,109.1
Overhaul Turbine/Generator Units - Various Sites		428.1	349.0	508.5	319.0	365.0	1,969.6
Upgrade Burnt Dam Spillway - Bay d'Espoir		885.8	1,046.5				1,932.3
Automate Generator Deluge Systems - Bay d'Espoir		532.0	471.2	751.3			1,754.5
Upgrade Generator Bearings - Bay d'Espoir		480.9	745.8	427.5			1,654.2
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir		298.1	306.1	315.2	322.6	328.0	1,570.0
Replace Emergency Diesel Generator - Bay d'Espoir	611.4	282.7					894.1
Replace Units 1 to 6 Auto Greasing Systems - Bay d'Espoir		260.1	195.2	196.7			652.0
Install Automatic Fuel Monitoring System - Upper Salmon		192.7	270.3				463.0
Upgrade Units 1 to 6 By-Pass Valves - Bay d'Espoir		141.9	109.0	108.9			359.8
Replace Automatic Transfer Switches - Hinds Lake		314.7					314.7
Replace MicroSCADA Computers - Granite Canal		297.4					297.4
Replace Fall Arrest System on Surge Tank 1 and 2 - Bay d'Espoir		153.0	118.9				271.9
Replace North End Equipment Door - Bay d'Espoir		265.5					265.5
Replace Cooling Water Pumps - Bay d'Espoir		175.4					175.4
Purchase Low Pressure Screw Compressor Set - Bay d'Espoir		97.3					97.3
Install Waste Oil Storage Tank for PCB's - Bay d'Espoir		48.9					48.9
Replace Emergency Diesel Fuel Tank - Paradise River		46.3					46.3
Upgrade Water Flow Control Structure RR Pond - Granite Canal		43.5					43.5
Upgrade Victoria Structure - Bay d'Espoir			513.6	969.5			1,483.1
Replace Interior Coating Surge Tanks- Bay d'Espoir			500.0	1,141.4	1,150.8	734.7	3,526.9
Upgrade Access Roads - Various Sites			1,251.6	1,505.6		776.8	3,534.0
Refurbish Turbines - Snook's Arm and Venam's Bight			375.4	850.9			1,226.3
Upgrade Breakwater (Shoreline Protection) - Cat Arm			664.8				664.8
Replace Turbine/Generator Flow Measuring Devices - Upper Salmon			127.8				127.8
Increase Height on Earth Dam - Paradise River			80.2				80.2
Install Unit 1 Governor Oil Filtration System - Upper Salmon			72.8				72.8
Replace West Salmon Emergency Lift System - Upper Salmon			69.9				69.9
Replace Penstock and Auxiliaries - Venam's Bight				4,712.9			4,712.9
Upgrade Site Facilities - Bay d'Espoir				780.2	912.7		1,692.9
Install Hydrometeorological Stations - Various Sites				378.3	321.2		699.5
Replace Site Pumphouse, Pumps and Controls - Bay d'Espoir				268.4			268.4
Replace Slip Ring Assembly - Hinds Lake				252.8			252.8
Upgrade Unit Relay Protection - Paradise River				164.3			164.3
Install Infrared Viewports - Various Sites				108.8		112.9	221.7

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
HYDRAULIC PLANT (cont'd.)							
Pilot Asset Health Monitoring Template - Upper Salmon					598.7	194.4	793.1
Install New Vent Chambers Units 1 to 6 - Bay d'Espoir					647.4		647.4
Refurbish Generation Unit - Venam's Bight					463.5		463.5
Replace Rectifier Transformer Unit 1 - Bay d'Espoir					384.8		384.8
Upgrade Station Service Water System - 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
Upgrade Jockey Pumps - Upper Salmon and Hinds Lake					54.5		54.5
Replace Spherical Valve Control System - Cat Arm						883.0	883.0
Replace Diesel Generator 2 at Victoria Control Structure - Bay d'Espoir						638.1	638.1
Upgrade North Salmon River Spillway - Bay d'Espoir						469.5	469.5
Upgrade EBBE Control Structure - Bay d'Espoir						456.5	456.5
Replace Rectifier Transformer Unit 2 - Bay d'Espoir						430.7	430.7
Upgrade Powerhouse 1 and 2 Station Service - Bay d'Espoir						429.8	429.8
Upgrade Powerhouse Equipment Doors - Various						382.2	382.2
Replace 6 Slip Rings Units 1 to 6 - Bay d'Espoir						341.3	341.3
Replace Main Generator Bearing - Upper Salmon						300.0	300.0
Install Automated Fuel Monitoring at Paradise River - Bay d'Espoir						267.4	267.4
Upgrade Domestic Water System - Cat Arm						242.6	242.6
Install Partial Discharge Monitors - Paradise River						197.0	197.0
Upgrade Unit 5 Generator Bearing - Bay d'Espoir						190.0	190.0
Upgrade Sump Level System Powerhouse 2 - Bay d'Espoir						185.0	185.0
Replace Shaft Seal System - Upper Salmon						150.0	150.0
Replace Plant High Pressure Compressor 1 - Upper Salmon						142.7	142.7
Install Permanent Monitoring Vibration System Unit 7 - Bay d'Espoir						124.5	124.5
TOTAL HYDRAULIC PLANT	2,425.3	12,903.0	13,089.2	13,441.2	5,824.4	8,342.1	56,025.2

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
THERMAL PLANT							
Rewind Generators Units 1 and 2 - Holyrood	112.2	1,107.6	4,885.7	5,795.7			11,901.2
Overhaul Steam Turbine Generators - Holyrood			4,500.4		4,810.1		9,310.5
Overhaul Turbine Valves - Holyrood		993.9		1,218.0		1,456.2	3,668.1
Install Variable Frequency Drives on Forced Draft Fans - Holyrood		697.6	2,659.7				3,357.3
Upgrade Fuel Oil Heat Tracing - Holyrood	1,474.3	1,413.9					2,888.2
Complete Condition Assessment Phase 2 (Year 2) - Holyrood		1,170.2	1,004.7				2,174.9
Upgrade Governor Controls on Units 1 and 2 - Holyrood		1,455.5					1,455.5
Install Backup System for Raw Water Supply and Clarifier - Holyrood		955.6					955.6
Overhaul Boiler Feed Pumps - Holyrood		178.5	177.9	182.6	186.0	188.1	913.1
Upgrade Electrical Equipment - Holyrood	209.6	212.1					421.7
Upgrade Fuel Oil Day Tank - Holyrood		584.2					584.2
Overhaul Extraction Pumps - Holyrood		101.5	85.3	175.0	88.9	89.9	540.6
Upgrade Vibration Monitoring Equipment Units - Holyrood		519.9					519.9
Install Cold-Rehead Condensate Drains and High Pressure Heater Trip Level Unit 3 - Holyrood		50.0	448.1				498.1
Install Fire Protection Upgrades - Holyrood		267.2					267.2
Overhaul Cooling Water Pumps - Holyrood			85.3		88.9	89.9	264.1
Replace Condensate Polisher Annunciator Panels - Holyrood		123.5					123.5
Refurbish Fuel Storage Facility - Holyrood			3,211.3				3,211.3
Upgrade Powerhouse Roofing - Holyrood			460.3	389.5	374.7	358.3	1,582.8
Complete Eng. Review to Determine System for SYN CND, Units 1 and 2 - Holyrood			1,425.2				1,425.2
Upgrade Excitation Systems Units 1 and 2 - Holyrood			536.9	682.4			1,219.3
Replace Plant Elevators - Holyrood			1,192.7				1,192.7
Replace Powerhouse Overhead Crane Doors - Holyrood			337.7	355.4	363.4		1,056.5
Replace Waste Water Basin Building - Holyrood			1,004.2				1,004.2
Replace Fuel Oil Heat Exchanger Units 1 and 2 - Holyrood			750.0				750.0
Replace Economizer Inlet Valves Units 1 and 2 - Holyrood			500.0				500.0
Replace Compressors - Holyrood			282.0	288.1			570.1
Upgrade 129 Volt DC Plant Wide Distribution System - Holyrood			184.5				184.5

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
THERMAL PLANT (cont'd.)							
Convert Units 1 and 2 to Synchronous Condensing System - Holyrood				13,500.0	13,500.0		27,000.0
Upgrade Quarry Brook Dam Equipment - Holyrood				395.1			395.1
Install Fire Protection (Out Buildings) - Holyrood				314.0			314.0
Replace 258 Volt DC Distribution Panels and Breakers - Holyrood				103.3			103.3
Rewind Generator 3 and Install Rotor Flux Probe - Holyrood					8,402.4		8,402.4
Replace UPS 1 , 2, 3 and 4 - Holyrood					254.1	266.7	520.8
Replace Unit Substations AT-A, AT-B, AT-C						3,000.0	3,000.0
Upgrade Forced Draft Fan Ductwork Unit 3 - Holyrood						1,827.7	1,827.7
Upgrade Plant Access Road - Holyrood						807.8	807.8
Replace Stage 2 Diesel - Holyrood						443.2	443.2
Install Visible Isolation for 600 V HVAC System Admin Area - Holyrood						76.3	76.3
TOTAL THERMAL PLANT	1,796.1	9,831.2	23,731.9	23,399.1	28,068.5	8,604.1	95,430.9

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
GAS TURBINES							
Upgrade Gas Turbine PLC - Happy Valley		61.4	1,128.6				1,190.0
Upgrade Gas Turbine Plant Life Extension - Stephenville			1,930.7	1,564.7	5,329.7		8,825.1
Install Diesel Automation and Charger System - Happy Valley				208.9			208.9
TOTAL GAS TURBINE PLANTS	0.0	61.4	3,059.3	1,773.6	5,329.7	0.0	10,224.0
TOOLS AND EQUIPMENT							
Purchase Tools and Equipment Less than $50,000 - Hydraulic		82.8	12.8	73.0	10.0	10.0	188.6
Install Handheld Pendant to Overhead Crane - Bay d'Espoir					100.7		100.7
Purchase Tools and Equipment Less than $50,000 - Thermal		10.5	10.7	11.0	11.2	11.5	54.9
TOTAL TOOLS AND EQUIPMENT	0.0	93.3	23.5	84.0	121.9	21.5	344.2
TOTAL GENERATION	4,221.4	22,888.9	39,903.9	38,697.9	39,344.5	16,967.7	162,024.3

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
TERMINAL STATIONS							
Upgrade Circuit Breakers - Various Sites		2,785.3	3,621.0	4,050.6	3,750.1	3,973.2	18,180.2
Upgrade Power Transformers - Various Sites		1,621.1	1,667.2	4,719.4	1,750.6	1,780.8	11,539.1
Replace Instrument Transformers - Various Sites		593.2	552.8	538.4	1,511.7	471.9	3,668.0
Replace Disconnects - Various Sites		492.6	480.5	501.1	583.6	626.8	2,684.6
Replace Compressed Air Systems - Various Sites	28.4	581.3	2,143.3	417.1		500.0	3,670.1
Perform Grounding Upgrades - Various Sites	645.2	329.0	337.1	345.4	338.2	341.5	2,336.4
Install Online Vibration Monitoring System - Corner Brook Frequency Converter		382.8					382.8
Upgrade Terminal Station - Wiltondale		697.7	1,173.3				1,871.0
Replace Optimho Relays on TL242 - Holyrood to Hardwoods		189.2	227.1	250.6			666.9
Replace Surge Arrestors - Various Sites		121.3	114.5	88.0	149.8	122.2	595.8
Replace Insulators - Various Sites		187.1	287.9				475.0
Install Transformer Fans - Conne River		114.9					114.9
Replace 230 kV Breaker Controls - Bottom Brook		68.9					68.9
Install 20 MVAR Reactor - Bottom Brook			1,210.2	2,515.6			3,725.8
Replace Telecontrol Building and Upgrade Equipment - Daniels Harbour			57.0	765.5			822.5
Terminal Stations Compressor Replacement Program - Various Sites			133.5	132.9	139.5	142.5	548.4

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
TERMINAL STATIONS (cont'd.)							
Perform Site Work to Accommodate Mobile Transformer - Various Sites				292.8	350.3		643.1
Replace 66kV S/S Cable Feed to Plant - Holyrood				223.2			223.2
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 1 and 2 to Terminal Station 1 - Bay d'Espoir				214.6	490.9		705.5
Extend Control Building Washroom - Indian River					405.6		405.6
Install Remote Control Sectionalizer TL251(2)(3) - Hampden					334.0		334.0
Upgrade Terminal Station for Mobile Substation - Cow Head					224.9		224.9
Install New Transformer - Massey Drive and Hardwoods						3,060.0	3,060.0
Construct 138kV Terminal Station - Hawkes Bay						2,280.0	2,280.0
Upgrade T12 - Bay d'Espoir						500.0	500.0
Install Transformer Online Gas Monitoring - Bay d'Espoir						300.0	300.0
Replace Station Lighting - Bay d'Espoir						250.0	250.0
Upgrade DC Station Service - Bay d'Espoir						200.0	200.0
Upgrade Terminal Station for Mobile Substation - Howley and Daniel's Harbour						175.0	175.0
TOTAL TERMINAL STATIONS	673.6	8,164.4	12,005.4	15,225.1	10,474.9	15,483.1	62,026.5

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
TRANSMISSION							
Perform Wood Pole Line Management Program - Various Sites		2,466.7	2,595.1	2,934.6	3,010.1	2,787.0	13,793.5
Replace Guy Wires - TL215	606.8	350.1	530.0				1,486.9
Upgrade Transmission Line Corridor - Bay d'Espoir and Western Avalon			2,621.8	30,232.4	41,587.2	66,699.9	141,141.3
Upgrade Transmission Lines - Various Sites			106.9	3,236.5		1,292.7	4,636.1
Upgrade Angle Structures - TL259			684.5				684.5
Reroute Remote Section of Line - TL215				111.9	2,312.4		2,424.3
Rebuild 5 km in Park - TL229				111.9	2,312.4		2,424.3
Replace Aircraft Markers at Grand Lake Crossing - TL228				231.9			231.9
Replace Transmission Lines - Various Sites					525.8	12,747.8	13,273.6
Relocate Remote Section of Line - TL220					2,115.7		2,115.7
Construct Transmission Line Equipment Off-Loading Areas - Various Sites					887.8	506.4	1,394.2
Conduct LIDAR Surveys - Various Sites					276.5	283.9	560.4
Upgrade Tower Foundation - Various Sites						500.0	500.0
Replace Dampers - TL247						143.0	143.0
TOTAL TRANSMISSION	606.8	2,816.8	6,538.3	36,859.2	53,027.9	84,960.7	184,809.7

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
DISTRIBUTION							
Provide Service Extensions - All Service Areas		5,006.0	5,134.0	5,276.0	5,393.0	5,498.0	26,307.0
Upgrade Distribution Systems - All Service Areas		2,790.0	2,861.0	2,941.0	3,007.0	3,063.0	14,662.0
Voltage Conversion - Labrador City	8,430.8	969.5					9,400.3
Upgrade Distribution Systems - Various Sites		1,940.1	3,995.5				5,935.6
Additions for Load - Distribution Systems - Various Sites		3,114.7	294.9	112.6	1,316.1	1,000.0	5,838.3
Upgrade L2 Distribution Feeder - Glenburnie	2,960.1	596.6					3,556.7
Upgrade Distribution Lines - Bay d'Espoir, Parsons Pond and Plum Point	1,385.2	1,110.5					2,495.7
Replace Recloser Control Panels - Various Sites		209.7	175.0				384.7
Upgrade Distribution System - Various Sites			8,364.3	4,587.2	2,201.0	2,955.0	18,107.5
Additions for Load - Labrador South Interconnection - Various Sites			5,370.0	7,464.1			12,834.1
Automate Reclosers - Various Sites			436.3				436.3
Convert Section of Robert's Arm (L3) to 25 kV - South Brook					569.6		569.6
Survey Lines - Various Sites					147.2		147.2
Build Line to Connect New Refinery - Sunny Side						300.0	300.0
Construct Storage Building - Springdale						259.8	259.8
Install Mobile Diesel Quick Connect/Disconnect - Various Sites						178.8	178.8
Construct heated Storage Building - Change Islands						141.8	141.8
Implement G.I.S. - Various Sites						74.0	74.0
TOTAL DISTRIBUTION	12,776.1	15,737.1	26,631.0	20,380.9	12,633.9	13,470.4	101,629.4

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
GENERATION							
Additions for Load Isolated Generation Stations - Various Sites		2,040.2	12,402.5	7,183.3	3,830.0	1,000.0	26,456.0
Overhaul Diesel Units - Various Sites		977.8	999.3	1,026.4	1,051.2	1,069.7	5,124.4
Perform Arc Flash Remediation - Various Sites	809.8	391.0	401.8	413.1			2,015.7
Replace Diesel Units - Various Sites			118.7	1,603.8	1,325.5	2,220.0	5,268.0
Replace Fuel tanks - Ramea			366.9				366.9
Upgrade Fuel Storage - Various Sites				218.5	125.3		343.8
Upgrade Unit 2044 - St. Lewis				267.9			267.9
Install Intermediate Tank - Nain				145.9			145.9
Install Sequence of Events Monitor in Diesel Plants - Various Sites					280.6	288.5	569.1
Upgrade Lighting System - Cartwright and Hopedale					157.9		157.9
Upgrade Station Service - Grey River					130.9		130.9
Replace Radiators - L'Anse au Loup						500.0	500.0
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 Underground Glycol Line - Francois						100.0	100.0
Insulate Diesel Plant - St. Anthony						63.5	63.5
TOTAL GENERATION	809.8	3,409.0	14,289.2	10,858.9	6,901.4	6,101.6	42,369.9

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
PROPERTIES							
Install Additional Washrooms - Various Sites		250.9	257.2	263.7	270.2	277.0	1,319.0
Legal Survey of Primary Distribution Right of Ways - Various Sites		156.2	196.9	199.4	197.3	197.3	947.1
Install Automatic Fire Sprinkler System - Bay d'Espoir		429.9					429.9
Install Fall Protection Equipment - Various Sites		196.6	222.9				419.5
Replace Accommodations at Ebbegunbaeg - Bay d'Espoir			383.0				383.0
Install Pole Storage Ramps - Various Sites					603.8	507.2	1,111.0
Upgrade Warehouse Lighting - Bishop's 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's Falls						77.4	77.4
TOTAL PROPERTIES	0.0	1,033.6	1,060.0	463.1	1,166.2	2,434.3	6,157.2
METERING							
Install Automated Meter Reading - Various Sites	379.6	685.6	772.7	299.5			2,137.4
Purchase Meters, Equipment and Metering Tanks - Various Sites		199.5	198.6	198.8	199.1	199.0	995.0
Purchase 10 Position Meter Calibration Test Console - Hydro Place		192.5					192.5
TOTAL METERING	379.6	1,077.6	971.3	498.3	199.1	199.0	3,324.9
TOOLS AND EQUIPMENT							
Replace Off Road Track Vehicles - Various Sites	482.5	812.4	1,054.1	1.1	406.6		2,756.7
Replace Light Duty Mobile Equipment - Various Sites		476.5	343.3	498.2	489.3	494.8	2,302.1
Purchase Tools and Equipment Less than $50,000		525.3	204.0	162.0	132.3	135.2	1,158.8
Purchase High Voltage Breaker Timing Sets - Various Sites			85.9	88.3	90.8		265.0
Purchase Track Mounted Backyard RBD - Bishop's Falls			158.1				158.1
Replace Excavator - Unit No. 7833 - St. Anthony			110.2				110.2
Replace Bulldozer - Unit No. 7657 - Bishop's Falls					329.1		329.1
TOTAL TOOLS AND EQUIPMENT	482.5	1,814.2	1,955.6	749.6	1,448.1	630.0	7,080.0
TOTAL TRANSMISSION AND RURAL OPERATIONS	15,728.4	34,052.7	63,450.8	85,035.1	85,851.5	123,279.1	407,397.6

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
INFORMATION SYSTEMS							
SOFTWARE APPLICATIONS							
New Infrastructure							
Perform Minor Application Enhancements - Hydro Place		126.8	139.7	142.6	147.4	150.0	706.5
Cost Recoveries		(45.7)	(40.9)	(41.8)	(47.4)	(50.0)	(225.8)
Upgrade of Technology							
Upgrade Energy Management System - Hydro Place		129.9	387.7	212.5	212.7	215.0	1,157.8
Upgrade Microsoft Products - Hydro Place		656.7	455.1	465.2			1,577.0
Cost Recoveries		(236.4)	(163.8)	(167.5)			(567.7)
Upgrade JD Edwards - Hydro Place	284.0	587.6					871.6
Cost Recoveries	(96.6)	(199.8)					(296.4)
Upgrade Business Intelligence Software - Hydro Place		576.9					576.9
Cost Recoveries		(207.7)					(207.7)
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	187.4	1,388.3	777.8	1,311.0	580.5	1,388.1	5,633.1

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
COMPUTER OPERATIONS							
Infrastructure Replacement							
Replace Personal Computers - Hydro Place		463.9	575.0	537.8	382.3	365.0	2,324.0
Replace Peripheral Infrastructure - Hydro Place		309.9	285.9	521.9	208.5	194.0	1,520.2
Upgrade Enterprise Storage Capacity - Hydro Place		194.9	335.6	309.8	182.0	300.0	1,322.3
Cost Recoveries		(70.2)	(114.1)	(103.5)	(61.9)	(96.0)	(445.7)
Replace ECC Map Board - Hydro Place			52.9	311.1			364.0
Upgrade of Technology							
Upgrade Server Technology Program - Hydro Place		499.4	323.8	568.1	167.2	580.0	2,138.5
Cost Recoveries		(131.8)	(110.1)	(193.2)	(56.8)	(185.6)	(677.5)
Upgrade Computer Room Air Conditioner - Hydro Place		130.0					130.0
Cost Recoveries		(46.8)					(46.8)
Replace Helpdesk Service Manager Application - Hydro Place		96.5					96.5
Cost Recoveries		(34.7)					(34.7)
TOTAL COMPUTER OPERATIONS	0.0	1,411.1	1,349.0	1,952.0	821.3	1,157.4	6,690.8
TOTAL INFORMATION SYSTEMS	187.4	2,799.4	2,126.8	3,263.0	1,401.8	2,545.5	12,323.9

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	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		336.0	178.7	183.2	192.0	196.0	1,085.9
Purchase Tools and Equipment Less than $50,000		45.6	46.4	47.6	48.7	49.7	238.0
Replace Mobile Radio System Churchill Falls to Happy Valley			58.7	624.5			683.2
Replace Power Line Carrier Bottom Brook to Doyles - TL214			482.8				482.8
Replace Communication Shelter - Gull Pond Hill			254.0				254.0
Replace MDR4000 Microwave Radio (East) - Various Sites					984.9	1,471.1	2,456.0
Replace Microwave Radio - Various Sites					2,172.6		2,172.6
Install Fiber Optics - Stony Brook					54.5		54.5
Expand East Coast Microwave - Various Sites						725.0	725.0
Replace Remote Computer Link - Cat Arm						307.0	307.0
Network Infrastructure							
Replace Battery Banks and Chargers - Various Sites		782.0	314.8	322.9	302.0	305.0	2,026.7
Replace Network Communications Equipment - Various Sites		182.4	155.0	158.6	174.0	180.0	850.0
Install Substation Communications Management - Various Sites						237.8	237.8
Upgrade of Technology							
Upgrade Site Facilities - Various Sites		49.8	55.6	57.0	59.0	50.0	271.4
Replace Telephone Systems - Various Sites		135.4	98.1	98.0			331.5
Replace Program Logic Controllers - Various Sites				1,753.3			1,753.3
Upgrade IP Scada Network - Various Sites			93.1	399.7			492.8
Build Communication Shelters - Various Sites						360.0	360.0
TOTAL TELECONTROL	0.0	2,070.2	2,444.1	3,644.8	3,987.7	3,881.6	16,028.4

PROJECT DESCRIPTION	Expended 2012	2013	2014	2015	2016	2017	Total
				($000)			
TRANSPORTATION							
Replace Vehicles and Aerial Devices Hydro System - Various Sites	1,711.4	2,521.1	2,433.5	2,751.0	2,497.4	2,114.0	14,028.4
TOTAL TRANSPORTATION	1,711.4	2,521.1	2,433.5	2,751.0	2,497.4	2,114.0	14,028.4
ADMINISTRATION							
Remove Safety Hazards - Various Sites		250.5	257.3	264.4	271.8	279.4	1,323.4
Purchase Tools and Equipment Less than $50,000		89.9	65.9	68.0	131.0	71.1	425.9
Front End Engineering Design - Hydro Place		472.1					472.1
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's Falls						799.6	799.6
Upgrade Outside Property - Various Sites						234.8	234.8
TOTAL ADMINISTRATION	0.0	812.5	323.2	832.4	2,017.4	1,384.9	5,370.4
TOTAL GENERAL PROPERTIES	1,898.8	8,203.2	7,327.6	10,491.2	9,904.3	9,926.0	47,751.1

APPENDIX B

Twenty-Year Capital Plan

20 Year Sustaining Capital
($000)

	Accuracy 20%	Accuracy 40%				Accuracy 50% order of magnitude														
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Generation																				
Hydro plants	13,333	13,472	13,441	5,824	9,570	1,179	515	1,691	575	810	275	425	510	1,025	150	510	525	545	550	455
Thermal Plant	10,028	23,955	23,399	28,069	8,604	11,131	5,100	7,250	3,700	6,750	5,300	2,325	2,850	3,000	4,700	3,650	3,900	3,620	3,775	3,930
Gas Turbines	61	3,059	1,774	5,330	0	1,978	3,263	3,750	3,550	3,125	3,410	3,450	3,250	3,530	2,220	1,600	1,200	2,360	2,180	1,910
Tools and Equipment	93	24	84	122	22	393	393	393	393	393	393	393	393	393	393	393	393	393	393	393
Transmission and Terminals																				
Terminal Stations	8,415	12,263	15,489	10,745	15,760	15,238	10,105	10,535	7,935	8,751	8,280	7,870	7,685	8,205	8,115	8,395	5,395	7,560	7,535	7,400
Transmission	2,973	6,735	37,059	53,225	85,158	108,997	8,123	8,591	11,574	12,476	11,370	18,594	16,250	15,201	16,072	17,556	23,434	25,786	18,282	25,049
Metering	1,078	971	498	199	199	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Tools and Equipment	1,814	1,956	750	1,448	630	1,672	1,030	1,069	1,904	1,981	2,658	1,605	1,659	1,341	2,190	931	2,855	1,260	558	1,765
Rural Systems																				
Distribution	15,737	26,631	20,381	13,238	13,978	14,276	14,307	12,340	11,895	9,559	10,138	10,452	9,955	10,066	9,362	11,730	10,367	4,691	4,745	4,797
Diesel Plants	3,409	14,289	10,859	6,901	6,249	5,085	4,460	2,605	2,730	2,760	1,180	575	1,247	4,029	3,940	1,595	2,275	2,615	2,890	2,660
General Properties																				
Information Systems	2,799	2,127	3,263	1,402	2,546	4,682	3,488	2,848	6,700	1,880	6,652	2,203	2,746	1,752	1,752	2,235	1,818	2,061	1,924	1,958
Telecontrol	2,070	2,444	3,645	3,988	3,882	2,119	2,000	3,550	6,037	5,762	1,984	3,247	1,805	2,592	1,251	2,931	2,373	2,190	2,267	2,203
Transportation	2,521	2,434	2,751	2,497	2,114	2,419	2,601	4,687	1,735	1,634	3,354	2,290	3,071	2,495	3,718	1,984	1,408	4,371	1,729	2,007
Administrative	813	323	832	2,112	1,462	955	478	618	518	518	418	678	718	468	718	618	318	618	718	318
Contingency Fund	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Total Existing Assets	**66,145**	**111,682**	**135,224**	**136,100**	**151,173**	**171,324**	**57,063**	**61,127**	**60,446**	**57,599**	**56,612**	**55,308**	**53,339**	**55,297**	**55,781**	**55,328**	**57,461**	**59,271**	**48,745**	**56,045**
Total for 20 Years	**1,560,070**																			
Average	**78,054**																			
Total Holyrood without Lower Churchill	0	0	0	0	0	232,650	261,950	132,900	21,425	1,000	0	1,500	50	0	0	2,500	0	0	0	0
Total for 20 Years	653,975																			
Average	32,699																			

	Expended to 2012	2013	Future Years	Total
		($000)		
GENERATION	4,221.4	22,888.9	14,917.8	42,028.1
TRANSMISSION AND RURAL OPERATIONS	15,728.4	34,052.7	23,375.6	73,156.7
GENERAL PROPERTIES	1,898.8	8,203.2	1,975.1	12,077.1
ALLOWANCE FOR UNFORESEEN EVENTS	0.0	1,000.0	0.0	1,000.0
TOTAL CAPITAL BUDGET	21,848.6	66,144.8	40,268.5	128,261.9

	Expended to 2012	2013	Future Years	Total
		($000)		
GENERATION				
Hydraulic Plant	2,425.3	12,903.0	0.0	15,328.3
Thermal Plant	1,796.1	9,831.2	13,789.2	25,416.5
Gas Turbines	0.0	61.4	1,128.6	1,190.0
Tools and Equipment	0.0	93.3	0.0	93.3
TOTAL GENERATION	4,221.4	22,888.9	14,917.8	42,028.1
TRANSMISSION AND RURAL OPERATIONS				
Terminal Stations	673.6	8,164.4	7,324.4	16,162.4
Transmission	606.8	2,816.8	530.0	3,953.6
Distribution	12,776.1	15,737.1	3,995.5	32,508.7
Generation	809.8	3,409.0	10,172.8	14,391.6
Properties	0.0	1,033.6	40.0	1,073.6
Metering	379.6	1,077.6	258.8	1,716.0
Tools and Equipment	482.5	1,814.2	1,054.1	3,350.8
TOTAL TRANSMISSION AND RURAL OPERATIONS	15,728.4	34,052.7	23,375.6	73,156.7
GENERAL PROPERTIES				
Information Systems	187.4	2,799.4	589.0	3,575.8
Telecontrol	0.0	2,070.2	706.9	2,777.1
Transportation	1,711.4	2,521.1	679.2	4,911.7
Administrative	0.0	812.5	0.0	812.5
TOTAL GENERAL PROPERTIES	1,898.8	8,203.2	1,975.1	12,077.1
ALLOWANCE FOR UNFORESEEN EVENTS	0.0	1,000.0	0.0	1,000.0
TOTAL CAPITAL BUDGET	21,848.6	66,144.8	40,268.5	128,261.9

PROJECT DESCRIPTION	Expended to 2012	2013	Future Years	Total	Page Ref
			($000)		
HYDRAULIC PLANT					
Replace Stator Windings Unit 1 - Bay d'Espoir		5,663.5		5,663.5	C - 3
Replace Static Excitation Systems - Upper Salmon, Holyrood and Hinds Lake	1,813.9	2,295.2		4,109.1	
Replace Emergency Diesel Generator - Bay d'Espoir	611.4	282.7		894.1	
Upgrade Burnt Dam Spillway - Bay d'Espoir		885.8		885.8	C - 18
Automate Generator Deluge Systems Units 5 and 6 - Bay d'Espoir		532.0		532.0	C - 24
Upgrade Generator Bearings- Bay d'Espoir		480.9		480.9	D - 33
Overhaul Turbine/Generator Units - Bay d'Espoir and Cat Arm		428.1		428.1	D - 45
Replace Automatic Transfer Switches - Hinds Lake		314.7		314.7	D - 51
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir		298.1		298.1	D - 56
Replace MicroSCADA Computers - Granite Canal		297.4		297.4	D - 78
Replace North End Equipment Door - Bay d'Espoir		265.5		265.5	D - 107
Replace Auto Greasing Systems Units 1 and 3 - Bay d'Espoir		260.1		260.1	D - 116
Install Automated Fuel Monitoring System - Upper Salmon		192.7		192.7	E - 2
Replace Cooling Water Pumps - Bay d'Espoir		175.4		175.4	E - 19
Replace Fall Arrest System on Surge Tank 2 - Bay d'Espoir		153.0		153.0	E - 22
Replace By-Pass Valves Units 3 and 4 - Bay d'Espoir		141.9		141.9	E - 26
Purchase Low Pressure Screw Compressor Set - Bay d'Espoir		97.3		97.3	E - 41
Install Waste Oil Storage Tank for PCB's - Bay d'Espoir		48.9		48.9	
Replace Emergency Diesel Fuel Tank - Paradise River		46.3		46.3	
Upgrade Water Flow Control Structure RR Pond - Granite Canal		43.5		43.5	
TOTAL HYDRAULIC PLANT	2,425.3	12,903.0	0.0	15,328.3	

PROJECT DESCRIPTION	Expended to 2012	2013	Future Years	Total	Page Ref
			($000)		
THERMAL PLANT					
Rewind Generator Units 1 and 2 - Holyrood	112.2	1,107.6	10,681.4	11,901.2	
Install Variable Frequency Drives on Forced Draft Fans - Holyrood		697.6	2,659.7	3,357.3	C - 6
Replace Fuel Oil Heat Tracing - Holyrood	1,474.3	1,413.9		2,888.2	
Upgrade Governor Controls on Units 1 and 2 - Holyrood		1,455.5		1,455.5	C - 8
Complete Condition Assessment Phase 2 (Year 2) - Holyrood		1,170.2		1,170.2	C - 12
Overhaul Unit 3 Turbine Valves - Holyrood		993.9		993.9	C - 14
Install Backup System for Raw Water Supply and Clarifier - Holyrood		955.6		955.6	C - 16
Upgrade Vibration Monitoring Equipment - Holyrood		519.9		519.9	C - 20
Upgrade Fuel Oil Day Tank - Holyrood		584.2		584.2	C - 22
Install Cold-Rehead Condensate Drains and High Pressure Heater Trip Level Unit 3 - Holyrood		50.0	448.1	498.1	D - 2
Upgrade Electrical Equipment - Holyrood	209.6	212.1		421.7	
Install Fire Protection Upgrades - Holyrood		267.2		267.2	D - 84
Overhaul Unit 3 Boiler Feed Pump West - Holyrood		178.5		178.5	E - 11
Replace Condensate Polisher Annunicator Panels - Holyrood		123.5		123.5	E - 31
Overhaul Unit 2 Extraction Pump South - Holyrood		101.5		101.5	E - 34
TOTAL THERMAL PLANT	1,796.1	9,831.2	13,789.2	25,416.5	
GAS TURBINES					
Upgrade Gas Turbine Controls - Happy Valley		61.4	1,128.6	1,190.0	C - 10
TOTAL GAS TURBINE PLANTS	0.0	61.4	1,128.6	1,190.0	
TOOLS AND EQUIPMENT					
Purchase Tools and Equipment Less than $50,000		93.3		93.3	
TOTAL TOOLS AND EQUIPMENT	0.0	93.3	0.0	93.3	
TOTAL GENERATION	4,221.4	22,888.9	14,917.8	42,028.1	

PROJECT DESCRIPTION	Expended to 2012	2013	Future Years	Total	Page Ref
			($000)		
TERMINAL STATIONS					
Replace Instrument Transformers - Various Sites		593.2	3,074.8	3,668.0	C - 33
Upgrade Circuit Breakers - Various Sites		2,785.3		2,785.3	C - 42
Replace Compressed Air Systems - Sunnyside and Stoney Brook		303.0	2,105.9	2,408.9	C - 47
Upgrade Terminal Station - Wiltondale		697.7	1,173.3	1,871.0	C - 50
Perform Grounding Upgrades - Various Sites	645.2	329.0	682.5	1,656.7	
Upgrade Power Transformers - Various Sites		1,621.1		1,621.1	C - 52
Replace Disconnects - Various Sites		492.6		492.6	D - 123
Replace Insulators - Various Sites		187.1	287.9	475.0	D - 142
Install Online Vibration Monitoring System - Corner Brook Frequency Converter		382.8		382.8	D - 161
Replace Compressed Air Piping - Buchans	28.4	278.3		306.7	
Replace Optimho Relays on TL242 - Holyrood to Hardwoods		189.2		189.2	E - 102
Replace Surge Arrestors - Various Sites		121.3		121.3	E - 118
Install Transformer Fans - Conne River		114.9		114.9	E - 126
Replace 230 kV Breaker Controls - Bottom Brook		68.9		68.9	E - 129
TOTAL TERMINAL STATIONS	673.6	8,164.4	7,324.4	16,162.4	
TRANSMISSION					
Perform Wood Pole Line Management Program - Various Sites		2,466.7		2,466.7	C - 45
Replace Guy Wires TL215 - Doyles to Grand Bay	606.8	350.1	530.0	1,486.9	
TOTAL TRANSMISSION	606.8	2,816.8	530.0	3,953.6	
DISTRIBUTION					
Voltage Conversion - Labrador City	8,430.8	969.5		9,400.3	
Upgrade Distribution Systems - Various Sites		1,940.1	3,995.5	5,935.6	C - 29
Provide Service Extensions - All Service Areas		5,006.0		5,006.0	C - 31
Upgrade L2 Distribution Feeder - Glenburnie	2,960.1	596.6		3,556.7	
Additions for Load Distribution Systems - Various Sites		3,114.7		3,114.7	C - 35
Upgrade Distribution Systems - All Service Areas		2,790.0		2,790.0	C - 38
Upgrade Distribution Lines - Bay d'Espoir, Parsons Pond and Plum Point	1,385.2	1,110.5		2,495.7	
Replace Recloser Control Panels - Various Sites		209.7		209.7	D - 215
TOTAL DISTRIBUTION	12,776.1	15,737.1	3,995.5	32,508.7	

PROJECT DESCRIPTION	Expended to 2012	2013	Future Years	Total	Page Ref
			($000)		
GENERATION					
Additions for Load Isolated Generation Stations - Various Sites		2,040.2	9,357.9	11,398.1	C - 27
Perform Arc Flash Remediation - Various Sites	809.8	391.0	814.9	2,015.7	
Overhaul Diesel Units - Various Sites		977.8		977.8	C - 56
TOTAL GENERATION	809.8	3,409.0	10,172.8	14,391.6	
PROPERTIES					
Install Automatic Fire Sprinkler System - Bay d'Espoir		429.9		429.9	D - 149
Install Additional Washrooms - Various Sites		250.9		250.9	D - 210
Install Fall Protection Equipment - Various Sites		196.6		196.6	E - 64
Legal Survey of Primary Distribution Line Right of Way - Various Sites		156.2	40.0	196.2	E - 113
TOTAL PROPERTIES	0.0	1,033.6	40.0	1,073.6	
METERING					
Install Automated Meter Reading - Plum Point and Bear Cove	379.6	287.7		667.3	
Install Automated Meter Reading - Various Sites		397.9	258.8	656.7	C - 58
Purchase Meters, Equipment and Metering Tanks - Various Sites		199.5		199.5	E - 45
Purchase 10 Position Meter Calibration Test Console - Hydro Place		192.5		192.5	E - 73
TOTAL METERING	379.6	1,077.6	258.8	1,716.0	
TOOLS AND EQUIPMENT					
Replace Off-Road Track Vehicles - Whitbourne, Happy Valley and Port Saunders		416.8	1,054.1	1,470.9	C - 54
Replace Off Road Track Vehicles - Flower's Cove and Cow Head	482.5	395.6		878.1	
Purchase Tools and Equipment Less than $50,000		525.3		525.3	
Replace Light Duty Mobile Equipment - Various Sites		476.5		476.5	D - 136
TOTAL TOOLS AND EQUIPMENT	482.5	1,814.2	1,054.1	3,350.8	
TOTAL TRANSMISSION AND RURAL OPERATIONS	15,728.4	34,052.7	23,375.6	73,156.7	

PROJECT DESCRIPTION	Expended to 2012	2013	Future Years	Total	Page Ref
			($000)		
INFORMATION SYSTEMS					
SOFTWARE APPLICATIONS					
New Infrastructure					
Perform Minor Application Enhancements - Hydro Place		126.8		126.8	E - 149
Cost Recoveries		(45.7)		(45.7)	
Upgrade of Technology					
Upgrade Microsoft Products - Various Sites		656.7	920.3	1,577.0	C - 64
Cost Recoveries		(236.4)	(331.3)	(567.7)	
Upgrade JD Edwards - Hydro Place	284.0	587.6		871.6	
Cost Recoveries	(96.6)	(199.8)		(296.4)	
Upgrade Business Intelligence Software - Hydro Place		576.9		576.9	C - 69
Cost Recoveries		(207.7)		(207.7)	
Upgrade Energy Management System - Hydro Place		129.9		129.9	E - 138
TOTAL SOFTWARE APPLICATIONS	187.4	1,388.3	589.0	2,164.7	
COMPUTER OPERATIONS					
Infrastructure Replacement					
Replace Personal Computers - Various Sites		463.9		463.9	D - 234
Replace Peripheral Infrastructure - Various Sites		309.9		309.9	D - 259
Upgrade Enterprise Storage Capacity - Hydro Place		194.9		194.9	E - 140
Cost Recoveries		(70.2)		(70.2)	
Upgrade of Technology					
Upgrade Server Technology Program - Various Sites		499.4		499.4	D - 239
Cost Recoveries		(131.8)		(131.8)	
Replace Computer Room Air Conditioner - Hydro Place		130.0		130.0	E - 143
Cost Recoveries		(46.8)		(46.8)	
Replace Helpdesk Service Manager Application - Hydro Place		96.5		96.5	E - 151
Cost Recoveries		(34.7)		(34.7)	
TOTAL COMPUTER OPERATIONS	0.0	1,411.1	0.0	1,411.1	
TOTAL INFORMATION SYSTEMS	187.4	2,799.4	589.0	3,575.8	

PROJECT DESCRIPTION	Expended to 2012	2013	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	C - 62
Replace Radomes - Various Sites		336.0		336.0	D - 245
Purchase Tools and Equipment Less than $50,000		45.6		45.6	
Network Infrastructure					
Replace Battery Banks and Chargers - Various Sites		782.0		782.0	C - 67
Replace Network Communications Equipment - Various Sites		182.4		182.4	E - 133
Upgrade of Technology					
Replace Telephone System - St. Anthony		135.4		135.4	E - 135
Upgrade Site Facilities - Various Sites		49.8		49.8	
TOTAL TELECONTROL	0.0	2,070.2	706.9	2,777.1	
TRANSPORTATION					
Replace Vehicles and Aerial Devices (2012-2013) - Various Sites	1,711.4	1,218.8		2,930.2	
Replace Vehicles and Aerial Devices (2013-2014) - Various Sites		1,302.3	679.2	1,981.5	C - 60
TOTAL TRANSPORTATION	1,711.4	2,521.1	679.2	4,911.7	
ADMINISTRATION					
Front End Engineering Design - Hydro Place		472.1		472.1	D - 231
Remove Safety Hazards - Various Sites		250.5		250.5	D - 264
Purchase Tools and Equipment Less than $50,000		89.9		89.9	
TOTAL ADMINISTRATION	0.0	812.5	0.0	812.5	
TOTAL GENERAL PROPERTIES	1,898.8	8,203.2	1,975.1	12,077.1	

	2013
GENERATION	16,536.4
TRANSMISSION AND RURAL OPERATIONS	22,086.9
GENERAL PROPERTIES	4,149.7
ALLOWANCE FOR UNFORESEEN EVENTS	1,000.0
TOTAL PROJECTS UNDER $50,000	942.6
MULTI-YEAR (2013 Expenditures):	
Multi-year Projects Commencing in 2013	9,802.8
Multi-year Projects Commencing in 2012	6,482.9
Multi-year Projects Commencing Prior to 2012:	
Replace Static Excitation Systems - Upper Salmon,Holyrood and Hinds Lake	2,295.2
Upgrade Electrical Equipment - Holyrood	212.1
Perform Grounding Upgrades - Various Sites	329.0
Replace Guy Wires TL215 - Doyles to Grand Bay	350.1
Voltage Conversion - Labrador City	969.5
Upgrade L2 Distribution Feeder - Glenburnie	596.6
Perform Arc Flash Remediation - Various Sites	391.0
TOTAL CAPITAL BUDGET	**66,144.8**

PROJECT DESCRIPTION	**2013**
Generation	
HYDRAULIC PLANT	
Replace Stator Windings Unit 1 - Bay d'Espoir	5,663.5
Upgrade Burnt Dam Spillway - Bay d'Espoir	885.8
Automate Generator Deluge Systems Units 5 and 6 - Bay d'Espoir	532.0
Upgrade Generator Bearings - Bay d'Espoir	480.9
Overhaul Turbine/Generator Units - Bay d'Espoir and Cat Arm	428.1
Replace Automatic Transfer Switches - Hinds Lake	314.7
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir	298.1
Replace MicroSCADA Computers - Granite Canal	297.4
Replace North End Equipment Door - Bay d'Espoir	265.5
Replace Auto Greasing Systems Units 1 and 3 - Bay d'Espoir	260.1
Install Automated Fuel Monitoring System - Upper Salmon	192.7
Replace Cooling Water Pumps - Bay d'Espoir	175.4
Replace Fall Arrest System on Surge Tank 2 - Bay d'Espoir	153.0
Replace By-Pass Valves Units 3 and 4 - Bay d'Espoir	141.9
Purchase Low Pressure Screw Compressor Set - Bay d'Espoir	97.3
THERMAL PLANT	
Upgrade Governor Controls on Units 1 and 2 - Holyrood	1,455.5
Complete Condition Assessment Phase 2 (Year2) - Holyrood	1,170.2
Overhaul Unit 3 Turbine Valves - Holyrood	993.9
Install Backup System for Raw Water Supply and Clarifier - Holyrood	955.6
Upgrade Vibration Monitoring Equipment - Holyrood	519.9
Upgrade Fuel Oil Day Tank - Holyrood	584.2
Install Fire Protection Upgrades - Holyrood	267.2
Overhaul Unit 3 Boiler Feed Pump West - Holyrood	178.5
Replace Condensate Polisher Annunicator Panels - Holyrood	123.5
Overhaul Unit 2 Extraction Pump South - Holyrood	101.5
TOTAL GENERATION	16,536.4

PROJECT DESCRIPTION	2013
Transmission and Rural Operations	
TERMINAL STATIONS	
Upgrade Circuit Breakers - Various Sites	2,785.3
Upgrade Power Transformers - Various Sites	1,621.1
Replace Disconnects - Various Sites	492.6
Install Online Vibration Monitoring System - Corner Brook Frequency Converter	382.8
Replace Optimho Relays on TL242 - Holyrood to Hardwoods	189.2
Replace Surge Arrestors - Various Sites	121.3
Install Transformer Fans - Conne River	114.9
Replace 230 kV Breaker Controls - Bottom Brook	68.9
TRANSMISSION	
Perform Wood Pole Line Management Program - Various Sites	2,466.7
DISTRIBUTION	
Provide Service Extensions - All Service Areas	5,006.0
Additions for Load Distribution Systems - Various Sites	3,114.7
Upgrade Distribution Systems - All Service Areas	2,790.0
Replace Recloser Control Panels - Various Sites	209.7
GENERATION	
Overhaul Diesel Units - Various Sites	977.8
PROPERTIES	
Install Automatic Fire Sprinkler System - Bay d'Espoir	429.9
Install Additional Washrooms - Various Sites	250.9
Install Fall Protection Equipment - Various Sites	196.6
METERING	
Purchase Meters, Equipment and Metering Tanks - Various Sites	199.5
Purchase 10 Position Meter Calibration Test Console - Hydro Place	192.5
TOOLS AND EQUIPMENT	
Replace Light Duty Mobile Equipment - Various Sites	476.5
TOTAL TRANSMISSION AND RURAL OPERATIONS	22,086.9

PROJECT DESCRIPTION	2013
General Properties	
INFORMATION SYSTEMS	
SOFTWARE APPLICATIONS	
New Infrastructure	
Perform Minor Application Enhancements - Hydro Place	126.8
Cost Recoveries	(45.7)
Upgrade of Technology	
Upgrade Business Intelligence Software - Hydro Place	576.9
Cost Recoveries	(207.7)
Upgrade Energy Management System - Hydro Place	129.9
COMPUTER OPERATIONS	
Infrastructure Replacement	
Replace Personal Computers - Various Sites	463.9
Replace Peripheral Infrastructure - Various Sites	309.9
Upgrade Enterprise Storage Capacity - Hydro Place	194.9
Cost Recoveries	(70.2)
Upgrade of Technology	
Upgrade Server Technology Program - Various Sites	499.4
Cost Recoveries	(131.8)
Replace Computer Room Air Conditioner - Hydro Place	130.0
Cost Recoveries	(46.8)
Replace Helpdesk Service Manager Application - Hydro Place	96.5
Cost Recoveries	(34.7)
TELECONTROL	
NETWORK SERVICES	
Infrastructure Replacement	
Replace Radomes - Various Sites	336.0
Network Infrastructure	
Replace Battery Banks and Chargers - Various Sites	782.0
Replace Network Communications Equipment - Various Sites	182.4
Upgrade of Technology	
Replace Telephone System - St. Anthony	135.4
ADMINISTRATION	
Front End Engineering Design - Hydro Place	472.1
Remove Safety Hazards - Various Sites	250.5
TOTAL GENERAL PROPERTIES	4,149.7
TOTAL SINGLE YEAR PROJECTS OVER $50,000	**42,773.0**

Multi-year Projects Commencing in 2013

PROJECT DESCRIPTION	2013	2014	2015	2016	2017	Total
Install Cold-Rehead Condensate Drains and High Pressure Heater Trip Level Unit 3 - Holyrood	50.0	448.1				498.1
Install Variable Frequency Drives on Forced Draft Fans - Holyrood	697.6	2,659.7				3,357.3
Upgrade Gas Turbine Controls - Happy Valley	61.4	1,128.6				1,190.0
Replace Instrument Transformers - Various Sites	593.2	552.8	538.4	1,511.7	471.9	3,668.0
Replace Compressed Air Systems - Sunnyside and Stoney Brook	303.0	2,105.9				2,408.9
Upgrade Terminal Station - Wiltondale	697.7	1,173.3				1,871.0
Replace Insulators - Various Sites	187.1	287.9				475.0
Upgrade Distribution Systems - Various Sites	1,940.1	3,995.5				5,935.6
Additions for Load Isolated Generation Stations - Various Sites	2,040.2	9,357.9				11,398.1
Install Automated Meter Reading - Various Sites	397.9	258.8				656.7
Legal Survey of Primary Distribution Line Right of Way - Various Sites	156.2	40.0				196.2
Replace Off-Road Track Vehicles - Whitbourne, Happy Valley and Port Saunders	416.8	1,054.1				1,470.9
Upgrade Microsoft Products - Various Sites	656.7	455.1	465.2			1,577.0
Cost Recoveries	(236.4)	(163.8)	(167.5)			(567.7)
Replace MDR4000 Microwave Radio (West) - Various Sites	539.0	706.9				1,245.9
Replace Vehicles and Aerial Devices (2013-2014) - Various Sites	1,302.3	679.2				1,981.5
Total Multi-Year Projects over $50,000 commencing in 2013	**9,802.8**	**24,740.0**	**836.1**	**1,511.7**	**471.9**	**37,362.5**

Multi-year Projects Commencing in 2012

PROJECT DESCRIPTION	Expended to 2012	2013	2014	2015	2016	2017	Total
Replace Emergency Diesel Generator - Bay d'Espoir	611.4	282.7					894.1
Rewind Generator Units 1 and 2 - Holyrood	112.2	1,107.6	4,885.7	5,795.7			11,901.2
Replace Fuel Oil Heat Tracing - Holyrood	1,474.3	1,413.9					2,888.2
Replace Compressed Air Piping - Buchans	28.4	278.3					306.7
Upgrade Distribution Lines - Bay d'Espoir, Parsons Pond and Plum Point	1,385.2	1,110.5					2,495.7
Install Automated Meter Reading - Plum Point and Bear Cove	379.6	287.7					667.3
Replace Off Road Track Vehicles - Flower's Cove and Cow Head	482.5	395.6					878.1
Upgrade JD Edwards - Hydro Place	284.0	587.6					871.6
Cost Recoveries	(96.6)	(199.8)					(296.4)
Replace Vehicles and Aerial Devices (2012-2013) - Various Sites	1,711.4	1,218.8					2,930.2
TOTAL MULTI-YEAR PROJECTS OVER $50,000 COMMENCING 2012	**6,372.4**	**6,482.9**	**4,885.7**	**5,795.7**	**0.0**	**0.0**	**23,536.7**

PROJECT DESCRIPTION	Expended to 2012	2013	Future Years	Total	Page Ref
		($000)			
GENERATION					
Rewind Generator Units 1 and 2 - Holyrood	112.2	1,107.6	10,681.4	11,901.2	
Replace Stator Windings Unit 1 - Bay d'Espoir		5,663.5		5,663.5	C -3
Replace Static Excitation Systems - Upper Salmon, Holyrood and Hinds Lake	1,813.9	2,295.2		4,109.1	
Install Variable Frequency Drives on Forced Draft Fans - Holyrood		697.6	2,659.7	3,357.3	C - 6
Replace Fuel Oil Heat Tracing - Holyrood	1,474.3	1,413.9		2,888.2	
Upgrade Governor Controls on Units 1 and 2 - Holyrood		1,455.5		1,455.5	C - 8
Upgrade Gas Turbine Controls - Happy Valley		61.4	1,128.6	1,190.0	C - 10
Complete Condition Assessment Phase 2 (Year 2) - Holyrood		1,170.2		1,170.2	C - 12
Overhaul Unit 3 Turbine Valves - Holyrood		993.9		993.9	C - 14
Install Backup System for Raw Water Supply and Clarifier - Holyrood		955.6		955.6	C - 16
Replace Emergency Diesel Generator - Bay d'Espoir	611.4	282.7		894.1	
Upgrade Burnt Dam Spillway - Bay d'Espoir		885.8		885.8	C - 18
Upgrade Vibration Monitoring Equipment - Holyrood		519.9		519.9	C - 20
Upgrade Fuel Oil Day Tank - Holyrood		584.2		584.2	C - 22
Automate Generator Deluge Systems Units 5 and 6 - Bay d'Espoir		532.0		532.0	C - 24
TOTAL GENERATION	4,011.8	18,619.0	14,469.7	37,100.5	
TRANSMISSION AND RURAL OPERATIONS					
Additions for Load Isolated Generation Stations - Various Sites		2,040.2	9,357.9	11,398.1	C - 27
Voltage Conversion - Labrador City	8,430.8	969.5		9,400.3	
Upgrade Distribution Systems - Various Sites		1,940.1	3,995.5	5,935.6	C - 29
Provide Service Extensions - All Service Areas		5,006.0		5,006.0	C - 31
Replace Instrument Transformers - Various Sites		593.2	3,074.8	3,668.0	C - 33
Upgrade L2 Distribution Feeder - Glenburnie	2,960.1	596.6		3,556.7	
Additions for Load Distribution Systems - Various Sites		3,114.7		3,114.7	C - 35
Upgrade Distribution Systems - All Service Areas		2,790.0		2,790.0	C - 38
Upgrade Circuit Breakers - Various Sites		2,785.3		2,785.3	C - 42
Upgrade Distribution Lines - Bay d'Espoir, Parsons Pond and Plum Point	1,385.2	1,110.5		2,495.7	
Perform Wood Pole Line Management Program - Various Sites		2,466.7		2,466.7	C - 45
Replace Compressed Air Systems - Sunnyside and Stoney Brook		303.0	2,105.9	2,408.9	C - 47
Perform Arc Flash Remediation - Various Sites	809.8	391.0	814.9	2,015.7	
Upgrade Terminal Station - Wiltondale		697.7	1,173.3	1,871.0	C - 50
Perform Grounding Upgrades - Various Sites	645.2	329.0	682.5	1,656.7	
Upgrade Power Transformers - Various Sites		1,621.1		1,621.1	C - 52
Replace Guy Wires TL215 - Doyles to Grand Bay	606.8	350.1	530.0	1,486.9	

PROJECT DESCRIPTION	Expended to 2012	2013	Future Years	Total	Page Ref
			($000)		
TRANSMISSION AND RURAL OPERATIONS (cont'd.)					
Replace Off-Road Track Vehicles - Whitbourne, Happy Valley and Port Saunders		416.8	1,054.1	1,470.9	C - 54
Overhaul Diesel Units - Various Sites		977.8		977.8	
Replace Off Road Track Vehicles - Flower's Cove and Cow Head	482.5	395.6		878.1	C - 56
Install Automated Meter Reading - Plum Point and Bear Cove	379.6	287.7		667.3	
Install Automated Meter Reading - Various Sites		397.9	258.8	656.7	C - 58
TOTAL TRANSMISSION AND RURAL OPERATIONS	15,700.0	29,580.5	23,047.7	68,328.2	
GENERAL PROPERTIES					
Replace Vehicles and Aerial Devices (2012-2013) - Various Sites	1,711.4	1,218.8		2,930.2	
Replace Vehicles and Aerial Devices (2013-2014) - Various Sites		1,302.3	679.2	1,981.5	C - 60
Replace MDR4000 Microwave Radio (West) - Various Sites		539.0	706.9	1,245.9	C - 62
Upgrade Microsoft Products - Various Sites		420.3	589.0	1,009.3	C - 64
Replace Battery Banks and Chargers - Various Sites		782.0		782.0	C - 67
Upgrade JD Edwards - Hydro Place	187.4	387.8		575.2	
Upgrade Business Intelligence Software - Hydro Place[1]		369.2		369.2	C - 69
TOTAL GENERAL PROPERTIES	1,898.8	5,019.4	1,975.1	8,893.3	
TOTAL PROJECTS $500,000 AND OVER	21,610.6	53,218.9	39,492.5	114,322.0	

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

Project Title: Replace Stator Windings Unit 1

Location: Bay d' Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This proposal is a one year project for the replacement of a stator windings on Unit 1 at the Bay d'Espoir Hydroelectric Station. The work will include the removal of the existing windings and its replacement will include the purchase, installation and commissioning of complete sets of stator windings, upgrading the generator protection, remediation of asbestos from the stator components and the refurbishment of the rotor poles to ensure the new windings operate at their full capability. Hydro intends to replace the Unit 1 stator in 2013.

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

Table 1: Budget Estimate

Project Cost: ($ x1,000)	**2013**	**2014**	**Beyond**	**Total**
Material Supply	307.9	0.0	0.0	307.9
Labour	535.1	0.0	0.0	535.1
Consultant	14.0	0.0	0.0	14.0
Contract Work	3,453.2	0.0	0.0	3,453.2
Other Direct Costs	103.0	0.0	0.0	103.0
Interest and Escalation	367.7	0.0	0.0	367.7
Contingency	882.6	0.0	0.0	882.6
TOTAL	**5,663.5**	**0.0**	**0.0**	**5,663.5**

Operating Experience:

Unit 1 is designed for continuous operation with varying loads to meet system requirements. With the exception of maintenance outages, Unit 1 has been operating continuously since it was commissioned in 1967.

Project Title: Replace Stator Windings Unit 1 **(cont'd.)**

Project Justification:

This project is required to maintain system reliability. Unit 2 stator windings were replaced in 2010 on budget and on schedule, with Unit 4 being replaced in 2012. Unit 1 is in a similar state of deterioration as Units 2 and 4 before their replacements and Unit 1 should be replaced. Hipot Testing in 2012 had to be stopped due to the rate of rise of the leakage current for concern of damage to the stator windings. This failed test is an indication of minimal remaining insulation level on the stator winding.

The failure of a stator winding while in service would cause significant damage to the stator core and rotor and an emergency replacement would cost considerably more than a planned replacement. Present estimates would put a planned outage of the unit at six months and an emergency replacement at 12 to 18 months. The run to failure approach would impair Hydro's ability to provide least-cost, reliable electricity.

The life expectancy for asphalt insulated stator windings is 40 years. Since the stator windings on Unit 1 are beyond its anticipated useful life, a replacement of stator windings is requested.

During Unit 2 stator replacement work in 2010, it was determined that movement or migration of the stator laminations had occurred. It is anticipated that this condition also exists on Unit 1 however, the level of this condition cannot be determined until the actual replacement occurs. The migration of the stator core is a serious condition that can lead to failure of the stator windings. To be prudent, a planned approach is the replacement of the Unit 1 stator windings before failure and the uncertain reliability of this unit. Unit 1 is used for station service within the powerhouse and its failure would reduce the reliability of all the generating units and the Island Interconnected System.

Hydro engaged the services of an independent consultant, AMEC Americas Limited (AMEC) to assess the condition the Bay d'Espoir generating units in 2011 with a follow-up report in 2012. The 2012 report recommends the replacement of Unit 1 as soon as possible.

Project Title: Replace Stator Windings Unit 1 **(cont'd.)**

Future Plans:

Other replacement of stator windings will be proposed in future capital budget applications.

Attachments:

See report entitled "Replacement of Stator Windings" located in Volume I, Tab 1 for further details.

Project Title: Install Variable Frequency Drives on Forced Draft Fans

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Justified

Project Description:

This project will involve the design, procurement, installation, and commissioning of six variable frequency drives (VFD) units to the existing system at Holyrood. This will enable the six forced draft fan motors to directly adjust the airflow into the boilers as necessary. The ability to directly manipulate the airflow will remove the need for some elements of the existing forced draft system so they will be removed as well. It will also require programming of the Foxboro control system to utilize the new variable speed capabilities of the motors. The budget for the project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	453.9	1,285.0	0.0	1,738.9
Labour	53.9	43.4	0.0	97.3
Consultant	21.0	0.0	0.0	21.0
Contract Work	90.0	523.0	0.0	613.0
Other Direct Costs	37.7	25.5	0.0	63.2
Interest and Escalation	41.1	276.1	0.0	317.2
Contingency	0.0	506.7	0.0	506.7
TOTAL	**697.6**	**2,659.7**	**0.0**	**3,357.3**

Operating Experience:

The generating units at Holyrood have a range of operation between 20 to 105 percent of their maximum capacity rating (MCR). Generally, the units are not operated below 40 percent as these operating levels are highly inefficient. As a generating unit nears 100 percent of its MCR, the efficiency of the constant speed fan motors becomes higher. A majority of each year is spent with the generating units operating at loading levels which are less than its maximum. Regardless of operating level, the forced draft fan motors operate at full speed (1189 RPM) and consume the full 1120 kW of energy on a continuous basis.

Project Title: Install Variable Frequency Drives on Forced Draft Fans **(cont'd.)**

Project Justification:

The installation of VFDs onto the forced draft fan motors at the Holyrood thermal plant will yield significant energy and cost savings for Hydro. This project will yield an average annual fuel savings of $4.7 million while the Holyrood plant is generating electricity when compared to the status quo of constant speed fan motors. The project will cost $3.36 million and will commence in 2013 and be completed in 2014. A detailed analysis shows that the project will pay for itself within less than one year of being put into service in 2014.

Future Plans:

None.

Attachments:

See report entitled "Install Variable Frequency Drives on Six Forced Draft Fans" located in Volume I, Tab 2, for further project details.

Project Title: Upgrade Governor Controls on Units 1 and 2

Location: Holyrood Plant

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is to upgrade the existing General Electric (GE) Mark V turbine controller on Units 1 and 2 at Holyrood Thermal Generating Station (HTGS) to the modern GE Mark VIe turbine controller. GE offers a migration of the Mark V controller to the Mark VIe controller bringing the older technology to today's standards. Modern circuit boards and controllers using Mark VIe technology will be used. Engineering design, hardware, software and field services will be provided by GE. The migration allows for minimal downtime and site disruption with no impact to the field wiring, turbine devices or location of the existing Mark V cabinet. Project Execution will provide project management, design and installation and commissioning support. A contractor will complete the installation and Holyrood personnel will assist with the installation and commissioning.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	346.0	0.0	0.0	346.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	774.3	0.0	0.0	774.3
Other Direct Costs	19.1	0.0	0.0	19.1
Interest and Esclation	88.2	0.0	0.0	88.2
Contingency	227.9	0.0	0.0	227.9
TOTAL	**1,455.5**	**0.0**	**0.0**	**1,455.5**

Operating Experience:

The Mark V turbine controller has operated well since the installation on Unit 1 in 2003 and Unit 2 in 1999. There have been forced shutdowns to reset the communications core when the communications card has locked up.

Project Title: Upgrade Governor Controls on Units 1 and 2 **(cont'd.)**

Project Justification:

The Mark V turbine controller will enter Phase 5, Obsolete, of the Life Cycle Plan in 2014. In this phase, as per General Electric (GE), " the product is no longer supported, and is not recommended for continued use in a machinery protection application." The turbine controller is critical for operation of the units and a failure of a component without the proper part or support would prevent the unit from operating. The turbine controller is used for the application of load, turbine over speed protection, thermal stress protection and automatic run-up and synchronizing capabilities.
GE offer a migration solution to move the hardware and software to the Mark VIE modern turbine controller.

Future Plans:

None.

Attachments:

See report entitled "Upgrade Governors on Units 1 and 2" located in Volume I, Tab 3 for further details.

Project Title: Upgrade Gas Turbine Controls

Location: Happy Valley

Category: Generation - Gas Turbines

Definition: Other

Classification: Normal

Project Description:

The existing control system on the 27MW Happy Valley Gas Turbine generating unit is comprised of a Texas Instruments Programmable Logic Controller (PLC) that provides sequencer functions, a Woodward Netcon 5000 system that provides governor functions, Genesis32 software that provides the operator interface, and IRD Mechanalysis and United Technologies units that provide vibration monitoring and protection. These systems, most of which are no longer supported by their manufacturers, are to be replaced by a complete new system. This purpose of this project is to integrate the functionality of the existing PLC and Netcon 5000 into a common control system with an associated local operator console. In addition, a new vibration monitoring system will replace the existing outdated system, and subject to the control system manufacturer, may be part of the new control system.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	0.0	10.0	0.0	10.0
Labour	42.0	331.0	0.0	373.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	460.7	0.0	460.7
Other Direct Costs	15.0	58.0	0.0	73.0
Interest and Escalation	4.4	85.6	0.0	90.0
Contingency	0.0	183.3	0.0	183.3
TOTAL	**61.4**	**1,128.6**	**0.0**	**1,190.0**

Operating Experience:

The existing control and monitoring system has performed in an acceptable manner over the past 20 years. Although not prone to failures or frequent maintenance, each of the three main devices are obsolete and most components are either not supported or can only be repaired or exchanged subject to their availability in the manufacturer's stock of refurbished units. The PLC, governor, vibration

Project Title: Upgrade Gas Turbine Controls **(cont'd.)**

Operating Experience: (cont'd.)

monitors and operator console are from four different manufacturers. In addition, the logic for the governor and sequencer are not in easily serviceable formats. Refer to Section 3.2 of the attached report for details on the operating experience of this project.

Project Justification:

The existing control system that is presently operating on the 27 MW Happy Valley Gas turbine generating unit is obsolete and no longer supported by the manufacturers of the various components. Due to the lack of available spare parts, a major failure on any of these systems could result in a lengthy unit outage while a new system is being redesigned, purchased and installed. Depending on the time of year, a failure of this type could result in lack of power transmission over the transmission line from Churchill Falls and thus extensive customer outages. As a result, Hydro is proposing that these systems be upgraded to increase reliability of the control system and before customer outages are experienced as a result of component failures.

Future Plans:

None.

Attachments:

See report entitled "Upgrade Gas Turbine Control and Monitoring System" located in Volume 1, Tab 4 for further details.

Project Title: Complete Condition Assessment Phase 2 (Year 2)

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is the second 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 in 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 year of Phase 2 was approved by the Board for completion under Hydro's 2012 capital program application with a project budget of $1.22 million.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	20.0	0.0	0.0	20.0
Labour	125.2	0.0	0.0	125.2
Consultant	325.0	0.0	0.0	325.0
Contract Work	435.2	0.0	0.0	435.2
Other Direct Costs	4.0	0.0	0.0	4.0
Interest and Escalation	78.9	0.0	0.0	78.9
Contingency	181.9	0.0	0.0	181.9
TOTAL	**1,170.2**	**0.0**	**0.0**	**1,170.2**

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 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 Title: Complete Condition Assessment Phase 2 (Year 2) **(cont'd.)**

Project Justification:

The Holyrood thermal generating station is over 40 years old and is past its expected life. 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 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 program should be pursued and what its scope should be.

Attachments:

See report entitled "Condition Assessment and Life Extension" located in Volume I, Tab 5, for further project details.

Project Title: Overhaul Unit 3 Turbine Valves

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

Turbine valves overhauls are scheduled to be carried out every three years. The valves of Unit 3 turbine were overhauled in 2010 and the next overhaul is due in 2013.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	180.0	0.0	0.0	180.0
Labour	73.8	0.0	0.0	73.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	520.0	0.0	0.0	520.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	65.3	0.0	0.0	65.3
Contingency	154.8	0.0	0.0	154.8
TOTAL	**993.9**	**0.0**	**0.0**	**993.9**

Operating Experience:

The Unit 3 turbine is operated in two modes:

1) Either as an electricity generator; or
2) As a synchronous condenser.

The unit is in electricity generation mode from November to April and then changed to synchronous condenser mode.

Project Justification:

The valves of a turbine control the steam flow to the steam turbine generator and hence the electricity production. An improperly functioning valve can cause an over speed of the turbine and

Project Title: Overhaul Unit 3 Turbine Valves **(cont'd.)**

Project Justification: (cont'd.)

result in damage to the steam turbine, and potentially to other property and result in potentially life threatening staff injuries. It is important for continued operations as well as safety to maintain the valves in proper condition. Hence, the turbine valves need to be overhauled and the three year frequency is supported by industry practice as well as consultants and original equipment manufacturers.

Future Plans:

To overhaul turbine valves every three years.

Attachments:

See report entitled "Unit 3 Turbine Valves Overhaul" located in Volume II, Tab 6, for further project details.

Project Title: Install Backup System for Raw Water Supply and Clarifier

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

The purpose of this project is to implement business continuity plans for two key processes at the Holyrood Thermal Generating Station (Holyrood):

- Raw water supply; and
- Raw water clarification.

This project will ensure that business continuity is achieved on the raw water supply by providing provisions for a secondary supply system. These provisions include a new diesel-powered pump, piping, and an enclosure to house the new equipment.

Business continuity concerns with the clarification processes at Holyrood will be addressed under this project through the installation of a bypass line around the existing clarifier.

At the completion of this project, business continuity plans will be in place for all key processes at Holyrood that pose a high risk for causing the plant's Maximum Acceptable Down Time to be exceeded.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	200.0	0.0	0.0	200.0
Labour	124.7	0.0	0.0	124.7
Consultant	56.0	0.0	0.0	56.0
Contract Work	366.1	0.0	0.0	366.1
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	59.5	0.0	0.0	59.5
Contingency	149.3	0.0	0.0	149.3
TOTAL	**955.6**	**0.0**	**0.0**	**955.6**

Project Title: Install Backup System for Raw Water Supply and Clarifier **(cont'd.)**

Operating Experience:

While there are no known operational issues with the existing raw water supply piping or raw water clarification system, full power output could only be sustained for 24 hours following a failure of either of these processes.

Project Justification:

Power production levels at Holyrood are expected to nearly double by 2017. This increase in power production will put a strain on the facility's aging infrastructure, namely its raw water supply and clarifier. Since Holyrood's raw water supply and clarifier have the potential to impede business continuity at a time when the production output from the plant is vital to meet growing demand, it is important that business continuity plans are put in place for these plant processes.

Future Plans:

None.

Attachments:

See report entitled "Install Backup System for Raw Water Supply and Clarifier" located in Volume II, Tab7, for further details.

Project Title: Upgrade Burnt Dam Spillway

Location: Burnt Dam

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is the third year of a four-year program to upgrade the Burnt Dam Spillway Structure (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 budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	160.0	0.0	0.0	160.0
Labour	411.3	0.0	0.0	411.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	122.0	0.0	0.0	122.0
Interest and Escalation	53.8	0.0	0.0	53.8
Contingency	138.7	0.0	0.0	138.7
TOTAL	**885.8**	**0.0**	**0.0**	**885.8**

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 required position 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 cause a fuse plug failure. However, it did cause the loss of a significant amount of reservoir water when both gates for a period of time could not be closed when required. It was estimated at that time that the cost to replace the value of the lost hydro generation with thermal generation from the Holyrood station was $2.6 million (based on $50 per barrel).

Project Title: Upgrade Burnt Dam Spillway **(cont'd.)**

Project Justification:

This project is justified on the requirement to replace failing or deteriorated infrastructure 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 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. When the four-year upgrade program for Burnt Spillway is complete, this hydraulic structure will be in a condition to operate safely and reliably for at least another 25 years.

Future Plans:

This is the third year of a four year program to upgrade Burnt Spillway. Further upgrades to the Burnt Spillway will be proposed as part of the 2014 capital budget application.

Attachments:

See report entitled "Upgrade Burnt Dam Spillway Structure" located in Volume II, Tab 8, for further project details.

Project Title: Upgrade Vibration Monitoring Equipment

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 generator portion (i.e the portion required for synchronous condensing operation) 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 located on the steam turbine generators.

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

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	2.0	0.0	0.0	2.0
Labour	124.0	0.0	0.0	124.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	285.0	0.0	0.0	285.0
Other Direct Costs	1.0	0.0	0.0	1.0
Interest and Escalation	25.5	0.0	0.0	25.5
Contingency	82.4	0.0	0.0	82.4
TOTAL	**519.9**	**0.0**	**0.0**	**519.9**

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 steam turbine generator 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 3 while in generation and synchronous condenser modes. The system is in Phase 4 of its life cycle in which

Project Title: Upgrade Vibration Monitoring Equipment **(cont'd.)**

Operating Experience: (cont'd.)

components can only be repaired or exchanged. The existing Bently Nevada 3300 Turbine Supervisory Instrumentation 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 where the vendor provides only for repair or exchange of components. It is required to upgrade the existing steam turbine monitoring system so Holyrood Units 1, 2, and 3 can continue to perform as a safe and reliable source of generation during their planned lifetimes. This upgrade should be undertaken prior to the components entering into the final 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 9 for further details.

Project Title: Upgrade Fuel Oil Day Tank

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

The fuel oil day tank at the Holyrood Thermal Generating Station (Holyrood) will be inspected and refurbished under this project. The project scope includes preparing tank for detailed inspections, tank inspections and refurbishments as required.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	10.0	0.0	0.0	10.0
Labour	84.0	0.0	0.0	84.0
Consultant	45.0	0.0	0.0	45.0
Contract Work	315.0	0.0	0.0	315.0
Other Direct Costs	2.0	0.0	0.0	2.0
Interest and Escalation	37.0	0.0	0.0	37.0
Contingency	91.2	0.0	0.0	91.2
TOTAL	**584.2**	**0.0**	**0.0**	**584.2**

Operating Experience:

The fuel oil day tank has been operating as intended; however, its condition is unknown. Since the tank's condition is unknown, its structural and operational integrity may unknowingly be at risk. This could impact personnel safety, operational reliability, and the environment.

Project Justification:

The American Petroleum Institute (API) recommends that tanks, such as the day tank at Holyrood, undergo an external inspection every five years and an internal inspection every ten years after its initial service date. The required inspection procedures are outlined in *API Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction*. The day tank at Holyrood has not been inspected since 1998. Therefore, it is recommended that the tank undergo a full inspection that is in compliance with the API 653 standard in 2013.

Project Title: Upgrade Fuel Oil Day Tank **(cont'd.)**

Future Plans:

None.

Attachments:

See report entitled "Upgrade Fuel Oil Day Tank" located in Volume II, Tab 10, for further details.

Project Title: Automate Generator Deluge Systems Units 5 and 6

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

The scope of work for this project is to replace the existing manually operated generator deluge system on generating Units 5 and 6 with a modern fully automatic deluge system. A new deluge control cabinet will be installed along with a new sprinkler distribution ring as the existing ring is not compatible with the new system. 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 concurrently 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 and the work is scheduled to be performed in 2013.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	40.0	0.0	0.0	40.0
Labour	160.6	0.0	0.0	160.6
Consultant	24.9	0.0	0.0	24.9
Contract Work	170.0	0.0	0.0	170.0
Other Direct Costs	16.1	0.0	0.0	16.1
Interest and Escalation	38.1	0.0	0.0	38.1
Contingency	82.3	0.0	0.0	82.3
TOTAL	**532.0**	**0.0**	**0.0**	**532.0**

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 is 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.

Project Title: Automate Generator Deluge Systems Units 5 and 6 **(cont'd.)**

Operating Experience: (cont'd.)

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 FM Global in 2007 and Hydro believes this risk should be mitigated.

Project Justification:

This project is justified based on the need for Hydro to upgrade the existing equipment to reduce exposure of operations personnel to harm 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 the 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 is the first year of a three year program to replace the manual deluge system on all seven units in Bay d'Espoir. The plan is to automate two units in each of the first two years and then three units in the third year (2015).

Project Title: Automate Generator Deluge Systems Units 5 and 6 **(cont'd.)**

Attachments:

See report entitled "Automate Generator Deluge Systems on Units 5 and 6" located in Volume II, Tab 11, for further project details.

Project Title: Additions for Load Isolated Generating Stations

Location: Various Sites

Category: Transmission and Rural Operations - Generation Northern

Definition: Pooled

Classification: Normal

Project Description:

The purpose of this project is to increase the firm generation capacity at the Hopedale, L'Anse au Loup and Nain Generating Stations. For each plant, this proposal consolidates all costs associated with the procurement and installation of a new diesel unit or the replacement of an existing unit with one or more of a larger prime rating.

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

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	382.1	2,810.3	0.0	3,192.4
Labour	413.8	1,658.9	0.0	2,072.7
Consultant	103.6	489.5	0.0	593.1
Contract Work	871.0	1,061.4	0.0	1,932.4
Other Direct Costs	143.3	678.0	0.0	821.3
Interest and Escalation	126.4	937.5	0.0	1,063.9
Contingency	0.0	1,722.3	0.0	1,722.3
TOTAL	**2,040.2**	**9,357.9**	**0.0**	**11,398.1**

Operating Experience:

When load exceeds the available generation capacity, a power outage will result and therefore reduce the overall reliability of the system. In determining the required generation capacity, Hydro applies a set of criteria that compares peak demand to the existing system capacity.

Project Justification:

This project is justified on the requirement to meet growing electricity needs of Hydro's customers serviced by the Hopedale, L'Anse Au Loup and Nain diesel plants. Sufficient generation capacity must be available in an isolated system on a firm basis such that the peak load can be met at all times.

Project Title: Additions for Load Isolated Generating Stations **(cont'd.)**

Future Plans:

Upon completion of this project, the Hopedale and Nain Generating Stations will have sufficient generation capacity to support the load beyond the 2032 forecast. The increase of firm capacity at L'Anse au Loup will support the load up to the year 2019. At that point another generation expansion will be required.

Attachment:

See report entitled "Additions to Accommodate Load Growth - Isolated Generating Stations - Hopedale, L'Anse au Loup and Nain" located in Volume II, Tab 12, for further project details.

Project Title: Upgrade Distribution Systems

Location: Various Sites

Category: Transmission and Rural Operations

Definition: Other

Classification: Normal

Project Description:

Hydro provides service to customers in rural communities within its service territory. 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 Grey River, South Brook, Holyrood, St. Brendan's, Charlottetown, Roddickton, Cow Head, and St. Lewis that have been identified as requiring upgrades to the existing infrastructure.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	399.0	670.0	0.0	1,069.0
Labour	525.0	404.0	0.0	929.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	585.0	1,845.0	0.0	2,430.0
Other Direct Costs	35.0	40.0	0.0	75.0
Interest and Escalation	144.3	387.7	0.0	532.0
Contingency	251.8	648.8	0.0	900.6
TOTAL	**1,940.1**	**3,995.5**	**0.0**	**5,935.6**

Operating Experience:

The distribution lines were originally constructed over 40 years ago. Most of the line components were installed at the time of original construction and have exceeded their 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 Title: Upgrade Distribution Systems **(cont'd.)**

Project Justification:

This project is justified 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 2012 Tab, Appendix A).

Attachments:

See report entitled "Distribution Line Upgrades - 2013" located in Volume II, Tab X, 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)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	2,248.0	0.0	0.0	2,248.0
Labour	1,442.0	0.0	0.0	1,442.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	531.0	0.0	0.0	531.0
Other Direct Costs	130.0	0.0	0.0	130.0
Interest and Escalation	215.0	0.0	0.0	215.0
Contingency	440.0	0.0	0.0	440.0
TOTAL	**5,006.0**	**0.0**	**0.0**	**5,006.0**

Operating Experience:

An analysis of average historical expenditures (2007 - 2011) on new customer connections by region is shown in the Table 2. All historical dollars were converted to 2011 dollars using the Statistics Canada Utility Distribution Line Construction index and a five year average was calculated.

Table 2: Average Annual Expenditures for 2007 to 2011

Region	**Avg. Annual Expenditures (2011 $000)**
Central	1,360
Northern	1,297
Labrador	2,079
Total	4,736

Project Title: Provide Service Extensions **(cont'd.)**

Operating Experience: (cont'd.)

The five year actual expenditures for service extensions by region are shown in Table 3.

Table 3: Five Year Expenditures

Expenditures ($000)											
	2007		2008		2009		2010		2011		2012
Region	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget
Central	844	967	910	1,186	1,028	1,133	1,001	1,448	1,045	1,886	1,200
Northern	618	960	637	803	758	1,432	768	1,356	1,092	1,040	1,267
Labrador	622	873	612	1,340	653	1,446	659	2,051	1,248	2,665	1,705
Total	2,084	2,800	2,159	3,329	2,439	4,011	2,428	4,855	3,385	5,591	4,172

Project Justification:

Based on the three-year average of service extension expenditures for the period 2009 - 2011 the budget shown in Table 4 was developed for the Northern and Labrador regions, assuming distribution line cost escalation in 2013 of approximately three percent over 2012. The same assumptions are valid for the Central region as well except that it was based on a five-year average for the period 2007-2011.

Table 4: Budget

Region	2013 Budget[1] ($000)
Central	1,437
Northern	1,371
Labrador	2,198
Total	5,006

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 (2013 Capital Plan Tab, Appendix A).

[1] *In recent years all areas of Labrador has experienced high customer growth – 201 new customers in 2007, 254 in 2008, 371 in 2009, 261 in 2010 and 279 in 2011. This growth is forecast to taper off in the near term. Because of this, a three year historical average was used to determine the service extension budget for 2012 for the Labrador region and the Northern region which serves the south coast of Labrador including the L'Anse au Loup system. A five year average was used for the Central region.*

Project Title: Replace Instrument Transformers

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Pooled

Classification: Normal

Project Description:

The instrument transformer replacement project is part of a multi-year program supported by Hydro's Long Term Asset Management Plans (LTAMPs). This project proposal is for the purchase and replacement of instrument transformers (ITs) contained within Hydro's five-year plan. The instrument transformer replacement program targets current transformers (CTs) and potential transformers (PTs) which operate within Hydro's terminal stations. Instrument transformers are included in the replacement plan as maintenance assessments dictate or as failures occur. The criteria for inclusion, based on maintenance assessments, consider the condition, PCB contamination and IMBA type CTs.

The budget estimate for the five-year plan is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**2015**	**2016**	**2017**	**Total**
Material Supply	257.2	233.8	222.1	795.0	10.0	1,518.1
Labour	182.0	165.4	157.2	273.0	289.5	1,067.0
Consultant	0.0	0.0	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0	0.0	0.0
Other Direct Costs	26.0	23.8	22.7	37.9	40.0	150.3
Interest and Escalation	35.1	45.2	56.0	184.6	64.5	385.4
Contingency	93.0	84.6	80.4	221.2	67.9	547.1
TOTAL	**593.2**	**552.8**	**538.4**	**1,511.6**	**471.9**	**3,668.0**

Operating Experience:

Instrument transformers provide critical inputs to protection, control and metering equipment required for the reliable operation and protection of the electrical power system. Instrument transformers that fail in-service can result in faults on the electrical system and outages to customers. Instrument transformers have been known to fail in-service, resulting in an explosion and fire, and pose a serious safety risk. When instrument transformers fail they are not repairable and require replacement.

Project Title: Replace Instrument Transformers **(cont'd.)**

Project Justification:

Hydro has developed a Long Term Asset Management Plan for instrument transformer replacements. The five-year plan is a series of project plans derived from the LTAMP and revised with the latest condition information. Lessons learned from previous instrument transformer replacement projects show that one year project plans are not feasible considering the long lead time for material delivery, the challenges with scheduling outages and unforeseen equipment failure. The ultimate expectation of the project will be to replace ITs within the budget set for each target year.

The instrument transformers have been prioritized and ranked for replacement based on condition, type and PCB contamination. Many of the instrument transformers have exceeded their useful service life and have been found to have leaks and are corroded. The IMBA type CTs have also exceeded their useful service life and pose safety and reliability risks with their continued operation. Finally, it is necessary for Hydro to administer a determined instrument transformer replacement program in order to meet Environment Canada *PCB Regulation SOR/2008-273*.

The five-year plan will support Hydro's initiative to replace deficient instrument transformers, all the while sustaining the long term objectives of the replacement program until 2025.

Future Plans:

Hydro intends to submit a five-year plan proposal in 2017 for instrument transformer replacements targeted within the LTAMP for each of the years from 2018 to 2022.

Attachments:

See report entitled "Replace Instrument Transformers" located in Volume II, Tab 14, for further project details.

Project Title: Additions for Load Distribution Systems

Location: Various Sites

Category: Transmission and Rural Operations - Distribution

Definition: Pooled

Classification: Normal

Project Description:

For 2013, four projects have been identified which are justified on the requirement to support load growth and to ensure peak capacity can be met. The projects for Hydro's 2013 Capital Budget Application are as follows:

1. Farewell Head Distribution System – Feeder L5 (FHD L5)

The project involves the construction of approximately eight kilometers of new distribution feeder to replace a section of the existing primary distribution line from the Fogo Substation to the community of Joe Batt's Arm. The work will consist of the construction of approximately eight kilometers of new distribution line which consists of 100 new primary structures and supports 4/0 AASC (Vancouver) primary conductor with 1/0 AASC (Montreal) neutral conductor. The work will be completed under contract obtained through public tender.

2. Farewell Head Distribution System – Feeder L6 (FHD L6)

The project involves the construction of approximately seven kilometers of new distribution feeder to replace a section of the existing primary distribution line from the Fogo Substation to the community of Seldom. The work will consist of the construction of approximately seven kilometers of new distribution line consisting of 85 new primary structures supporting 4/0 AASC (Vancouver) primary conductor with 1/0 AASC (Montreal) neutral conductor. The work will be completed under contract obtained through public tender.

3. St. Anthony Distribution System – Feeder L6 (STA L6)

The project involves the conversion of the distribution system voltage of St. Lunaire and Griquet from 12.5 kV to 25 kV, and the relocation of the substation currently located outside St. Lunaire to the Gunners Cove area past St. Lunaire and Griquet.

Project Title: Additions for Load Distribution Systems **(cont'd.)**

The work will consist of the following:

- Material and labour cost to replace distribution transformers;
- Relocate transformer bank (St. Lunaire Substation);
- Relocate voltage regulator bank SL6-VR1; and
- Retire capacitor bank from service.

The work will be completed under contract obtained through public tender.

4. Wabush Distribution System (WAB L11)

The project involves the construction of a new distribution feeder to supply the Wabush Industrial Park. The work consists of the following:

- Construction of approximately 1.5 km of new distribution line consisting of 22 new primary structures and 4/0 AASC (Vancouver) primary conductor.
- Supply and install recloser at the substation.
- Supply and install a group operated switch to complete a tie between L11 and the new feeder in the industrial park.

The work will be completed under contract obtained through public tender.

This is a single year project and the budget estimate is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**FHD L5**	**FHD L6**	**STA L6**	**WAB L11**	**Total**
Material Supply	170.0	145.0	250.0	87.5	652.5
Labour	150.0	140.0	100.0	100.7	490.7
Consultant	0.0	0.0	0.0	0.0	0.0
Contract Work	540.0	460.0	155.0	125.0	1,280.0
Other Direct Costs	0.0	0.0	0.0	2.8	2.8
Interest and Escalation	78.1	67.9	35.9	21.6	203.5
Contingency	172.0	149.0	101.0	63.2	485.2
TOTAL	**1,110.1**	**961.9**	**641.9**	**400.8**	**3,114.7**

Project Title: Additions for Load Distribution Systems **(cont'd.)**

Operating Experience:

Growing load will, over time, result in the load exceeding the capacity of the existing system. This results in abnormal voltage conditions (voltages outside standard limits) which can cause damage to customer equipment or cause it to operate incorrectly, and it will also result in overloads, which if unchecked will cause equipment failures and subsequent power outages. To prevent this from happening, the abnormal voltages and overloads are corrected before they occur.

Project Justification:

These projects are justified on the requirement to accommodate growing electrical load. The projects will ensure that the distributions systems at Farewell Head, St. Anthony, and Wabush are capable of meeting growing demand for the foreseeable future.

Future Plans:

There will be other additions to accommodate load growth on distribution systems in future years.

Attachment:

See report entitled "Additions to Accommodate Load Growth - Distribution Systems" located in Volume II, Tab 15, for further project details.

Project Title: Upgrade Distribution Systems

Location: All Service Areas

Category: Transmission and Rural Operations - Distribution

Definition: Pooled

Classification: Normal

Project Description:

This project is an annual allotment based on historical expenditures to provide for the replacement of deteriorated poles, substandard structures, corroded and damaged conductors, rusty 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)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	1,504.0	0.0	0.0	1,504.0
Labour	798.0	0.0	0.0	798.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	109.0	0.0	0.0	109.0
Other Direct Costs	17.0	0.0	0.0	17.0
Interest and Escalation	120.0	0.0	0.0	120.0
Contingency	242.0	0.0	0.0	242.0
TOTAL	**2,790.0**	**0.0**	**0.0**	**2,790.0**

Operating Experience:

An analysis of historical expenditures (2007 - 2011) on distribution upgrades by region is shown in Table 2. All historical dollars were converted to 2011 dollars using the Statistics Canada Utility Distribution Line Construction index and a five-year average was calculated.

Project Title: Upgrade Distribution Systems **(cont'd.)**

Operating Experience: (cont'd.)

Table 2: Average Annual Expenditures for 2007 to 2011

Region	Avg. Annual Expenditures (2011 $000)
Central	1,036
Northern	1,170
Labrador	434
All Regions	2,639

The five-year expenditures for distribution upgrades by region are shown in Table 3.

Table 3: Five-Year Expenditures

Expenditures ($000)											
	2007		2008		2009		2010		2011		2012
Region	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget
Central	806	824	915	782	1,050	1,028	1,032	1,037	998	1,365	993
Northern	873	842	969	1,140	1,026	1,148	1,072	1,071	1,051	1,489	1,089
Labrador	356	558	409	313	450	484	468	191	450	548	426
Total	2,035	2,224	2,293	2,235	2,526	2,660	2,572	2,299	2,499	3,402	2,508

Other specifically approved projects for 2007 – 2012B are listed in Table 5.

Project Justification:

Based on the five-year average for distribution system upgrades for the period 2007 - 2011 the budget shown in Table 4 was developed, assuming distribution line cost escalation in 2013 of approximately three percent.

Table 4: Budget for Distribution System

Region	2013 Budget ($000)
Central	1,095
Northern	1,237
Labrador	458
Total	2,790

Project Title: Upgrade Distribution Systems **(cont'd.)**

Future Plans:

This is an annual allotment which is adjusted from year to year depending on historical expenditures. See the five-year capital plan (2013 Capital Plan Tab, Appendix A).

Table 5 shows the history of other specific distribution system upgrades that have been completed over the past 5 years as well as the budget for 2012.

Table 5: Five-Year Historical Information

Year	Project Description	Budget ($000)	Actuals ($000)
2012B	Upgrade Distribution Feeder - Line 1 Bay d'Espoir	856.6	
	Upgrade Distribution Feeder - Line 2 Bay d'Espoir	952.9	
	Upgrade Distribution Feeder - Line 1 Francois	440.9	
	Upgrade Distribution Feeder - Line 1 Parson's Pond	381.9	
	Upgrade Distribution Feeder - Line 2 Plum Point (Year 1 of 2)	50.4	
	Upgrade Distribution Feeder - Line 7 Happy Valley	1,260.1	
	Upgrade Distribution Feeder - Line 2 Glenburnie (Year 3 of 4)	2,114.6	
	Reconfigure Feeders – Wabush	55.4	
	Upgrade Distribution Feeder - Line 1 Rigolet (Year 2 of 2)	725.7	
	Upgrade Distribution Feeder - Line 1 Makkovik (Year 2 of 2) - (Materials ordered in 2011)	799.5	
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 1 of 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
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

Project Title: Upgrade Distribution Systems **(cont'd.)**

Future Plans: (cont'd.)

Table 5: Five-Year Historical Information

Year	Project Description	Budget ($000)	Actuals ($000)
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
2007	Replace Poles - Barachoix Line 4	229.9	276.0
	Insulator Replacement - Barachoix Line 4	120.1	123.0
	Replace Distribution Line - Brighton	192.9	230.9
	Replace Distribution Line - Seal Cove to Pass Island	547.6	552.1
	Upgrade Distribution System - Line 2, Line 3 Farewell Head	385.3	282.0
	Replace Poles - Farewell Head	355.0	295.3
	Replace Poles - St. Brendan's	159.1	175.4
	Extend Mud Lake Submarine Cable	480.9	813.6
	Upgrade Distribution System - Line 1, Line 2 St. Anthony	364.3	301.0
	Upgrade Distribution System - Line 1, Line 2 Rocky Harbour	513.5	393.7
	Upgrade Distribution System - Nain	179.4	185.8

Project Title: Upgrade Circuit Breakers

Location: Various Stations

Category: Transmission and Rural Operations

Definition: Pooled

Classification: Normal

Project Description:

Hydro has been working to maximize the life of its circuit breakers. In recent years Hydro has been upgrading air blast circuit breakers, overhauling operating mechanisms on Sulphur Hexafluoride (SF6) breakers, and attempting to deal with the phase out of PCBs bushing associated with oil circuit breakers.

This project is to replace and refurbish Air Blast and SF6 circuit breakers, and replace oil circuit breakers throughout Hydro's Island Interconnected System. Many circuit breakers have been in service for more than 30 years and are approaching the at-risk phase of their life cycle.

The scope of work for each type of circuit breaker includes:

Air Blast Circuit Breakers

Complete one overhaul on air blast circuit breakers, replace air blast circuit breakers after being in service between 10 and 15 years after an overhaul, and replace breakers between the age of 50 and 55 years.

Oil Circuit Breakers

For all oil circuit breakers containing sealed bushings which have the possibility of containing Polychlorinated Byphenols (PCBs) greater than 500 mg/kg, Hydro has a plan to replace all oil circuit breakers prior to 2025.

SF6 Breakers

Complete one overhaul at 20 years of service for all new SF6 breakers, and complete an overhaul between 20 to 30 years on existing in-service units. The plan for routine replacement will be after 40 years of service.

Project Title: Upgrade Circuit Breakers **(cont'd.)**

Project Description: (cont'd.)

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	570.0	0.0	0.0	570.0
Labour	714.8	0.0	0.0	714.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	558.0	0.0	0.0	558.0
Other Direct Costs	324.5	0.0	0.0	324.5
Interest and Escalation	184.5	0.0	0.0	184.5
Contingency	433.5	0.0	0.0	433.5
TOTAL	**2,785.3**	**0.0**	**0.0**	**2,785.3**

Operating Experience:

The average age of the overall population of circuit breakers is well past a breaker's midlife of 20 years and is approaching the manufacturers' specified design end-of-life of 40 years. Presently, 59 breakers are greater than 40 years of age.

Hydro has experienced problems with air blast circuit breakers including air leaks and sticking valves, increasing maintenance costs and breaker unavailability. Problems experienced with SF6 breakers include SF6 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 the problems though similar upgrading programs.

In the past ten years there have been overhauls completed on air blast circuit breakers and the operating mechanism associated with selected SF6 breakers. These overhauls 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 overhaul 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 Title: Upgrade Circuit Breakers **(cont'd.)**

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 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 breakers replaced by 2031, all current in-service SF6 breakers overhauled at mid-life and replaced at or near age 40, and all oil circuit breakers replaced by 2023.

Future Plans:

Continue with this long term replacement and refurbishment program.

Attachments:

See report entitled "Upgrade Circuit Breakers" located in Volume II, Tab 16, 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)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	348.0	0.0	0.0	348.0
Labour	1,451.7	0.0	0.0	1,451.7
Consultant	100.0	0.0	0.0	100.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	75.9	0.0	0.0	75.9
Interest and Escalation	96.1	0.0	0.0	96.1
Contingency	395.1	0.0	0.0	395.1
TOTAL	**2,466.7**	**0.0**	**0.0**	**2,466.7**

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 targeting 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

Project Title: Perform Wood Pole Line Management Program **(cont'd.)**

Operating Experience: (cont'd.)

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 2012 Tab, Appendix A).

Attachment:

See report entitled "2013 Wood Pole Line Management" located in Volume II, Tab 17, for further project details.

Project Title: Replaced Compressed Air Systems

Location: Sunnyside and Stony Brook

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

The aging compressed air distribution systems at the Sunnyside and Stony Brook Terminal Stations supply compressed air to 23 air blast circuit breakers. The existing copper tube and Synflex hose distribution systems will be replaced with socket weld stainless steel piping systems during this project. In addition, new compressed air dew point monitoring systems and new back-up compressed air dryers will also be installed. This will improve the quality and reliability of compressed air supplied to critical equipment in the terminal stations, namely the air-blast circuit breakers.

The budget estimate for this project is $1,293,100 (Table 1) for Sunnyside Terminal Station and $1,115,800 (Table 2) for Stony Brook Terminal Station with engineering design starting in the first quarter of 2013 and installation and commissioning of each system during June to September 2014. An outage will be required on each individual circuit breaker, which will result in outages on associated transmission lines but no customer outages will be required to execute the work.

The budget estimate for Sunnyside Terminal Station shown in Table 1.

Table 1: Sunnyside Terminal Station Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	28.0	17.0	0.0	45.0
Labor	35.0	190.5	0.0	225.5
Consultant	75.0	0.0	0.0	75.0
Contract Work	0.0	593.5	0.0	593.5
Other Direct Costs	2.0	30.6	0.0	32.6
Interest and Escalation	11.5	115.8	0.0	127.3
Contingency	0.0	194.3	0.0	194.3
TOTAL	**151.5**	**1,141.6**	**0.0**	**1,293.1**

Project Title: Replaced Compressed Air Systems **(cont'd.)**

Project Description: (cont'd.)

The budget estimate for Stony Brook Terminal Station is shown in Table 2.

Table 2: Stony Brook Terminal Station Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	28.0	17.0	0.0	45.0
Labour	35.0	187.3	0.0	222.3
Consultant	75.0	0.0	0.0	75.0
Contract Work	0.0	475.5	0.0	475.5
Other Direct Costs	2.0	17.4	0.0	19.4
Interest and Escalation	11.5	99.7	0.0	111.2
Contingency	0.0	167.4	0.0	167.4
TOTAL	**151.5**	**964.3**	**0.0**	**1,115.8**

Operating Experience:

The compressed air distribution piping at the Sunnyside and Stony Brook Terminal Stations is mostly fabricated from copper tube and fittings. The tube is laid in cable trenches extending from the control building to the air-blast circuit breakers. Over the years, there have been many leaks that have developed in the tube joints. Air leaks cause the compressors and air dryers to operate excessively as the system attempts to replenish the compressed air that is being lost through the leaks. This not only wastes energy, but also causes unnecessary wear and tear on the equipment. In addition, frost heave has displaced trenches and tubing runs, putting stress on the tubing and joints, which increases the incidence of joint failure and additional leaks. Significant sections of the piping, installed in cable trenches, are inaccessible due to the installation of electrical cables on top of the piping. The weight of the cables bearing down on the piping has caused the copper piping to bend and fail, resulting in leaks. Also, the soldered copper pipe fittings have deteriorated and have developed leaks at the joints. Piping failures have been repaired by replacing the failed copper piping with Synflex hose, which is a flexible pneumatic hose. This hose was used because it is flexible and much easier to install than rigid pipe. However, Hydro's experience with this hose over many years has proven that its fittings are susceptible to corrosion, resulting in more compressed air leaks. Furthermore the Synflex Hose material absorbs moisture, is permeable and moisture is transferred to the compressed air.

Project Title: Replaced Compressed Air Systems **(cont'd.)**

Project Justification:

This project is required to ensure that the Sunnyside and Stony Brook Terminal Stations have reliable supplies of dry compressed air to safely operate the stations 23 air-blast circuit breakers (22 by the end of 2012 as one at Sunnyside Terminal Station is scheduled for replacement). A reliable supply of dry compressed air can only be guaranteed at each terminal station through the replacement of the existing compressed air distribution piping, the addition of a second compressed air dryer, and the installation of a new dew point monitoring system. The compressed air distribution systems are approximately 45 years old. Leaks have become common in the brazed joints due to wear and Synflex hose connections due to corrosion compromising air quality. Replacement is required to restore the integrity of the systems. The addition of a second compressed air dryer will provide a back-up system in the event that the primary air dryer fails or is taken out of service for maintenance. The installation of a new dew point monitoring system will send an alarm to the Energy Control center (ECC) in the event of an undesirable dew point measurement on the compressed air system. Receiving an alarm notification will permit Hydro to address problems with the systems in a timely fashion which will improve the ability of the air-blast circuit breakers to operate successfully when called upon.

Future Plans:

In the five year plan the program continues with the replacement of the compressed air system at Bottom Brook terminal station scheduled in 2014 and at Western Avalon in 2017.

Attachments:

See report entitled "Replace Compressed Air System – Sunnyside and Stony Brook Terminal Stations" located in Volume II, Tab 21, for further project details.

Project Title: Upgrade Terminal Station

Location: Wiltondale

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project proposal is for the restoration and modernization of the support structures and electrical equipment within the Wiltondale Terminal Station. The scope of work includes replacing the wood pole structures with steel structures, replacing the circuit breaker, recloser, disconnect switches, bus work, hardware and insulator as well as the associated protection and controls, and upgrading the station's grounding system. In order to minimize the outage duration to nearby customers, the mobile substation will be used to bypass the station during construction.

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

Table 1 – Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	291.8	140.0	0.0	431.8
Labour	108.0	148.8	0.0	256.8
Consultant	36.2	10.0	0.0	46.2
Contract Work	156.7	390.0	0.0	546.7
Other Direct Costs	59.5	54.7	0.0	114.2
Interest and Escalation	45.5	150.7	0.0	196.2
Contingency	0.0	279.1	0.0	279.1
TOTAL	**697.7**	**1,173.3**	**0.0**	**1,871.0**

Operating Experience:

The Wiltondale Terminal Station provides power to the residential and commercial customers located in the areas of Wiltondale and the south side of Bonne Bay. The reliability performance of this terminal station is poor in comparison to the Canadian Electricity Association and Hydro's system averages. The safety performance is also poor considering the deteriorated condition of the support structures, inadequate ground system and age of the electrical equipment.

Project Title: Upgrade Terminal Station **(cont'd.)**

The thirty-seven year old wood pole structures in the Wiltondale terminal station are in poor condition. The crossarm assemblies are showing signs of structural stress and are cracked in several locations. Additionally, the wood pole structure design is congested and restricts access to the station's equipment.

The electrical equipment in the terminal station is also thirty-seven years old and is in deteriorated condition. Coupling the electrical equipment replacement work with the support structure upgrade work under one project avoids the duplication of cost otherwise incurred by using the mobile substation for two separate projects.

The grounding system requires upgrading as the current grounding system is substandard. The inadequate grounding system poses a safety concern with the step and touch potential hazard to staff working in the station. Additionally, the upgraded grounding system will provide a solid ground reference, which is critical for the proper operation of protection and control devices.

Future Plans:

The restoration and modernization of the Wiltondale terminal station will renew the station's service life for another forty years. The terminal station upgrade does not include replacement of the forty-eight year old power transformer. Engineering assessments and test results show favourable operating performance of the power transformer. Future work will include replacement of this transformer depending on inspection and testing.

Attachments:

See report entitled "Upgrade Terminal Station at Wiltondale" located in Volume II, Tab XX, 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 a 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 2: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	564.0	0.0	0.0	564.0
Labour	391.3	0.0	0.0	391.3
Consultant	7.0	0.0	0.0	7.0
Contract Work	135.0	0.0	0.0	135.0
Other Direct Costs	170.9	0.0	0.0	170.9
Interest and Escalation	99.3	0.0	0.0	99.3
Contingency	253.6	0.0	0.0	253.6
TOTAL	**1,621.1**	**0.0**	**0.0**	**1,621.1**

Operating Experience:

Approximately 68 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.

Project Title: Upgrade Power Transformers **(cont'd.)**

Future Plans:

Future upgrades will be proposed in future capital budget applications.

Attachments:

See report entitled " Upgrade Power Transformers" located in Volume II, Tab 19, for further project details.

Project Title: Replace Off-Road Track Vehicles

Location: Happy Valley, Port Saunders and Whitbourne

Category: General Properties - Transportation

Definition: Other

Classification: Normal

Project Description:

This project involves the replacement of V7728 (Happy Valley), a 1990 heavy-duty off-road track vehicle, and V7973 (Port Saunders), a 1998 heavy-duty off-road track vehicle and V7942, a 1997 heavy-duty off-road track vehicle.

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

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	390.0	930.0	0.0	1,320.0
Labour	3.5	1.5	0.0	5.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	6.0	6.0	0.0	12.0
Interest and Escalation	17.3	49.7	0.0	67.0
Contingency	0.0	66.9	0.0	66.9
TOTAL	**416.8**	**1,054.1**	**0.0**	**1,470.9**

Operating Experience:

The heavy-duty off-road track vehicles have an average life expectancy which ranges from 12 to 15 years, dependent on location and usage. Unit V7973 will be 16 years old at replacement and Unit V7942 will be 16 years old. Unit V7728 was 23 years old at retirement in 2011.

Project Justification:

This project provides for the normal replacement of heavy-duty off-road track vehicles due to age and condition.

Project Title: Replace Off-Road Track Vehicles **(cont'd.)**

Future Plans:

Future replacements will be proposed in future capital budget applications. See five year capital plan (2013 Capital Plan Tab, Appendix A).

Attachment:

See report entitled "Replace Off-Road Track Vehicles – Happy Valley, Port Saunders and Whitbourne ", Volume II, Tab 20, for further project details.

Project Title: Overhaul Diesel Units

Location: Various Sites

Category: Transmission and Rural Operations - Generation Central

Definition: Pooled

Classification: Normal

Project Description:

This project is required to overhaul the diesel engines at diesel generating plants. The project consists of 48 overhauls over the next 5 years (which is an average of 9.6 overhauls annually). 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 8.7 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 an engine's actual operating hours. While the specific engines projected to be due for overhaul in a given year can vary from year to year, the number of engines projected to be due for overhaul in a given year tend to be consistent.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	622.0	0.0	0.0	622.0
Labour	133.1	0.0	0.0	133.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	15.0	0.0	0.0	15.0
Other Direct Costs	61.0	0.0	0.0	61.0
Interest and Escalation	63.6	0.0	0.0	63.6
Contingency	83.1	0.0	0.0	83.1
TOTAL	**977.8**	**0.0**	**0.0**	**977.8**

Operating Experience:

Isolated diesel generation plants operate continuously since they provide the primary source of electricity to communities isolated from the province's electrical grid. A given unit is not in service continually since the number of units in service varies based on the demand. In automated plants the

Project Title: Overhaul Diesel Units **(cont'd.)**

Operating Experience: (cont'd.)

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 current maintenance philosophy is to complete an engine overhaul on all diesel engines every 20,000 hrs. This philosophy was established as a result of a 2003 review of the 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 to be the optimum interval for providing least-cost, reliable electrical service.

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 (2013 - 2032) projects 188 overhauls (which is an average of 9.4 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 - Various Locations" located in Volume II, Tab 22, for further project details.

Project Title: Install Automated Meter Reading

Location: Various Sites

Category: Transmission and Rural Operations - Metering

Definition: Other

Classification: Normal

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 Bear Cove and Plum Point. The AMR functionality is proposed for all customers in these service areas. The work includes (i) the replacement of existing customer meters with AMR equipped meters; (ii) the installation of data collectors in the substations in these service areas; (iii) communications to the AMR server located in St. John's; and (iv) configuring the AMR central server to include customers in these service areas.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	251.0	50.6	0.0	301.6
Labour	79.0	45.2	0.0	124.2
Consultant	30.0	12.0	0.0	42.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	9.4	2.6	0.0	12.0
Interest and Escalation	28.5	52.4	0.0	80.9
Contingency	0.0	96.0	0.0	96.0
TOTAL	**397.9**	**258.8**	**0.0**	**656.7**

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 Title: Install Automated Meter Reading **(cont'd.)**

Project Justification:

This project is primarily justified on the results of a cost-benefit analysis which shows that the new AMR system has economic benefit 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 Automatic Meter Reading 2013-2014" located in Volume II, Tab 23, 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 18 light-duty vehicles and eight heavy-duty vehicles in accordance with the established replacement criteria for vehicle age and kilometers (kms) as follows:

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

Prior to the preparation of the capital budget proposal, a review of the latest version of the database is performed to select the units which meet the replacement criteria for age or kilometers, and to verify those which should be included in the capital budget proposal based on their maintenance history or ongoing maintenance issues.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	1,235.0	550.0	0.0	1,785.0
Labour	8.0	2.0	0.0	10.0
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	53.3	34.0	0.0	87.3
Contingency	0.0	90.2	0.0	90.2
TOTAL	**1,302.3**	**679.2**	**0.0**	**1,981.5**

Project Title: Replace Vehicles and Aerial Devices **(cont'd.)**

Operating Experience:

The 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 conducted 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 166,000 kms and the heavy duty vehicles are an average of 11 years old with 182,000 kms.

Future Plans:

Transportation will continue to replace vehicles and aerial devices as per our replacement criteria. See five year plan (2013 Capital Plan Tab, Appendix A).

Attachments:

See report entitled "Replace Vehicles and Aerial Devices" located in Volume II, Tab 24 for further details.

Project Title: Replace MDR4000 Microwave Radio (West)

Location: Various Sites

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This project will replace the high-capacity OC-03 MDR4000 Radio System that was installed in 1999 between the Stoney Brook Terminal Station and Bay d'Espoir Plant including the upgrade or replacement of the Telnar 1603 Sonet multiplexer to include Ethernet access. This radio system provides teleprotection, supervisory control, departmental and administrative voice and administrative data between Hydro Place and the Bay d'Espoir, Upper Salmon and Granite Canal hydro generating stations. High speed and reliable telecommunication facilities are required to ensure the stability and reliability of the provincial power grid.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	400.0	73.6	0.0	473.6
Labour	90.0	307.6	0.0	397.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	22.0	41.4	0.0	63.4
Interest and Escalation	27.0	97.4	0.0	124.4
Contingency	0.0	186.9	0.0	186.9
TOTAL	**539.0**	**706.9**	**0.0**	**1,245.9**

Operating Experience:

The original Alcatel MDR4000 radio and 1603 multiplexers were installed in 1999 and have proved to be valuable assets in the remote control and monitoring of the provincial power system. This equipment has been discontinued by Alcatel.

Project Title: Replace MDR4000 Microwave Radio (West) **(cont'd.)**

Project Justification:

The project is justified on the fact that the Alcatel MDR4000S radio has been discontinued since 2004. The manufacturer will not guarantee that failed modules can be repaired due to the obsolescence of the components within the modules. Hydro has obtained some components from the used market, however this supply is unreliable. The replacement of the radio system is required to ensure a reliable and safe provincial power system.

Future Plans:

None.

Attachments:

See report entitled "Replace MDR-4000 Microwave Radio (West)" located in Volume II, Tab 25, for further project details.

Project Title: Upgrade Microsoft Products

Location: Various Sites

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

The scope of this project is to renew the Enterprise Agreement with Microsoft such that specified Microsoft products in use within the company will be able to be upgraded to the latest versions available for the life of the agreement. Through the Microsoft Enterprise Agreement the company achieves an overall cost savings. Cost will be spread over a three year period with equal payments in each year, commencing in 2013. In the first year of the renewal, additional licensing required for key systems will be acquired under the Enterprise Agreement pricing levels. The additional licenses are required to be able to move applications to the Windows 2008 Server version and additional SQL Server licenses to allow applications to move to a newer version of the software.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**2015**	**2016**	**Total**
Material Supply	625.6	421.1	421.1	0.0	1,467.8
Labour	10.0	10.0	10.0	0.0	30.0
Consultant	0.0	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0	0.0
Interest and Escalation	21.1	24.0	34.1	0.0	79.2
Contingency	0.0	0.0	0.0	0.0	0.0
Sub-Total	**656.7**	**455.1**	**465.2**	**0.0**	**1,577.0**
Cost Recoveries	**(236.4)**	**(163.8)**	**(167.5)**	**0.0**	**(567.7)**
TOTAL	**420.3**	**291.3**	**297.7**	**0.0**	**1,009.3**

Operating Experience:

Hydro currently deploys a standard desktop that includes the Microsoft Office Suite of products and the Windows 7 Desktop Operating System, which will replace Windows XP on corporate desktops and

Project Title: Upgrade Microsoft Products **(cont'd.)**

Operating Experience: (cont'd.)

laptops. The laptop/desktop environment and server infrastructure is based on the Windows Operating System. Within the operating environment, the company also uses a number of Microsoft Tools and applications to ensure efficient operation.

This project will see Hydro continue its Enterprise Agreement with Microsoft such that all of the products currently in use will remain available to be upgraded to the latest versions. The company will also maintain access to reduced rates on any new products we decide to implement for the life of the agreement. Other benefits of the Enterprise Agreement include ability to upgrade to the latest version of products for the life of the agreement and to benefit from training and e-learning resources.

The Enterprise Agreement is a three year agreement and is proposed to be paid for in three equal payments to be spread over the three years. This agreement will renew in 2013 and end in 2016.

Project Justification:

This project is a part of Hydro's ongoing effort to ensure that users are able to meet ongoing productivity requirements and to effectively collaborate with outside resources as required. This is achieved by ensuring that the desktop application base is maintained to the appropriate version levels to limit incompatibilities.

Hydro currently supports a standard desktop that includes the Microsoft Office Suite of products and the Windows 7 and Windows XP Desktop Operating Systems (transitioning to Windows 7). The laptop/desktop environment and server infrastructure is based on the Windows Operating System. Within the computer infrastructure environment the company also uses a number of Microsoft technologies to ensure efficient operation, including but not limited to SQL server for databases, Microsoft System Center for server and PC management, and Microsoft Terminal Services with Citrix technology for application delivery to users.

As a result of the investment made in the existing Enterprise Agreement, Hydro's desktop and server software is maintained at current, supported standards which enables more effective collaboration

Project Title: Upgrade Microsoft Products **(cont'd.)**

Project Justification: (cont'd.)

both internally and externally. Server software used to manage the desktop and server environments and the database servers many key systems depend on are also maintained under this agreement. The costs to acquire and maintain business software from Microsoft is reduced under the Enterprise Agreement.

The Enterprise Agreement allows the company to upgrade to the current server, desktop and application versions over the life of the agreement. This agreement renewal is for a three year period.

Future Plans:

This is an ongoing software assurance contract with yearly evaluations of the products purchased based on business need/usage of the day.

Attachments:

See report entitled "Microsoft Enterprise Agreement" located in Volume II, Tab 26, for further project details.

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 Uninterruptable Power Supply (UPS) batteries that also converts back to AC.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	289.1	0.0	0.0	289.1
Labour	273.0	0.0	0.0	273.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	47.1	0.0	0.0	47.1
Interest and Escalation	51.0	0.0	0.0	51.0
Contingency	121.8	0.0	0.0	121.8
TOTAL	**782.0**	**0.0**	**0.0**	**782.0**

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 require replacement. The rate of battery deterioration increases with age and battery banks eventually reach a point where they are unable to provide the required power level to operate equipment in the event of an outage. Please see the attached report for further details.

Project Title: Replace Battery Banks and Chargers **(cont'd.)**

Project Justification:

When the capacity of a battery falls to 80 percent of its rated capacity it has to be replaced as recommended by the Institute of Electrical and Electronic Engineers (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 failure occurs to ensure continued reliable operation.

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 27, for further project details. Also see the five-year capital plan (2013 Capital Plan Tab, Appendix A).

Project Title: Upgrade Business Intelligence Software

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

Hydro uses several tools to provide budgeting and forecasting functionality, financial reporting, capital asset depreciation modeling and key performance indicators reporting. Two of the tools required, Essbase and Web Analysis, will no longer be supported after May 2013. The vendor for these two products has no plans for substitution or replacement. A third tool, Clarity, will have support for the existing version end in December 2012. The new version will be supported by IBM.

This project will upgrade these products and move them to computer environments that will allow this software to be supported by the vendor.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	114.0	0.0	0.0	114.0
Labour	81.6	0.0	0.0	81.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	222.0	0.0	0.0	222.0
Other Direct Costs	61.6	0.0	0.0	61.6
Interest and Escalation	25.8	0.0	0.0	25.8
Contingency	71.9	0.0	0.0	71.9
Sub Total	576.9	0.0	0.0	576.9
Cost Recoveries	(207.7)	0.0	0.0	(207.7)
TOTAL	**369.2**	**0.0**	**0.0**	**369.2**

Project Title: Upgrade Business Intelligence Software **(cont'd.)**

Operating Experience:

The software is used on a daily basis by head office and field personnel for analysis and input of information and comparisons of actual results against budgets and forecasts. These tools are also used to analyze and report on key performance indicators data for safety, environmental responsibility and financial performance.

Project Justification:

This project is needed to replace software that is being retired completely by the vendor, and/or for which version support is ending. The Business Intelligence software is used for vital financial functions including budgeting, forecasting and financial reporting and serves as a basis for other reporting and analysis.

Future Plans:

None.

Attachments:

See report entitled "Upgrade business Intelligence Software" located in Volume II, Tab 28, for further project details.

PROJECT DESCRIPTION	Expended to 2012	2013	Future Years	Total	Page Ref
			($000)		
GENERATION					
Install Cold-Rehead Condensate Drains and High Pressure Heater Trip Level Unit 3 - Holyrood		50.0	448.1	498.1	D - 2
Upgrade Generator Bearings - Bay d'Espoir		480.9		480.9	D - 33
Overhaul Turbine/Generator Units - Bay d'Espoir and Cat Arm		428.1		428.1	D - 45
Replace Automatic Transfer Switches - Hinds Lake		314.7		314.7	D - 51
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir		298.1		298.1	D - 56
Replace MicroSCADA Computers - Granite Canal		297.4		297.4	D - 78
Install Fire Protection Upgrades - Holyrood		267.2		267.2	D - 84
Replace North End Equipment Door - Bay d'Espoir		265.5		265.5	D - 107
Replace Auto Greasing Systems Units 1 and 3 - Bay d'Espoir		260.1		260.1	D - 116
TOTAL GENERATION	0.0	2,662.0	448.1	3,110.1	
TRANSMISSION AND RURAL OPERATIONS					
Replace Disconnects - Various Sites		492.6		492.6	D - 123
Replace Light Duty Mobile Equipment - Various Sites		476.5		476.5	D - 136
Replace Insulators - Various Sites		187.1	287.9	475.0	D - 142
Install Automatic Fire Sprinkler System - Bay d'Espoir		429.9		429.9	D - 149
Upgrade Electrical Equipment - Holyrood	209.6	212.1		421.7	
Install Online Vibration Monitoring System - Corner Brook Frequency Converter		382.8		382.8	D - 161
Replace Compressed Air Piping - Buchans	28.4	278.3		306.7	
Install Additional Washrooms - Various Sites		250.9		250.9	D - 210
Replace Recloser Control Panels - Various Sites		209.7		209.7	D - 215
TOTAL TRANSMISSION AND RURAL OPERATIONS	238.0	2,919.9	287.9	3,445.8	
GENERAL PROPERTIES					
Front End Engineering Design - Hydro Place		472.1		472.1	D - 231
Replace Personal Computers - Various Sites		463.9		463.9	D - 234
Upgrade Server Technology Program - Various Sites		367.6		367.6	D - 239
Replace Radomes - Various Sites		336.0		336.0	D - 245
Replace Peripheral Infrastructure - Various Sites		309.9		309.9	D - 259
Remove Safety Hazards - Various Sites		250.5		250.5	D - 264
TOTAL GENERAL PROPERTIES	0.0	2,200.0	0.0	2,200.0	
TOTAL PROJECTS OVER $200,000 AND UNDER $500,000	238.0	7,781.9	736.0	8,755.9	

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

Location: Holyrood

Category: Generation - Thermal

Type: 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: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	15.0	30.0	0.0	45.0
Labour	14.0	118.9	0.0	132.9
Consultant	17.5	0.0	0.0	17.5
Contract Work	0.0	180.5	0.0	180.5
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	3.5	43.5	0.0	47.0
Contingency	0.0	75.2	0.0	75.2
TOTAL	**50.0**	**448.1**	**0.0**	**498.1**

JUSTIFICATION:

Hydro's insurer (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. See Appendix A for FM Global's report *FM Global Risk Report – Equipment Hazards Interim Risk Evaluation, Holyrood Thermal Plant, May 12, 2011 (Target Recommendation 06-01-003, Parts A and B, pages A-10 to A-12)*.

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. See Appendix B for ASME standard TDP-1-1998, Section 3.5.

Existing System

Generating Unit 3 (150 MW) at Holyrood was installed in 1979 as part of the plant upgrade known as Stage 2 and has been in service for 33 years. Unit 3 operates in a seasonal regime with full capacity required to meet winter peak loads on the Island Interconnected System. No major work or upgrades have been performed on the equipment involved in this project since installation.

Steam, exhausting from the high pressure section of the steam turbine, flows into a piping system known as the cold reheat lines. A portion of the steam in the cold reheat lines is used to preheat the boiler feedwater using a heat exchanger known as the high pressure heater.[1] As steam cools, it condenses into hot water known as condensate. Because of its damaging effects on equipment,

[1] Both the cold reheat lines and the high pressure heater are integral components of the generating units. The cold reheat lines and the high pressure heater system for Unit 3 are being modified under this project.

condensate must be continually drained from steam piping systems.

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 Units 1 (2010)[2] and Unit 2 (2009)[3] at the recommendation of FM Global. The condensate drain pots operate by collecting condensate in a large pipe (see Figure 1). 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 FM Global, this puts Unit 3 at risk of experiencing water-induced steam turbine damage.

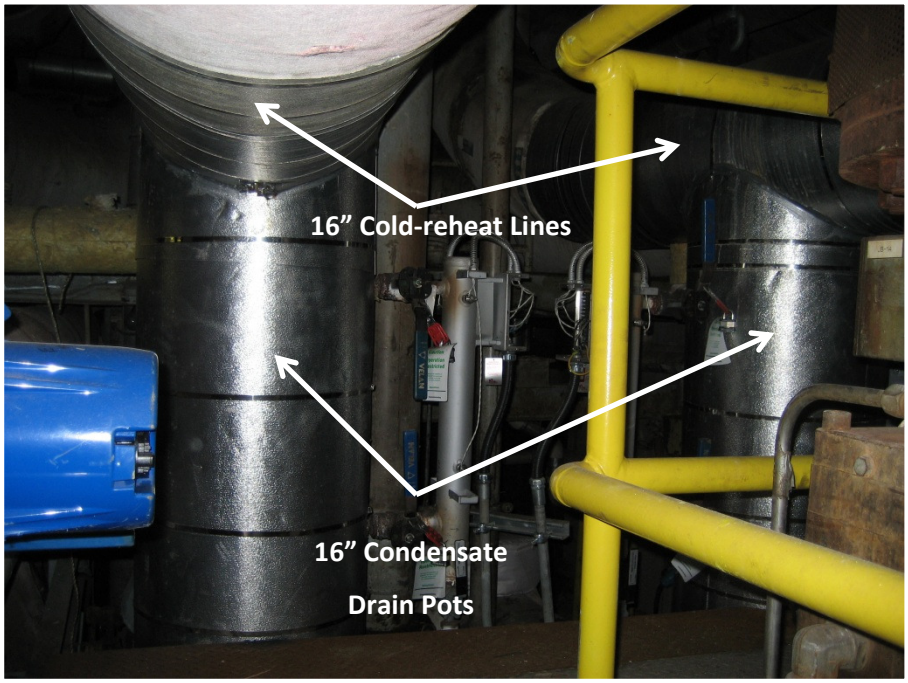


Figure 1: Holyrood Unit 2 Condensate Drain Pots and Cold Reheat Lines

[2] Board Order P.U. 41 (2009)

[3] Board Order P.U. 19 (2009)

Also at the recommendation of FM Global, modifications were made to the piping arrangements on Units 1 and Unit 2 so that in-situ testing of the condensate level switches on the high pressure heaters (see Figure 2) serving these units is possible. With the current equipment arrangement, in-

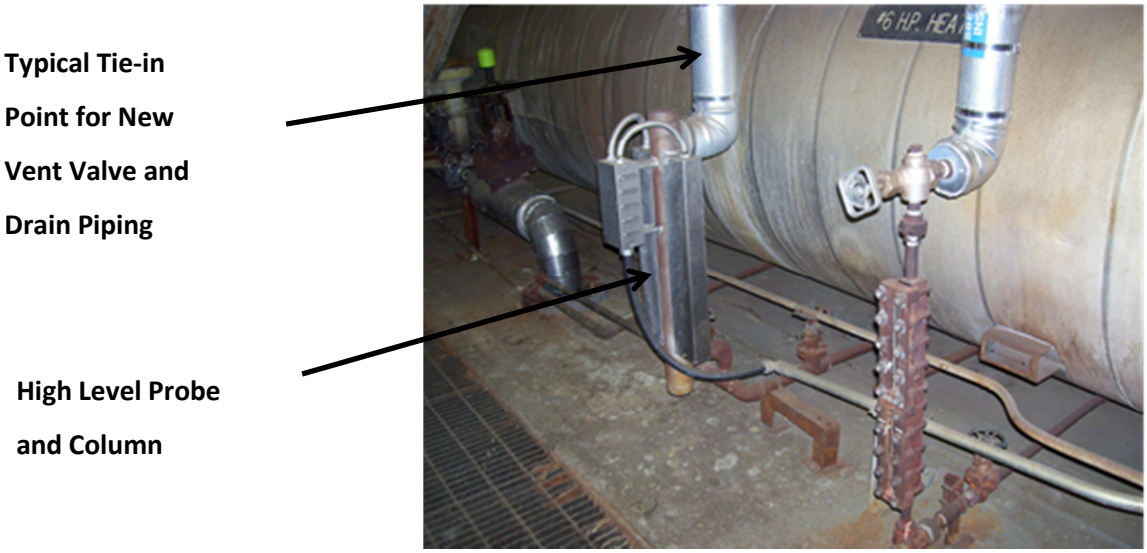


Figure 2: Typical High Pressure Heater Level Probe

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.

The following categories are not relevant to this project: reliability performance, legislative or regulatory requirements, safety performance, environmental performance, and vendor recommendations. Also, there is no maintenance history associated with this project.

Industry Experience

Hydro's insurer (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. They have also reported that feedwater heaters in particular represent the most frequent potential source of water

induction into a steam turbine.

Maintenance or Support Arrangements

Hydro currently has a service contract with Alstom Power, a boiler service contractor, to perform boiler maintenance during the annual scheduled outage.

Historical Information

A similar project was completed on Unit 1 in 2010 and Unit 2 in 2009. See Table 2 for historical information.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Comments
2010	231.4	345.5	Unit 1
2009	191.6	284.0	Unit 2

While the historical costs reflect the cost of performing work of similar scope, this project will require an increased budget because it will be completed in 2014. Costs to perform work of this nature have been increasing annually.

Anticipated Useful Life

The anticipated useful life of Unit 3 has been forecasted to extend to 2020.

CONCLUSION

FM Global reports that numerous occurrences of water-induced damage to steam turbines at thermal generating plants have been attributed to the presence of condensate in cold reheat lines. Holyrood is currently at risk of experiencing water-induced damage to the Unit 3 steam turbine because it does not have a condensate collection system (drain pots) installed on the cold reheat lines near the steam turbine. Also, Unit 3 does not have a provision to perform in-situ function testing of the condensate level switches installed on the high pressure heater. This also places the Unit 3 steam turbine at risk of experiencing water induced damage

These risks can be eliminated by performing the work recommended under this project. The

solutions presented in this report have already been implemented on Units 1 and 2.

Project Schedule

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

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Initiate project Prepare resource plan and schedule	January 2013	January 2013
Design	Complete detailed engineering design	February 2013	June 2013
Procurement	Prepare tender and award contracts for materials and construction	July 2013	April 2014
Construction	Install systems	May 2014	August 2014
Commissioning	Commission systems	September 2014	September 2014
Closeout	Complete project documentation and perform project closeout	October 2014	December 2014

APPENDIX A

FM Global Risk Report
Equipment Hazards Interim Risk Evaluation
Holyrood Thermal Plant
May 12, 2011

FM Global Risk Report

Location Findings

Nalcor Energy

Holyrood Thermal Plant
Route 62
Holyrood, Newfoundland and Labrador A0A 2R0
Canada

Equipment Hazards
Interim Risk Evaluation

Visit by:	Michel N. Burbaud
Visit date:	12 May 2011
Conference with:	Mr. Terry LeDrew, P.Eng, Manager, Thermal Generation

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FM Global Risk Report — Nalcor Energy

Principal Site Activity

This is a 500-MW oil-fired thermal power plant.

Understanding the Risk at this Facility

This well-maintained thermal station feeds 40% of the island's power demand during the winter and no other feeds can compensate for the sudden loss of one unit. Reliability of critical systems at this station remains crucial to avoid unexpected trips or downtime during the winter.

The insured should be granted as an EPRI Level 1 Life Assessment survey was made in 2010 on the plant generating equipment. This led to the planned rewind of the stators of Generators of Units 1 and 2 in 2015 and 2014 respectively due to aging and weak slot support systems. An EPRI Level 2 Life Assessment survey will be received soon.

Many improvements are on-going or were completed at this station in the last year, pertaining to water induction potential to steam turbines, nozzle block replacement on Unit Nos. 1 and 2, extensive nondestructive examination (NDE) program development, and fuel tank farm refurbishment.

Water induction protection at this facility should be improved by testing the high-high-level switches on feedwater heaters, and by installing a drain pot with a high-level switch on the cold reheat line of Unit 3. Testing will be made this year on Unit 1 and 2 feedwater heaters.

The pressure of the water in the hydrogen coolers is higher than the hydrogen, which exposes the generators to a major fault in the event of a leak. Although there are positive factors already in place, installing continuous hydrogen dew point monitoring and developing a procedure will help mitigate that potential. This will possibly be completed this year.

The major overhauls are done every 9 years on the turbogenerators, based on their good condition. In order to properly follow-up on the condition of the generators' windings and field, periodic dielectric testing should be conducted between major outages to avoid unnoticed insulation deterioration. This was discussed with management and will be implemented this summer on Unit 1.

Other recommendations are also presented, or suggestions in the Comments section, which should be given due consideration.

FM Global continues to sustain severe Babbitt bearing failures on large steam turbines due to inadequate dc power to the emergency lube oil pump when required. The insured will study the maintenance strategy of the flooded lead-calcium battery banks.

Factory Mutual Insurance Company (FM Global) has developed this report for insurance underwriting purposes. The report is provided to you for informational purposes only to reduce the possibility of loss to property by bringing to your attention certain potential hazards or conditions. You must make the decision whether to take any action. FM Global undertakes no duty to any party by providing this report or performing the activities on which it is based. The liability of FM Global is limited to that contained in its insurance policies.

Understanding the Risk at this Facility continued

Management continues to show excellent interest in loss prevention, as demonstrated by the plans to complete critical recommendations in the next two years. The insured is even evaluating the possibility of a simulator for the operator training, which is highly supported by FM Global. This engineer is highly impressed by the aggressive action plans in place to increase the reliability of the units and their critical systems.

Target Recommendations are those that the Account Engineer has selected as part of the account risk improvement priorities.

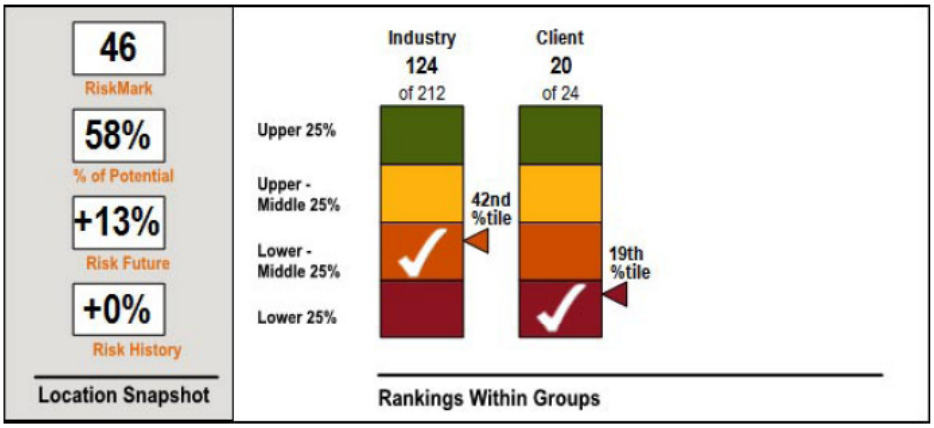
Location Overview

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 Fossil Fuel Power Plant.

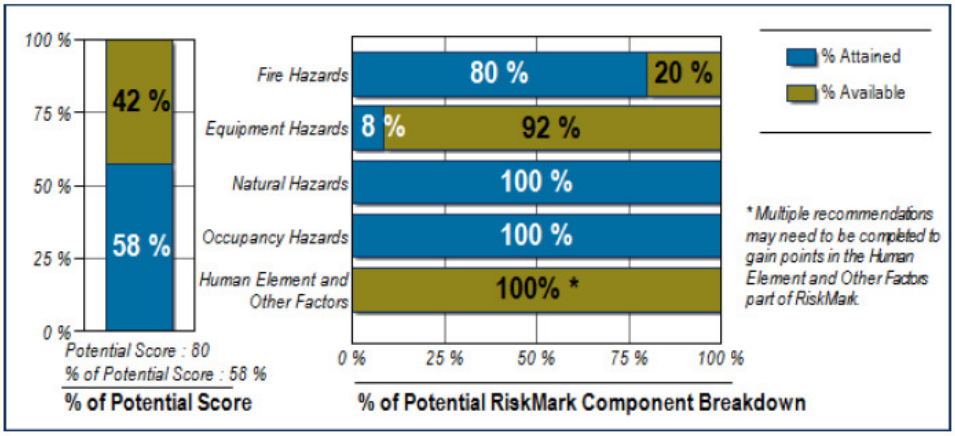
The Risk Future number is the per year improvement in your percentage of potential score, projected to 01 July 2013. The Risk History number is the per year improvement in your percentage of potential score, since 01 July 2009.

FM Global Risk Report Nalcor Energy

Location Overview continued

Risk*Mark* Breakdown

This display shows a breakdown of your Risk*Mark* score and its logical components on a percentage basis, and includes opportunities for risk improvement on a percentage basis as well.



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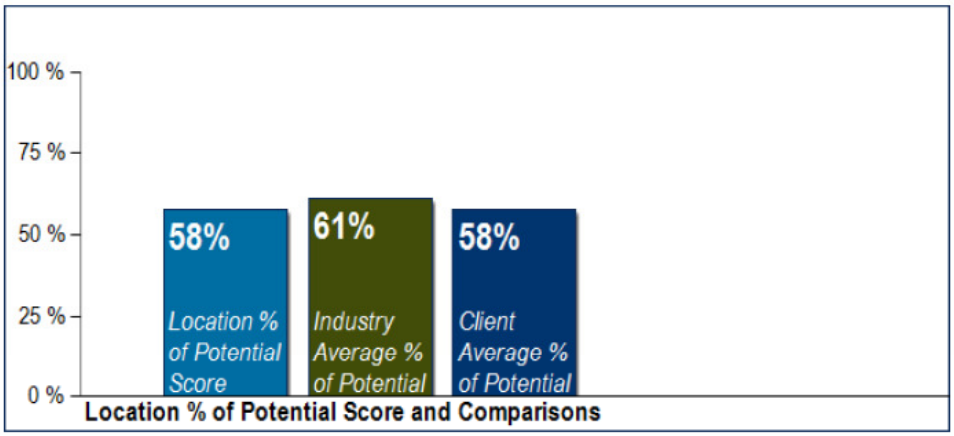
Location Overview continued

Risk*Mark* Comparisons

This display shows a comparison of your Risk*Mark* score (on a percent of potential score basis) to the average percent of potential scores of other groups as noted in the display.



The Industry used in the above chart is Fossil Fuel 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.

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.

09-03-001 **Implement a synchronous generator periodic dielectric testing of the stator windings and rotor field**

The Hazard	The major outage frequency was changed from 6 to 9 years based on the satisfactory condition of the turbines. This means the condition of the stator windings and rotor field would be assessed only every 9 years, which is too long to follow-up on the insulation condition of the generators. On-line partial discharge installed, although useful, is not enough to assess the evolution of the windings. Typically, the dielectric condition of the windings and field should be evaluated every 3 to 5 years during a minor outage. **Synchronous Generators in Need of Interim Testing**
Technical Detail	The typical electrical tests would be winding resistance, insulation resistance and controlled overpotential tests, along with suitable rotor testing such as impedance measurements and winding resistance. The major outage frequency was changed from 6 to 9 years based on the satisfactory condition of the turbines. This means the condition of the stator windings and rotor field would be assessed only every 9 years, which is too long to follow-up on the insulation condition of the generators. On-line partial discharge installed, although useful is not enough to assess the evolution of the windings. Typically, the dielectric condition of the windings and field should be evaluated every 3 to 5 years during a minor outage. These tests would be done by opening the terminal box and one end bell would be opened to allow the visual inspection of the end windings to see any looseness, greasing or signs of partial discharge. The recommended tests for a minor outage of an hydrogen cooled synchronous generator are as follows: **Stator windings**

09-03-001 continued

Technical Detail	Insulation resistance (Megger test) (dielectric absorption test) of each phase to ground with other two phases grounded and comparison with previous tests. The stator DC winding resistance measurements and comparison between phases and with previous tests. The AC dielectric loss test (Doble test) with phase to ground power factors and associated power factor tip-ups comparison among phases and with previous test results. The DC controlled step voltage or DC ramp test (High Pot) on each phase with other two phases grounded and comparison with previous test results is made at around 1.3 times line to line rated voltage. The Holyrood Station stated that a DC controlled or ramp test would not be done on the generators stators but ac searching tests such as power factor, power factor tip-up can be done. It will be acceptable not to conduct an overvoltage test if good condition-monitoring systems are in place, and good results have been obtained from partial-discharge monitoring and insulation resistance testing, and there is no reason to suspect a problem with the insulation. Typically, an overvoltage test becomes warrant under the following conditions: As part of commissioning. After a repair. A repair is considered to be any work requiring the removal of stator bars to restack the core, rewind the generator, or any other work involving the stator bar insulation. Re-wedging, end winding re-bracing, and core tightening may also warrant an overvoltage test. After any incident, such as serious water leaks, overheating, fire exposure, or seal oil ingress, that raises doubts about the integrity of the insulation. Visual inspection of the end windings for greasing or looseness and core for hot spots. **Rotor field windings** The Megger test (dielectric absorption test) The rotor DC winding resistance test Visual inspection of the retaining rings for corrosion with rotor in place.
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. Vincent, Manager of long term asset planning, agrees with the proposed frequency which coincides with the present turbine valve overhaul frequency. AC searching tests such as power factor and power factor tip-up in addition to insulation resistance testing would be done but with the end bells not removed. This is accepted based on past results. Unit 1 will be tested this summer in prevision of the 2012 major overhaul and the stator rewind planned for 2015.

07-10-001 **Take steps to mitigate the risk of a water leak inside a generator.**

The Hazard	Although the generator electrical protection is adequate, the potential for water entrainment with hydrogen into the generator winding exists since the hydrogen cooler water pressure is significantly higher (100 psi) than the hydrogen pressure (45 psi). Positive factors include good history (no leaks), water is quality controlled (would reduce contamination risk), liquid level indicators in generator casing, 18-5 retaining rings were replaced, and hydrostatic tests done every 6 years. However the risk of a leak cannot be eliminated. The hazard is that should a leak occur, the pressure dispersal of the water at 100 psi and the windage inside the generator would cause a very quick dispersal of water throughout the generator, which would quickly lead to an insulation failure.

The cooler water pressure inside these generators is higher than the hydrogen pressure.

Part B. **Install hydrogen dew point monitoring inside generators.**

Hydrogen dew point monitoring, set to alarm, should be installed in all generators where water pressure is above hydrogen pressure.

The Hazard	This device measures the relative humidity of the hydrogen and will provide an early indication if there is a leak in the hydrogen coolers. This is good practice even if the water pressure in the coolers is not higher than the hydrogen gas pressure (since water can leak from the coolers due to capillary action), but is more critical in this circumstance where water pressure is higher than hydrogen's.
Technical Detail	The generators are subject to hydrogen dew point analysis once per month. In order to reliably use dew point monitoring as a tool to detect leaks, a continuous hydrogen dew point monitoring system would be required.

07-10-001B continued

Technical Detail	It should be noted that the generators are fitted with hydrogen purity monitors. This instrumentation looks only at the gas concentration (to avoid the explosive range). It measures hydrogen concentration by analyzing the thermal conductivity of the gas and cannot detect moisture or other contaminants. This instrumentation cannot be credited for detecting cooler leaks. The insured will acquire a hydrogen generator from Proton Energy. The unit will have some built-in redundancy to maximize its reliability and will comprise a new dryer, purifier and dew point monitoring. T he battery room was chosen for the installation of the hydrogen generator.
Risk*Mark* Points	Completion of only this recommendation will result in a Risk*Mark* score increase of 2.74 Points.
Status	Hydrogen dew point monitoring will be installed in 2011 as per Mr. Vincent. The work includes the installation of a hydrogen electrolyzer complete with a low pressure hydrogen bulk storage tank and replacement of three hydrogen gas control panels (one per unit).

06-01-003

Improve protection against steam turbine water induction.

Part A. Target

Test high and high-high level switches on feedwater heaters.

The high and high-high level switches on the boiler HP feedwater heaters should be tested at least quarterly, using the simulation method. These should be provided with a means to test the high water level alarm and interlocks without endangering the operation of the unit.

The switches that have inconsistent test results should be repaired or replaced.

The Hazard	The admission of water into the hot turbine, valves and piping can cause premature failure of critical components, and feedwater heaters in particular represent the most frequent source of potential water induction. If a high-high water alarm is not quickly sensed in a feedwater heater and the protection interlocks do not operate as designed, water can pass through the block valve and reach the extraction nonreturn valve (NRV). This valve could be distorted due to thermal shock, allowing water to enter and damage rotating components of the turbine. In the worst case, thermal shock and distortion result in rubbing or blade failure and downstream damage. Testing the feedwater heaters' safety devices will help ensure that all components operate as designed to prevent such an event.
Technical Detail	Simulation of a high water level condition is feasible by means of a two-way valve (try cock), or the isolation and vent valves on the steam side of the

06-01-003A continued

Technical Detail	switch. The steam chamber can be isolated from the heater and, at the same time, be vented to the atmosphere, reducing the pressure above the condensate in the gauge, and permitting the condensate level to rise and actuate the level switch at alarm level. Prior to and upon completion of the test, make sure to test/inspect the heaters to confirm the normal water level is in range. Upon completion of the test, restore the equipment to its original condition of operation. So far, the modifications to allow this test were completed on Units Nos.1 + 2.
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	The test is considered warranted by management. An offline test will be conducted twice a year as agreed by FM GLOBAL. Unit Nos. 1 and 2 Feedwater Heaters will be tested prior to the heating season however, a procedure is required. Unit No. 3 Feedwater Heaters will sustain the same modifications in 2013.

Part B. Target

Install a drain pot with a high-level switch on the cold reheat lines of Unit No. 3.

The cold reheat drain line should be modified to provide a drain pot at the low point of each cold reheat line. These should be physically located as close as possible to the turbine, and should be fitted to provide a signal to permit operator action to stop water inflow.

The Hazard	Numerous occurrences of turbine water induction damage have been attributed to the presence of water in the cold reheat line. This water is usually introduced into the system from the reheat attemperators spray station, the feedwater heaters extracting steam from the cold reheat line, or condensation forming in the line and being introduced during startup. The recommended modifications will help prevent damage to the turbine from the above-mentioned sources.
Technical Detail	The drain pot should be fabricated from 6-in. or larger-diameter piping, and not be longer than required to install level sensing equipment. If there is a low point in the cold reheat line other than that near the turbine which is upstream of the attemperator or the extraction supply to the feedwater heaters, then an additional drain pot should be installed at this point for increased protection. Each pot should be provided with a drain line of nominal 2-in. minimum size and a full-size and full-ported automatic power-operated drain valve, arranged to fail open if possible. To prevent condensation, all lines should be fully insulated. Each drain pot should be provided with a minimum of two level sensing devices. The first (high level) should actuate the drain valve to fully open and

06-01-003B continued

Technical Detail	send an alarm notifying that the valve has opened. The second (high-high) should initiate an alarm in the control room. It was discussed that a motorized drain valve operable remotely from the control room upon indication of a high level alarm can be considered as a less desirable yet tolerable alternative to automatic actuation. For more details, please refer to ASME TDP-1-2006, Section 3.3.8.
Risk*Mark* Points	Completion of only this recommendation will result in a Risk*Mark* score increase of 1.31 Points.
Status	Management understands the hazard and indicated that Units Nos. 1 and 2 were provided with cold reheat drain pots with automatic drainage. However, the isolating valves around the automatic dump valve should be opened and managed. Unit No. 3 will receive the same modifications in 2013.

07-10-002 Target

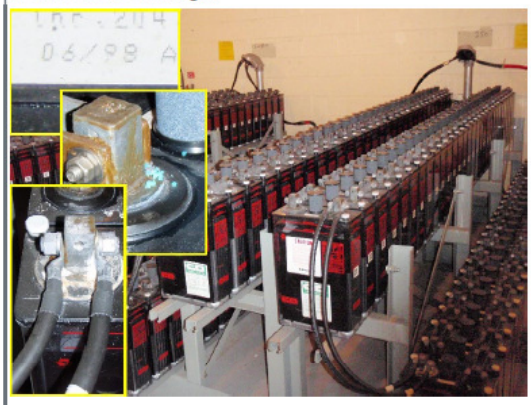
Conduct capacity discharge testing on station service batteries every 5 years

A formal battery maintenance and operational testing program should be implemented for the various station service battery banks. This should include capacity discharge testing once per 5 years on the lead acid flooded cell battery banks. Records of such testing should be kept onsite for future reference.

As a minor observation, no thermometers were noticed to have been installed in any of the cells, and consideration should be given to leaving thermometers in one cell per bank to provide for easy cell temperature readings during visual inspections, or perform infrared survey of some cells every 3 months.

In addition, 10 cells should have their specific gravity measured every 3 months, and 100% of the cells measured annually. Monthly visual inspection is already in place.

07-10-002 continued

The Hazard	By supplying the power needed to trip circuit breakers and to run emergency DC pumps, batteries are critical. When a battery fails, it prevents a circuit breaker from clearing an electrical fault, resulting in severe arcing, equipment damage and power interruption. Another scenario is that DC lube oil pumps are required but unavailable due to failed batteries. Such an event would result in severe bearing damage, and potentially radial rubbing of turbine parts which could result in major steam turbine damage.
	 **Batteries**
Technical Detail	Note that a capacity test (full-load discharge test) for flooded lead acid batteries is only recommended every 5 years. When deterioration in capacity is noticed, increase the frequency of testing to once every year. Replace the battery when its measured capacity approaches 80% of rated capacity. The testing procedure should respect the IEEE STD. 450- 2002 for which a copy was given to the insured. Currently, the batteries are informally verified at least weekly. During quarterly documented inspections, specific gravity readings taken on random cells, cell voltage of each cell are taken.
Risk*Mark* Points	Completion of <u>only</u> this recommendation will result in a Risk*Mark* score increase of 1.42 Points.
Status	According to Mr. Vincent, battery maintenance is currently being examined by Corporate Asset Maintenance review team. The strategy for ensuring a high reliability of those battery banks will be studied.

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.

Risk Reduction

Recommendations that have been completed or otherwise removed are summarized in this section. **Human Element Recommendations** that have been completed often do not have an associated loss estimate since they usually serve to lower the frequency and/or severity of a loss. For this reason, we quantify them by counting the number of such items that have been completed.

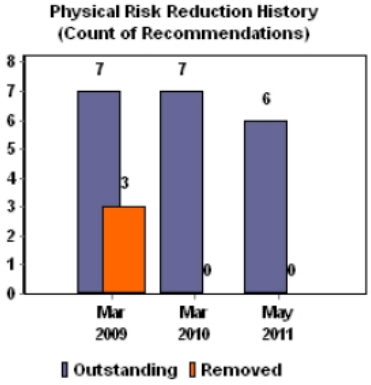
The "Counts" of recommendations referenced in this section include each part of multi-part recommendations except in cases where each part represents options to address a single deficiency. In such cases, the recommendation is only counted once.

These charts illustrate current risk reduction status since the last inspection visit, and also include an historical account of previous risk reduction activity on a cumulative basis. Focus and special visits are not tracked separately, but the total outstanding recommendation counts reflect the full history since March 2009.

Though the Management of Exposures section of this report does not include every currently active recommendation (Fire, Natural or Equipment Hazards), these charts reflect the location's entire exposure and risk reduction activity for all active recommendations at this time.

Physical Recommendations

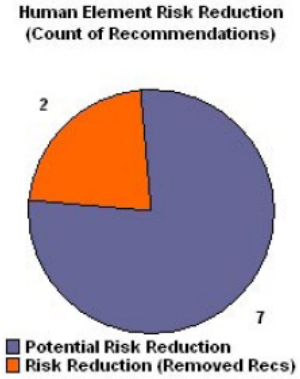
No **Physical** recommendations have been completed or removed since our last evaluation.

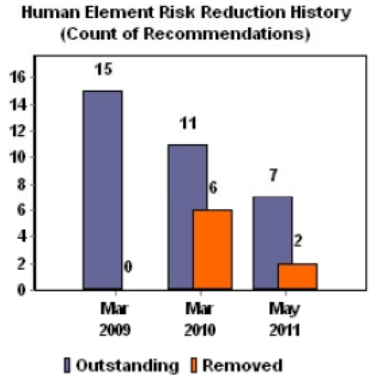


Human Element Recommendations

The following **Human Element** recommendations have been completed or removed as a result of this evaluation:

Rec Number	Recommendation Synopsis *Reason for Deletion/Completion*	Removal Method
07-10-001C	Develop procedures in case of water leak in the generator. *A well developed emergency procedure was developed with the validation of GE in case a water leak is suspected.*	Completed 23 Feb 11
09-03-002	The jumper management program should be upgraded with electronic traceability. *This is not part of FM GLOBAL standards.*	Deleted 12 May 11





Comments

The major overhaul of Unit 1 turbogenerator is planned for 2012 while the Generator stator and rotor will be tested this year with the tests recommended above. In preparation for the planned stator rewind in 2015, the insured should ensure of the integrity of the core laminations prior to invest into a stator rewind. Thus in 2012, core loop test with a sizeable level of flux should be held using a black light to detect warm spots on the core. This engineer will provide the acceptance criterias at a later date. This test needs a sizeable ac source so the delivery should be planned in advance. Also, for the rotor, the retaining rings should be removed to allow a thorough visual inspection of the rotor end windings. This will be considered as per Mr. Vincent. The same comments apply for Unit 2 Generator, which will be dismantled in 2013 and rewound in 2014.

It will be acceptable to exercise the emergency shutoff, control valves, and combined reheat stop valves weekly rather than daily as being done presently, provided exercising continues to show

Comments continued

adequate performance, and no sticking or magnetite buildup on stems or seats or oil varnishing is found in the actuators during overhauls. In those circumstances, the frequency of testing should be increased until these conditions are confirmed to be corrected.

A very detailed nondestructive program was developed for all pressurized components, such as each section of the boilers, deaerators, blowdown tanks, high-energy piping for potential creep damage, and low-pressure piping for potential flow-assisted corrosion. This year, all three blowdown tanks will be replaced.

The first stages of the HP sections of the Turbines are evaluated annually by borescope inspection. The IP stages cannot be evaluated the same way. However, the last stage blades of the LP sections should be visually inspected every three years from the hot well. Typically, the steam particles precipitate at lower steam pressures on the last blade rows of the LP section of a turbine. Sometimes cracking exists around the hole of lacing wires if any and at the leading edge of the LP blades or at the root. This will be considered.

The existing jumper management program, consisting of log sheets, should be upgraded by treating separately the somewhat permanent changes not being a nuisance to the operation, include a formal periodic review and updating, along with a systematic advising system for the operators, to know about the active jumpers on each shift. Unknown jumpers, or a too long list of forces and jumpers, may lead to inadequate system response when upsets occurs. If an expected protection or alarm does not function as expected, without knowing about this, it would affect the adequate reaction of the operators and lead to a serious failure of an important system component. The use of a software management system is preferred to a paper-based system. The insured presented a project to acquire and implement such software. Meanwhile, the insured propose to treat the bypassed critical trips as per the procedure for Safe Work Place, which is electronic. This is an excellent initiative as per this engineer.

A discussion was held with the insured about the frequency of calibration for the generators protective relays. The transmission and distribution group used to calibrate them every two years but now a six-year frequency is contemplated. FM GLOBAL normally recommends that such relays be calibrated every three years. A discussion will be held on this subject this summer at the time of the Boiler No. 2 internal inspection.

The generators have a field ground relay that will alarm upon the first ground and there is no automatic trip. Although most operators would know how to react upon such a situation, a procedure should be developed to address such a condition to determine whether the ground is located in the slip rings where it can be repaired, or confirmed to be in the windings where an orderly shutdown could be initiated. This is because plant experience has shown that most rotor E/Fs are in slip rings and can be removed without too much effort. The unit should not run with a rotor ground if it is confirmed to be a fault in the windings.

The boiler low-water drum level trips should be functionally tested at the end and at the start of the heating season as agreed.

Comments continued

As part of the EPRI Level 2 Life assessment survey made last year, the insured will implement a three-year boiler external piping integrity inspection program. The details were developed by Alstom and AMEC. This program will comprise Main Steam, Hot and cold reheat piping and low pressure piping for creep potential and FAC. The program will be spread over the years 2012 to 2014 and will comprise the hangers inspection for hot and cold positions. This is an excellent initiative supported by FM GLOBAL.

The insured will order an EPRI Level 2 Life Assessment survey for the Rolls-Royce Combustion turbine from AVON, GE, Siemens, and AMEC. Afterwards, decisions will be made on possible refurbishment or replacement based on costs involved.

Electrical System

Due to the high value of the three step-up transformers, on-line dissolved-gas analysis should be considered. This system analyzes an oil sample every 4 hours and can plot the results of each gas in a computer for trending. This allows to react faster should an insulation deterioration develop, by using the spare transformer and open the affected unit. The company Shneider and GE Syprotec manufactures such a system.

The battery bank room for the essential loads of all three units was found to be very clean. The interim maintenance appears adequate but will be reviewed again next time due to the absence of the electrical foreman.

It should be verified if the transmission group TRO is making a monthly visual inspection of the battery banks in the Main Switchyard Building.

Unit Nos. 1 and 3 step-up transformers had their oil filtrated last year based on the oil sampling program. Unit Nos. 1 and 3 step-up transformers had their oil filtrated in 2008. Unit No. 1 step-up transformer T1 was Doble tested, via excitation tests, on the windings, along with its high-tension bushings and surge arrestors in 2005. These tests appear to have been done in 2002 on Unit No. 2 and Unit No. 3 so they would be overdue, but it could not be confirmed during this visit. Power factor (Doble) testing on large transformers' windings and bushings should normally be done every 5 years. The last results of testing should be forwarded to this engineer for review.

The two PCB-Contaminated Exciter Transformers of Units 1 and 2 should have the results of their last PCB content test affixed on the transformer tanks.

Power Transformer T-8 in the Transmission Substation has a corroded radiator, which should be evaluated prior to painting.

Comments continued

Corroded Radiator of Transformer T-8.

Power Transformer T-9 adjacent to the plant has a corroded conservator tank. The tank is corroded at its bottom and this condition should be assessed and then protected by painting.

Comments continued

Corroded bottom conservator tank on T-9.

Ongoing Services

FM Global is available to provide support in all areas of property loss prevention. These services include:

- New equipment installation reviews
- Electrical system evaluations
- Equipment preventive maintenance planning

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

Dan F. Bratucu,
Account Engineer (Equipment):
165 Commerce Valley Drive West
Suite 500
Thornhill, Ontario, L3T 7V8
Canada
[1] (905) 763 5555

Reference Information

Location Findings

Nalcor Energy
Holyrood Thermal Plant
Route 62
Holyrood, Newfoundland and Labrador A0A 2R0
Canada

Equipment Hazards
Interim Risk Evaluation

Visit by:	Michel N. Burbaud
Visit date:	12 May 2011
Site Contact:	Mr. Darren Marsh, AON Broker, darren.marsh@aon.ca

Reference Information continued

Final Conference Attendees:	Mr. Terry LeDrew, P.Eng, Manager, Thermal Generation; Mr. Jeff Vincent, Manager of Long-Term Asset Planning; Mr. Gerard Cochrane, Operations Labour Manager - Thermal; Mrs. Gail M. Cullen, Risk and Insurance Analyst; Mr. Wayne P. Rice, Manager of Work Execution; Mr. Ron LeDrew, Emergency Measures Coordinator; Mr. Darren Marsh, AON Broker; Frank Gentile, FM Global
Location Index Number:	000009.36-02
Account Number:	1-74568

Risk*Mark* Information included in this report is current as of 16 May 2011.

APPENDIX B

ASME Standard TDP-1-1998, Section 3.5

be designed basically in accordance with criteria set forth earlier in this Section for drain lines. This similarity should include the installation of power-operated valves, control room indications of valve position, and control room operation of the valves. The drain lines, connections, and valve ports should, however, be a minimum of ¾ in. I.D.

3.4 Cold Reheat Piping

3.4.1 Numerous occurrences of turbine water induction damage have been attributed to the presence of water in the cold reheat line. This water is usually introduced into the system from either the reheat attemperator spray station or the feedwater heaters which extract steam from the cold reheat line. The design of a drainage system with sufficient capacity to remove all water that can be introduced into the cold reheat pipe from these sources is considered impractical because of the high rate of flow into the piping. For this reason the recommended system is designed to provide a signal to permit operator action to stop water inflow.

3.4.2 Provide a drain pot at the low point of each cold reheat line, preferably as close to the turbine as possible. This pot should be fabricated from 6 in. or larger diameter pipe and be no longer than is required to install level sensing equipment. If there is a low point in the cold reheat line other than that near the turbine (either in the cold or hot condition) which is upstream of the attemperator or the extraction supply to the feed-water heaters, an additional drain pot should be installed at this point for increased protection.

3.4.3 Each pot should be provided with a drain line of nominal 2 in. minimum size and a full size and full ported automatic power-operated drain valve. The valve should be arranged to fail open if such a choice is available.

3.4.4 To help ensure that the pot remains dry during normal unit operation, the pot and connecting piping should be fully insulated.

3.4.5 Each drain pot should be provided with a minimum of two level sensing devices (see Fig. 4). The first level (high level) shall actuate to fully open the drain valve and shall initiate an alarm in the main control room indicating that the valve has opened. The second level (high-hi level) shall initiate a high-hi level alarm in the control room.

3.4.6 The drain valve control should provide the following features:

(a) open automatically on high water level in the drain pot (see para. 3.4.5);

(b) ability to be opened or closed by remote manual controls in the main control room with a high level control capable of overriding the manual closed position;

(c) position indication in the control room.

3.4.7 When a cooling steam pipe is provided from the cold reheat pipe to the intermediate pressure turbine, this pipe should not be connected at or near the low point of the cold reheat pipe. If routing of the cooling steam pipe creates a low point, a continuous drain should be provided from the cooling steam pipe.

3.4.8 In addition to the drain pot and level switches to detect water in the system, thermocouples can be installed on the pipe or in wells. Two thermocouples, one on the cold reheat pipe close to the turbine connection and one on the bottom of the horizontal run below the turbine, can be used to detect water by differential temperature. This system, however, should not be considered as a substitute for the drain pot and level switches.

3.5 Reheat Attemperator

3.5.1 Spray water injection in the cold reheat line is used as a means to control steam temperature at the outlet of the reheater. These sprays are not effective or required for reducing final reheat steam temperature when used at low loads or during turbine rolling. Most incidents of turbine water damage caused by attemperators have occurred during these periods as a result of over-spraying. The water thus formed accumulates and, in most cases because of low steam velocity and the arrangement of the piping, flows back to the turbine. Another possibility, that occurs less frequently, results when water accumulates from condensation in pendant elements of the reheater during a low load operation. The water can then be injected into the turbine if flow is increased rapidly.

3.5.2 A power-operated block valve should be installed in series with the attemperator spray control valve. This valve provides tight shutoff to prevent water leaking past the spray control valve and provides a backup in the event that the spray control valve fails to close when required (see Fig. 5). The spray control and block valves constitute a double line of defense against the inadvertent introduction of spray water into the cold reheat lines. Since spray control valves are susceptible to leakage, additional protection can be obtained by use of a second block valve.

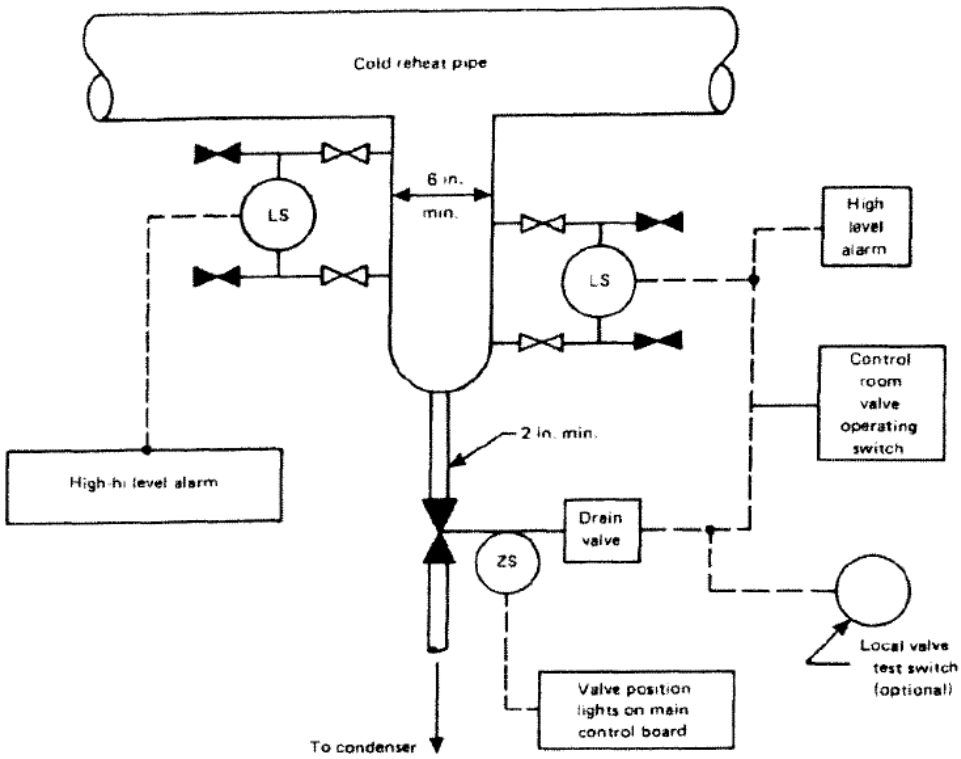


FIG. 4 TYPICAL COLD REHEAT DRAIN SYSTEM

3.5.3 The control system should automatically close and override all manual and automatic settings of the reheat spray control and block valves when the master fuel trip actuates or the turbine trips.

3.5.4 The block valve should be automatically closed below a predetermined minimum load and any time the demand signal to the control valves does not call for spray. Reheat spray should not be released for automatic control at loads where it can be determined that it is relatively ineffective in reducing final reheat steam temperature. The loads used should be in accordance with the boiler manufacturer's recommendations. Manual control must not prevent the automatic protection features specified in para. 3.5.3 from operating in the event the master fuel trip actuates or the turbine trips.

3.5.5 The control system for opening the spray control valve should be designed to prevent the sudden injection of large quantities of water.

3.5.6 A manually-operated drain valve should be installed between the power-operated block valve and the spray control valve. This connection can be equipped as a *tell-tale* for periodically testing for block valve leakage.

3.5.7 A manual bypass valve around the spray control valves is not recommended. If this recommendation is not followed, administrative control should be used to reduce the inherent possibilities of water induction.

Project Title: Upgrade Generator Bearings

Location: Bay d'Espoir

Category: Generation – Hydraulic

Type: Pooled

Classification: Normal

Project Description:

Hydro is seeking approval for year one of a three year program from 2013 to 2015 with a scope of work that involves modifications to Units 1 to 4 generator guide bearings and maintenance hatches in order to 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 (OEM) will include engineering design and technical support, machining of all guide bearing segments, fabrication and supply of new maintenance 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 modified guide bearing segments and new maintenance hatches. The planned schedule is to complete Unit 2 in 2013, Units 3 and 4 in 2014 and Unit 1 in 2015. Depending on other work and outage schedules the unit upgraded in a particular year could possibly change. The budget estimate for this project is shown in Table 1:

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**2015**	**Total**
Material Supply	10.0	0.0	0.0	10.0
Labour	202.9	0.0	0.0	202.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	145.0	0.0	0.0	145.0
Other Direct Costs	15.6	0.0	0.0	15.6
Interest and Escalation	32.7	0.0	0.0	32.7
Contingency	74.7	0.0	0.0	74.7
TOTAL	**480.9**	**0.0**	**0.0**	**480.9**

JUSTIFICATION:

Generating Units 1 to 4 at Bay d'Espoir were commissioned in 1967 and 1968 and since that time have had a continuous history of oil emission problems arising from vaporized lubricating oil escaping from the guide bearing seals (see Figure 1) and also out through poor maintenance access hatch seals (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. Over the past 40 years, and due to wear related to maintenance activities, problems have evolved with the clamps used to secure the maintenance access hatches. Leaks through the hatch seals have become common and have not been corrected due to poor original hatch design. 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 had already been in service for 10 years rather than just two years. This buildup of oil and carbon dust will clog up the ventilation ducts in the stator core over time, increasing the temperature rise in the stator.

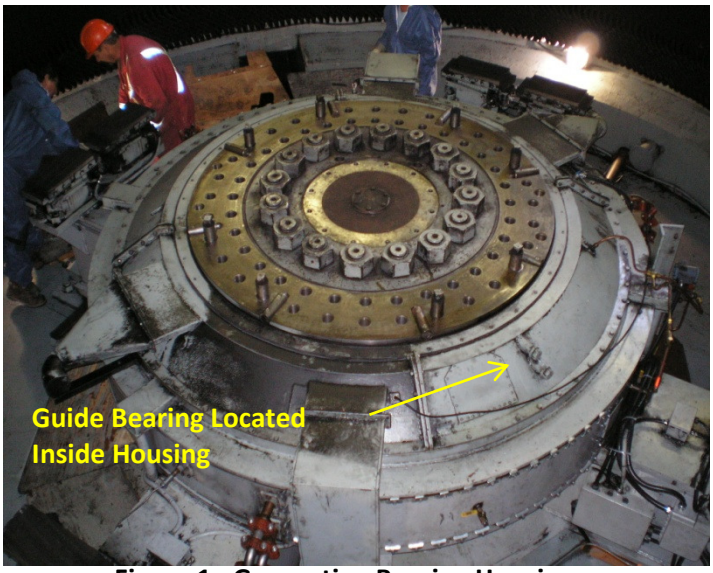
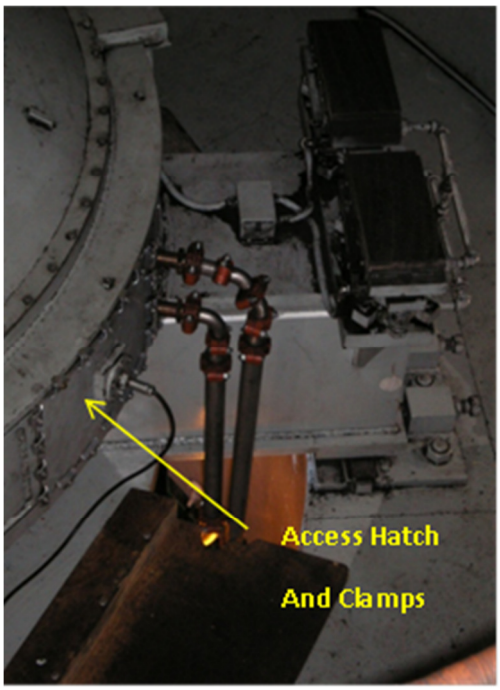


Figure 1: Generating Bearing Housing



Figue 2: Bearing Access Hatches

Existing System

Generation Units 1 to 4 at Bay d'Espoir were supplied by Canadian General Electric (CGE) and commissioned during 1967 and 1969. 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 are normally in continuous service whereas Units 2 and 4 are normally cycled on a daily basis. The generator bearings are now all approximately 44 years old and all four units have oil emission and leakage problems. Many attempts to repair leaks have been made in the past but with limited success. Previous modifications to the bearings to control oil emissions from vaporization were completed shortly after the generating units were originally commissioned during the period from 1971 to 1975. These modifications were only partially successful and there have been no major modifications since that time to resolve the problem.

Operating Experience

Generating Units 1 to 4 at Bay d'Espoir have generator guide bearings that leak oil and contaminate each unit which creates a reliability concern and also 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 bearing oil levels are also occasionally experienced which require maintenance outages to correct. When major leaks occur the units are normally removed from service when generation loading permits. Repairs are normally completed during unplanned or planned maintenance outages. Many of the major leaks occur around the joints between the bearing housing and the maintenance hatch doors seals. The oil vapors are usually emitted through the clearances between the top of the generator bearing housing and the generator's shaft.

Reliability Performance

If oil leaks are significant, the reliability of a generating unit can be significantly affected, however to this point in time, oil leaks have not resulted in a major generator failure. The possibility of a major 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. 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 up the ventilation ducts which prematurely ages the windings.

Outage Statistics

During the last five years, Unit 3 has had three recorded outages and Unit 1 has had one recorded outage to repair major oil leaks. Oil is normally replenished to the units when they are off line. As the generating units are not deemed to be unavailable at that time, an outage is not recorded by the system operations group. A copy of the operator's log book for addition of oil to the generator bearings at Bay d'Espoir for the last six years is shown in Table 2:

Table 2: Addition of Oil to Generator Bearings

ANNUAL REPORTED OIL ADDITIONS TO BEARINGS DUE TO LEAKAGE (LITERS)						
UNIT	2007	2008	2009	2010	2011	2012
1	27	20	10	20	22	263
2	12	26	7	18	81	55
3	48	110	140	110	32	15
4	16	12	35	8	26	10

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements for this project.

Safety Performance

Due to the air flow inside the generator/turbine pits oil emissions from the generator bearing is 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 oil leaks are eliminated.

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. Oil escaping from the guide bearings can 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 timely basis. Environmental regulations prohibit discharging oil into natural water bodies.

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 requiring disposal.

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 Quebec Hydro.

Vendor Recommendations

Andritz Hydro now owns the former CGE and completed some engineering work for Hydro in 2011 to provide advice on how to remedy generating unit oil leak problems. They recommended the modifications proposed to be completed in this project.

Maintenance or Support Arrangements

Normal generating unit maintenance work is completed by Hydro's in-house personnel at Bay d'Espoir, however modifications to the generator guide bearings and fabrication of new maintenance access hatches is a specialized piece of work. Design, modifications and equipment supply will be provided by Andritz Hydro along with site technical support to Hydro in-house labor performing the installation work.

Maintenance History

In the past, efforts have been made to eliminate oil leaks but with limited success. The problem remains to a large degree. Due to the poor original design of the guide bearings and access hatches maintenance procedures can not resolve the problem. Design modifications are required.

The five-year maintenance history for Units 1 to 4 to address oil leaks is shown in the following Table 3.

This maintenance was all corrective.

Table 3: Five-Year Maintenance History

Year	Corrective Maintenance ($000)	Total Maintenance ($000)
2011	6.4	6.4
2010	11.7	11.6
2009	8.5	8.5
2008	1.7	1.7
2007	4.9	4.8

Historical Information

There have been no major modifications to control oil omissions from the generator bearings in the last five years. Unit 2 will be the first unit to undergo major modifications to the bearings since the 1970's.

Anticipated Useful Life

Modifications to the generator bearing and access hatches as presented in this project will not help to extend the expected service life of the generating unit. The main purpose of the modifications is to prevent oil emissions and leaks which contaminate all the unit's components and in particular the generator windings. Eliminating oil contamination will help ensure the normal life of the generating unit is reached.

Forecast Customer Growth

This project is not required to accommodate customer growth.

Development of Alternatives

Through technical support from Andritz Hydro and our past maintenance history this has been determined to be the only alternative.

Evaluation of Alternatives

Since there are no alternatives an evaluation is not required.

Energy Efficiency Benefits

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

Economic Analysis

Since there are no alternatives an economic analysis was not required.

CONCLUSION

This project is necessary to eliminate oil emissions and leaks from the generators on Units 1 to 4 at Bay d'Espoir. Elimination of emissions and leaks will improve the reliability of the generating units and also reduce fire, safety and environmental hazards. Elimination of oil emissions and leaks will also reduce the frequency that a unit must be cleaned. Hydro is seeking approval for the first year of this program to modify Unit 2 generator bearing and access hatches.

Project Schedule

The anticipated project schedule for Unit 2 is shown in Table 4.

Table 4: Project Schedule

Activity		Start Date	End Date
Planning	Open Project Procurement of generator manufacturer	February 2013	March 2013
Design	Design of Hatches and Modifications to guide bearings	March 2013	April 2013
Procurement	Machining of guide bearings and fabrication of Hatches	May 2013	June 2013
Construction	Installation of modified guide bearings and maintenance of hatches	August 2013	August 2013
Commissioning	Testing of modifications	August 2013	August 2013
Closeout	Close out of project, Documentation and lessons learned	September 2013	October 2013

APPENDIX A

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

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

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.

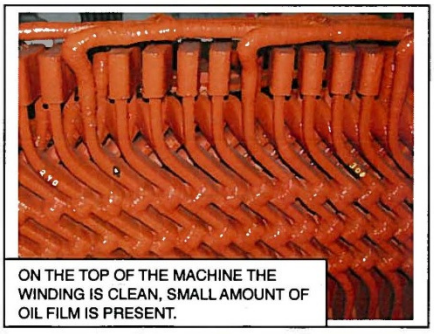
2. Conductive contamination over the end winding on the bottom of the unit

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).

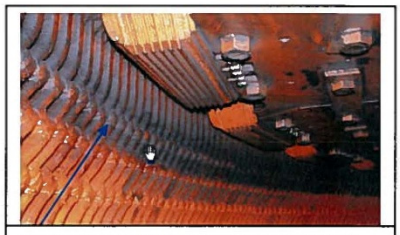
3. Recommendation

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

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NALCOR / Bay d'Espoir, G2	
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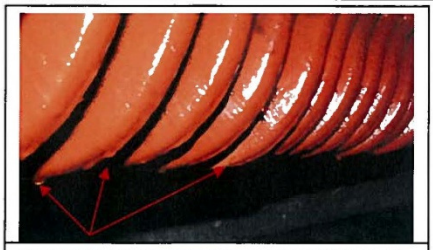

OIL DRIPPING FROM COIL NOSE AT THE BOTTOM OF THE UNIT

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

Project Title: Overhaul Turbine/Generator Units

Location: Bay d'Espoir and Cat Arm

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project is required to partially dismantle Bay d'Espoir Unit 1 and Cat Arm Unit 2 turbine/generator units to inspect, test, clean, repair and replace equipment components. This overhaul involves removal of and cleaning and inspection of the rotor and stator assembly, electrical testing on the rotor/stator assembly, calibration and testing of turbine and generator protection devices, verification of bearing and seal clearances, and a thorough inspection of turbine, draft tube and penstock.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	30.0	0.0	0.0	30.0
Labour	282.9	0.0	0.0	282.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	26.1	0.0	0.0	26.1
Interest and Escalation	21.3	0.0	0.0	21.3
Contingency	67.8	0.0	0.0	67.8
TOTAL	**428.1**	**0.0**	**0.0**	**428.1**

Operating Experience:

Bay d'Espoir Unit 1 and Cat Arm Unit 2 turbine/generator units are two of 16 hydraulic generating units that Hydro operates and maintains to meet system load requirements. These units went into service in 1967 and 1985 respectively.

All Hydro's turbine/generator units are given a major preventative maintenance inspection every six years which is based on operating and maintenance experience combined with the Original Equipment Manufacturer (OEM) recommendations.

Existing System:

Hydro Generation has Hydro Electric Generating units at Bay d'Espoir, Upper Salmon, Hind's Lake, Cat Arm, Paradise River, Granite Canal, Star Lake, Snooks Arm and Venams Bight, for a total installed capacity of 957 MW. All hydro electric generators, intakes, spillways, control structures and plant auxiliary equipment are inspected annually but major inspections/overhauls are conducted on a 6 year frequency.

Age of Equipment or System

The following are the Unit online dates:

- Bay d'Espoir Unit No. 1 - 1967
- Cat Arm Unit No. 2 – 1985

Major Work and/or Upgrades

Major upgrades on Bay d'Espoir Unit 1 hydroelectric generator include: runner replacement (1996), exciter replacement (1998), spherical valve controls upgrade (2003) and cooling water piping replacement (2008).

Major upgrades on Cat Arm Unit 1 hydroelectric generator include: spherical valve maintenance seal refurbishment (2008) and governor controls replacement (2008).

Anticipated Useful Life

The overhaul of the turbine/generating units are completed every six years. Therefore the useful life is six years.

Maintenance History

Five-Year Maintenance History Bay d'Espoir Unit 1			
Year	**Annual Preventive Maintenance Cost ($000)**	**Annual Corrective Maintenance Cost ($000)**	**Total Maintenance ($000)**
2011	31.9	32.0	63.9
2010	24.7	46.5	71.2
2009	16.6	25.0	41.6
2008	11.3	24.4	35.7
2007	66.9	78.6	145.5

Five-year Maintenance History Cat Arm Unit 2			
Year	**Annual Preventive Maintenance Cost ($000)**	**Annual Corrective Maintenance Cost ($000)**	**Total Maintenance ($000)**
2011	26.8	17.5	44.3
2010	25.9	60.5	86.4
2009	12.9	15.7	28.6
2008	18.2	37.7	55.9
2007	43.1	12.5	55.6

Outage Statistics

Bay d'Espoir - Unit 1			
Year	Forced Outages	Maint. Outages	Planned Outages
2011	0	1	2
2010	0	4	1
2009	0	3	2
2008	1	4	4
2007	1	2	1

Cat Arm - Unit 2			
Year	Forced Outages	Maint. Outages	Planned Outages
2011	3	1	2
2010	3	2	3
2009	2	5	7
2008	3	1	3
2007	9	0	9

Industry Experience

Works performed during major inspections/overhauls are based on operational experience and manufacturer recommendations.

Maintenance or Support Arrangements

All maintenance of Hydro Generation hydroelectric generators is conducted internally by Hydro employees. Contractors/consultants may be used to perform large exceptional pieces of work where the skill sets are lacking internally.

Vendor Recommendations

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

Availability of Replacement Parts

Critical spares are maintained in inventory and exceptional replacement parts are readily available.

Safety Performance

The activities that take place during these 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

Environmental impacts are considered for all jobs and necessary precautions, including following applicable Environmental Standard Operating Procedures, to ensure the environment is not affected in an adverse manner.

Operating Regime

During the winter season, December to March, these units are required to be available 99.5 percent of the time. It is also critical that these units be available to handle excess head pond water that runs off during the spring season. All maintenance on all hydroelectric units has to be completed between mid-April and mid-November.

JUSTIFICATION

These large turbine/generator units are required to be operating efficiently and effectively. To meet the winter availability targets and annual system load requirements, these units must have all major components inspected, tested and/or repaired on a six year frequency to avoid forced outages, forced de-ratings or unplanned maintenance outages, which may result in customer interruptions.

Net Present Value

A net present value calculation was not performed since there is no viable alternative to performing these major inspections/overhauls on the established six year frequency.

Levelized Cost of Energy

As this project does not involve new generation services, the levelized cost of energy is not applicable.

Cost Benefit Analysis

A cost benefit analysis was not performed as there are no quantifiable benefits.

Legislative or Regulatory Requirements

There are no Legislative or Regulatory requirements related to these major inspections/overhauls.

Historical Information

Overhauls of turbine/generator units in Granite Canal and Upper Salmon were approved in Board Order No. P.U. 2 (2012) as part of the 2012 Capital Budget. The approved budget is for $456,000, however this work has not yet been completed.

Forecast Customer Growth

Forecast customer growth does not impact this project.

Energy Efficiency Benefits

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

Losses during Construction

There will be no losses during construction.

Status Quo

Major inspections/overhauls are periodically evaluated with respect to work performed and the frequency at which it is performed. Changes will be made to the overhaul content and frequency as deemed necessary.

Alternatives

There are no viable alternatives.

CONCLUSION

Hydroelectric generators are required to be available 99.5 percent of the time during the winter season. They are also required to meet system load requirements on a daily basis. Inspection/overhaul programs are evaluated regularly to ensure they are the most efficient/effective program. Our major inspections/overhauls are an essential part of these programs and are critical to the reliability of the provincial electrical system.

Project Schedule

Major inspections/overhauls are performed by Hydro employees. The schedule varies between three and four weeks. The preventive maintenance program is well established with a well-defined timeline. At times, planned outages have to be extended up to an additional week to deal with corrective maintenance items.

Project Title: Replace Automatic Transfer Switches

Location: Hind's Lake

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This proposal is for the replacement of two automatic transfer switches that are located at the Hind's Lake Hydroelectric Generating Station (Hind's Lake). The proposal includes all costs to procure, install and commission these transfer switches. The automatic transfer switch provides access to a reliable source of electrical power for the essential power systems within the Hind's Lake facility.

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

Table 1: Budget Cost

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	93.5	0.0	0.0	93.5
Labour	113.0	0.0	0.0	113.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	40.5	0.0	0.0	40.5
Interest and Escalation	18.3	0.0	0.0	18.3
Contingency	49.4	0.0	0.0	49.4
TOTAL	**314.7**	**0.0**	**0.0**	**314.7**

INTRODUCTION

The automatic transfer switch is an automated switch which transfers the supply of electrical power from a normal electrical supply to a secondary or emergency electrical supply when the normal supply becomes unavailable. The Hind's Lake electrical system has two automatic transfer switches that can transfer between the normal 13.8kV bus supply and the emergency diesel generator supply as shown in Figure 2.

The existing Hind's Lake automatic transfer switches have had multiple failures when completing transfer operations during the last ten years of operation. This unreliability of operation with the automatic transfer switches has included:

- In March 2003: The automatic transfer switches failed to transfer to the emergency power supply (diesel generator) during an outage and failed to return to the normal supply when the power was restored.
- In September 2005 and August 2006: The automatic transfer switches' motor friction drive mechanism was found to be slipping when the motor operated.
- In October 2005: The automatic transfer switches' timing relays were found to be not functioning correctly. As a result, the emergency diesel would not shut down as anticipated.

The automatic transfer switch is operated infrequently but is a critical system that must operate properly once initiated; its function is to maintain the power supply to the essential electrical systems within the generating station. The existing switches, manufactured by Sytrolrec Controls; now represented by ITE/ABB, were installed in 1980 with the construction of the generating station. Since that time, the switches have deteriorated and become unreliable with maintenance of its components becoming more costly. The replacement of components would require a custom build which is cost prohibitive. The custom manufacture of components would require a site visit by the manufacturer, ITE /ABB and a special setup at the factory to manufacturer these components.

Existing System

The existing two automatic transfer switches, have two sources connected; a normal supply from the station service transformer on the 13.8kV bus and an emergency supply from the diesel generator. Each automatic transfer switch is identical with each containing two molded case circuit breakers, a drive mechanism for switching the circuit breakers and a series of relays and control equipment to initiate the transfer between the supply sources.

Figure 1 shows the external and internal views of the two existing automatic transfer switches in Hind's Lake Hydro Generating Station.

Figure 1: Hind's Lake Automatic Transfer Switches

The replacement of the automatic transfer switches as shown in Figure 2 will involve more than a one-for-one changeover. The commercially available automatic transfer switches have a one-load arrangement on their output that will not work with the existing two-load arrangement in Hind's Lake. Upon further investigation, a manufactured solution was found with a product typically used outside of the utility business. This product has the two-load output and can be used for critical systems but is physically larger than the existing arrangement. This larger automatic transfer switch is floor-mounted and will require a new location. The new location is positioned directly above the existing location on the main floor level of the facility. The benefits of this location are based on it being cost effective, as no cable replacement is required, with the exception of a new diesel generator cable connection. Also, the two automatic transfer switches are located inside the one enclosure.

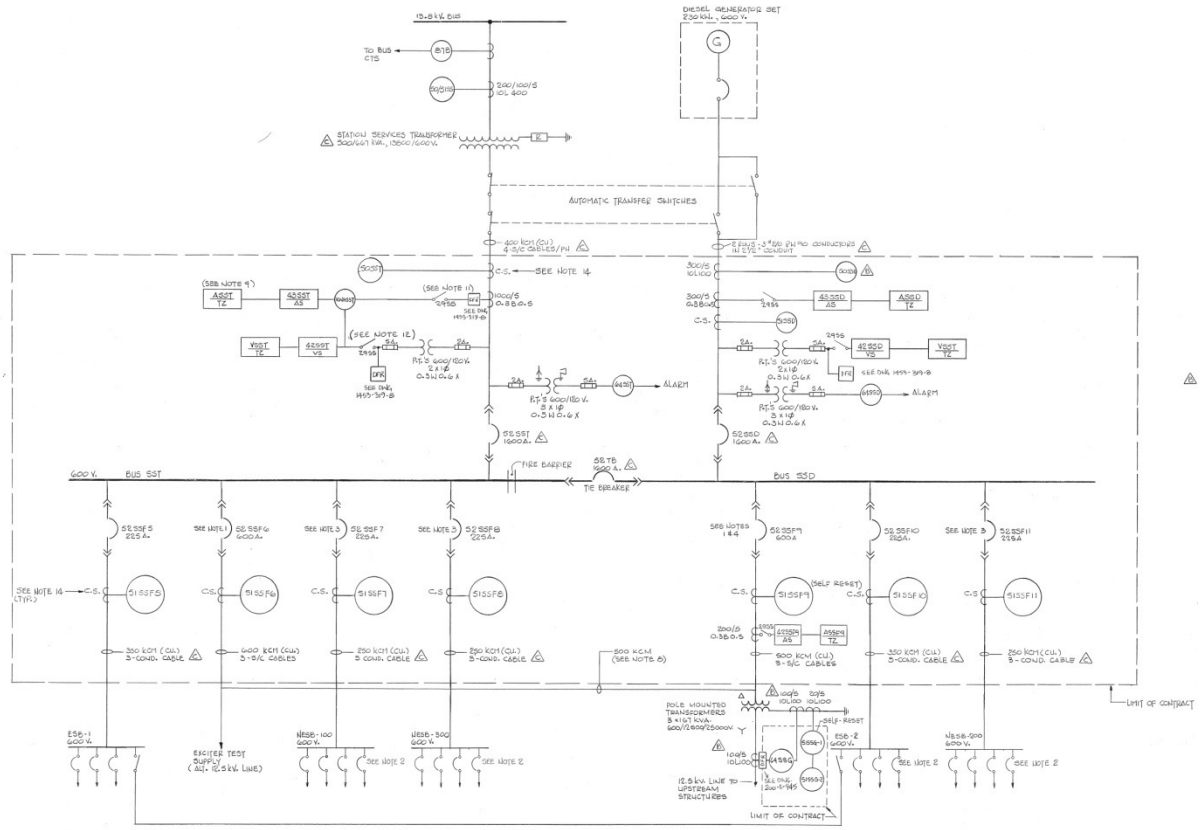

Figure 2: Hind's Lake Single Line Diagram for Powerhouse Station Services

JUSTIFICATION

To understand the criticality of the automatic transfer switch within the Hind's Lake station, the failure of the automatic transfer switch in its operation would create a situation with a high probability for a plant outage. An automatic transfer switch failure removes automatic access to backup power generating capacity from the plant. A plant outage would reduce power available on the Island Interconnected System.

With each failure a manual intervention is required to transfer the essential systems to their backup supply. There are also costs incurred to investigate each failure which normally requires an eight hour outage of the Hind's Lake facility to complete.

<u>Anticipated Useful Life</u>

The automatic transfer switch has an estimated service life of 30 years. The Hind's Lake asset is 31 years and has reached the end of its service life.

Evaluation of Alternatives

There are no alternatives for this equipment but replacement. This asset has reached the end of its service life, it is critical to the operation of a Hind's Lake Hydro Generating Station, and it has no readily available spare parts for the replacement of components or as a complete unit.

CONCLUSION

As the automatic transfer switch is a critical asset to the operation of a Hydro Generating Station that has no design alternatives, the only viable solution is replacement of the existing automatic transfer switch.

Project Schedule

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Determine Outage, Develop Schedule and Cost Flow, Confirm Resource Availability	January 2013	March 2013
Design	Finalise Design	April 2013	May 2013
Procurement	Procure Material, Complete Tender	May 2013	August 2013
Construction	Install ATS	September 2013	October 2013
Commissioning	Commissioning ATS	October 2013	October 2013
Closeout	Closeout Contract and Budget, Lessons Learned	November 2013	December 2013

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[4]. It is required 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. 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.

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.

[4] 2012 project was under $50,000.

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

2011 - Conduct Public Safety Risk Assessment of structures on the Long Pond Reservoir in Bay d'Espoir.

2012 - Purchase and install lower cost control improvements on the Long Pond Reservoir structures that were identified in the 2011 risk assessment.

2012 - Conduct Public Safety Risk Assessment of structures on the Meelpaeg Reservoir on the Bay d'Espoir System.

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 will be identified in the 2012 risk assessment.

2013 - Conduct Public Safety Risk Assessment of an additional reservoir on the Bay d'Espoir System.

The Long Pond Public Safety Audit was completed by Hatch Ltd. in December 2011. Before the 2011 audit, Hydro estimated the costs of this project for 2013 as $250,000. Following release of the audit report, more information became available increasing the cost estimate to $298,100. 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)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	170.0	0.0	0.0	170.0
Labour	23.5	0.0	0.0	23.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	30.0	0.0	0.0	30.0
Other Direct Costs	7.5	0.0	0.0	7.5
Interest and Escalation	20.9	0.0	0.0	20.9
Contingency	46.2	0.0	0.0	46.2
TOTAL	**298.1**	**0.0**	**0.0**	**298.1**

The $170,000 identified under Material Supply in Table 1 includes $145,000 for three safety booms and $25,000 for signage and fencing improvements. The signs vary in size depending on their

location and required sight distances. As part of the 2011 public safety risk assessment, signs ranging in size from 450 by 600 mm up to 3000 by 4300 mm were identified.

INTRODUCTION:

The Canadian Dam Association (CDA) is recognized as the industry leader 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 new CDA guideline entitled "Guidelines for Public Safety Around Dams" was released in 2011. Hydro has a copyrighted edition of this guideline. 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
- 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.

As this project is required to comply with 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;

Historical Information; Forecast Customer Growth; 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 a lack of awareness 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 due diligence 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 2011 Public Safety Audit of the Long Pond Reservoir, Hatch identified gaps at the five main dams, the three intake structures, both powerhouses and the spillway structure, 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 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 the start of the program by Hydro to look more closely at existing control measures that are in place. The Long Pond Reservoir is the main head pond reservoir of the Bay d'Espoir Development and is located close to communities in the area and is easily accessible by

the public. The risk assessment completed in 2011 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 Long Pond Reservoir.

The 2011 assessment noted that signage at the tailrace, intakes and spillway areas were inadequate. The small lettering did not provide the visibility to attract the public's attention and was illegible from a safe distance.

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 has made a conscious decision to follow the industry accepted CDA guidelines.

Status Quo

The only control measures that Hydro has in place to alert the public of hazards are signs. 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. There are no larger control measures such as buoys and booms in place.

Conclusion:

Hydro has been following the CDA "Dam Safety Guidelines" pertaining to dam safety for approximately 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 are occurring at hydroelectric facilities throughout 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 are 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 Long Pond Reservoir was the first in a series that Hydro will be conducting over the next several years and the 2013 program primarily involves the implementation of significant control measures at the Long Pond Reservoir in addition to continuing with risk assessments at other Hydro dams and waterways.

Project Schedule

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Open Project File	March 2013	March 2013
Design	Conduct Risk Assessment	April 2013	May 2013
Procurement	Purchase Materials for Control Measures	May 2013	June 2013
Construction	Install Control Measures	June 2013	September 2013
Closeout	Finalize Payments and prepare closeout documentation	October 2013	November 2013

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

Hatch Recommendations

Table 4-3: Risk Rating

Risk Rating			Incident Consequences				
			Insignificant	Minor	Major	Critical	Fatality
			1	2	3	4	5
Incident Likelihood	Very Frequent	5	MEDIUM Note 2 / LOW	HIGH	HIGH	HIGH	HIGH
	Frequent	4	LOW	MEDIUM	HIGH	HIGH	HIGH
	Occasional	3	LOW	MEDIUM	MEDIUM	HIGH	HIGH
	Possible	2	LOW	LOW	MEDIUM	MEDIUM	HIGH
	Remote	1	LOW	LOW	LOW	LOW	MEDIUM

Note 1 - The CDA Guideline provides leeway for the determinations of High, Medium, & Low Risk based on organizational risk tolerance. This Table has been used by others, and was selected by Hatch for this review, but other table configurations generally displaying less risk tolerance (greater conservatism) are available.

Note 2 - In cases when the hazard identification and assessment process indicates that there are no adverse consequences related to a particular activity (and the ICR rating assigned to this activity could be 0), the resulting risk rating can be LOW instead of MEDIUM.

4.2.2 *Summary of Existing Risks*

According to the CDA Guideline, a dam owner may set a policy which classifies risks as High, Medium or Low, as discussed above. The intent is that the categories act as triggers for action. The highest risks would be addressed with the highest degree of concern and urgency, whereas the lowest risks might be considered to be acceptable. However, the governing principle is that all risks should be reduced to the extent that is reasonable, given the intended function of the dam. Thus, if a simple risk control measure is readily available to reduce an already low or medium risk, then it should be implemented.

This can be summarized as High risks being first priorities to at least be reduced to a Medium risk, and Medium risks being second priorities to at least be reduced to a Low risk [interpreted from Section 4, p. 22 of CDA Guideline (2010-02-17 Draft)]..

The Risk Assessment matrices for the sites of the Bay d'Espoir Long Pond Reservoir are found in Appendix D. Generally the identified location and activity combinations with ***"High"*** **and** ***"Medium"*** risk ratings are discussed below.

4.2.2.1 *Main and Unit No. 7 Powerhouses and the Tailrace Areas*

The Main and Unit 7 powerhouses area is generally well secured to prevent or mitigate public interaction (Figure 2). The primary deficiency identified was related to the potential for boats to travel from Bay d'Espoir up to the powerhouses without encountering a barrier or any effective public safety signage (High Risk - see Risk Matrix in Appendix D). Recommendations for appropriate control measures are discussed below in Section 6.

Safety • Quality • Sustainability • Innovation

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4.2.2.2 *LD-1 and Intakes 1 through 4*

The Dam LD-1 and Intakes area is generally well secured to prevent or mitigate public interaction (Figure 3 and 4). The primary deficiency identified was related to the potential for members of the public to walk past the right abutment gate and proceed onto Dam LD-1 for fishing, or curiosity reasons. There is potential for this because the public congregates at the right abutment because of the boat launch and ad-hoc camping area. Once past the gate (which is trespassing), members of the public could get to the Intake 1 area which is not fully secured from the upstream with respect to potential entrainment in the intake flow. It is worth noting that it is possible that the trespassers could be unaccompanied young people. Also, as there are only debris booms, water approaches by boat could also be made to the similar areas, directly upstream of any or all four intakes (up to Medium Risk - see Risk Matrix in Appendix D). Recommendations for appropriate control measures are discussed below in Section 6.

4.2.2.3 *LD-2*

There is no water-conveying capability at the LD-2 structure which significantly reduces the overall risk to the public with respect to this structure (Figure 5). Nevertheless, there are some hazards related to vehicle operation across and on the dam. In particular, vehicle operation across the crest is allowed by Hydro because there are cottages beyond the north end of the dam, while access is from the south. It is understood by Hatch that this fact effectively precludes Hydro from gating the dam crest to restrict traffic (up to Medium Risk - see Risk Matrix in Appendix D). Recommendations for appropriate control measures are discussed below in Section 6.

4.2.2.4 *LD-3*

There is no water-conveying capability at the LD-3 structure which significantly reduces the overall risk to the public with respect to this structure (Figure 6). Nevertheless, there are some hazards related to vehicle operation across and on the dam. In particular, vehicle operation across the crest is allowed by Hydro because the LD-3 crest actually forms part of the Long Pond/Air Strip Access Road. There are also cottages beyond the north end of the dam, which are more easily accessed from the St. Albans side and Dam LD-3, than via Bay d'Espoir and Air Strip Road. It is understood by Hatch that this fact effectively precludes gating the dam crest to restrict traffic (up to Medium Risk - see Risk Matrix in Appendix D). Recommendations for appropriate control measures are discussed below in Section 6.

4.2.2.5 *LD-4*

There is no water-conveying capability at the LD-4 structure which significantly reduces the overall risk to the public with respect to this structure (Figure 7). Nevertheless, there are some hazards related to vehicle operation across and on the dam. In particular, vehicle operation across the crest is allowed by Hydro because the LD-4 crest is the most convenient access to a single cottage which is located just beyond the right abutment of the dam. It is understood by Hatch that this fact effectively precludes gating the dam crest to restrict traffic (up to Medium Risk - see Risk Matrix in Appendix D). Recommendations for appropriate control measures are discussed below in Section 6.

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4.2.2.6 *LD-5 (Salmon River Dam) and LD-5S (Salmon River Spillway)*

This structure has water-conveying capability by virtue of the LD-5S spillway component. But the Salmon River Spillway (LD-5S) is rarely operated and only in exceptional circumstances involving extreme system high water conditions. The tailrace has dry or near-dry conditions the vast majority of the time so this is what any members of the public who have previously attended the tailrace area would expect. The only water found downstream in the tailrace is in pools in the bedrock. Unexpected spill from the LD-5S spillway could result in the potential for members of the public to be swept away or stranded. Because of this, Hydro has a Salmon River response plan that reportedly involves radio announcements, temporary signage, flying of the downstream areas to look for members of the public etc. as well as the excavation/removal and closure of the Upper Salmon Access Road at the river crossing located about 1.3 km downstream of the spillway. Given this existing internal Hydro approach to this important aspect of public safety at LD-5/LD-5S (spill events), Hatch has thus focused on hazards related to the upstream, the structure itself, and the downstream left bank falling hazards.

The Dam LD-5 and LD-5S spillway area is generally somewhat well secured to prevent or mitigate public interaction (Figure 8 and 9). The primary deficiencies identified were related to the potential for members of the public to intentionally breach the security fencing perimeter and reach interior hazards, the public potentially accessing the dam by boat, or on the ice by foot or snowmobile in the winter, without barriers to restrict them, and the potential downstream left bank falling hazards at the spillway structure and at the high rock cut (up to High Risk, particularly the latter noted risks - see Risk Matrix in Appendix D). It is worth noting that it is possible that because of the proximity of at least one cottage, some of the members of the public attending the area could be unaccompanied young people. Recommendations for appropriate control measures are discussed below in Section 6.

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5. Hydraulic Assessments

According to the Hydro RFP (Scope of Service) and Hatch's proposal, hydraulic assessments are beyond the scope of this review, and so were not carried out. For this reason, the suggested locations and configurations for the public safety booms at the Powerhouses merged tailrace, at the intakes forebays, and at the spillway LD-5S forebay are approximate only (schematic).

According to the CDA Guideline, a hydraulic assessment can assist in identifying hazards and or the extent of the hazardous area. It provides a clearer understanding of the reaction of the reservoir, downstream channel and river bed, to changes in flow. Of particular interest are the magnitude and rate of rise of water levels as well as any increases in velocities caused by constrictions or changes in the channel geometry.

Hydraulic assessments based on actual flow tests can be considered to assist in determining the increments of sluice gate opening that either eliminate the hazard posed by the spill operation, or provide sufficient time for the public to safely exit the spillway channel. They can prove especially valuable to understand the priming characteristics of the downstream areas when the spillway channel or river bed can be reduced to no flow or ‚dry conditions'. The results of the hydraulic assessments can be used to establish the time to safely exit the spillway channel, which in turn will direct the appropriate timing for sounding an audible alert and or a visual warning.

The intent of the hydraulic assessment is to define the extent of dangerous water areas created specifically by the operation in the immediate vicinity of the water-conveying structure, in the reservoir, and at downstream reaches of the river. While fast flowing water can, in itself, present a hazard to the public, the CDA Guidelines generally focus on hazards created during the changes in levels and flows up until the point where conditions have stabilized and the public has become acclimatized to the changes.

According to the CDA Guideline, the results of any hydraulic assessments should be documented in terms of antecedent conditions, discharge rates, physical water levels and velocities, as well as visual observations and photographic record.

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6. Recommendations for Control Measures

All recommendations for Public Safety control measures for all the dams/structures at Bay d'Espoir and the Long Pond Reservoir sites are addressed and included in Tables 6-1 through 6-8 below. These Tables address all six water-retaining sites, and two intersections for which signage is recommended. Figures 1 through 10 are useful references for the content of these Tables. The risk matrices (assessments) referenced in the third column are located in Appendix D.

Table 6-1: Main and Unit No. 7 Powerhouses and the Tailrace Areas - Recommendations for Public Safety Control Measures

Activity	Maximum Associated Hazard &/or Consequence	Risk Rating per Risk Matrix and Priority Type	Recommended Controls
Approaches from downstream by boat and related activities	Drowning	High (1)	Install a public safety boom downstream of the confluence of the two powerhouse tailraces. Install large signs on each bank just downstream of boom anchors as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)*. English sign 4.7 is recommended (in the family of *"Danger- Keep Out – Access Beyond this Point May Result in Drowning"* signs). Particularly if the boom can be left installed year-round, additional signage closer to or at the powerhouses may not be necessary.
Trespassing at back gate area near Unit 7 Powerhouse	Drowning/Death (the worst case if person trespasses and subsequently has worst case mishap)	Medium (2)	Install gate mounted signs (English sign 4.14.1 - *"Danger- No Trespassing"*) as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)* at both the Unit 7 Powerhouse back gate and the nearby North Cutoff Road gate.
Approaches by the Public to the Bay d'Espoir main gate	Non-specific	N/A	For consistency of messaging, it is recommended as an option to install English sign 4.14.1 (*"Danger- No Trespassing"*) as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)* at the main gate. It could replace or supplement the existing *No Trespassing* sign.
Industrial activities at Salmon Hatchery, particularly at pumphouse on Unit 7 tailrace	Drowning	Medium (2)	Property boundaries and/or agreements with respect to the Salmon Hatchery may need to be reviewed. An official letter from Hydro to Salmon Hatchery to officially advise the Salmon Hatchery of the hazard, consequence, and risk directly adjacent to their operation may be advisable.

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Table 6-2: LD-1 and Intakes 1 through 4 – Recommendations for Public Safety Control Measures

Activity	Maximum Associated Hazard &/or Consequence	Risk Rating per Risk Matrix and Priority Type	Recommended Controls
Driving a vehicle on access road to boat launch at right abutment area of LD-1	Non-Specific	Low (3)	Install a new yellow rectangular post-mounted sign at the entrance to this road from Airstrip Road. The sign should read; ***"Warning - Persons Using This Road and/or the Boat Launch Do So At Their Own Risk – If You Choose To Proceed, Slow Down and Drive Safely".*** The sign will need to be customized as there is nothing similar in the *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)*, but the sign should be formatted as per CDA signage.
Launching boats and associated boat launch area activities	Non-specific	Low (3)	Install a post-mounted sign [English Public Use sign 4.13 (size TBD)] as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft),* which relates to boat launches, at the boat launch area at prominent location
Trespassing at LD-1 right abutment crest gate and at right abutment toe road gate	Drowning/Death (the worst case if person passes gate and subsequently has worst case mishap)	Medium (2)	Install a post-mounted sign (English sign 4.9) as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)* at the LD-1 right abutment crest gate area, and a gate-sized sign at LD-1 at right abutment toe road gate (English sign 4.14.2). Both signs are from the family of *"Danger- Keep Out – Access Beyond this Point May Result in Drowning"* signage.
Trespassing at main Intake Road gate	Drowning/Death (the worst case if person passes gate and subsequently has worst case mishap)	Medium (2)	Install a post-mounted sign (English sign 4.9 - in the family of *"Danger- Keep Out – Access Beyond this Point May Result in Drowning"* signs) as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)* at the main Intake Road gate area, and a gate-sized "No Trespassing" sign on gate (English sign 4.14.1)
Boating and snowmobiling in the forebay areas up to the Intakes	Drowning/Death	High (1)	Install an upstream public safety boom (or 2 public safety booms in series) possibly to replace existing debris boom at existing debris boom location (with use of debris skirt)
Activities on foot while trespassing near the Intakes	Drowning/Death	Medium (2)	Install a chain link fence on right bank (at LD-1) from the intake side of new public safety boom to Intake 1. At the boom end of the fence, the fence should "return" towards the waterline, and cantilever over the water as practicable/required in order to prevent the public from trespassing onto the water side of the fence. The new fence should be a best-practices height of at least 2.1 m with 3 strands of barbed wire canted to public side.
Activities on foot while trespassing near the Intakes	Drowning/Death	Medium (2)	Keep internal gate between Intake 3 and Intake 4 closed and locked to restrict access to upstream left bank areas and Intake 4 etc.
Any activity at left bank of forebay upstream of Intake 4	Non-specific	Low (3)	Extend existing left bank fence further upstream to the intake side of the new public safety boom. At the boom end of the fence, the fence should "return" towards the waterline, and cantilever over the water as practicable/required in order to prevent the public from trespassing onto the water side of the fence. The new fence should be a best-practices height of at least 2.1 m with 3 strands of barbed wire canted to public side.

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Activity	Maximum Associated Hazard &/or Consequence	Risk Rating per Risk Matrix and Priority Type	Recommended Controls
Boating and snowmobiling in the forebay areas up to the Intakes and activities on foot while trespassing near the Intakes	Drowning/Death	High (1)	Install up to 3 post-mounted signs (English sign 4.3 - in the family of *"Danger- Keep Out – Access Beyond this Point May Result in Drowning"* signs) as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)* at the new public safety boom anchor locations (right bank at LD-1, head of "peninsula" between Intakes 3 and 4, and left bank)
Boating and snowmobiling in the forebay areas up to the intakes, and dam and any activities on foot at the upstream of the intakes	Drowning/Death	High (1)	Consider installation of up to 3 additional large signs on the upstream sides of Intakes 1 & 2, Intake 3, and Intake 4, especially if text would be viewable from upstream of the proposed booms. As per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)*, this would be English sign 4.1 which reads *"Danger- Dam Ahead - Keep Out"*.
Activities on foot while trespassing near the Intakes	Drowning/Death	Medium (2)	Install 4 gate-sized signs at Intake 1 & 2, Intake 3 and Intake 4 (2 signs, one at each gate) as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)*. The recommended sign is English sign 4.14.2 which is in the family of *"Danger- Keep Out – Access Beyond this Point May Result in Drowning"* signs.

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Table 6-3: Dam LD-2 – Recommendations for Public Safety Control Measures

Activity	Maximum Associated Hazard &/or Consequence	Risk Rating per Risk Matrix and Priority Type	Recommended Controls
Driving a vehicle across dam crest	Death due to vehicle rollover on downstream slope	Medium (2)	Install yellow post-mounted warning signs on both approaches to the dam crest access road. The signs should read: ***"Warning – Persons Using This Dam Crossing Do So At Their Own Risk – If You Choose To Proceed, Slow Down and Drive Safely".*** The signs will need to be customized as there is nothing similar in the *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)*, but the signs should be formatted as per CDA signage.
Accessing downstream slope of dam via vehicle or snowmobile	Medical Treatment	Medium (2)	Install a gate, and adjacent short fencing as required, at main toe area access road near dam right abutment. Also install a gate-sized *"No Trespassing"* sign on gate (English sign 4.14.1), as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft).* Install a barrier such as Jersey barriers, armour stone, or equivalent at upper slope berm access near left abutment, just below crest elevation. Also install a small post-mounted *"No Trespassing"* sign (English sign 4.14.1), as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft).*

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Table 6-4: Dam LD-3 – Recommendations for Public Safety Control Measures

Activity	Maximum Associated Hazard &/or Consequence	Risk Rating per Risk Matrix and Priority Type	Recommended Controls
Driving a vehicle across dam crest	Death due to vehicle rollover on downstream slope	Medium (2)	Install yellow post-mounted warning signs on both approaches to the dam crest access road. The signs should read: ***"Warning – Persons Using This Dam Crossing Do So At Their Own Risk – If You Choose To Proceed, Slow Down and Drive Safely"***. The signs will need to be customized as there is nothing similar in the *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)*, but the signs should be formatted as per CDA signage.
Driving a vehicle across dam crest	Death due to vehicle rollover on downstream slope	Medium (2)	If advantageous with respect to public safety, Hydro should consider contacting the owner of the cottage at the dam right abutment and ensure they understand the hazards of crossing the dam crest, and are exercising caution. Their attention should be directed to any/all new Hydro signage that is in place at the time of the meeting. Any such meetings/discussions should be documented by Hydro.
Accessing downstream slope of dam via vehicle or snowmobile	Medical Treatment	Medium (2)	Install 3 small post-mounted *"No Trespassing"* signs (English sign 4.14.1) at the left and right access points to the downstream toe road/trail (all near road), as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)*.

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Table 6-5: Dam LD-4 – Recommendations for Public Safety Control Measures

Activity	Maximum Associated Hazard &/or Consequence	Risk Rating per Risk Matrix and Priority Type	Recommended Controls
Driving a vehicle across dam crest	Permanent or partial or total disability due to vehicle rollover on downstream slope	Low (3)	Install a yellow post-mounted warning sign on the approach to the dam crest near the left abutment. The signs should read: ***"Warning – Persons Using This Dam Crossing Do So At Their Own Risk – If You Choose To Proceed, Slow Down and Drive Safely"***. The sign will need to be customized as there is nothing similar in the *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)*, but the sign should be formatted as per CDA signage.
Driving a vehicle across dam crest	Permanent or partial or total disability due to vehicle rollover on downstream slope	Low (3)	If advantageous with respect to public safety, Hydro should consider contacting the owner of the cottage at the dam right abutment and ensure they understand the hazards of crossing the dam crest, and are exercising caution. Their attention should be directed to any/all new Hydro signage that is in place at the time of the meeting. Any such meetings/discussions should be documented by Hydro.
Accessing downstream slope of dam via vehicle or snowmobile	Medical Treatment	Medium (2)	Install a small post-mounted *"No Trespassing"* sign (English sign 4.14.1) at the left abutment area access point to the downstream toe road/trail, as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)*.
Launching boats and associated boat launch area activities	Non-specific	Low (3)	Install a post-mounted sign [English Public Use sign 4.13 (small size)] as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)*, which relates to boat launches, at the upstream left abutment boat launch area.

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Table 6-6: LD-5 (Salmon River Dam) and LD-5S (Salmon River Spillway) – Recommendations for Public Safety Control Measures

Activity	Maximum Associated Hazard &/or Consequence	Risk Rating per Risk Matrix and Priority Type	Recommended Controls
Boating and snowmobiling in the forebay areas up to the spillway and dam	Drowning/Death	High (1)	Install an upstream public safety boom at a location to be determined by hydraulic assessment and other considerations.
Boating and snowmobiling in the forebay areas up to the spillway, and dam and activities on foot at the upstream left of the dam	Drowning/Death	High (1)	Install 2 post-mounted signs (English sign 4.3 - in the family of *"Danger- Keep Out – Access Beyond this Point May Result in Drowning"* signs) as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)* at the new public safety boom anchor locations (left and right banks).
Boating and snowmobiling in the forebay areas up to the spillway, and dam and activities on foot at the upstream left of the dam	Drowning/Death	High (1)	Especially if viewable from upstream of the proposed boom, consider installation of an additional large sign on the upstream side of the LD-5S structure. As per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)*, this would be English sign 4.1 which reads *"Danger- Dam Ahead - Keep Out"*.
Activities on foot at the upstream left of the dam	Drowning/Death	Medium (2)	Install a chain link fence on left bank from the spillway side of new public safety boom to Spillway LD-5S. At the boom end of the fence, the fence should "return" towards the waterline, and cantilever over the water as practicable/required in order to prevent the public from trespassing onto the water side of the fence. The new fence should be a best-practices height of at least 2.1 m with 3 strands of barbed wire canted to public side. Also install at least one fence-mounted sign as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)* [English sign 4.14.2 which reads *"Danger- Keep Out – Access Beyond this Point May Result in Drowning"*].
Activities on foot at the downstream left of the dam	Death due to fall from height, or Drowning if spilling	High (1)	Install a chain link fence on the left bank from the downstream side of Spillway LD-5S at the left abutment to a suitable distance downstream of the spillway that will keep the public away from the falling hazards related to the downstream spillway left retaining wall and the downstream left bank high rockcut. The suitable distance would be determined in a design phase and ideally would secure the most hazardous areas which reside on Hydro property. The new fence should be a best-practices height of at least 2.1 m with 3 strands of barbed wire canted to public side. There should be a "return" section of fence towards the tailrace to discourage walking around the end of the fence. Also install at least 2 fence-mounted sign as per *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)* (English sign 4.14.1 which read *"Danger- No Trespassing"*.
Attempt to trespass into the	Death (the worst case if person	Medium (2)	Upgrade LD-5S perimeter fencing at the most downstream vehicle gate where there is a gap

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Table 6-8: Intersection of Highway 361 and the Left Tailrace Bank Access Road and/or the Highway 361 Bridge Area – Recommendations for Public Safety Control Measures

Activity	Maximum Associated Hazard &/or Consequence	Risk Rating per Risk Matrix and Priority Type	Recommended Controls
Approaches from downstream by boat and related activities	Drowning	High (1)	At the intersection of Highway 361 and the Left Tailrace Bank Access Road where there is an existing Hydro "Caution" sign, a large new sign is recommended for installation to supplement the existing sign (if keeping it is practicable), or to replace the existing sign. The new sign should be a yellow post-mounted warning sign (English sign 4.11 as per CDA). If possible, it could be advantageous to install the same sign 4.11 on the downstream side of the Highway 361 bridge to deliver the same message to boaters i.e. *"Warning – Dam Upstream – Water Levels and Flow May Change Without Notice"*. It is understood these areas are not owned by Hydro and so permissions would have to be sought. **[Note that these signs are not shown on a Figure].**

Table 6-7: Intersection of Long Pond Access Road and Upper Salmon Access Road – Recommendations for Public Safety Control Measures

Activity	Maximum Associated Hazard &/or Consequence	Risk Rating per Risk Matrix and Priority Type	Recommended Controls
Driving a vehicle on Long Pond Access Road and in particular across dam crest of LD-3	Permanent or partial or total disability due to vehicle rollover on downstream slope on LD-4	Medium (2)	Install a large new yellow rectangular post-mounted sign similar to existing sign located at this intersection, but locate sign on Long Pond Access Road just in from Upper Salmon Access Road on the north side of Long Pond Access Road, so that it will be seen by all, even by those turning left off Upper Salmon Access Road. Similar to the existing sign, the sign should read; ***"Warning - Persons Using This Road Do So At Their Own Risk - This Road Is Travelled By Vehicles, Heavy Equipment, Snowmobiles, and ATV's, Road Has Winding Turns, Blind Spots, Narrow Sections, and a Dam Crossing - If You Choose To Proceed, Slow Down and Drive Safely".*** The sign will need to be customized as there is nothing similar in the *CDA Technical Bulletin – Signage Around Dams (2010-02-17 Draft)*, but the sign should be formatted as per CDA signage [see Figure 10].

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Table 6-8: Intersection of Highway 361 and the Left Tailrace Bank Access Road and/or the Highway 361 Bridge Area – Recommendations for Public Safety Control Measures

Activity	Maximum Associated Hazard &/or Consequence	Risk Rating per Risk Matrix and Priority Type	Recommended Controls
Approaches from downstream by boat and related activities	Drowning	High (1)	At the intersection of Highway 361 and the Left Tailrace Bank Access Road where there is an existing Hydro "Caution" sign, a large new sign is recommended for installation to supplement the existing sign (if keeping it is practicable), or to replace the existing sign. The new sign should be a yellow post-mounted warning sign (English sign 4.11 as per CDA). If possible, it could be advantageous to install the same sign 4.11 on the downstream side of the Highway 361 bridge to deliver the same message to boaters i.e. *"Warning – Dam Upstream – Water Levels and Flow May Change Without Notice"*. It is understood these areas are not owned by Hydro and so permissions would have to be sought. [**Note that these signs are not shown on a Figure**].

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Project Title: Replace MicroSCADA Computers

Location: Granite Canal

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

Granite Canal Generating Station was commissioned and put into service in 2003 with a single unit rated at 45 MVA. The local Human Machine Interface (HMI) is an ABB supplied MicroSCADA SYS500 running on a Dell PowerEdge 1400 Pentium III computer with a Windows 2000 Server operating system.

This project will replace the MicroSCADA SYS500 at Granite Canal with the modern MicroSCADA Pro SYS600C and install a second MicroSCADA Pro SYS600C in Bay d'Espoir to provide redundancy. This will involve replacement of the personal computer in Granite Canal, updated MicroSCADA software, and an updated Windows Server 2008 operating system. The second MicroSCADA Pro SYS600C will be located in the Bay d'Espoir Plant control room and function as a redundant system providing backup in the event of a failure. The existing laptop used as an engineering workstation and to store the files for the field controllers will also be upgraded. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	149.5	0.0	0.0	149.5
Labour	78.8	0.0	0.0	78.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	7.4	0.0	0.0	7.4
Interest and Escalation	14.6	0.0	0.0	14.6
Contingency	47.1	0.0	0.0	47.1
TOTAL	**297.4**	**0.0**	**0.0**	**297.4**

JUSTIFICATION

The existing HMI, MicroSCADA SYS500, has been operating since 2003 when the Granite Canal Generating Station was put into service. It was provided by ABB Inc. as part of the complete control and monitoring system. The existing MicroSCADA computer runs a Windows Server 2000 operating system while the proprietary ABB MicroSCADA SYS500 software runs as a Windows Server 2000 application. Windows Server 2000 reached the end of its extended support service date on July 13, 2010 meaning that Microsoft will no longer be providing technical support and updates for this operating system. Microsoft recommends that all customers update to an operating system which is fully supported in order to continue to receive system updates, security improvements and technical support. The existing MicroSCADA SYS500 application is not compatible with modern versions of Windows Server and is only compatible with Windows Server 2000. Therefore, a modern computer cannot be purchased to run the MicroScada SYS500 software.

ABB has recommended that we upgrade to the new MicroSCADA Pro SYS600C system as the MicroSCADA SYS500 has entered into its Legacy Phase. In its Legacy Phase, the hardware will no longer be supported but the software will be supported until 2020. Major errors will not be fixed and the MicroSCADA SYS500 is no longer available for sale. Upgrading to the MicroSCADA Pro SYS600C system will also provide redundancy not available with the current system. Having this redundant system eliminates the concern of not having a backup system for data availability, seamless system control, and monitoring in the event of failure of the existing system. Real-time data will be mirrored and stored on the redundant MicroSCADA system which will be located at the Bay D'Espoir Plant control room. The MicroSCADA Pro SYS600C system will run on Windows Server 2008, Microsoft's latest version of Windows Server, which will continue to be supported until 2018.

The MicroSCADA system has operated reliably since 2003, but in 2010 it required a reboot because the system locked up when automatically logged files consumed hard disk space which would have been used for smooth system operation. This prevents major alarms such as vibration from being logged due to hard disk space not being available. There are several data points collected from the Granite Canal unit, its auxiliaries, and structures required for reliable operation. Maintenance to clean up the logged files has to be done quarterly to avoid the system becoming full and locking up. This is an indication that the system has reached its end of reliable service life before an eventual failure. Without technical support from Microsoft for its Windows Server 2000 and with the

MicroSCADA SYS500 in the Legacy Phase there is a risk of the existing system failing without a contingency plan in place. This upgrade will mitigate this risk.

The existing laptop used as the engineering workstation also contains the files for the five field controllers that control the operation of the unit, the auxiliary systems, the substation, the intake gate, and the bypass gates. It runs on Windows 2000 Professional whose support had an end date of July 13, 2010. The laptop has been having problems charging and should be replaced. It is running an obsolete operating system with known security vulnerabilities.

Existing System

The control and monitoring system for Granite Canal consists of five field controllers overseeing the unit, the auxiliary systems, the substation, the intake gate, and the bypass gates. These field controllers communicate with the local Human Machine Interface (HMI) in the control room and, through a remote terminal unit (RTU), to the Energy Control Centre (ECC) in St. John's. The HMI is an ABB supplied MicroSCADA SYS500 running on a Dell PowerEdge PIII computer with a Windows 2000 server operating system. The HMI is used for local operation of the generating plant providing indications, control, alarm sequencing and report generation. It is in continuous service except for times when it is shutdown for maintenance.

Operation of the Granite Canal Generating Plant is normally done through the Energy Control Centre in St. John's and operators travel to the site for checks of the facilities and to respond to alarm conditions.

There have been no major upgrades since installation. A quarterly preventive maintenance procedure has been put in place to clean up the logged files to provide adequate memory space for system operation.

Operating Experience

The MicroSCADA SYS500 has performed well since it went into service in 2003. In 2010, the computer did lock up and require a reboot to return to normal service. A system cleanup was done to delete old logged files to provide more hard disk space for the operating system to run without locking up. The locking up prevents alarms from being recorded in the system. A quarterly

preventive maintenance procedure had to be put in place to ensure the logged files are removed regularly.

Reliability Performance

The reliability of the MicroSCADA SYS500 is reduced since a regular preventive maintenance procedure is needed to remove logged files which can cause the system to require a reboot. The MicroSCADA SYS500 is in the Legacy Phase of its life cycle and it operates on Microsoft Windows 2000 Professional which has not been supported by Microsoft since July 13, 2010.

Outage Statistics

No outages are attributed to the MicroSCADA SYS500 system. However, in 2007 there was an incident where the unit could not be shut down from the MicroSCADA SYS500 due to a suspected communication problem.

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements to replace the MicroSCADA SYS500 system.

Safety Performance

This is not applicable as the replacement of the MicroSCADA SYS500 is not justified on safety performance.

Environmental Performance

There are no environmental performance requirements to replace the MicroSCADA SYS500 system.

Industry Experience

The industry experience with the MicroSCADA SYS500 is not known. This is a proprietary system from ABB Inc. and the vendor's recommendation would be followed.

Vendor Recommendations

The vendor, ABB Inc. recommends the replacement of the MicroSCADA SYS500 as it is in the Legacy Phase of its life cycle and the operating system, Windows 2000 Server is no longer supported by

Microsoft. The MicroSCADA SYS500 cannot operate on newer Windows platforms such as Windows Server 2008.

Maintenance or Support Arrangements

There are no maintenance or support agreements for this equipment. Maintenance is done by in house personnel.

Maintenance History

The MicroSCADA SYS500 has worked well since 2003 with the exception of the computer locking up in 2010 necessitating a reboot. A system cleanup exercise is required quarterly as a preventive maintenance procedure to eliminate this situation. This quarterly maintenance cycle has been the only maintenance required over the past five years.

Historical Information

The replacement of the MicroSCADA SYS500 is not a recurring project.

Anticipated Useful Life

The MicroSCADA SYS500 has an estimated service life of 10 years.

Forecast Customer Growth

This project is not applicable to load growth.

Development of Alternatives

There are no alternatives as the MicroSCADA SYS500 is the Human Machine Interface (HMI) for the proprietary ABB Inc. control and monitoring system used at the Granite Canal Generating Station. It was programmed by ABB to collect information from the five field controllers and to provide local control functions.

Evaluation of Alternatives

This is not applicable as there are no alternatives.

Energy Efficiency Benefits

This project does not have an efficiency gain.

Economic Analysis

An economic analysis is not applicable as there are no alternatives.

CONCLUSION

This project is needed because the existing MicroSCADA SYS500 Human Machine Interface is in the Legacy Phase with limited support from the manufacturer. The Windows Server 2000 operating system is no longer supported by Microsoft and the MicroSCADA SYS500 cannot be installed on a modern computer. The MicroSCADA SYS500 has to be replaced with the MicroSCADA Pro SYS600C to ensure that the HMI is supported by the manufacturer in case of failure.

Project Schedule

The anticipated project schedule is shown in Table 2

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Prepare design transmittal, site visit	January 2013	March 2013
Design	Prepare specification	March 2013	April 2013
Procurement	Award tender to ABB	May 2013	May 2013
Construction	Install MicroSCADA Pro SYS600C	August 2013	September 2013
Commissioning	Commissioning MicroSCADA Pro SYS600C	September 2013	September 2013
Closeout	As built drawings Project Closeout documentation	October 2013	October 2013

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)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	12.0	0.0	0.0	12.0
Labour	101.3	0.0	0.0	101.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	95.0	0.0	0.0	95.0
Other Direct Costs	1.0	0.0	0.0	1.0
Interest and Escalation	16.0	0.0	0.0	16.0
Contingency	41.9	0.0	0.0	41.9
TOTAL	**267.2**	**0.0**	**0.0**	**267.2**

JUSTIFICATION

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 are 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 two-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.

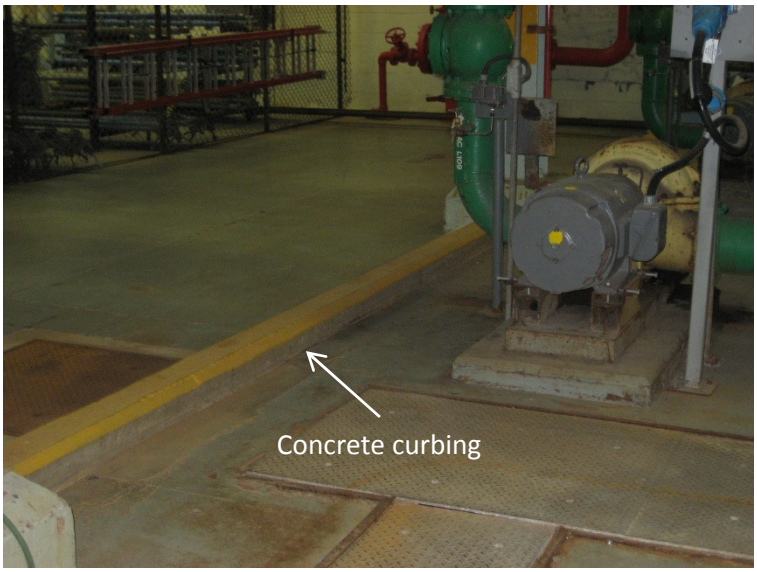

Figure 1: Concrete Curbing

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.

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.

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[5] 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.

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 2: No. 6 Fuel Oil Shut-off Valve

[5] Flash point is the lowest temperature at which a material can vaporize to form an ignitable mixture in air.

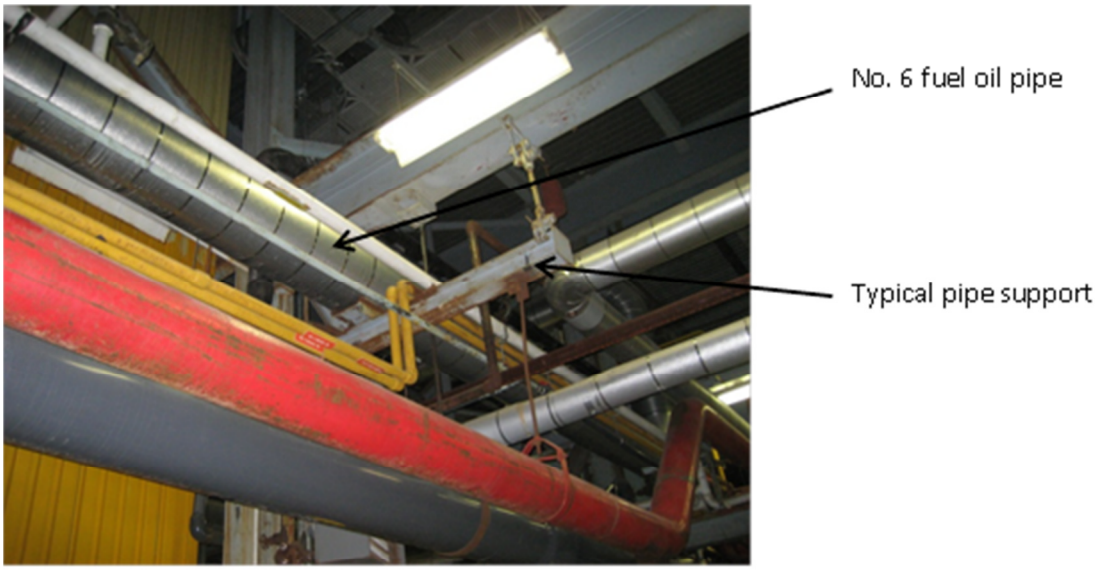

Figure 3: Typical Pipe Support for No. 6 Fuel Oil Piping

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 two 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.

The following sections have been removed from the Operating Experience section because they do not pertain to this project: Outage Statistics, Legislative or Regulatory Requirements, Safety Performance, Reliability Performance, Environmental Performance, Vendor Recommendations, Maintenance History, and Historical Information.

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 extend 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 the Holyrood Thermal Generating Station (Holyrood). The upgrades include: a) the installation of concrete curbing around Unit 1 and Unit 3 fuel-pumping skids; b) 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 c) the 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	January 2013	January 2013
Design	Complete detailed engineering design	February 2013	March 2013
Procurement	Prepare tender and award contract	March 2013	April 2013
Construction	Install systems	August 2013	November 2013
Commissioning	Commission systems	November 2013	November 2013
Closeout	Complete project documentation and perform project closeout	December 2013	December 2013

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

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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.

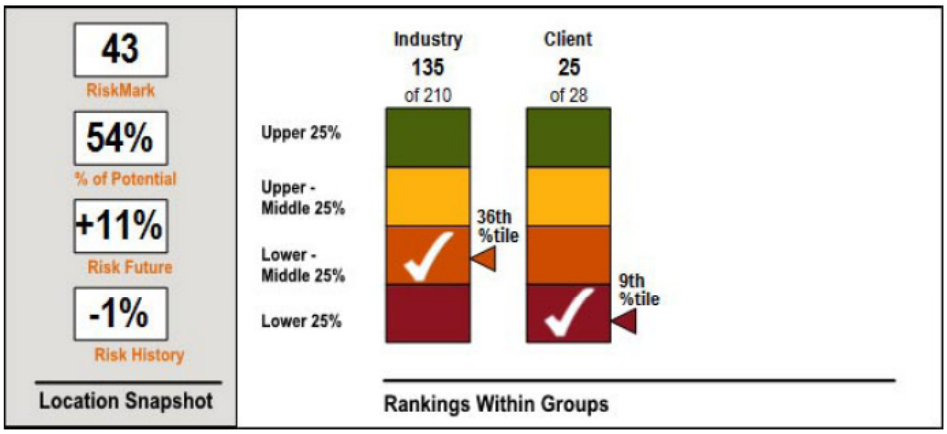
Factory Mutual Insurance Company (FM Global) has developed this report for insurance underwriting purposes. The report is provided to you for informational purposes only to reduce the possibility of loss to property by bringing to your attention certain potential hazards or conditions. You must make the decision whether to take any action. FM Global undertakes no duty to any party by providing this report or performing the activities on which it is based. The liability of FM Global is limited to that contained in its insurance policies.

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.

FM Global Risk Report — Nalcor Energy

RiskMark (Risk Quality Benchmarking)

Through the analysis of various components of loss prevention, FM Global has rated the risk quality of the location against:

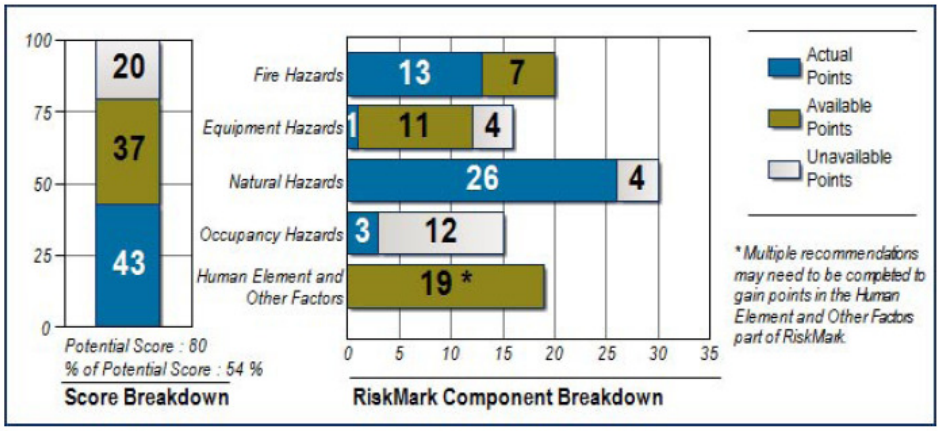
- All locations of a similar Occupancy/Industry
- All locations within your entire organization

The following displays show RiskMark information for this location. Note that the RiskMark scores and displays are different than in the past. RiskMark was recalibrated and enhanced to now include Equipment Hazards and an emphasis on Human Element programs. RiskMark 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.

RiskMark Breakdown

This display shows a breakdown of your RiskMark 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.

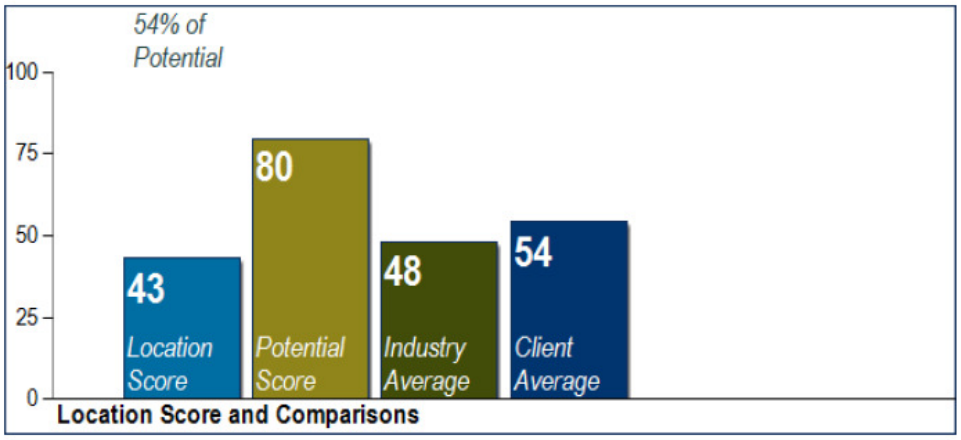


FM Global Risk Report — Nalcor Energy

RiskMark continued

RiskMark Comparisons

This display shows a comparison of your RiskMark 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 RiskMark 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 RiskMark 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 RiskMark 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 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	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 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	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.

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 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	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.

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

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: Replace North End Equipment Door

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Mandatory

Project Description:

This project involves the replacement of the existing 4.5 meter wide by 7.3 meter high steel, multiplex overhead door, located in Powerhouse 1 of the Bay d'Espoir Hydroelectric Facility. The scope of the project includes removal and disposal of the existing overhead door; supply and installation of a new overhead door; and the supply and installation of a new electric door operator, complete with modern safety features including mechanical drop stop devices, limit switches, and reversing photo eye sensor.

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

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	42.2	0.0	0.0	42.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	167.0	0.0	0.0	167.0
Other Direct Costs	1.2	0.0	0.0	1.2
Interest and Escalation	13.0	0.0	0.0	13.0
Contingency	42.1	0.0	0.0	42.1
TOTAL	**265.5**	**0.0**	**0.0**	**265.5**

JUSTIFICATION

In December 2010 the overhead equipment door, located at the north end of Powerhouse 1, failed while in the "full open" position resulting in a sudden, uncontrolled free fall to the powerhouse floor. The door suffered extensive damage as a result of the failure and was taken out of service to prevent further use until such time that it could be properly repaired. The door lacked safety features typical of modern day overhead door installations, including a mechanical drop stop safeguarding device, which would have prevented the door from free falling upon failure.

Given the age of door and the extent of the damage it received during the free fall, replacement of the door is required. The installation of a new door will permit the safe access of material, equipment and personnel through the powerhouse for the next fifty years.

Existing System

Powerhouse 1 contains two vertical lift overhead equipment doors. The doors are located in the north and south ends of the plant. The north end equipment door was installed during phase 2 of the Bay d'Espoir development which was completed in 1968. The door is nearing the end of its useful service life and numerous issues have recently surfaced, leading to concerns over the integrity of the unit.

In December, 2010 the north end door experienced significant damage due to an uncontrolled drop which occurred as the result of a cable failure in the door's operating mechanism (see Figure 1). The existing north end equipment door is 44 years old and has been out of service since the failure incident in December 2010. Stops have been placed on the lower door sections to hold the door panels in place. Caution tape and signs are also placed to ensure workplace safety for the short term (see Figures 1 and 2).

No major work or upgrades have been completed on this door. The only record of work associated with the door involves minor corrective maintenance, completed on an as required basis.

Figure 1: BDE-North End equipment door outer view at Powerhouse#1 (after free fall incident)

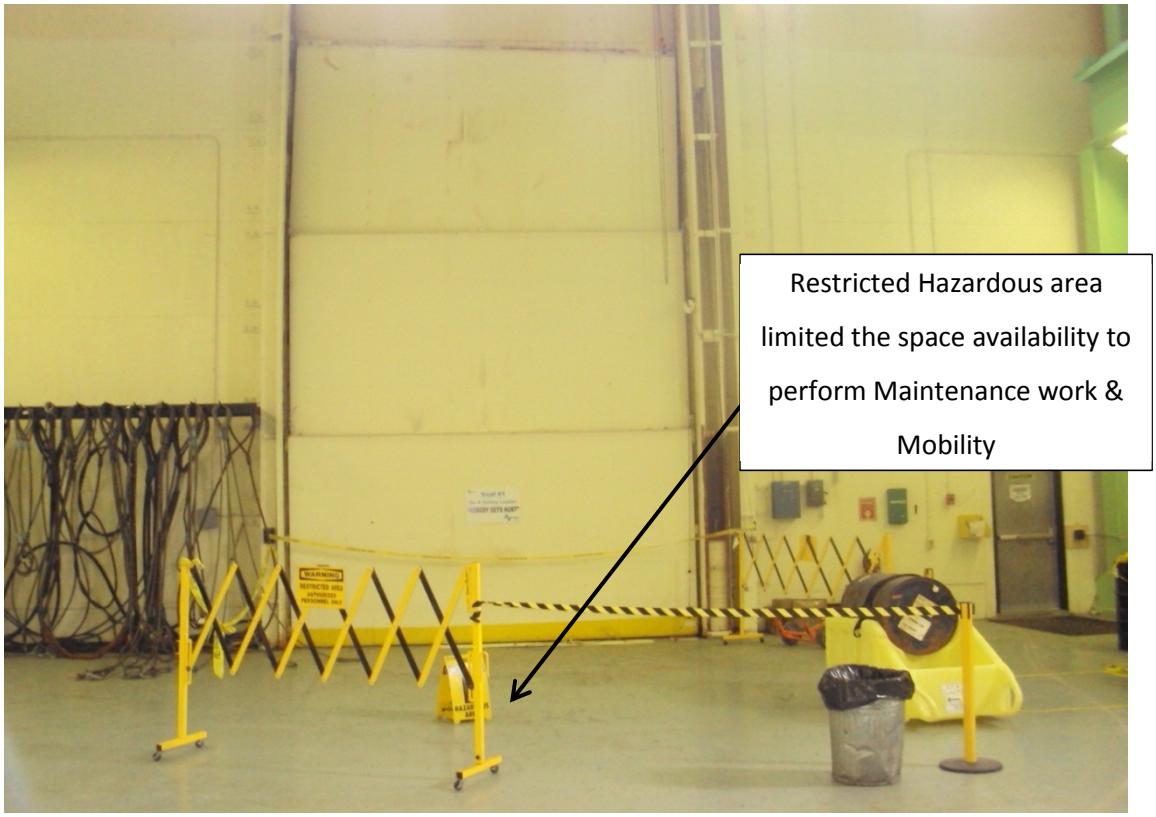


Figure 2: North end equipment door inside view showing Restricted Hazardous area

Operating Experience

The north end equipment door is used periodically for the transport of materials, tools, and equipment though the powerhouse. The frequency of operation increases during the annual maintenance season. Another door failure of this nature could result in serious personal injury or death.

Legislative or Regulatory Requirements

The Occupational Health and Safety Regulations (OHS), 2012 (NLR 5/12) do not specifically refer to equipment doors. However, section 94 of the OHS Regulations requires that all unsafe equipment be identified and taken out of service These Regulations are generally applicable to workplace equipment and require that the employer provide and ensure worker safety.

Safety Performance

The American Society of Mechanical Engineers publishes ASME B15.1, Mechanical Power Transmission Apparatus. This calls for safeguarding of motion hazards. Section 3.2.2 states "A motion hazards safeguarding device shall provide protection to people by preventing and/or stopping normal motion of the mechanical power transmission source of hazard if people enter the hazardous area, and by providing the means to stop the system in the event of involvement with the hazard." Equipment door crushing hazards are a motion hazard. The ASME standard calls for safeguarding methods that will prevent a closing overhead door from impacting a person, or stop the door if there is involvement with the hazard.

Industry Experience

This existing door design is typical of its era. Modern door models are manufactured with essential safety systems to avoid or mitigate the effects of sudden failure. The incorporation of these safety features greatly enhance the ability of the door to operate in a safe and reliable fashion.

Vendor Recommendations

An inspection completed by Richards & Wilcox, an independent overhead door service contractor, identified numerous deficiencies with the equipment door components and recommended that substantial repairs and/or replacement be completed to return the door to a safe operating condition. A copy of the inspection report is contained in Appendix A.

Recommendations provided by Richards & Wilcox Inc. were also considered when specifying features of the new overhead door.

The proposed new Multiplex steel door will have the following features:

- Capable to resist the effects of accidental explosions and manufactured to modern industry standard;
- Electrically operated with non-explosion proof operator and control cable;
- Mechanical drop stop devices with a CSA approved reel cord and CSA limit switches- to prevent free fall in the event of cable breakage;
- Through-beam photo eyes to prevent door closure when someone or something passes under the door; and
- Floor level disconnect device to allow for manual operation.

Maintenance or Support Arrangements

Maintenance of the new door will be performed by Hydro personnel, under the guidance of a new maintenance program implemented for equipment doors.

Maintenance History

There are no maintenance records kept specifically for the north end equipment door however there was $2,100 and $4,100 spent in 2011 and 2010 respectively for corrective maintenance on the door.

Anticipated Useful Life

The powerhouse has a whole life of 85 years. The door will be depreciated on the average remaining life of the powerhouse which is approximately 49 years.

Development of Alternatives

There were two options considered for this work. The first option considered repairing the failed door, while the second option looked at replacement of the door.

To complete a proper evaluation of the two alternatives Richards-Wilcox Inc., a supplier specializing in the supply, installation and servicing of overhead doors was consulted. Estimates completed by

the vendor indicated a marginal cost differential for the two alternatives - Alternative 1 was estimated at $137,600 and Alternative 2 was estimated to cost $149,600. Given the minor variance present between the two alternatives the installation of a new door, complete with the required safety features was deemed to be the most cost effective alternative.

CONCLUSION

To ensure that required access is maintained to Powerhouse 1 for the completion of essential maintenance and inspection duties, both overhead equipment doors need to be in operation. The inspection by the overhead door service group has identified significant safety issues and deficiencies in the door condition that must be corrected. The supply and installation of a new door will eliminate any safety concerns surrounding the north end door and provide a reliable asset for the next fifty years.

Project Schedule

The anticipated schedule for this project is provided in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Review Scope Confirm Schedule Review Budget	April 2013	May 2013
Design	Submit design transmittal Risk workshop	June 2013	July 2013
Procurement	Confirm Schedule Tender materials / review tenders Award tender for supply	June 2013	August 2013
Construction	Safety meetings Schedule meetings Risk / Change management Site safety tour	September 2013	October 2013
Commissioning	Safety meeting Training	October 2013	November 2013
Closeout	Financial close out Post implementation review	November 2013	December 2013

APPENDIX A

Richards-Wilcox Inspection Report

R-W CUSTOM SYSTEMS
CRANES, CUSTOM PRODUCTS, SERVICE

HAMILTON OFFICE
211 LANARK STREET, UNIT B
HAMILTON, ON L8E 2Z9

PHONE: (905) 523-7727
FAX:(905) 523-7741

RICHARDS-WILCOX
CUSTOM SYSTEMS-CRANES
A DIV. OF WILCOX DOOR SERVICE INC.

Newfoundland & Labrador Hydro
PO Box 100
Milltown, NL A0H 1W0

Dear Lev:

Richards-Wilcox Custom Systems would like to thank you for the opportunity for letting us inspect your multi-plex doors

Reference: ***Door inspection reports that were completed February 27th to the 29th 2012***

Noted below are the deficiencies that Chris found while performing your inspections

Powerhouse Door #2 – Unit 7

- Drive chain is rubbing on structural steel wearing the side of the chain. Sprockets need to be moved out and chain replaced.
- Crosby clips are installed incorrectly on the cables
- There are broken strands in the cables
- The sprockets are mis-aligned
- The flange bearing bolts need to be reversed and longer bolts installed
- Auto reversing switch does not lift door, it just kills the power
- A proper disconnect needs to be installed, this door only has a breaker
- A Fail safe stop should be installed

South End Door PH-1

- Bent eyebolt on left side looking out, on the dead end
- There are Five – Six broken strands in the lift cable, all cables should be replaced
- The manual driven gear is riding on bracket
- Meeting specs with two Crosby slips, contractor recommends **three** per connection and new thimbles
- The main drums need to be moved downstream to keep cables from rubbing on structural steel
- Dead end on counterweight needs to be modified, the holes have been flame cut
- The sheave bearings need to be replaced on all sheaves – four pieces
- Welding cracked on centre support for upper sheaves, left side of door looking out
- Adjusters need to be tightened on drive
- The sheaves on top panel worn from rubbing and should be replaced
- Spacers should be made for sheaves to keep them from rubbing
- New weather-stripping needs to be installed
- Door stops need to be strengthened with gussets, fabricate new angle stops

Head Office 1045 Rangeview Rd. Mississauga, ON L5E 1H2 Phone (905) 274-5850 Fax (905) 274-9413 Toronto (416) 698-8892
RW CUSTOM SYSTEMS BRANCH OFFICE- Hamilton (905) 523-7727 Fax (905) 523-7741
SELECT OVERHEAD DOOR SERVICE BRANCH OFFICE- Cambridge (519) 650-9320 Fax (519) 650-9322
CRANE SERVICE TOLL FREE: 1-877-677-0062 WWW.RWSYSTEMS.COM

- 6" C-channel on the doors top structure is welded but the bolted connection does not have nuts, but the bolts are just placed into holes
- Drop stop devices should be installed onto the door
- There should be photo eyes for the door
- Fail safe stops should be installed

B D E Powerhouse 1 North End Door

- The flange bearings are welded on, welds are cracked
- Drum bearing supports modified with torch, drum is not mounted properly
- The main drive shaft is not aligned
- Drive chain is missing
- The drive shaft bearings are loose and mis-aligned
- All cables need to ne replaced
- The manual drive engagement chain is not supported properly
- Dome cable thimbles are missing and some need to be replaced
- Counterweights are cracked and the ones that are not cracked need to be inspected
- Door panels are in poor condition and should be overhauled or replaced
- Shaft on manual drive gear is peened over to keep gear on shaft

North End Door

- The drum bearings not properly supported
- Cable connecting device on counterweights are bent and in poor condition and should be re-designed
- All sheave bearings need to be replaced
- Cables are out of sheaves
- Counterweight cage support brackets should be re-designed and changed
- The large drive sprocket is bent and should be replaced
- Drive base has been modified and this has weakened the base
- Top lintel seal is damaged and needs to be replaced
- Fail stops should be installed

USL Powerhouse Door

- Crimp rubbing on guide angle, crimp is worn through and door is in danger of falling, second blade
- The cables are frayed and should be changed
- Upper limits should be lowered
- Top two panels need to be balanced, weight should be removed from counterweights
- There should be photo eyes installed
- Drive chain needs to be properly connected to counterweights on lead blade
- Bearing spacers need to be lengthened between sheaves on the left side looking out
- The drive sprocket is loose, dimple shaft and re-tighten set screws

***** THIS DOOR IS LOCKED OUT*****

Jay Lehman
Operations manager
jlehman@rwcustomsystems.com

J Lehman.

Project Title: Replace Auto Greasing Systems Units 1 and 3

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project is required to replace the auto greasing systems on Units 1 and 3 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. 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)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	72.2	0.0	0.0	72.2
Labour	116.9	0.0	0.0	116.9
Consultant	8.0	0.0	0.0	8.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	3.9	0.0	0.0	3.9
Interest and Escalation	18.9	0.0	0.0	18.9
Contingency	40.2	0.0	0.0	40.2
TOTAL	**260.1**	**0.0**	**0.0**	**260.1**

JUSTIFICATION

This is a normal project 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 1). The master assembly accepts lubrication from the pump and distributes it to the secondary assemblies (Figure 2). The pump is operated at the desired frequency and flow rates, by a controller (Figure 3). 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. Recently, 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.

Table 2: Major Work and/or Upgrades

Year	Major Work and/or Upgrade	Comments
2006	Grease type changed to VSG type	Environmentally friendly lubricant
1996	Controller replaced on Unit 1	Non programmable type
1994	Controller replaced on Unit 3	Non programmable type
1982	System modified to isolate the wicket gate lubrication	To minimize excess grease in the turbine pit
1979	System modified to isolate the wicket gate lubrication	To minimize excess grease in the turbine pit

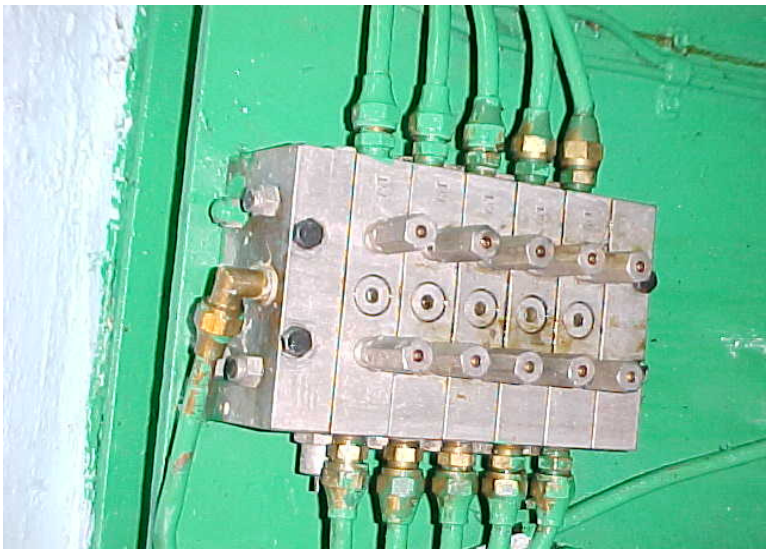


Figure 1: Master Assembly

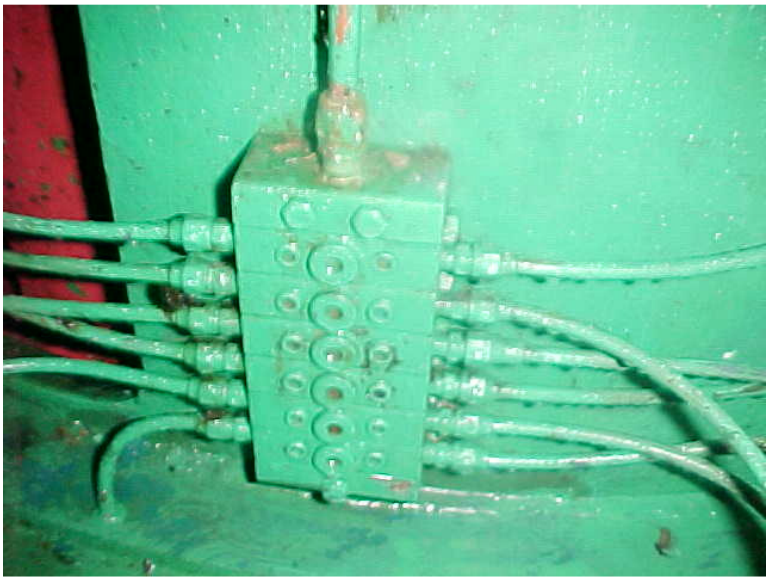


Figure 2: Secondary Assembly

Figure 3: Controller

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 many 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 concern that Bay d'Espoir is facing 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 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 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 unit to go into run away speed 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 come into question 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. There has been one unit outage in the past five years that was due to the auto greasing system. This was on Unit 3 (outage number 2009-78) and at that time, the Unit was down for 7 hours and 20 minutes.

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, BC Hydro, and Hydro Quebec.

Maintenance or Support Arrangements

To date all maintenance of the current auto greasing systems in Bay d'Espoir has been completed by Hydro's operations/maintenance 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 1 and 3 is shown in Table 3.

Table 3: Five-Year Maintenance History

Year	Unit 1 Corrective Maintenance ($000)	Unit 3 Corrective Maintenance ($000)
2011	2.2	1.9
2010	0.5	0.5
2009	0.1	1.4
2008	1.8	1.0
2007	0.0	0.2
Total	4.6	5.0

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 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 necessary 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. As seen in the past, partial upgrades of the system do not work as the distribution aspect of the system, the copper tubing, is original and needs to be replaced. This would eliminate the problem of any residual grease prior to 2006 mixing with the environmentally friendly grease which is known to cause plugged lines. 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 2013	March 2013
Design	- Submit design transmittal - Risk workshop	March 2013	March 2013
Procurement	- Confirm Schedule - Tender materials / review tenders - Award tender for supply	April 2013	April 2013
Construction	- Safety meetings - Schedule meetings - Risk / Change management - Site safety tour	June 2013 July 2013	June 2013 July 2013
Commissioning	- Safety meeting - training	June 2013 July 2013	June 2013 July 2013
Closeout	- Financial close out - Post implementation review	October 2013	October 2013

Project Title: Replace Disconnects

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Type: 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. The condition of the disconnects is defined in terms of age, history of failures, availability of spare parts, and corrosion. The priority of replacements is based on the disconnect's operating location in the system, availability of outage time for repairs, and availability of spare parts. These criteria are considered collectively to determine the order of repairs or replacements. Table 1 lists the disconnect switches planned for replacement in 2013.

Table 1: 2013 Disconnect Replacement Plan

Location	Number of Units	Disconnect Switch	Voltage (kV)
Holyrood	1	B3L18-1	230
Holyrood	1	B11B13	230
Holyrood	1	B3T3/T3G	230

All three disconnects support the sync-condense operation of Unit 3 in Holyrood. In addition to the disconnect replacements listed in Table 1, disconnect switch B3T3/T3G requires installation of a new support structure as the existing structure cannot provide safe nor reliable operation of the new disconnect switches. Temporary transformation or generation is not included in the scope of the 2013 project, as work will be completed during scheduled equipment outages and will not affect customer service.

The budget estimate for this project is shown in Table 2.

Table 2: Budget Estimate

Project Cost *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	141.0	0.0	0.0	141.0
Labour	133.5	0.0	0.0	133.5
Consultant	22.5	0.0	0.0	22.5
Contract Work	79.8	0.0	0.0	79.8
Other Direct Costs	6.2	0.0	0.0	6.2
Interest and Escalation	33.0	0.0	0.0	33.0
Contingency	76.6	0.0	0.0	76.6
TOTAL	**492.6**	**0.0**	**0.0**	**492.6**

The 2013 budget estimate is different from the typical disconnect replacement capital estimates as a result of the work involved in installing a new support structure. The new support structure work includes cost for materials, consultant and contractor services, which totals approximately $200,000 (excluding contingency, interest and escalation). Overall, the five-year plan for disconnect replacements is comprised of an average estimate of $500,000 for approximately nine disconnect replacements per year.

The new disconnects have improved technology compared with the existing disconnects. For vertically mounted disconnects, the insulator is manufactured with high strength material to reduce the risk of the insulators breaking and falling. Cement growth issues prevalent in older type insulators have been addressed by manufacturers. Insulator manufacturers use new technology to cure and set cement in insulators in order to eliminate cement growth problems. Additionally, new disconnects mounted on the wood pole structure have more rigid support frames to maintain the alignment of the switches.

JUSTIFICATION

Disconnect switches are used to isolate equipment either for maintenance activities or system operations and controls. Proper operation of the 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 useful lives and replacement parts are not available.

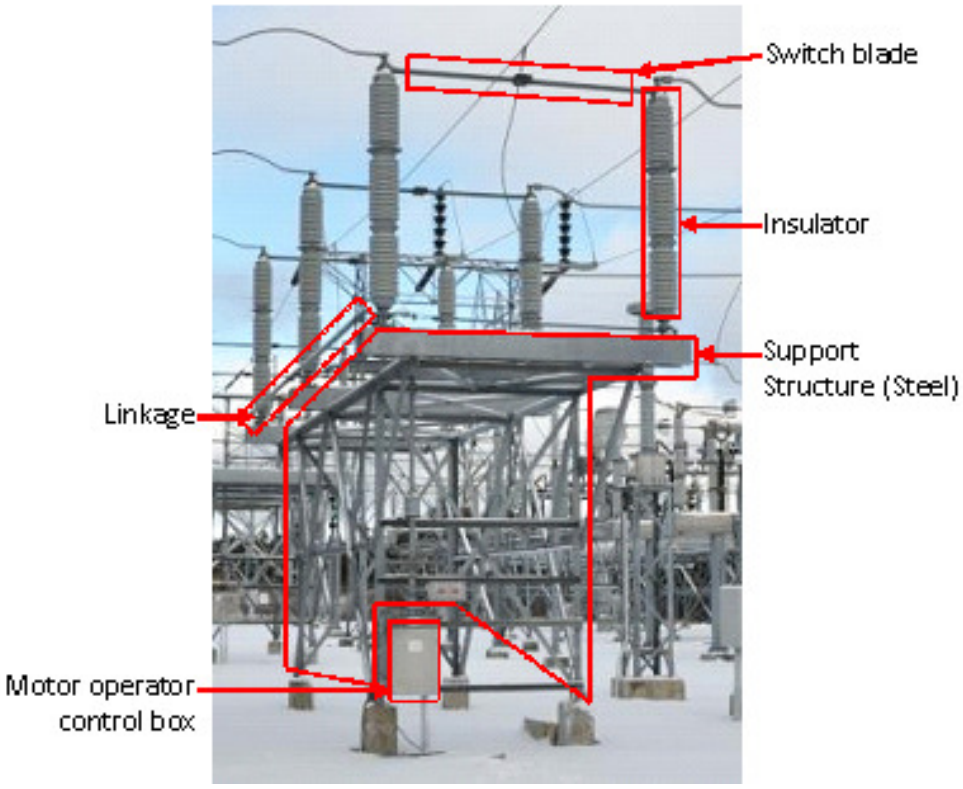


Figure 1 – Typical 230 kV Disconnect Switch

The condition of the disconnects have deteriorated such that continued piecemeal repair is not an effective solution for eliminating the safety hazards and ensuring reliable operation. Complete replacement of the disconnects is required and is best executed within a feasible, orderly and prioritized replacement program. Hydro has developed a Long Term Asset Management Plan (LTAMP) to support the disconnect replacement program. This proposal includes replacement of disconnect switches based on the first year of the LTAMP. Appendix A shows a list of the disconnect switches planned for replacement.

Existing System

Disconnect switches are an integral part of the power system. Disconnects are used to isolate a piece of equipment, such as a breaker, transformer or transmission line, in support of maintenance and repair activities. Disconnect switches are also used to bypass equipment to prevent customer

outages while work is being performed on the equipment. Disconnects are also an important part of the Work Protection Code as they provide a visible air gap, i.e. visible isolation, for utility workers.

The basic components of a disconnect switch are the blade, insulators, switch base and operating mechanism. The blade is the main current carrying component in the switch and it moves to open and close the switch. The insulators are made of porcelain and insulate the switch base from the current carrying parts. The switch base supports the insulators and is mounted to a metal frame for wood pole structures or on a steel tower structure. The switches are operated either manually, using a handle at ground level to open and close the blade, or automatically, by a motor operated device.

Operating Regime

Disconnects function on a continuous cycle in their normal operating condition (either open or closed). Disconnect switches are operated on an as needed basis to isolate or bypass a piece of equipment.

Age of Equipment or System

The age of disconnect switches on the Island Interconnected System range from one to 45 years. The switches scheduled for replacement in 2013 are between 30 to 45 years old.

Major Work and/or Upgrades

Aside from the current disconnect replacement program, there have been no major replacements of terminal station disconnect switches since they were installed. Repairs have been made to replace broken or damaged disconnect parts. The maintenance history of these disconnects includes repair or replacement of insulators, control systems, drive motors, gearboxes, auxiliary contact cams, brakes, heaters, motor contactors, control arms, jaws, springs, blades, couplings, and hinges. This work history is summarized in Table 3. The hot spot data shown in the table refers to events where operations staff had to respond to overheating conditions resulting from the failure of mechanical and current carrying parts.

Table 3: Work History Summary

Work History Summary (2000 to 2011)				
kV Class	**Replace Insulators**	**Repair Controls**	**Hardware And Mechanical Issues**	**Hot Spots and Emergencies**
230	26	110	136	20
138	11	21	31	6
69	17	7	54	20
Total	54	138	221	46

Operating Experience

The existing 230kV disconnect switches in the Holyrood terminal station no longer perform their intended function. Faulty or damaged disconnects 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 need to be operated in order to isolate the equipment. This decreases the systems 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 not typically included in the isolation of the equipment.

Disconnect switch B3B18-1 is inoperative as a result of broken parts, and spare parts are no longer available. Disconnect switch B11B13 is inoperative as a result of mechanical linkage failure. Welding reparations to the linkages provided short term functionality. The welded linkages have since failed and are beyond repair. Additional spare parts are no longer available. Disconnect switch B3T3/T3G is inoperative as a result of excessive corrosion, misalignment of the switch blade and mechanical linkage failure. Several attempts have been made to realign the blade components. Each time it has been repaired, it has failed on the next operation.

Additionally, disconnect switch B3T3/T3G has structure design issues that compound the mechanical linkage issue. B3T3/T3G is mounted at a high elevation on its steel structure and has long mechanical linkages used to operate the switches. As a result of this design, excessive force was required to operate the switches and currently the linkages no longer work. Straight replacement of B3T3/T3G switches using the existing structure would result in similar failure and compromise the

reliability to the Island Interconnect System. The same design is used for two other disconnect switches at the Holyrood terminal station, both of which have mechanical linkage failure as well. Proper operation of the new B3T3/T3G disconnect switch requires shorter mechanical linkages and cannot be accomplished by installation on the existing steel structure. Instead, a new steel structure is to be constructed to support the disconnect. The new B3T3/T3G disconnect switch and support structure is justified on the basis that it will support safe and reliable operation of the disconnect switch, and is consistent with current Hydro terminal station standards for 230kV disconnect structures.

The status quo is not an acceptable alternative. The disconnect switches are old and present safety and reliability issues.

Reliability Performance

Hydro does not monitor the reliability performance of disconnect switches, as the disconnect switches are a sub-component within terminal stations. Instead, Hydro tracks the performance of terminal stations, which is made up of disconnect switches, circuit breakers, insulators, surge arresters, transformers and station power buses.

Outage Statistics

Outage statistics for terminal station equipment includes outages as a result of disconnect failures, but the performance of the disconnect switches is not directly measured. Following Canadian utility practice of tracking system performance, Hydro measures the forced outage performance of terminal stations. Table 4 lists the 2007 to 2011 average T-SAIFI and T-SAIDI data by region, and compares Hydro's system averages to Canadian Electricity Association (CEA) system averages.

Table 4: Forced Outage Performance Statistics

Five-year Averages of Forced Outages (2007 to 2011)		
Delivery Point Affected	**T-SAIFI**	**T-SAIDI**
Hydro, Central Region	0.51	53.11
Hydro, Northern Region	5.20	215.97
Hydro, Labrador Region	5.67	117.33
Hydro	1.60	88.43
CEA (2006-2010)	0.72	66.12

T-SAIFI is a measure of the frequency of transmission interruptions that a delivery point experiences during a given period.

T-SAIDI is a measure of average total interruption duration, in hours, that a delivery point experiences during a give period.

Legislative or Regulatory Requirements

There is no legislative or regulatory requirement for this project.

Safety Performance

Faulty or malfunctioning disconnect switches create safety hazards. A disconnect switch having a damaged insulator can result in parts breaking off, which could potentially fall on personnel working on or around the disconnect structure. Insulator failures on disconnect switches have occurred three times; at the Bay d'Espoir, Barachoix, and Conne River terminal stations. Hydro has revised its terminal station standards for disconnect switches to include insulators with higher cantilever strength in an effort to reduce the risk of parts breaking and falling.

Environmental Performance

There are no environmental concerns related to the execution of this project.

Industry Experience

Hydro's approach to the disconnect replacement program is consistent with the utility industry practice, in which replacements are based on the condition (age and functionality), safety and reliability of the disconnect switch.

Vendor Recommendations

The vendor recommends replacement of a disconnect switch after 1000 operations.

Maintenance or Support Arrangements

Maintenance on the disconnect switches is performed by Hydro personnel.

Maintenance History

The five-year maintenance history for disconnect switches is shown in the following table.

Table 5: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($ 000)
2011	46.9	24.0	70.9
2010	24.3	28.9	53.2
2009	6.8	16.0	22.8
2008	13.6	22.4	36.0
2007	8.8	23.1	31.9

Historical Information

Table 6 provides a recent history of disconnect switch replacements.

Table 6: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2011	295.0	408.2	9	45.4	Purchased and replaced four disconnects at Conne River and English Harbour West Purchase only five other disconnects
2010	199.0	301.0	5	60.2	Planned replacements of switch at English Harbour West, Conne River, and Corner Brook Converter stations
2009	0.0	0.0	0	0.0	No disconnect replacement project in 2009
2008	367.6	568.4	16	35.5	Replacement of switches at Cow Head and Daniel's Harbour.

Anticipated Useful Life

Disconnect switches have an anticipated service life of 30 to 40 years, depending on the service environment.

Forecast Customer Growth

Customer load growth does not affect this project.

Development of Alternatives

There are no viable alternatives for the replacement of disconnect switches

Evaluation of Alternatives

There are no viable alternatives for this project.

Energy Efficiency Benefits

There are no energy efficiency benefits with this project.

Economic Analysis

Economic analysis is not required for this project as there are no alternatives.

CONCLUSION

Proper operation of disconnect switches is essential to a safe work environment and for reliable and secure system operation. Many of the disconnect switches within the Island Interconnected System have exceeded their useful life and have faulty or damaged parts, which compromise the safety and reliability in their performance. This capital budget proposal supports a feasible, orderly and prioritized program to replace the most problematic disconnect switches.

The 2013 capital budget proposal is for the replacement of three, 230 kV disconnect switches, which are tagged inoperative. Due to the substandard mounting arrangement of switch B3T3/T3G on the existing structure, a new structure is required to support the new switch installation to ensure proper operation for the entirety of its expected service life.

Project Schedule

The anticipated project schedule is shown below in Table 7.

Table 7: Project Schedule

Activity		Start Date	End Date
Planning	Scope, schedule, cost, risk, quality and communication planning. Also involves monitoring and controlling project activities.	January 2013	September 2013
Design	Site visits, engineering and design of disconnect replacement drawings, commissioning procedures and checklists, issue for construction work package	February 2013	June 2013
Procurement	Disconnect specification and purchase order, 230 kV structure technical specification and tender contract, tender evaluation and selection. Delivery of material (6 month lead time for disconnects)	March 2013	August 2013
Construction	Installation of new disconnect structure, replacement of 230 kV disconnects	September 2013	September 2013
Commissioning	Energization and testing of new disconnects	September 2013	September 2013
Closeout	As built drawing review. Procurement contract close out, project financial close out and post implementation review.	October 2013	October 2013

APPENDIX A

Five-Year Plan For Disconnect Replacements

Target Year	Terminal Station	Asset Description	Voltage Rating (kV)	Date Installed	Condition Assessment Results
2013	Holyrood	B3L18-1	230	1969	Tagged inoperative and cannot be operated. Broken parts.
2013	Holyrood	B11B13	230	1969	Manual Switch. Welded linkages have failed. Parts unavailable.
2013	Holyrood	B3T3/T3G	230	1969	Issues with corrosion and mechanical linkage failures. Alignment issues. Switch is mounted on high steel requiring excessive force to operate.
2014	Bay d'Espoir	B3B4-1	230	1966	Motor operator and contactor failure. Parts unavailable.
2014	Western Avalon	L03L17-2	230	1966	Motor operator and contactor failure.
2014	Come By Chance	B1L07/L07G	230	1966	Bearing problems. Seizing. Repairs not successful. Parts not available.
2014	Come By Chance	B1B2-1	230	1966	Bearing problems. Seizing. Reapirs not successful. Parts not available.
2014	Come By Chance	B1T1	230	1966	Bearing problems. Seizing. Reapirs not successful. Parts not available.
2014	Sunnyside	L06L07-2/L07G	230	1967	Gear box failure.
2014	Bay d'Espoir	B13T11-1	69	1966	Damaged insulator.
2015	Come By Chance	B2L37/L37G	230	1966	Bearing problems. Seizing. Repairs not successful. Parts not available.
2015	Come By Chance	B1B2-2	230	1966	Bearing problems. Seizing. Reapirs not successful. Parts not available.
2015	Oxen Pond	B2B5-1	69	1966	Severe corrosion causing seizing and severe heating.
2015	English Harbour West	L20-1	69	1968	Linkage failure. Safety risk due to inoperative ground switch mechanism.
2015	English Harbour West	L20G	69	1968	Insulator failures causing safety hazard.

Target Year	Terminal Station	Asset Description	Voltage Rating (kV)	Date Installed	Condition Assessment Results
2015	Come By Chance	B2T2	230	1966	Bearing problems. Seizing. Reapirs not successful. Parts not available.
2015	Conne River	L20-1	69	1967	Damaged insulator.
2015	Bay d'Espoir	B13L20-2/L20G	69	1966	Damaged insulator.
2015	Bay d'Espoir	B13L20-1	69	1966	Damaged insulator.
2015	Bay d'Espoir	B13L20-BP	69	1966	Damaged insulator.
2016	Farewell Head	L54T1/L54G	69	1988	Linkage issues resulting from excessive force required to operate switch.
2016	Farewell Head	T1AG	69	1988	Damaged insulator and linkage failure.
2016	Bay d'Espoir	B13T12	69	1966	Damaged insulator.
2016	Bottom Brook	B1L11-1	230	1967	Gear box and linkage failure.
2016	Bottom Brook	B1L11-2/L11G	230	1967	Gear box and linkage failure.
2016	Bay d'Espoir	B13T10	69	1966	Damaged insulator.
2016	Massey Drive	B4T1-1	69	1966	Linkage failure and damaged insulator.
2016	Massey Drive	B2B4-1	69	1966	Linkage failure and damaged insulator.
2016	Massey Drive	B4L1-1	69	1966	Linkage failure and damaged insulator.
2016	Massey Drive	B4L16-1	69	1966	Linkage failure and damaged insulator.
2016	Massey Drive	B4L17-1	69	1966	Linkage failure and damaged insulator.
2017	Hampden TAP	L51-1/L51G	69	1981	Linkage failure and alignment issues.
2017	Hampden TAP	L52-1/L52G	69	1981	Linkage failure and alignment issues.
2017	Bottom Brook	B2L14-2/L14G	138	1967	Linkage failure. Safety risk due to inoperative ground switch.
2017	Bottom Brook	B2T1	138	1967	Gear box and linkage failure.
2017	Bottom Brook	B2T2	138	1967	Gear box and linkage failure.
2017	Bottom Brook	B2L14-1	138	1967	Couplings and linkage failure.
2017	Massey Drive	B3L357-1	69	1966	Linkage failure and damaged insulator.
2017	Massey Drive	B3L351-1	69	1966	Linkage failure and damaged insulator.
2017	Massey Drive	B3T3-1	69	1966	Linkage failure and damaged insulator.

Project Title: Replace Light-Duty Mobile Equipment

Location: Various Sites

Category: General Properties - Transportation

Type: Other

Classification: Normal

Project Description:

This project proposes the replacement of 14 all-terrain vehicles, 21 snowmobiles, 1 light-duty trailer, 2 heavy-duty trailers, and 1 forklift in accordance with the 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.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	434.0	0.0	0.0	434.0
Labour	3.0	0.0	0.0	3.0
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	17.6	0.0	0.0	17.6
Contingency	21.9	0.0	0.0	21.9
TOTAL	**476.5**	**0.0**	**0.0**	**476.5**

JUSTIFICATION

Hydro operates in many diverse locations across the province, and it is critical that employees are provided with safe and reliable equipment in order to provide economical and reliable electricity.

As this proposal provides for the normal replacement of mobile equipment in accordance with established criteria, there is no relevant information related to:

- Levelized Cost of Energy;
- Forecast Customer Growth;

- Energy Efficiency Benefits; and
- Losses During Construction.

Existing System

Newfoundland and Labrador Hydro (Hydro) operates a fleet of light-duty mobile equipment comprised of approximately 120 snowmobiles, 70 all-terrain vehicles, 120 trailers, 10 forklifts and ten miscellaneous attachments (for example, lawn mowers, backhoes, salt spreaders, snow plows).

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.

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.
As this project is for the replacement of light-duty mobile equipment, there is no relevant information for the following:

- Outage Statistics;
- Reliability Performance;
- Safety Performance; and
- Operating Regime.

<u>Age of Equipment or System</u>

Please see Appendix A for a detailed listing of the age of the assets being replaced under this system.

<u>Major Work and/or Upgrades</u>

There have been no major upgrades since purchase.

<u>Operating Experience</u>

Failure to replace units in accordance with the replacement policy will lead to increasing maintenance costs and less reliable vehicles. Employees maintain the electrical system 24 hours a day, seven days a week, and require dependable and safe vehicles for their work. As equipment ages, it experiences

increasing downtime, which could negatively affect response times for emergency outages or planned maintenance.

Legislative or Regulatory Requirements

Hydro complies with the environmental requirements stipulated in the following:

- Canadian Environmental Protection Act
- Marine Spark-Ignition Engine and Off-Road Recreational Vehicle Emission Regulations.

Environmental Performance

Hydro complies with the Canadian Environmental Protection Act, Section 160, which applies to engines and vehicles of 2008 and later model years emissions requirements.

Industry Experience

Light-duty mobile equipment replacement scheduling varies dependent on location, exposure to harsh environmental conditions, and the severity of the service use for the equipment.

Vendor Recommendations

There are no vendor recommendations in regards to this project.

Maintenance or Support Arrangements

The Hydro fleet of light-duty mobile equipment is maintained by external service garages.

Maintenance History

Hydro does not maintain maintenance records for this type of equipment to this level of detail.

Historical Information

Table 2 provides a history of light-duty mobile equipment purchases.

Table 2: Mobile Equipment Less than $50,000

Year	Units Purchased					Budget ($000)	Actual ($000)
	All Terrain Vehicles	Snowmobiles	Trailers	Forklifts	Attachments		
2012 B	7	5	15	1	2	400.6	
2011	14	12	29	1	0	757.0	597.0
2010	15	18	17	0	0	553.6	519.0
2009	15	26	14	1	0	561.2	529.9
2008	20	24	9	1	2	522.2	454.4
2007	15	10	-	-	-	241.0	243.5

Anticipated Useful life

Snowmobiles and all terrain vehicles are depreciated over seven years and trailers depreciated over 20 years.

Evaluation of Alternatives

Purchase of this equipment is the only viable option to support the maintenance of Hydro's assets.

Project Schedule

This project is to be completed by December 31, 2013.

Conclusion

This project provides for the normal replacement of light-duty mobile equipment which is at the end of its useful life and is no longer dependable.

APPENDIX A

Replace Light-Duty Mobile Equipment – Various

Unit #	Type	Area	Age at retire	Normal Life	AGE	Condition	Life To Date $ Maint
V7131	ATV	BDEDEPOTM	4.9	5	X	High Maint	3,371
V7130	ATV	BIFOFFICE	4.9	5	X	High Maint	8,311
V7194	ATV	BIFOFFICE	4.2	4	X	High Maint	3,742
V7099	ATV	POSOFFICE	6.1	5	X	High Maint	2,740
V7133	ATV	SVLOFFICE	4.9	5	X	High Maint	2,332
V7135	ATV	SVLOFFICE	4.9	5	X	High Maint	4,524
V7132	ATV	WHBOFFICE	4.9	5	X		1,461
V7193	ATV	WHBOFFICE	4.2	4	X		1,578
V7058	ATV	BDEDEPOTM	7.5	5	X		1,374
V7122	ATV	BDEOFFICE	5.0	4	X	High Maint	2,709
V7119	ATV	BIFOFFICE	5.2	4	X	High Maint	2,581
V7124	ATV	SVLOFFICE	5.0	4	X	High Maint	3,895
V7126	ATV	SVLOFFICE	5.0	4	X		1,106
V7195	ATV	WHBOFFICE	4.1	4	X		1,100
V9795	Forklift	WHBOFFICE	20.2	20	X	High Maint	7,694
V8831	HD Trl	BDEDEPOTM	14.6	12	X	High Maint	16,652
V8790	HD Trl	SVLOFFICE	19.2	12	X	High Maint	9,416
V8867	LD Trl	SVLOFFICE	9.7	6	X	High Maint	3,410
V7068	Snowmobile	BDEOFFICE	6.2	5	X		1,427
V7083	Snowmobile	BDEOFFICE	6.2	4	X		1,497
V7076	Snowmobile	POSOFFICE	6.2	5	X		1,241
V7082	Snowmobile	POSOFFICE	6.2	4	X		1,997
V7179	Snowmobile	POSOFFICE	4.3	4	X		1,244
V7188	Snowmobile	WHBOFFICE	4.3	4	X		1,708
V7114	Snowmobile	BIFOFFICE	5.9	6	X	High Maint	2,746
V7115	Snowmobile	BIFOFFICE	5.9	6	X	High Maint	3,224
V7137	Snowmobile	BIFOFFICE	4.8	5		High Maint	3,452
V7100	Snowmobile	HVYOFFICE	5.9	5	X		1,626
V7101	Snowmobile	HVYOFFICE	5.9	5	X	High Maint	2,703
V7102	Snowmobile	HVYOFFICE	5.9	5	X		1,590
V7103	Snowmobile	HVYOFFICE	5.9	5	X		1,109
V7104	Snowmobile	HVYOFFICE	5.9	5	X	High Maint	3,357
V7105	Snowmobile	HVYOFFICE	5.9	5	X	High Maint	3,369
V7106	Snowmobile	HVYOFFICE	5.9	5	X	High Maint	2,046
V7110	Snowmobile	HVYOFFICE	5.9	5	X	High Maint	2,081
V7111	Snowmobile	HVYOFFICE	5.9	5	X		741
V7112	Snowmobile	HVYOFFICE	5.9	5	X	High Maint	2,010
V7113	Snowmobile	HVYOFFICE	5.9	5	X		1,521
V7139	Snowmobile	SVLOFFICE	4.8	5			1,945

Project Title: Replace Insulators

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Type: Pooled

Classification: Normal

Project Description:

This project involves the installation of 230 kV, 138 kV, and 69 kV station post and suspension insulators at various high voltage terminal stations on Hydro's Island Interconnected System. It was anticipated that 2013 was going to be the last year of the insulator replacement program, but to help balance resources and system outages, it was decided to extend the program by two years. This capital budget proposal is for a two year project to complete the replacement of insulators with known cement growth problems. It is important to note future assessments will determine if there will be a need for other insulator replacement projects beyond 2014. The capital budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	8.9	11.1	0.0	20.0
Labour	145.8	145.4	0.0	291.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	19.4	22.4	0.0	41.8
Interest and Escalation	12.9	38.5	0.0	51.4
Contingency	0.0	70.6	0.0	70.6
TOTAL	**187.1**	**287.9**	**0.0**	**475.0**

JUSTIFICATION

This project is justified on the requirement to replace failing and deteriorated insulators in order for Hydro to provide safe, least-cost, and reliable electrical service to its customers. As part of a multi-year program, the 2013/14 insulator replacement project will replace the remaining known insulators targeted in the replacement program. Insulators provide electrical insulation between energized equipment and ground. When insulators fail they provide a short circuit to ground, which creates a safety hazard to personnel and system outages. In service failures have occurred, such as the outage in Stephenville on September 7, 2010. All Newfoundland Power customers supplied

from the Stephenville terminal station, including the towns of Stephenville, Stephenville Crossing, St. George's, Robinsons and all towns on the Port au Port Peninsula, experienced a power outage of 334 minutes in duration.

The outage was caused by the failure of two bus support insulators on the 66kV bus at the Stephenville terminal station. The failure of these two insulators, and damage to a third, resulted in the overhead bus falling to ground. To prevent such failures from occurring, Hydro has replaced the problem insulators at the Stephenville terminal station and plans to replace similar remaining deteriorated post, suspension and multi-cone type insulators.

Existing System

Insulators are an integral part of the Island Interconnected System. They support and insulate the energized portion of the system from structures and ground. Terminal stations contain post type, cap and pin-top, multi-cone and suspension type insulators, all of which are manufactured with cement. As the cement in the insulators ages, cracks occur and water is able to penetrate the cracks. Through freezing and thawing cycles, pressure is placed upon the porcelain material in the insulator. This is a common problem in the utility industry known as cement growth. Over time, the pressure caused by cement growth will crack the porcelain and result in failure of the insulator. Insulator manufacturers have identified and researched cement growth problems. They have improved their cement quality to eliminate this problem. For existing installations, manufacturers recommend replacing the older style insulators with new insulators.

<u>Operating Regime</u>

All insulators are used on a continuous operating cycle.

<u>Age of Equipment or System</u>

The insulators in use on the Island Interconnected System range in age from 1 to 43 years. The insulators targeted for replacement under this project were manufactured before the mid 1970s.

Major Work and/or Upgrades

There have been no major work or upgrades on the terminal station insulators targeted in this proposal since they were installed.

Operating Experience

In general, the existing insulators have performed their intended function over the duration of their life cycle. The issue of cement growth within the old insulators is reflective of the technology used at the time of purchase of these older style insulators. Since the inception of the insulator replacement program, no issue has arisen with new insulators using the newer cement compound. Normal operation and maintenance is performed on insulators by Hydro personnel. A visual inspection of terminal stations is done every 120 days, in which insulators are visually inspected for cracks and chips.

Status Quo

The status quo is not an option. The insulators targeted for replacement in 2013 and 2014 are at the end of their life cycle and must be replaced in order to maintain system reliability and a safe working environment. Failure to replace these aging insulators may result in personal injury, damage to property, or losses to revenue. As aged insulators deteriorate over time, the risk of failure is increased.

Outage Statistics

Outage statistics for terminal station equipment includes outages as a result of insulator failures, but the performance of the insulators is not directly measured. Following Canadian utility practice of tracking system performance, Hydro measures the forced outage performance of terminal stations. Table 2 lists the 2007 to 2011 average T-SAIFI and T-SAIDI data by region, and compares Hydro's system averages to Canadian Electricity Association (CEA) system averages.

Table 2: Forced Outage Performance Statistics

Five-year Averages of Forced Outages (2007 to 2011)		
Delivery Point Affected	**T-SAIFI**	**T-SAIDI**
Hydro, Central Region	0.51	53.11
Hydro, Northern Region	5.20	215.97
Hydro, Labrador Region	5.67	117.33
Hydro	1.60	88.43
CEA (2006-2010)	0.72	66.12

T-SAIFI is a measure of the frequency of transmission interruptions that a delivery point experiences during a given period.

T-SAIDI is a measure of average total interruption duration, in hours, that a delivery point experiences during a given period.

Safety Performance

In general terms, the safety performance of insulators is good. However, in situations where the insulators are under structural stress, the cement growth condition will lead to a failure of the insulator. All insulators are subject to structural stress as they are used to support energized equipment. Normal conditions include stresses from the weight of the equipment, wind and ice loading, and so forth. Insulators prescribed with cement growth issues will fail under normal stress conditions. This failure creates a safety hazard for Operations personnel when broken insulator parts fall to the ground.

Environmental Performance

There are no specific environmental issues relating to insulators other than the proper disposal of the retired insulators.

Industry Experience

The industry experience of cement growth and cracking with insulators manufactured prior to the mid 1970s is the same as Hydro's.

Vendor Recommendations

Hydro maintains contact with other major utilities and equipment manufacturers on matters related to the operation and maintenance of its equipment. Current insulator manufacturers have identified and researched the cement growth problems and have developed more sophisticated cement compounds to eliminate the cement growth problem. The manufacturers recommend that older insulators manufactured before the mid 1970s be replaced.

Maintenance or Support Arrangements

There are currently no external maintenance or support arrangements in place for insulators. Maintenance and replacement for the insulators is performed by Hydro personnel.

Maintenance History

Normal maintenance for insulators is to replace them as failures occur or as part of this insulator replacement program.

Historical Information

Table 3 contains the historical information for the insulator replacements for the period between 2007 to 2011 as well as the 2012 budgeted amount.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost Per Unit ($000)
2012 B	411.6			
2011	401.3	512.5	892	0.6
2010	399.0	323.9	1133	0.3
2009	390.9	426.9	1344	0.3
2008	294.3	324.0	1718	0.2
2007	323.0	297.5	603	0.5

The unit cost for insulators varies by type and voltage class. For example, a 230 kV station post insulator will cost approximately $750, whereas 138 kV and 69 kV station post insulators are approximately $350 each.

Comparatively, a 230 kV suspension type insulator (14 insulators per string) is approximately $300, whereas a 138 kV (nine insulators per string) and 69 kV suspension type insulators (six insulators per

string) are approximately $200 and $150, respectively. For this reason, the annual average cost per unit can vary considerably depending on the quantity, type and voltage class of insulators replaced in any given year.

Anticipated Useful Life

The anticipated service life of the new insulators is 30 years. Actual service life may vary depending on the service environment.

Forecast Customer Growth

The forecast customer load growth on the system has no effect on this project.

Development of Alternatives

There are no alternative solutions to replacing aged insulators.

Energy Efficiency Benefits

There are no issues related to energy efficiencies associated with this project.

Economic Analysis

Economic analysis is not required for this project proposal as there are no quantifiable financial benefits.

CONCLUSION

When insulators fail, they create a short circuit to ground and result in loose and falling parts. This creates safety hazards to personnel and results in system outages. To prevent such failures from occurring, Hydro proposes to replace all post, suspension, and multi-cone type insulators known to have cement growth concerns.

Project Schedule

The anticipated project schedule is shown in Table 4.

Table 4: Project Schedule

Activity		Start Date	End Date
Project Management	Scope, schedule, cost, risk, quality and communication planning. Also involves monitoring and controlling project activities	January 2013	November 2014
Design	Site visits, engineering and design of insulator replacement work package	January 2013	March 2013
Procurement	Purchase of materials such as adapter plates and bolts	April 2013	February 2014
Construction	Replacement of insulators	April 2013	November 2014
Commissioning	Energization and inspection of new insulators	April 2013	November 2014
Closeout	Project close out and post implementation review	December 2014	December 2014

Project Title: Install Automatic Fire Sprinkler System

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

The purpose of this project is to install automatic sprinkler protection in the administration area and workshops of Powerhouse 1 at Bay d'Espoir. The proposed sprinkler system is of the wet type design commonly used in heated areas such as offices and maintenance shops. It is a network of pipes charged with water and connected to a water supply. Water for the new system will be supplied from the existing fire water header which is fed from the penstocks. The pipe system delivers water to normally closed spray nozzles arranged in a grid pattern installed at ceiling height. Each spray nozzle has a thermally activated mechanism which releases water when the heat in that area exceeds a high temperature set point indicating a fire is in progress. Since the spray nozzles are heat activated, water will only flow to areas that detect a significant heat rise. In the event of a fire, and activation of the system, the fire control panel will send an alarm back to the plant control room in Bay d'Espoir to alert operations personnel.

The proposed system will provide protection to the following areas:

On the ground floor:

- Electrical workshop;
- Electrical offices;
- Small lunch room;
- Protection and control offices;
- Planning boardroom / library;
- Long term asset planning offices; and
- Corridor.

On the top floor:

- Reception office area;
- Lobby and corridor;

- Two washrooms;
- Small lunch room; and
- Seven offices.

The supply and installation of the sprinkler system will be performed by a certified sprinkler contractor. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ X1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	2.0	0.0	0.0	2.0
Labour	62.3	0.0	0.0	62.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	264.0	0.0	0.0	264.0
Other Direct Costs	4.5	0.0	0.0	4.5
Interest and Escalation	30.5	0.0	0.0	30.5
Contingency	66.6	0.0	0.0	66.6
Total	**429.9**	**0.0**	**0.0**	**429.9**

Justification

This project is required on the need to enhance fire safety in the administration and workshop areas of Powerhouse 1 at Bay d'Espoir. The Bay d'Espoir plant does not have an automatic sprinkler protection system installed in these areas. A fire in any of the areas has the potential to spread to the control room and may result in a complete shutdown of operations at the Bay d'Espoir plant.

Hydro's insurer, FM global, performs regular loss control inspections of hydro's facilities. Their report for Bay d'Espoir, issued after completing a site inspection, makes recommendations on how to manage exposures to hazards. It is stated in the latest FM global risk report (see excerpt provided in Appendix A) on fire and natural hazards dated June 17, 2011, under recommendation number 01-08-005, that sprinkler protection minimizes fire, smoke, and water damage, and allows for quick resumption of normal operations. FM global recommends the installation of an automatic sprinkler protection inside the office administration and workshop areas of the service building.

FM global has expertise in evaluating fire hazards at power generating stations. By following their recommendations hydro will achieve the following:

- Lower its risk to the severity of loss in the event of a fire, thereby minimizing the possibility

of power interruptions and improving the reliability of the provincial power supply.

For this project, there is no relevant information for the following:

- Age of Equipment or System;
- Major Work and/or Upgrades;
- Outage Statistics;
- Vendor Recommendations;
- Availability of Replacement Parts;
- Environmental Performance;
- Levelized Cost of Energy;
- Historical Information;
- Forecast Customer Growth; and
- Loss During Construction.

Existing System

Presently there is no automatic fire suppression system in the administration and workshop areas at Bay d'Espoir. There are only manually operated fire extinguishers available. This can be a slow response system if a fire starts and personnel are not in the area to respond quickly. Without a quick response, a small fire can rapidly grow into a large one.

Operating Experience

The use of manually operated fire extinguishers is intended for small fires. In the event of a large scale fire, this type of fire extinguisher is not recommended to be used as there is a safety risk to the person operating the extinguisher.

Legislative or Regulatory Requirements

There is no legislative or regulatory requirement to install automatic sprinkler systems. However, the national fire protection association (NFPA) maintains a recommended practice known as "NFPA 851: recommended practice for fire protection for hydroelectric generating plants". Within this document the NFPA recommends protection of offices, storage rooms, and shops by an automatically actuated system. Currently hydro meets this recommended practice at all of its hydroelectric generating stations with the exceptions of powerhouse 1 at Bay d'Espoir. The

applicable section of NFPA 851 is provided in Appendix B.

Safety Performance

As per the FM global recommendations, the installation of an automatic fire sprinkler system would lower the risk and severity of personal injury losses due to a fire.

Industry Experience

Currently it is unknown if other utilities only use fire extinguishers or have converted to automatic fire suppression systems, but all other Hydro generating facilities have these potential life and equipment saving systems.

Maintenance or Support Arrangements

Minor maintenance of the proposed system will be performed by Hydro personnel and major maintenance and inspections will be performed by a certified sprinkler contractor.

Maintenance History

Presently there is no automatic sprinkler system in Bay d'Espoir however there are manually operated fire extinguishers in place. Extinguishers must be properly maintained to ensure that they will work when needed and are safe to use. Adequate maintenance of extinguishers consists of regular inspections, recharging as needed, and a complete annual checkup with servicing.

Anticipated Useful Life

The fire suppression sprinkler has an estimated service life of 45 years.

Development of Alternatives

A wet sprinkler system is the standard form of automatic fire protection for this application. There are no viable alternatives.

There is no relevant information for the following:

- Net Present Value;
- Cost Benefit Analysis; and
- Energy Efficiency Benefits.

Conclusion

It is known that automatic sprinkler systems are most effective during the fire's initial flame growth stages. A properly selected sprinkler will detect the fire's heat, initiate alarm and begin suppression within moments after flames appear. In most instances, sprinklers will control fire advancement within a few minutes of their activation. This will in turn result in significantly less damage than otherwise would happen without sprinklers. Powerhouse 1 in Bay d'Espoir is a critical asset on the Island Interconnected system. If a small fire were to develop in the office area, that is only occupied during regular business hours and went unnoticed or uncontrolled, there is a potential to interrupt the electrical service on the Island Interconnected system.

FM global recommends that hydro install an automatic sprinkler system to minimize personal and property loss in the event of a fire that could also disrupt power generation. FM global indicates that having a sprinkler system not only minimizes fire damage but also minimizes water and smoke damage, and allows for quick resumption of normal operations.

In addition, this project is supported by the national fire protection association. The recommendation "NFPA 851 - recommended practice for fire protection for hydroelectric generating plants" states that all office areas, storage rooms and shops should be equipped with automatically actuated systems.

Due to the critical nature of the Bay d'Espoir asset, an automatic sprinkler would provide an extra level of protection to the isolated grid in Newfoundland and increase employee safety at the facility. With the mentioned benefits and the recommendations from our insurance provider, FM global, and the national fire protection association, there are no viable alternatives and the status quo is not acceptable.

Project Schedule

The anticipated schedule for this project is provided in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Review Scope Confirm Schedule Review Budget	March 2013	April 2013
Design	Submit Design Transmittal Risk Workshop	April 2013	May 2013
Procurement	Confirm Schedule Tender Materials/Review Tenders Award Tender For Supply	April 2013	May 2013
Construction	Safety Meetings Schedule Meetings Risk/Change Management Site Safety Tour	June 2013	September 2013
Commissioning	Safety Meeting Training	October 2013	October 2013
Closeout	Financial Close Out Post Implementation Review	November 2013	November 2013

Appendix A

FM Global 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

Fire & Natural Hazards
Interim Risk Evaluation

Visit by:	Guy Labonté
Visit date:	17 June 2011
Conference with:	Mr. Sam Rose, Manager Hydro Generation

Index: 000009.80-01 / Account: 1-74568 / Order ID: 676517-51

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11-06-003B continued

Status	The insured indicated that this will be done and that they will review why it was taken off.

01-08-005 **Provide additional automatic sprinkler protection in various areas at this facility.**

Automatic sprinklers should be installed in the following areas.

The Hazard	Invented more than 100 years ago, sprinklers are tried and tested, and have proven to be the most practical and reliable means of controlling a fire in business and industry. Sprinkler protection minimizes not only fire damage, but also water and smoke damage, and allows for quick resumption of normal operations.

Part C. Target **Install automatic sprinkler protection inside the office area of the Service Building.**

Automatic sprinkler protection should be provided inside the 2-storey Service Building.

Technical Detail	Automatic sprinkler protection is needed in all areas of the 2-storey building, except in the following rooms: - on the ground floor, the service tunnel (is already provided with sprinkler protection, 1,268 sq. ft.) - on the ground floor, the battery room (748 sq. ft.) - on the ground floor, the shielded room (already protected with an Inergen system, 616 sq. ft.) - on the ground floor, the secondary communication room (already protected with an Inergen system, 484 sq. ft.) - on the second floor, the control room (constantly attended and noncombustible occupancy, 2,380 sq. ft.)
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	Mr. Woodman, plant engineer, indicated that there are plans in the budget request for 2013 to install the suggested automatic fire protection.

10-06-004 **Perform annual discharge test on the deluge system, Power House No. 2 station service's transformer.**

Include the two deluge sprinkler systems protecting Power House No. 2 station service's transformer in the annual deluge sprinkler system testing program.

The systems are called SST-2 and SST-3.

Appendix B

Nfpa 851

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NFPA 851

Recommended Practice for

Fire Protection for Hydroelectric Generating Plants

2000 Edition

This edition of NFPA 851, *Recommended Practice for Fire Protection for Hydroelectric Generating Plants*, was prepared by the Technical Committee on Electric Generating Plants and acted on by the National Fire Protection Association, Inc., at its November Meeting held November 14–17, 1999, in New Orleans, LA. It was issued by the Standards Council on January 14, 2000, with an effective date of February 11, 2000, and supersedes all previous editions.

This edition of NFPA 851 was approved as an American National Standard on February 11, 2000.

Origin and Development of NFPA 851

The Committee on Non-Nuclear Power Generating Plants was organized in 1979 to have primary responsibility for documents on fire protection for non-nuclear electric generating plants. The Hydroelectric Subcommittee was formed in 1982 to write this document. The first edition of NFPA 851 was issued in 1987 and revised in 1992. The 1996 edition contained minor changes to clarify the life safety recommendations and generator windings protection. The 2000 edition editorially revised Chapter 2 to be consistent with NFPA 850, *Recommended Practice for Fire Protection of Electric Generating Plants and High Voltage Direct Current Converter Stations*. In addition, the document was revised to clarify the requirements for fire suppression systems for generator windings of different composition.

ual equipment or cabinet protection could be considered in lieu of total flooding systems.

5-4.4 Cable raceways not terminating in the control room should not be routed through the control room.

5-5 Cable Concentrations.

5-5.1 Consideration should be given to the use of fire-retardant cable insulation such as the types that pass the flame propagation test of the Institute of Electrical and Electronics Engineers (IEEE-383).

5-5.2 Areas with significant concentrations of combustible cable jacketing or oil-filled cable should be protected with automatic sprinkler or water spray systems. However, if water-type systems cannot be used, foam or gaseous extinguishing systems should be provided.

5-5.3 Sprinkler or water spray systems should be designed for a density of 0.30 gpm/ft^2 (12.2 mm/min) over 2500 ft^2 (232 m^2). This coverage is for area protection. Individual cable tray tier coverage could be required based on the fire risk evaluation.

5-5.4 Cable with Fire-Retardant Coatings.

5-5.4.1 A suitable alternative for combustible jacket cable automatic protection would be cable with fire-retardant coatings. The method of protection should be based on the fire risk evaluation.

5-5.4.2 Care should be exercised in selection of fire-retardant coatings to ensure that derating of the cable is considered. Consideration should also be given to the ability to add or remove cables and to make repairs to cables protected with fire-retardant coatings.

5-5.5 Grouped electrical cables should be routed away from exposure hazards or protected as required by the fire risk evaluation. In particular, care should be taken to avoid routing cable trays near sources of ignition or flammable or combustible liquids. Where such routing is unavoidable, cable trays should be designed and arranged to prevent the spread of fire.

5-6 Cable Tunnels.

5-6.1 Where protection is required by the fire risk evaluation, cable tunnels should be protected by automatic water spray, automatic wet pipe sprinkler, or foam systems. Automatic sprinkler systems should be designed for a density of 0.30 gpm/ft^2 (12.2 mm/min) over 2500 ft^2 (232 m^2) or the most remote 100 linear ft (30.5 m) of cable tunnel up to 2500 ft^2 (232 m^2).

5-6.2 Portable high-expansion foam generators can be permitted to be used to supplement fixed fire protection system(s). *(See NFPA 1901, Standard for Automotive Fire Apparatus.)*

5-6.3 Ventilation and drainage should be provided for these areas in accordance with Chapter 3.

5-7 Transformers. Oil-filled main, station service, and start-up transformers should be protected with automatic water spray or foam-water spray systems.

5-8 Indoor Oil-Filled Electrical Equipment. Automatic sprinkler, foam-water, and water spray systems should be considered for oil-filled electrical equipment. Where the hazard is not great enough to warrant a fixed fire suppression system, automatic fire detection should be considered. *(See 4-8.2.)*

5-9 Battery Rooms. Battery rooms should be provided with ventilation to limit the concentration of hydrogen to 1 percent by volume. For further information, refer to ANSI/IEEE 484, *Recommended Practice for Installation Design and Installation of Large Lead Storage Batteries for Generating Stations and Substations.*

5-10 Switchgear and Relay Rooms. Switchgear rooms and relay rooms should be provided with smoke detection systems.

5-11 Emergency Generators.

5-11.1 The installation and operation of emergency generators should be in accordance with NFPA 37, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines.*

5-11.2 Emergency generators located within main plant structures should be protected by automatic sprinkler, water spray, foam-water sprinkler, or gaseous-type extinguishing systems. Sprinkler and water spray protection systems should be designed for a 0.25 gpm/ft^2 (10.2 mm/min) density over the fire area.

5-11.3 Where gaseous suppression systems are used on combustion engines, which can be required to operate during the system discharges, consideration should be given to the supply of engine combustion air and outside air for equipment cooling.

5-12 Air Compressors. Automatic sprinkler protection, with a density of 0.25 gpm/ft^2(10.2 mm/min) over the postulated oil spill, should be considered for air compressors containing a large quantity of oil. Where the hazard is not great enough to warrant a fixed fire suppression system, automatic fire detection should be considered. *(See 4-8.2.)*

5-13 Hydraulic Systems for Gate and Valve Operators. Hydraulic control systems should use a listed fire-resistant fluid. Automatic sprinkler protection designed for a density of 0.25 gpm/ft^2 (10.2 mm/min) over the fire area should be considered for hydraulic systems not using a listed fire-resistant fluid. Where the hazard is not great enough to warrant a fixed fire suppression system, automatic fire detection should be considered. *(See 4-8.2.)*

5-14 Fire Pumps. Rooms housing diesel-driven fire pumps should be protected by automatic sprinkler, water spray, or foam-water sprinkler systems. If sprinkler and water spray protection systems are provided, they should be designed for a density of 0.25 gpm/ft^2 (10.2 mm/min) over the fire area. For automatic foam-water sprinkler systems, a density of 0.16 gpm/ft^2 (6.5 mm/min) should be provided.

5-15 Storage Rooms, Offices, and Shops. Automatic sprinklers should be provided for storage rooms, offices, and shops containing combustible materials that present an exposure to surrounding areas that are critical to plant operations. *(For oil storage rooms, see 5-2.8.)*

5-16 Warehouses. Automatic sprinklers should be provided for warehouses that contain high-value equipment and combustible materials that are critical to power generation or that constitute a fire exposure to other important buildings.

5-17 Auxiliary Heating. The storage and piping systems of fuels in the gaseous or liquefied state should comply with NFPA 31, *Standard for the Installation of Oil-Burning Equipment,* NFPA 54, *National Fuel Gas Code,* NFPA 58, *Liquefied Petroleum Gas Code,* and NFPA 8501, *Standard for Single Burner Boiler Operation,* as applicable.

Project Title: Install Online Vibration Monitoring System

Location: Corner Brook Frequency Converter

Category: Transmission and Rural Operations - Terminal Stations

Type: Other

Classification: Normal

Project Description:

This project is required to install a vibration monitoring system at the Corner Brook Frequency Converter. This system will be a micro-processor based vibration monitoring system. It will provide real time vibration monitoring and diagnostics for the converter, and have the capability to protect the unit through programmable alarms and trip levels. This system will also provide indication, through the communications system, to the Energy Control Center (ECC). This project involves the installation of transducers on the 5 major bearing casings (See Figure 1) to measure vibration, and a cabinet to house the vibration monitor (See Figure 2). Similar systems have been installed at the Holyrood Thermal Generating station, and the Stephenville and Hardwoods Gas Turbines.

A temperature module and RTD's will also be added to this system so that temperature monitoring and diagnostics are available for the frequency converter. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	2.0	0.0	0.0	2.0
Labour	137.0	0.0	0.0	137.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	140.0	0.0	0.0	140.0
Other Direct Costs	18.0	0.0	0.0	18.0
Interest and Escalation	26.4	0.0	0.0	26.4
Contingency	59.4	0.0	0.0	59.4
TOTAL	**382.8**	**0.0**	**0.0**	**382.8**

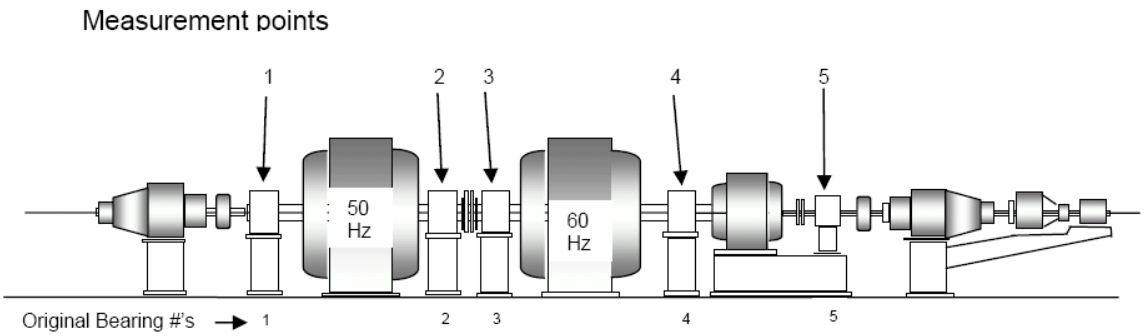

Diagram of the 50 and 60 Hz frequency Generator

Figure 1: Diagram of the 50 and 60Hz Frequency Generator

Figure 2: HRD Unit 3 Vibration Monitoring System

JUSTIFICATION

The primary function of a vibration monitoring system is to detect changes in the condition of a machine to identify a problem, or indicate a potential failure before it occurs. Changes in machine vibration can be the result of unbalance, misalignments, eccentricity (an indication of the stability of the rotor), or defective bearings. Early detection of these issues will minimize the amount of machine deterioration, enhance maintenance and outage planning, and improve safety and quality performance.

Installation of a vibration monitoring system will enhance the reliability of the frequency converter through continuous monitoring of vibration levels. Alarms and trips will be set to protect the unit, and will be remotely sent to ECC to alert personnel of potential problems. Problems can be addressed in the early stages of deterioration, limiting the amount of damage and prolonging the life of the unit.

Within Hydro's Safe Work Place Observation Program there is a recorded instance (SWOP # 2010001059) whereby an employee did not feel comfortable with re-starting the frequency converter. This occurred after a pole on the 50 Hz rotor shorted to ground. The employee cited "vibration on the unit" as one of his reasons for not re-starting. Installation of a vibration monitoring system can provide the assurance that the unit is protected if normal vibration levels are exceeded, and thus, minimize any concerns for employees. See SWOP report in Appendix A.

In 2011, an Asset Maintenance Review of the Corner Brook Frequency Converter was completed. Section 15.10 of the "Maintenance Strategy Report Corner Brook Frequency Converter" (See Appendix B) made the following recommendation:

> "*This frequency converter is comprised of several rotating components on a common flanged shaft, which is supported on 4 main bearings and 1 bearing with a self contained oil sump. A unit of such complexity should have a vibration monitoring system with both alarming and tripping capabilities."*

Existing System

The frequency converter at Corner Brook was installed in 1966 to convert power from 50 Hz to 60Hz and vice versa. Hydro owns, operates and maintains this frequency converter which is currently running continuously. This facility does not have an Operator and is typically unmanned. Prior to the Island Interconnected conversion to a 60 Hz power system, the paper mills used mainly 50 Hz

power. With the development of the island grid and the requirement for more energy at the paper mills including Corner Brook, the installation of 60 Hz equipment followed. As the majority of new 60 Hz loads were added there became less of a need for 50 Hz power. This then led to the conversion of some 50 Hz generators to 60 Hz. To date, Deer Lake Power has converted some of their generators to generate at 60Hz power and the Corner Brook paper mill has converted most of its electrical system to 60Hz but there still exist both 50 Hz generating equipment at Deer Lake and 50Hz loads at the Corner Brook Mill. Power to the 50 Hz equipment is supplied by the 50Hz generators at Deer Lake, while the remaining excess 50 Hz generation is directed through the frequency converter, and converted to 60Hz for equipment within the mill or supplied to the island grid.

In 2008, both the 50 and 60 hertz stators were re-wedged, which re-secured the windings that become loose over time, and the 50 and 60 hertz rotor poles were re-wound. In 2009, the ventilation system inside the converter building was upgraded; the voltage regulators were replaced; the liquid rheostat used for starting the frequency converter was replaced; and new synchronizing equipment was installed.

At present there is no vibration monitoring system installed on the Corner Brook Frequency Converter. Manual vibration checks are the only way to obtain vibration measurements and data. These checks are labour intensive and provide only a "point in time" assessment of vibration rather than the continual problem detection that a monitoring system can provide.

Table 2: Major Work and/or Upgrades

Year	Major Work and/or Upgrade	Comments
2007/08	50 & 60 Hz stators re-wedged	Re-wedged stators at site
2007/08	50 & 60 Hz rotor poles re-wound	Re-wound rotor poles off site
2007/08	Bearing #4 Replaced	
2007/08	Ventilation system upgraded	
2008	50 & 60 Hz AVR's replaced	
2008	Liquid rheostat replaced	
2008	Synchronizing system Replaced	

Operating Experience

Prior to any major improvements on the rotating assets at the Corner Brook frequency Converter, there have been very few known problems identified with vibration. When upgrade work on the

rotor and stator was performed in 2008, maintenance staff noticed that the upstairs rail would vibrate when the unit was on line. This was a condition that was not present prior to the refurbishment work. A detailed description of this issue, its impact, and the resolution are provided in the "Maintenance History" section below.

Considering the history of vibration problems, and the fact that the unit operated for over a year with an imbalance and misalignments, eventually resulting in a rotor pole failure, it is critical that an online vibration system be installed on this unit.

Reliability Performance

The reliability of the Corner Brook Frequency Converter with poor vibration performance is evident from the information provided above. Poor vibration performance is directly related to premature failure of components, resulting in extensive tests, outages, and the use of consultants to determine the problems, and adequately correct them.

Outage Statistics

The following outages were required to correct/improve vibration issues with the frequency converter:

- February/March 2010 – 50Hz rotor ground fault. Repair and re-alignment of the unit.
- August 2010 – re-alignment and balance of the unit.
- December 2010 – air gap modification.

Legislative or Regulatory Requirements

Legislation or Regulatory Requirements are not the drivers for this project.

Safety Performance

See Appendix A for SWOP Observation # 2010001059.

Environmental Performance

Not applicable.

Industry Experience

Vibration monitoring is standard practice for protection and monitoring of rotating machinery.

Vendor Recommendations

In 2010, Spectrum Vibration Services were asked to provide recommendations to monitor or protect the frequency converter by installing permanently mounted hardware. They made the following recommendations:

- *"The simplest would be to install a "Loop Power Sensor" looks like an accelerometer, produces a 4-20 mA signal. This unit is powered by 24 volts DC typically supplied via PLC supply. The signal is fed to a PLC and the 4 to 20 mA signal is linear and is easily "scaled" to OA vibration units/amplitude. The amplitudes can be used to display amplitudes locally, remotely HMI panels and alarms can be configured to warn, trip etc.*
- *A second recommendation would be the use of accelerometers connected to Xm modules that could be configured in future to collect and store complete vibration data in such as Odssey and transmit to a central analysis unit. Again this configuration could also be configured for remote monitoring, local display and alarming etc.*
- *A third consideration would be the latest offering of Rockwell Automation that being the Logix."*

See the complete Spectrum Vibration Services report in Appendix C.

Maintenance or Support Arrangements

There are currently no maintenance or support arrangements in place for the Corner Brook Frequency Converter.

Maintenance History

There has been very little maintenance history associated with vibration prior to 2008. In the fall of 2008, Siemens replaced the main 50Hz and 60Hz rotors, and re-wedged both stators on the frequency converter. Once the unit was put back in operation, Hydro personnel noticed that the level of vibration throughout the facility was higher than prior to the refurbishment work. Siemens were notified of the issue, but maintained the position that the unit was aligned and balanced in accordance with the specification provided by Hydro. In February of 2010, there was a rotor ground fault on the unit, which was determined to be the result of insulation wearing from one of the bolts on the V-Clamp on one of the 50 Hz rotor poles. Siemens was contracted to assess the problem and make the necessary repairs.

In March of 2010, a second company, Spectrum Vibration Services, was contracted to perform vibration analysis, determine the problem, and provide monitoring and protection recommendations. In their conclusions they stated "the dominant fault is an imbalance found mainly in the areas of bearings 4, 5 and 6." They also noted that there were misalignments between bearings 3 and 4 and between bearings 5 and 6."

In August of 2010, Siemens was brought in again to make the necessary adjustments and modifications to the unit, and record vibration measurements. Prior to commencement of the work, it was agreed, by Hydro and Siemens, that the acceptable imbalance level to be achieved for this machine would be less than 1.75 mils pk-pk. Once the work was completed the no load imbalance vibration level recorded was lower than 1.75 mils pk-pk at all positions on all bearings. However, when load was applied to the unit, the vibration level recorded was greater than 1.75 mils pk-pk in one area. Through further follow-up with the Siemens and their consultant it was determined that the air gap was not uniform. They returned in December of 2010 to make the appropriate corrections.

Historical Information

The existing vibration systems installed on all three Holyrood Units were manufactured by Bently Nevada and installed in the early 1990's. The vibration systems in the Hardwoods and Stephenville Gas Turbines, which are manufactured by Rockwell, were upgraded in 2008.

Table 3 shows a list of the actual expenditures for upgrades at the Corner Brook Frequency Converter over the past five years.

Table 3: Historical Information

Year	Actual Expenditures ($000)	Comments
2007	518	Ventilation Upgrade
2007	253	60 Cycle Rotor Re-wind
2007	253	50 Cycle Rotor Re-wind
2007	12	Bearing #4 Replacement
2007	20	60 Cycle Stator Re-wedge
2007	20	50 Cycle Stator Re-wedge
2008	98	Ventilation Upgrade
2008	506	60 Cycle Rotor Re-wind
2008	431	50 Cycle Rotor Re-wind
2008	84	Bearing #4 Replacement
2008	69	60 Cycle AVR Replacement
2008	69	50 Cycle AVR Replacement
2008	74	Synchronizer Replacement
2008	661	Liquid Rheostat Replacement

Anticipated Useful Life

The Vibration Monitoring system has an estimated service life of 15 years.

CONCLUSION

As a result of recent vibration issues at the Corner Brook Frequency Converter, this project is necessary in order to provide continuous monitoring of the vibration levels on this system, and raise alarms to alert ECC personnel of possible problems with this machinery. This will shorten response time in the event of an actual issue, and mitigate potential damage to the unit.

Project Schedule

The anticipated project schedule is shown in Table 4.

Table 4: Project Schedule

Activity		Start Date	End Date
Planning	Site visit and assessment of equipment Project Design Transmittal preparation	February 2013	February 2013
Design	Prepare Contract for supply of materials Update applicable drawings	March 2013 May 2013	March 2013 May 2013
Procurement	Issue Contract	March 2013	March 2013
Construction	Install vibration monitoring system cabinet and instrumentation.	August 2013	August 2013
Commissioning	Confirm signals and test monitoring system	August 2013	August 2013
Closeout	Project Closeout documentation Drafting of As-built drawings	September 2013	September 2013

APPENDIX A

SWOP Observation # 2010001059

Observation No: 2010001059

Observer Type:	Employee	**Observed By:**	Thomas Keough/NLHydro
Reported By Line of Business:	Newfoundland & Labrador Hydro	**Contractor Company:**	
Reported By Division:	Regulated Operations	**Reported By Department:**	Transmission & Rural Ops
Reported By Section:	TRO Central Region	**Reported By Safety Center:**	E/M Staff Stephenville (EC TRO Central Region)
Date Observed:	02/20/2010 Saturday	**Time Observed:**	03:00:00 PM
Observation Location and Description:	CBFCS: 50 cycle side of Unit 1 pole shorted to ground. Seimans were asked to come in and verify the problem as we knew it. The pole was grounded and Seimans suggested not to start the unit. I told my supervisor that I was not comfortable with doing this task.		
Aviation Related:	No	**Confidential:**	No
Immediate Action Taken:	Yes	**Immediate Action Taken Description:**	I said no to switching unit back on time. After further discussion with seimens, later that day, and due to the vibration on the unit It was decided not to start the unit next day and to continue on with the repairs.
Reported To:	Edward Park/NLHydro	**Date Reported:**	02/22/2010
FeedBack Required:	Yes	**Further Action Required:**	No

Observation Type
Condition

Observation Title:
CBFCS 50hz pole shorted to ground. Told supervisor that I was not comfortable with starting unit.

Aviation Category:
NA

Behavioural:
No

Severity
Insignificant

Probability
Unlikely

Safety Category

☐ Access Stairs & Walkways	☐ Off the Job Safety
☐ Confined Space	☐ Personal Injury/Illness
☐ Contractor Related	☐ PPE
☐ Cranes & Lifting Equip	☐ Pre Use Inspections
☒ Defective Equipment	☐ Production Loss
☐ Dropped/Falling Objects	☐ Property/Equipment Damage
☐ Electrical Contact	☐ QA Issues
☐ Emergency Response	☐ Surface Conditions
☐ Equipment/Process Improvements	☐ Theft/Vandalism
☐ Fall Arrest/Restraint	☐ Third Party Complaint
☐ Health Issues	☐ Third Party Related
☐ Housekeeping	☐ Tools - Power & Hand
☐ Job Planning	☐ Vehicle Involved
☐ Legislative Requirements	☐ Work Permit/Lockout Procedures
☐ Off-Road Equipment	☐ Work Procedures/Practices

Risk To
☐ Environment ☒ People ☐ Property
☒ Equipment ☐ Production ☐ Public

Environment Category

Location Description: Terminal Station Western Equipment

APPENDIX B

Maintenance Strategy Report Corner Brook Frequency Converter

MAINTENANCE STRATEGY REPORT

CORNER BROOK FREQUENCY CONVERTER

March 2, 2011

REGISTERED PROFESSIONAL ENGINEER T. ABUCKLE SIGNATURE PROVINCE OF NEWFOUNDLAND	Electrical – N/A
	Mechanical March 23, 2011
	Mechanical Ashley Bavis March 24, 2011
	Mechanical Gouleding April 4, 2011
	Civil – N/A
	Protection & Control – N/A
	Transmission & Distribution – N/A
	Telecontrol – N/A
	System Planning – N/A

L. Legge		March 3, 2011
Approved for Release		Date

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newfoundland labrador hydro
a nalcor energy company

MAINTENANCE STRATEGY REPORT

CORNER BROOK FREQUENCY CONVERTER

March 2, 2011

Figure 1 : Bearing Pedestal 50 Cycle

Figure 2 : Liquid Rheostat

H:\Engineering\Asset Maintenance Strategy Management Program\Projects 2009-2011\AMS Frequency Converter

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1.0 Introduction

In 2010-2011 maintenance strategies were established for Corner Brook Frequency Converter using the corporate process, "AMS Management Program, March 24th, 2009 (Draft)". This is a summary report of that work.

The entire maintenance endeavour can be seen as a means to control failure and its consequences. All failures have a cost to the corporation and, to varying degrees, hinder our progress in meeting the corporate goals and objectives, whether they are impediments to safety & health (Corporate Goal No. 1), environmental protection (Corporate Goal No. 2), or business excellence (Corporate Goal No. 3). The purpose of the AMS Management Program is to ensure that Nalcor Energy is employing maintenance strategies for its assets that best control failure, in a manner that supports business excellence, while maintaining high standards for safety, health and environmental responsibility. The product of a fully established AMS Management Program is a current maintenance philosophy for each major asset (plant, transmission line, communications site, etc.) and a set of maintenance strategies for the systems and components that make up each major asset.

While the primary objective is to control failure through application of appropriate maintenance strategies, the delivered product will also serve as an excellent resource for both operating budget justification and succession planning.

The process to establish maintenance strategies for the systems and components of a given major asset group includes the following steps:

1. Preparation and Kick-off
2. Consolidation of Existing Tactics
3. Practices in Other Companies
4. Practices in Other Areas of the Corporation
5. Equipment History
6. Manufacturers' Recommendations
7. Expert Recommendations
8. Maintenance Decision Tree
9. Technical Council
10. Risk Analysis and Final Acceptance
11. Documentation

As information was gathered in following those steps, it was consolidated within the Maintenance Strategy Workbook, organized by Equipment → Component → Strategy; the Workbook is described in greater detail in Section 4.0 Consolidation of Existing Tactics.

This accumulated information was subsequently reviewed through technical council discussions among experienced engineering and operations staff and conclusions were drawn regarding the best strategies going forward.

Using this process, maintenance strategies have been developed for all components that fall within the Corner Brook Frequency Converter facility. They are comprised of the following higher level systems, consistent within the JD Edwards asset hierarchy.

Compressed Air System
AC Station Service
DC Station Service
Building/Property
Cable/Bus Raceway
50/60 Hz Frequency Converters
Rheostat
Grounding
60Hz Neutral Grounding Transformer
Fire Protection System
Disconnects & Switches
Breakers
50/60 Hz Bus work
Power/Control Cable
Station Control, Metering Relays
Exciter
Flood Lube System
50Hz Neutral Grounding System
Heating/Ventilation System

In terms of physical boundaries, the scope includes all Frequency Converting and auxiliary equipment up to, but not including the low voltage bushings of the power transformer.

2.0 Preparation and Kick-off

In order to prepare for the Corner Brook Frequency Converter Asset Maintenance Strategy Development Project, a Project Team was assembled within Engineering Services (now Project Execution and Technical Services): Trevor Arbuckle (Lead), Ashley Bavis and Jerry Goulding, and site visits were arranged to introduce the team to the frequency converters (one at Corner Brook and one at Grand Falls). The project scope is focused on the Corner Brook Frequency Converter which is owned, operated and maintained by Newfoundland and Labrador Hydro. The Grand Falls facility is shut down and not expected to operate going forward but it is available for spare parts, as both facilities are identical.

On October 13th, 2010, the Project Team toured the Corner Brook facility and held a kick off meeting to inform of the upcoming project. Personnel contacts were arranged to provide information to the Project Team throughout the development of the workbook regarding clarification of MWO's and procedures and the location of check sheets.

3.0 Maintenance Philosophy

Recognizing there is a trade-off between the cost of failure and the cost of preventing failure, clearly guided decisions must be made on the type and amount of preventive action to undertake. Such decisions are to be made within the confines of the following basic framework: philosophy → strategy → tactic.

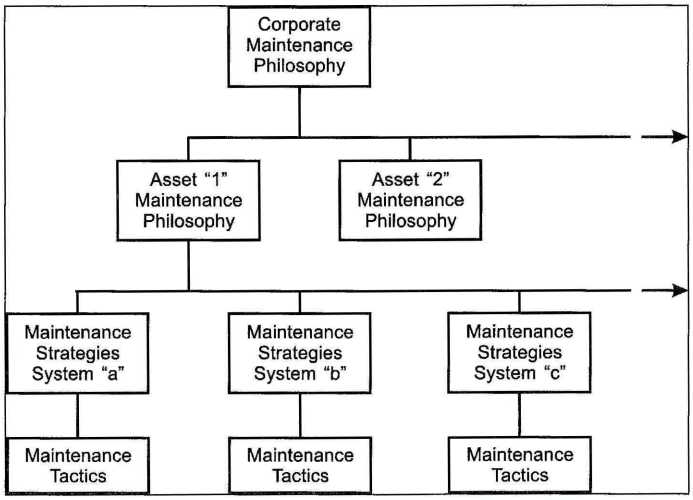

Figure 3.1: Framework

Each major asset is to have a clear maintenance philosophy - a statement of mission, vision and key objectives for the maintenance function. The philosophy will guide the development of maintenance strategies - approaches to manage failure - for each system or component that makes up the major asset. From these strategies there will be a set of maintenance tactics derived - the procedures and instructions to be used by workers to perform maintenance work.

3.1 Corporate Maintenance Philosophy

The corporation's Asset Maintenance Strategy Process outlines a Corporate Maintenance Philosophy that should be applied across the corporation. This philosophy ensures that maintenance efforts align with the corporation's mission and goals.

Corporate Maintenance Philosophy
"the right work, on the right assets, at the right time"

The objective of the maintenance functions within the corporation is to support the production of cost-effective energy with a high level of reliability, without compromise of safety, health, and environmental responsibility.

An effective maintenance program is a key element of becoming a leader in the areas of safety and the environment.

An effective maintenance program is a key element of providing exceptional value to all consumers of our energy.

An appropriate level of reliability for a given asset will depend on its contribution to the overall system reliability.

The optimum maintenance is that which will enable the appropriate level of reliability to be achieved for the planned economic life of the asset.

For a given major asset, the Corporate Maintenance Philosophy should be supplemented with statements that further refine the maintenance philosophy for the specific asset. In particular, the supplement should define the present and future contribution of the asset to overall system reliability and should declare the planned remaining life of the asset.

3.2 Corner Brook Frequency Converter Philosophy

The paper mill in Corner Brook and the generating plant in Deer Lake were built when 50Hz power was the norm in the pulp and paper industry. With the advent of 60Hz power and the construction of the island grid (60Hz), a frequency converter was installed (1966) at the Corner Brook mill thus linking the 60Hz system with the 50Hz system so that power could flow either way when required.

To date Deer Lake Power have converted most of their generators to 60Hz power and the Corner Brook paper mill have converted most of their electrical system to 60Hz but there is still some remaining 50Hz equipment. Power to this equipment is supplied by the unconverted 50Hz generators which are capable of producing more 50Hz power than the mill requires. This extra power is directed through the frequency converter, converted to 60Hz and pushed into the island grid.

Newfoundland and Labrador Hydro owns, operates and maintains this frequency converter which is currently running continuously supplying the 60Hz grid with 20MW of power.

The maintenance philosophy is to ensure unit availability and reliability with minimum forced outages and system disturbances. The Frequency Converter's basic maintenance philosophy is a combination of corrective and preventative maintenance. By trend monitoring, testing, using historical data, and PM schedules, the best information on when equipment should be maintained is normally provided. Also, by keeping accurate records of the 'As Found' condition of equipment, when equipment is dismantled for maintenance, one can determine what maintenance was really necessary. In this manner, maintenance schedules can be lengthened or shortened based on experience and monitoring. Major maintenance is normally completed concurrently with mill outages thus decreasing the power purchase costs to the paper company.

Newfoundland and Labrador Hydro completed an Engineering Condition Assessment study in 2005 and to this date (2010) most of the recommendations have been completed. This work included cleaning, upgrades and replacement of critical components. By applying the above maintenance philosophy, this frequency converter will provide reliable, available and efficient service.

4.0 Consolidation of Existing Tactics

Using asset hierarchies in the computerized maintenance management system, J.D. Edwards, the AMS Development Project Team gathered information regarding the existing tactics from the following means:

- Preventive Maintenance (PM) Schedule and associated model work orders – JD Edwards;
- PM check sheets –Lotus Notes-
- Condition monitoring – drawings, manuals, operator consoles;
- Consolidation of Existing Tactics Operators daily / weekly check sheets – operations;
- Discussion with knowledgeable personnel in the area-

The bulk of the existing preventive maintenance activity is triggered through "PMs" in JD Edwards, which automatically generate work orders at set intervals. These work orders generate from model work orders (MWOs). Typically, when the maintenance tactic can not fully be defined within the model work order description field, there is a reference to a PM check sheet.

All maintenance strategies from the various sources were consolidated in the Maintenance Strategy Workbook. The AMS Development Project Team entered all MWOs for the Corner Brook Frequency Converter. Within the organization, there were multiple strategies being performed on similar assets at different locations. This information was essential in making a decision on which strategy should be performed for certain assets. As there needed to be a consistent maintenance program for similar equipment, all sites had to be compared and broken down into each line item from the MWOs and PM check sheets.

The consolidation exercise revealed a number of inaccurate, inconsistent or unclear tactics. At this stage of the review, the AMS Development Project Team, with assistance from TRO corrected those tactics in what was referred to as the "tactic clean-up phase. In this exercise, a list of items such as correction of typing errors, removal of duplication, improved wording on work orders, and removal of obsolete model work orders was generated.

4.1 PM Check Sheet Interpretation

Check sheets or task lists include a list of activities to be performed in the field that could either extend the life of the asset (Use Based Maintenance) or be used as an indicator for early detection of failures (Predictive Maintenance).

Common terminology used for comparison of these maintenance strategies for given assets fall under one of the following two categories:

Predictive Maintenance:	**Use-based Maintenance:**
Inspect	Lubricate
Monitor/Record	Clean
Verify Operation	Replace
Oil Sampling	

In developing maintenance strategies, these activities were used to identify and categorize the preventative maintenance types. It is assumed that problems discovered while executing predictive maintenance activities will be identified and corrected as necessary. This could include the use of Corrective (CM) Work Orders for scheduling follow-up work.

All check sheets used by TRO are located on the Corporate Documents/TRO Maintenance Form Database within Lotus Notes. PM check sheets and MWOs are categorized based upon their PM frequency.

It was noted during this PM review that there is no direct correlation between the MWO and the applicable check sheet. This could be resolved by using a check sheet numbering system, similar to other Hydro areas that would link the check sheets to the appropriate MWO and remove any ambiguity especially for the less experienced employees.

5.0 Practices in Other Companies

During the Corner Brook Frequency Converter Asset Maintenance Strategy Development Project, the Project Team realized that, for comparison, there are not many rotating frequency converters in operation. Collection of maintenance plans from other like companies can provide a summary of typical industry practices that could enhance the review process but past experience, for similar AMS reviews, revealed that the quality of information received and the time required does not warrant such a process, as indicated in the two examples below.

Ontario Hydro operated a 54-MVA unit; 2 years ago they shut it down because it was no longer needed. When contacted, they would not pass on their maintenance plans for the facility, but when it was in operation they maintained it on the same frequency as their thermal generators.

Elkem operates a 6-MVA unit but does not have a preventative maintenance plan, their practise is to operate until failure or until it shows imminent signs of failure.

A number of industry common practices were readily available and subsequently entered into the workbook.

- US Army Corps of Engineers
- United States Bureau of Reclamation (USBR)

6.0 Practices in Other Areas of the Corporation

For some systems and components, proven maintenance strategies may exist elsewhere in the corporation. For example, strategies are well developed for compressed air systems in terminal stations and diesel generators for isolated generation. For each system and component, the AMS Development Project Team determined what similar assets existed in the corporation and determined the tactics for those assets.

The sites that the AMS Development Project Team found may be valuable in comparison and included into the Workbook were:

- Hydro Generation
- Diesel Plants
- Transmission and Rural Operations (TRO)
- Holyrood (HRP)

7.0 Equipment History

The historical information on our assets is an important consideration in the establishment of suitable maintenance strategies. For example, we may learn that a particular component has a high failure rate, or that the physical condition of the component has deteriorated. Such information may lead us to develop more robust maintenance strategies.

Throughout the consolidation of tactics and gathering of other information, the AMS Development Project Team talked with Hydro personnel knowledgeable in the history and maintenance of the Frequency Converter assets. Information regarding failure rates, recurring issues and other valuable history was also collected from a review of the following:

- Emergency and Corrective Maintenance work orders.
- 'Condition Assessment of the 50/60 Hz Frequency Final Report' submitted by Acres in 1998.
- 'Engineering Condition Assessment of the Corner Brook Frequency Converter' report by Paul Nolan in 2005.

These Condition Assessment reports pointed out the deficiencies in the facility and the corrective actions to be followed for prolonged life with increased reliability. In 2006 the report recommendations were acted upon and the facility has undergone a major refurbishment through cleaning, upgrading, modification and change-out. This task has not been completed to date e.g. the ventilation system to the transformer vaults is not complete, high temperatures still occur on the mezzanine floor during summer and the air compressors and dryer is due to be changed out this year (2011). More observations and recommendations are listed in section 15 of this report.

8.0 Manufacturers' Recommendations

Original equipment manufacturers' (OEMs') maintenance recommendations were collected for select assets and entered in the Workbook. Often the OEMs' recommended maintenance does not align with the needs of a particular asset. Typically manufacturers' recommended maintenance can be considered the maximum level of preventative maintenance, serving as a suitable baseline for discussion. The Liquid Rheostat OEM (Elektroschaltgerate Meerane GMBH) was reviewed by the Project Team, as this was new equipment to the Frequency Converter and there were no current maintenance strategies being performed on this equipment.

9.0 Expert Recommendations

Expert opinions regarding maintenance are extremely valuable in determining which strategies should be used for particular assets. These opinions, which were collected from documents such as consultant reports, support companies, known industry experts and insurance papers, were reviewed and entered in the Workbook. These documents are listed in the "Documents Reviewed" tab of the Workbook.

Some experts that provided details regarding maintenance strategies were:

- Acres International Limited
- FM Global

10.0 Maintenance Decision Tree

When there is a need to validate a potential maintenance strategy, or to determine a strategy where one does not become evident in the other steps of the process, the Maintenance Decision Tree can be used. This tool has been adapted from a Reliability Centred Maintenance (RCM) process. It is also used to determine the maintenance strategy type (condition monitoring, time-based maintenance, run to failure, etc.) through a consideration of the failure modes and consequences.

The Maintenance Decision Tree was not needed in the Hydraulic Units Asset Maintenance Strategy Development Process.

11.0 Technical Council

The most crucial step of the AMS process was to analyse the existing maintenance and the information from various sources that was consolidated in the Workbook and make recommendations for the best maintenance strategies to go forward with. Each line item of the Workbook, which is an existing or potential new maintenance tactic, was reviewed, discussed and considered based on all available information.

The forum for this review was a series of meetings facilitated by the AMS Development Project Team, with participation from operations and engineering staff in a Technical Council. The Technical Council for the Corner Brook Frequency Converter took approximately 3 days to complete (January 25, 26, 27, in 2011).

During these meetings, the following points were discussed:

- The philosophy for the major assets was reviewed to ensure understanding of the importance of the major assets and the purpose of maintenance.
- For each system or component in the Workbook, the existing tactics were summarized including all information gathered from other companies, experts, and other sources.
- The floor was open for discussion and it was attempted to reach a consensus on all strategies going forward.

In some cases, it was determined that there was not enough information to reach a consensus on the best maintenance strategy for a system or component. In such cases, further study was undertaken by the AMS Development Project Team after the Technical Council, with support from operations as required and strategies were developed by the Project Team.

The meetings were held at Bishops Falls to receive input from Western and Central personnel knowledgeable in the operation and maintenance of the frequency converter, with engineering participation by video and web conferencing.

12.0 Risk Analysis and Final Acceptance

As a final check that each recommended strategy is appropriate, a semi-quantitative risk analysis was conducted, using the Risk Matrix, to verify that strategies are expected to reduce risk to a tolerable level.

For each recommended maintenance strategy, the Project Team, along with Technical Council, determined both the unmitigated risk and the mitigated risk. The unmitigated risk is a determination of the consequence and probability of failure without taking preventive action. The mitigated risk is the consequence and probability of failure with the preventive action in effect. Through this exercise, one would expect all components that have Low unmitigated risk to have a Corrective Maintenance (run to failure) strategy. Components with Medium or High unmitigated risk would expect to have Preventive Maintenance strategies recommended, and the mitigated risk with these strategies in place should be expected to be reduced to a tolerable level.

In determining the level of consequence, a consequence range was selected for each defined category (safety & health, environment, property and reliability) and the highest range was used. For example, if one selects C4 for safety, C2 for environment, C3 for the property and C3 for reliability, then C4 is the overall consequence rating. For the purpose

of the risk analysis, the worst case consequences at the most critical location(s) were examined.

Where strategies were not reducing risk to tolerable levels, or where risk was at tolerable levels without PM, the AMS Development Project Team worked towards different strategies than those recommended during the Technical Council.

Once each maintenance strategy had been verified as appropriate from a risk perspective, the AMS Development Project Team noted final acceptance of the strategy in the Workbook.

Risk Analysis was performed during the Technical Council review, since the knowledge base required for risk analysis resides with the Technical Council members.

The following Risk Matrix Diagram was used to complete the Risk Analysis.

Asset Maintenance Strategy
Risk Matrix

Probability			C1 Negligible	C2 Marginal	C3 Moderate	C4 Critical	C5 Catastrophic
	Frequent	P5	MEDIUM 5	MEDIUM 10	HIGH 15	HIGH 20	HIGH 25
	Probable	P4	LOW 4	MEDIUM 8	HIGH 12	HIGH 16	HIGH 20
	Occasional	P3	LOW 3	MEDIUM 6	MEDIUM 9	HIGH 12	HIGH 15
	Remote	P2	LOW 2	LOW 4	MEDIUM 6	MEDIUM 8	MEDIUM 10
	Improbable	P1	LOW 1	LOW 2	LOW 3	LOW 4	MEDIUM 5

Consequence

DEFINITIONS

Risk Rank	
LOW	Low Risk (tolerable; 1 to 5)
MEDIUM	Medium Risk (undesirable; 6 to 10)
HIGH	High Risk (intolerable; 11 to 25)

Figure 12.1 : Risk Matrix

Corner Brook Frequency Converter
Maintenance Strategy Report

Probability

P1	Improbable	$P < 10^{-6}$ per year	so unlikely, it can be assumed that occurrence may not be experienced
P2	Remote	$10^{-6} < P < 10^{-3}$ per year	unlikely but possible to occur in the life of an item
P3	Occasional	$10^{-3} < P < 10^{-2}$ per year	likely to occur some time in the life of an item
P4	Probable	$10^{-2} < P < 10^{-1}$ per year	likely to occur several times in the life of an item
P5	Frequent	$P > 10^{-1}$ per year	likely to occur often in the life of an item

Consequence

		POTENTIAL LOSS			
		S&H	**Env.**	**Property**	**Reliability**
C1	**Negligible**	no medical aid or disabling injuries	no env. damage	<$500	no outage or planned/ scheduled outage
C2	**Marginal**	X	minimal env. damage; no violation of law; non-reportable	$500 to $5000	unplanned maintenace outage
C3	**Moderate**	X	mitigatible env. damage; no violation of law	$5000 to $50,000	forced outage - short interval (<1 week)
C4	**Critical**	medical aid or disabling injury	reversible env. damage; no violation of law	$50,000 to $500,000	forced outage - long interval (>1 week)
C5	**Catastrophic**	death or permanent disability	irreversible, severe env. Damage; non-compliance	>$500,000	major outage or trip (>1 month)

Figure 12.2 : Probability and Consequence Definitions

13.0 Documentation

The documentation associated with the Corner Brook Frequency Converter Asset Maintenance Strategy Development Project includes a Maintenance Strategy Report, which is this document, the Maintenance Strategy Workbook and the AMS Management Program Manual. The Maintenance Strategy Report is a document which explains the steps taken by the AMS Development Team in developing the maintenance strategies for the Corner Brook Frequency Converter. The Maintenance Strategy Workbook is the location of all the strategies for the Corner Brook Frequency Converter displaying equipment history, practices in other areas of the corporation and all other steps that were described in this manual. This Workbook also incorporates a change management process to be used on a go forward basis. The AMS Management Program Manual explains the program objective and the steps to arrive at a Maintenance Program for a particular asset. This includes a description of the process and instructions on how to use the Workbook.

14.0 Training

A two-day training session will be required to introduce the Workbook and Management Manual to Operations prior to hand over. A sample Workbook containing fake maintenance strategies performed on a house along with test scenarios will be completed as the training program for the Change Management Process.

15.0 Recommendations/Observations

The following general observations/recommendations were made during the Asset Maintenance Strategy Development for Corner Brook Frequency Converter.

1. There are a number PM check sheets located in TRO Corporate Documents which have since been revised and no longer apply. They should be removed to avoid any errors by the users.

2. To ensure the correct check sheets and procedures get assigned to PM work orders, all work orders should have reference to their specific procedures and check sheets. Many of the check sheets themselves do not have a check sheet number.

3. Since 2005, the compressed air system has accounted for 45% of emergency work orders, compressors and air dryers being the biggest problem. These two components should be changed out in the near future.

4. Plant hoist is out of service and reported at Technical Council that it may have been condemned due to cracks in some components. A lifting device is essential in a facility of this size and nature.

5. The ventilation system has been modified and is fulfilling one of the purposes of the modification, which is keeping the plant clean. The mezzanine floor is still reaching very high temperatures in the warmer months, which is affecting working conditions and detrimental to life of equipment. It was reported at Technical Counsel that an artificial restriction had been created in the ventilation ductwork during construction and this defect should be corrected, which should increase air flow.

6. The transformer vaults are open to the outside but there is no circulation of air, therefore T1 and T2 are overheating, sometimes reducing load on the converter is the only way to control transformer temperatures. Fans and ductwork have been purchased to remove this trapped heated air but haven't been installed to date.

7. Install a transformer deluge system.

8. The new plant air intake filters are falling out on occasion, maybe due to wind, upgrades should be made to the filters and retaining clips. Differential pressure gauge across these filters is not installed correctly, pointed out at Technical Council.

9. If items 5 & 6 don't correct the overheating problem, exhaust fans could be installed in the roof or upper wall areas.

10. This frequency converter is comprised of several rotating components on a common flanged shaft, which is supported on 4 main bearings and 1 bearing with a self contained oil sump. A unit of such complexity should have a vibration monitoring system with both alarming and tripping capabilities.

11. The battery bank should be relocated to cooler area (ground floor) and enclosed in a ventilated room. A ventilation room MUST be considered, as this is a high priority safety item.

12. Upgrade unit controls and protection system; bring temperatures, pressures, alarms, etc. to a common collection point.

13. Original mechanical relays should be upgraded.

14. Install oil sump level and water-in-oil alarm system in the bearing lubricating system.

15. Investigate automatic transfer of station service sources.

16. Investigate the consequences and controls for a transformer oil leak.

17. Commence an infrared condition monitoring program on all heat generating equipment including transformers, breakers, motors, unit components, etc.

18. Commence an NDT thickness test program or a five-year internal visual inspection of the air receiver tank.

19. Commence an oil analysis condition monitoring program for the units bearing lubrication system.

APPENDIX C

Spectrum Vibration Services Report

Spectrum Vibration Services Inc.

On Site Services Report

For

HYDRO
THE POWER OF COMMITMENT

St John's Newfoundland

In Partnership with
GraybaR CANADA

Spectrum Vibration Services Inc. | GraybaR CANADA

Field Service Report | Newfoundland and Labrador Hydro

Date:

On Site Date:

Company: Newfoundland and Labrador Hydro
P.O. Box 12400
St John's Newfoundland
A1B 4K7

RA Work Order #: **765834**

Machines: The Corner brook 50 and 60 Hz Frequency generator.

Requested By: Robert Shanera, P.Eng.
Engineering Services
Newfoundland and Labrador Hydro – a Nalcor Energy Company

CC: File

Objectives

- To collect vibration data from the 50/60 Hz Frequency Regulators to perform vibration analysis.
- To determine if there are machine faults that should be corrected.
- To make recommendations to monitor or protect the machine by installing permanently mounted hard ware.

Discussion

The 50 Hz unit was recently repaired on-site by the OEM to correct an electrical related fault. The repairs resulted in realignment between the 50 and 60 Hz unit. The 50 Hz unit indicated an imbalance at the start-up and the unit was dynamic balanced in-place to reported amplitude of 2 Mils. The amplitude was not indicated as peak-peak and at an operating frequency or an Overall Amplitude.

The unit is reported to still have significant amplitude while operating after the repairs were completed. The vibration is reported to be transient to the operating floor area as well as the mezzanine above.

The unit operates at a speed of 600 rpm. The predominant frequency measured on the machine bearings, around the surrounding structure and mezzanine was at the operating speed frequency.

I collected data from each bearing point as labeled "Measurement Points" in the machine diagram and off the upper mezzanine floor area.
The Main bearings are also labeled underneath 1 – 5.

The data was collected in three directions, Horizontal, Vertical and Axial.

I collected three sets of data;

1. Normal load of 16 Megawatts
2. Maximum load of 22 Megawatts
3. No load.

Altering the loads did not seem to affect the Overall amplitudes or frequencies significantly.
Figures 08 to 17 shows the "waterfall" plot of three frequency signatures, (upper left) collected at the three load conditions, the Overall Amplitude in Velocity peak at the three load conditions plotted, (bottom trend) and the full signature collected at 16 Megawatts. The OA Velocity plots

Discussion continued;

The predominant frequency in the data was at 600 CPM, (running frequency of machine), and many synchronous orders of the operating frequency. The 1 X speed is typical of unbalance. The synchronous orders are indication of looseness and or misalignment.

Looking at table 02 the areas outlined in red indicates the most prominent areas of unbalance, the yellow indicate areas of unbalance and misalignment at a lesser severity.

I performed a Phase Analysis across the various units to determine how each component moves axially in relation to each other from a fixed reference point in the drive train. The data indicates a significant phase difference across bearings # 3 and # 4, typical of a misalignment.

Conclusion:

- Use velocity peak to determine the machine severity using the included "General Machine Severity Chart as per ISO recommendations. I have also listed in *Table 02,* the "filtered" amplitudes measured in Mils peak-peak. This filtered amplitude is used in past tradition to describe the unbalance level, however must be applied to specific operating speeds on the General Machinery Severity Chart.
- The amplitudes did not change significantly when the load was adjusted to 22 megawatts from 16 and reduced to zero. Note OA plots Fig. 08 to 17. This would confirm the unbalance and misalignment and not an electrical related fault.
- The data indicates the dominant fault is an imbalance found mainly in the areas of bearings 4, 5 and 6.
- There is misalignment between bearings 3 and 4.
- There is misalignment between bearings 5 and 6.
- The amplitudes would indicate the machine is operating "FAIR" to "SLIGHTLY ROUGH".
- Bearings 3, 7, 8, 9, 10, 11 and 12 demonstrate unbalance as well, however at a lesser severity.
- The signature configurations are typical of misalignment verified by the phase analysis tests performed. *Note table 01*
- The high amplitude produced by the operating generators is transient throughout the building specifically the upper mezzanine area. Note Fig. 18 where the signatures indicate the predominant amplitude at 1 X operating speed of the generator

Recommendations:

- Continue to operate.
- Monitoring weekly for any significant changes in amplitude and temperature.
- Verify and correct alignment.
- Reduce the unbalance of the rotating assembly.
- The separated components may require removal to "shop" balance and trim balance in-place.
- Verify the air gaps during correction procedure.
- There are a number of ways to permanent "monitor" the unit.
- The simplest would be to install a "Loop Power Sensor" looks like an accelerometer, produces a 4-20 mA signal. This unit is powered by 24 volts DC typically supplied via PLC supply. The signal is fed to a PLC and the 4 to 20 mA signal is linear and is easily "scaled" to OA vibration units/amplitude. The amplitudes can be used to display amplitudes locally, remotely HMI panels and alarms can be configured to warn, trip etc.
- A second recommendation would be the use of accelerometers connected to Xm moduals that could be configured in future to collect and store complete vibration data in such as Odssey and transmit to a central analysis unit. Again this configuration could also be configured for remote monitoring, local display and alarming etc.
- A third consideration would be the latest offering of Rockwell Automation that being the Logix .
- I would be glad to discuss any of these options with you in the future.

Thank you for choosing Spectrum Vibration Services Inc for your machinery condition monitoring and protection system troubleshooting needs. It was a pleasure to meet you this visit.

If you have any questions or concerns, please feel free to contact me at one of the numbers or addresses below.

Best Regards:

Clifford D. Grundy

Clifford D. Grundy
President / ICM Solutions

Spectrum Vibration Services Inc.
Office: 905-648-2416
Cell: 905-572-1883
E-mail cgrundy@spectrumvibration.com

Spectrum Vibration Services Inc.

Field Service Report

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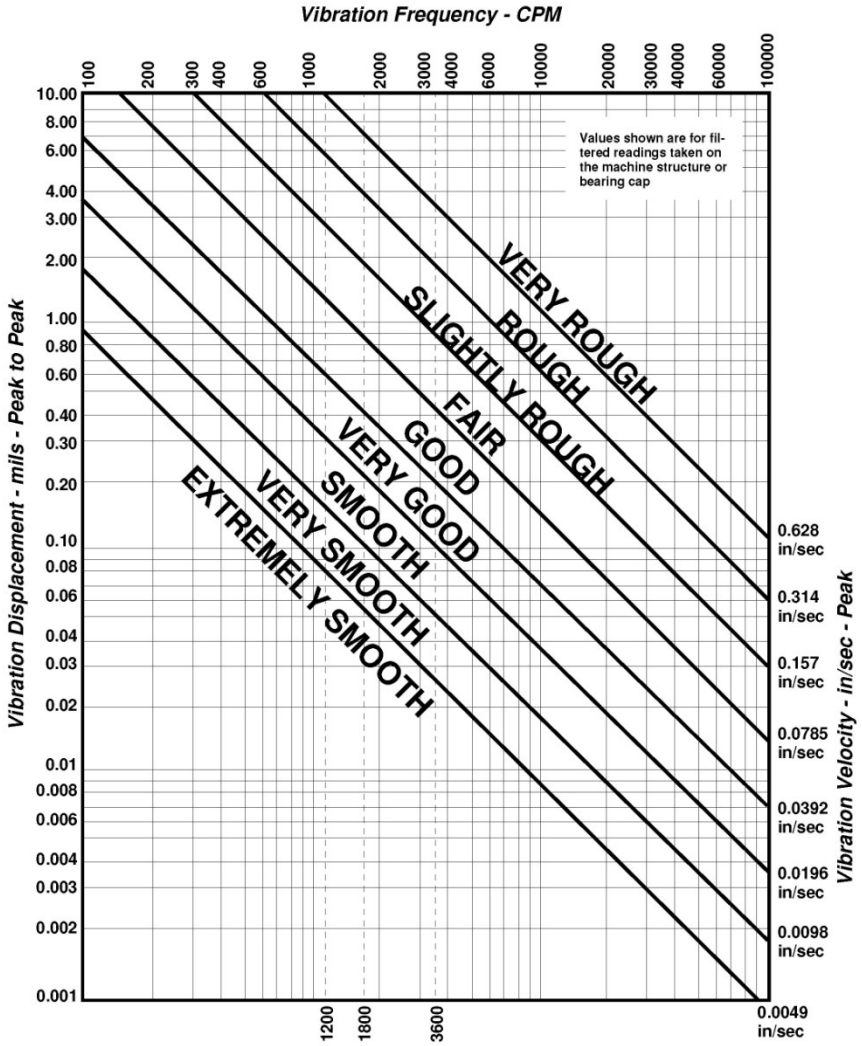
Newfoundland and Labrador Hydro

Compliments of Spectrum Vibration Services Inc.

IRD Mechanalysiis

GENERAL MACHINERY VIBRATION SEVERITY CHART



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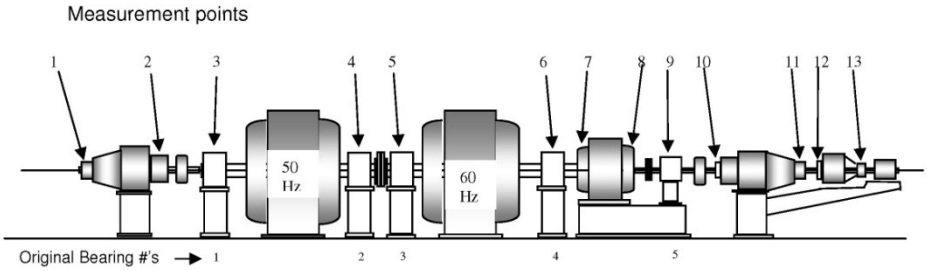

Diagram of the 50 and 60 Hz frequency Generator

Phase Analysis Measurements how components move Axially with each other based on a "fixed" reference.					
CLOCK POSITION	# 3 ANGLE	# 4 ANGLE	# 5 ANGLE	# 6 ANGLE	# 9 ANGLE
12	284	160	156	246	N/A
3	294	155	138	245	223
6	294	163	157	229	256
9	320	173	167	246	246
	Significant Phase difference between these two bearings, typical of a misalignment.		Significant Phase difference between these two bearings, typical of a misalignment.		

TABLE 01 the phase angles as recorded, where there is no difference in angles across bearings suggests the bearings are moving axially in a "planer" format and together in the same direction. Where there is a significant angle suggest moving opposite to each typical misalignment

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Newfoundland and Labrador Hydro

Amplitudes in Velocity overall(OA) peak, Velocity peak at 600 CPM, Displacement(OA) p- p and Displacement p-p at 600 CPM						
Orig Brg #	Meas. Points	Vel ips peak OA	Vel ips peak @ 600	Displ mil p-p OA	Displ mil p-p @ 600	***Comments:*** *use Velocity peak OA to determine* ***GENERAL MACHINERY SEVERITY Chart****, the Displacement at 600 cpm,(600 rpm) would indicate the amount of "****UNBASLANCE****".*
	1	.047	.028	.98	.89	
	2	.080	.027	.96	.85	
1	3	.045	.036	1.20	1.16	
2	4	.121	.107	5.51	3.43	unbalance
3	5	.088	.080	2.62	2.54	unbalance
4	6	.103	.094	3.04	2.99	unbalance
5	7	.031	.016	1.57	.533	
	8	.054	.043	1.42	1.387	
	9	.049	.039	1.05	.98	
	10	.048	.033	1.09	1.05	
	11	.044	.029	1.01	.928	
	12	.045	.035	1.16	1.12	
	13					
	14	.232	.224	7.29	7.11	This the highest amplitude, measured off the upper deck.

Fig. 01

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Field Service Report

Newfoundland and Labrador Hydro

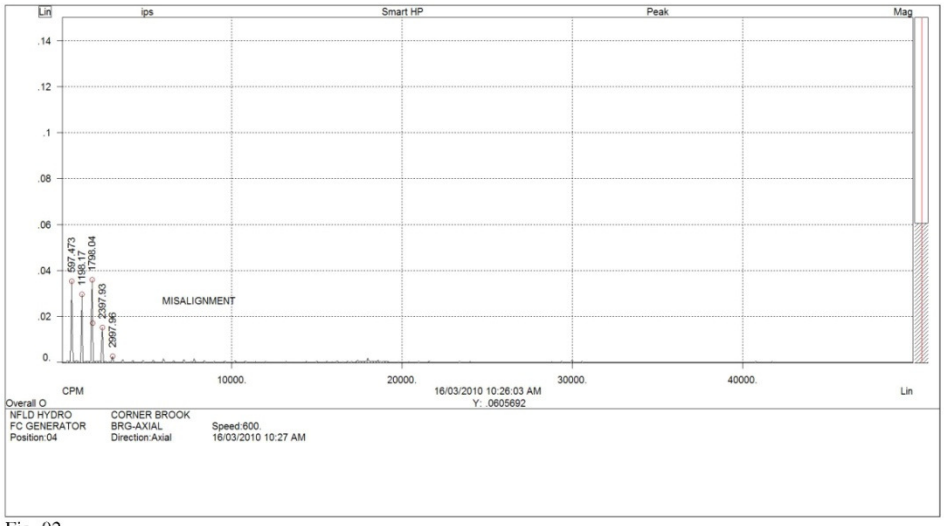

Fig. 02

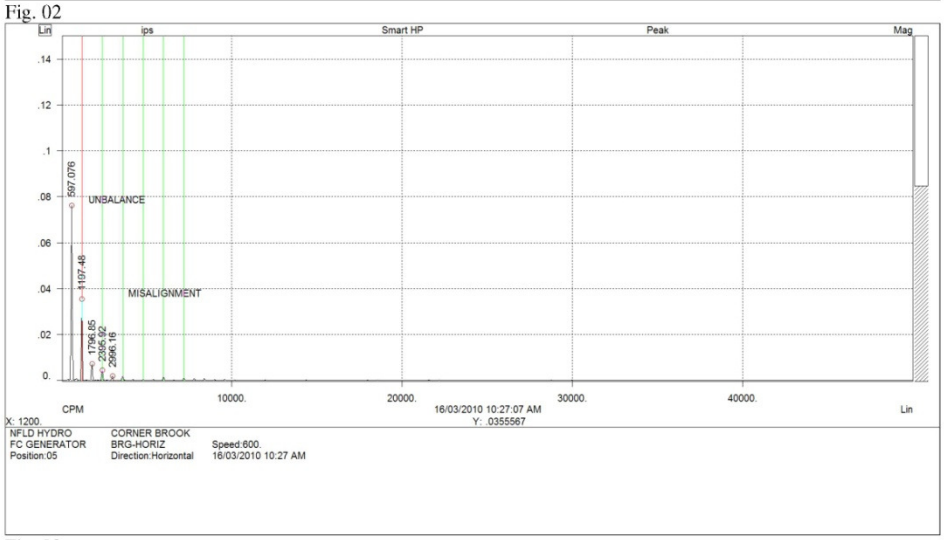

Fig. 03

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Newfoundland and Labrador Hydro

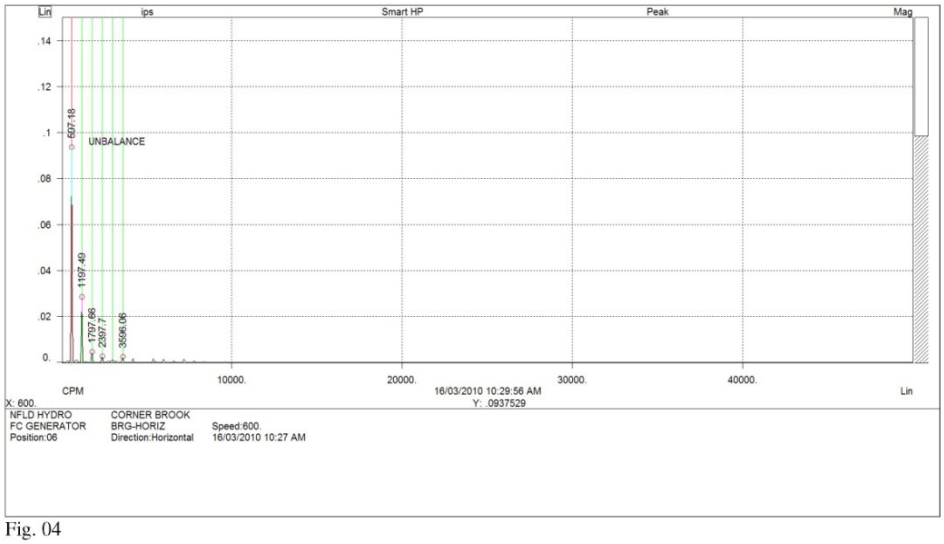

Fig. 04

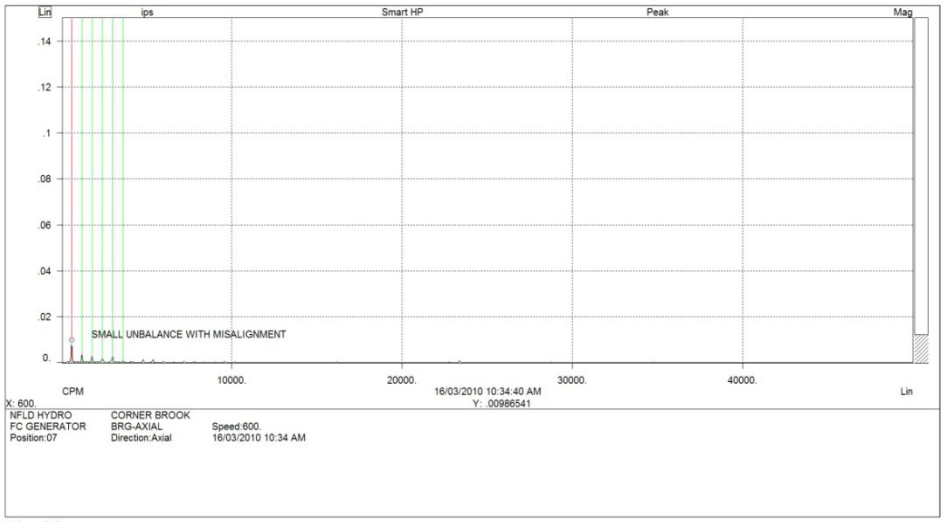

Fig. 05

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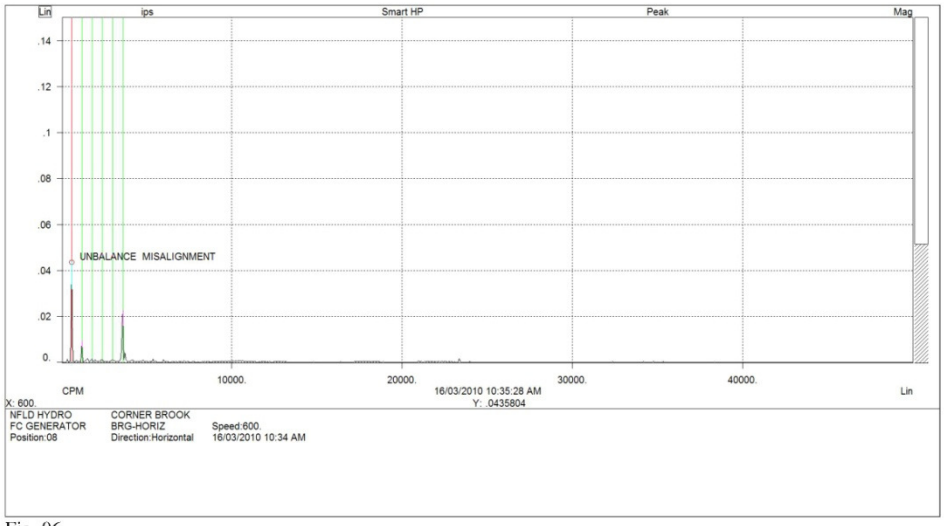

Fig. 06

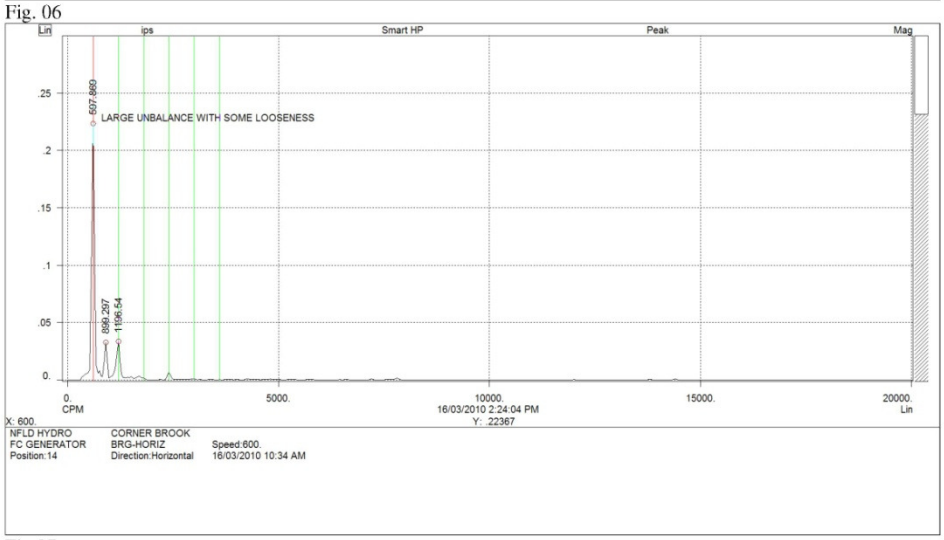

Fig.07

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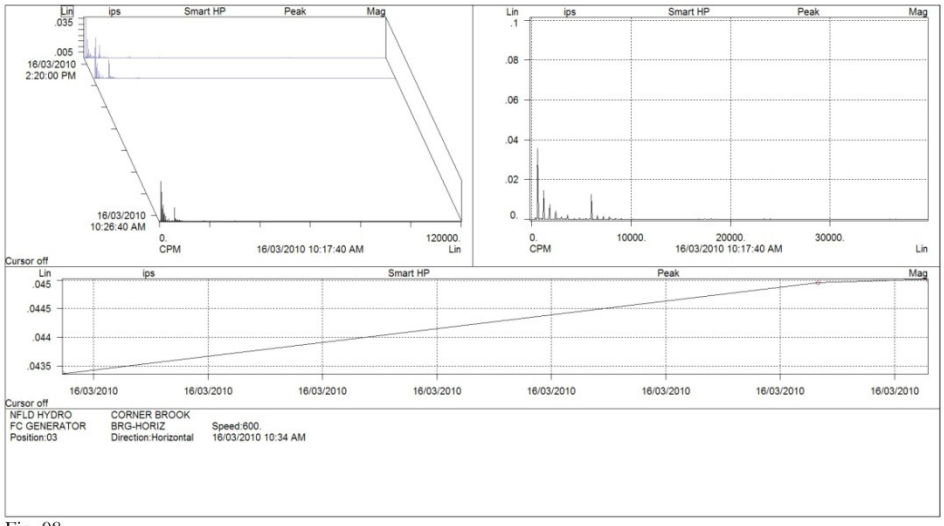

Fig. 08

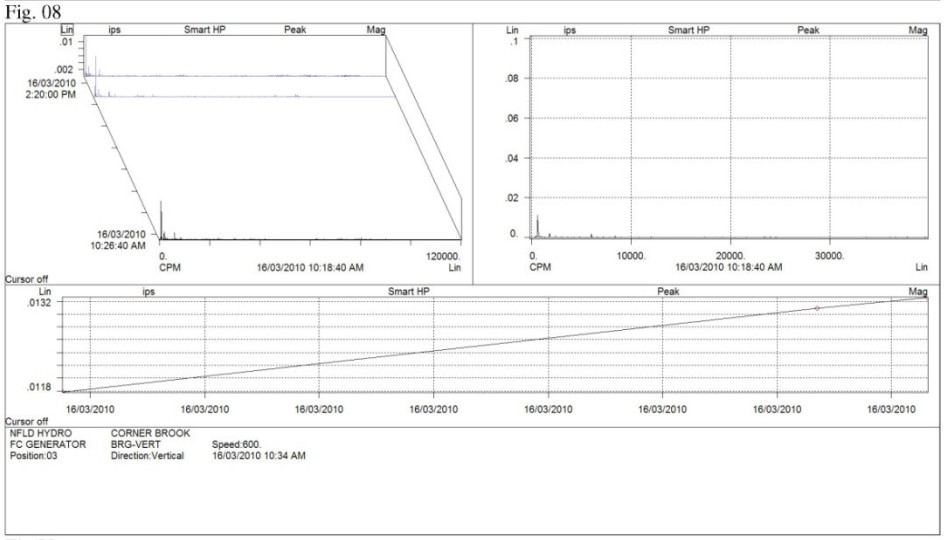

Fig 09

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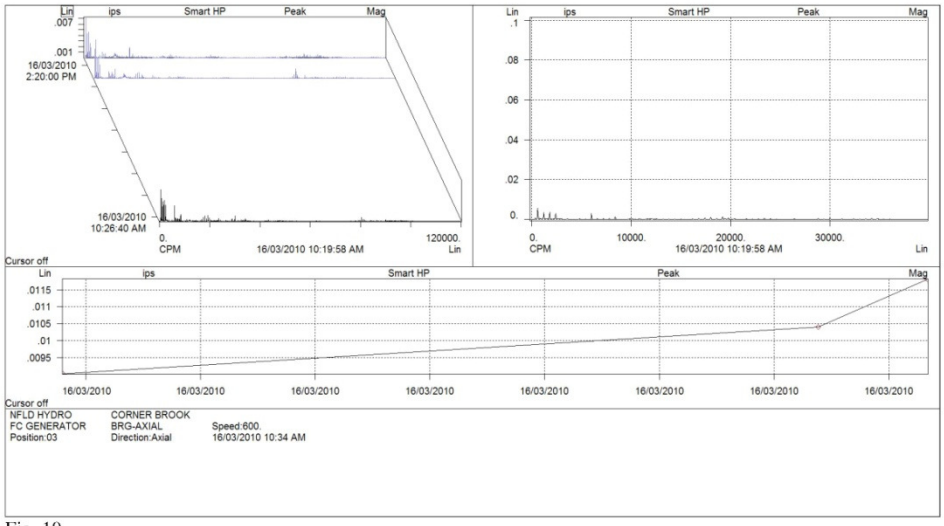

Fig. 10

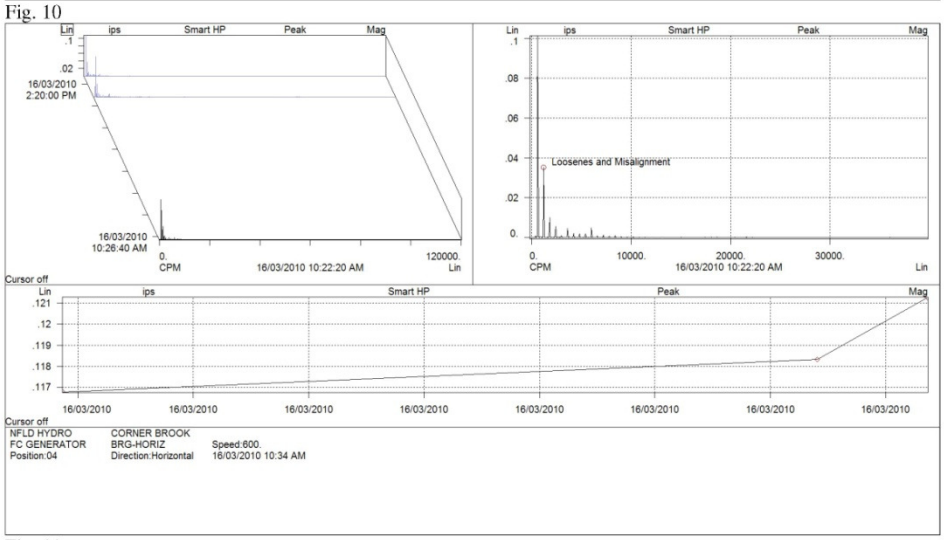

Fig. 11

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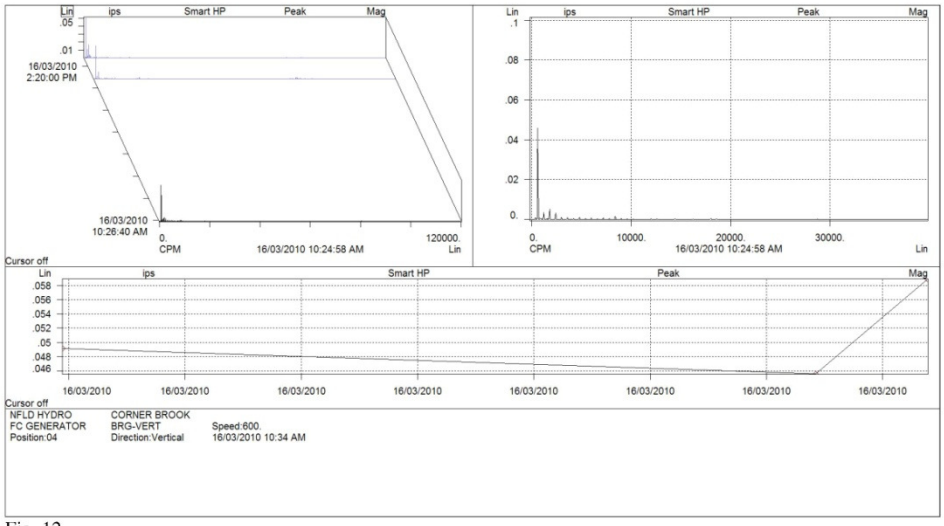

Fig. 12

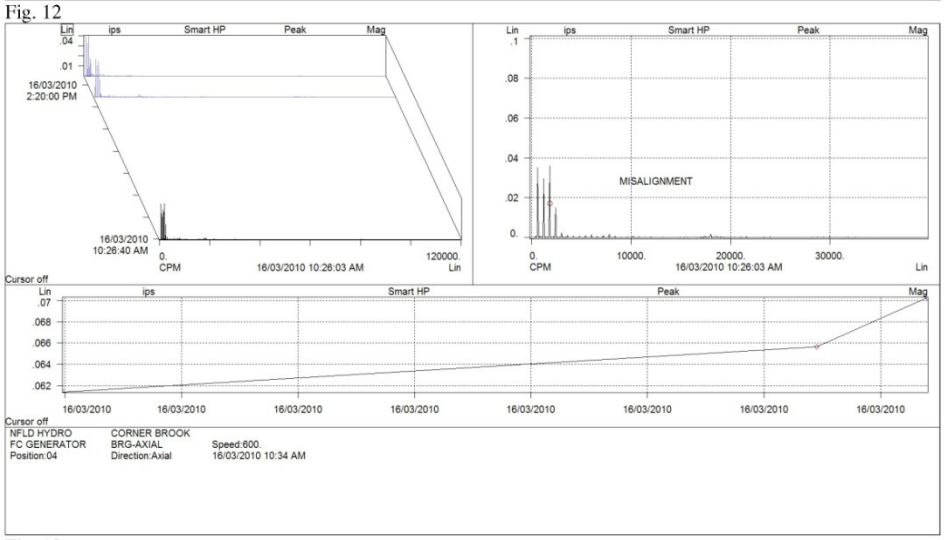

Fig. 13

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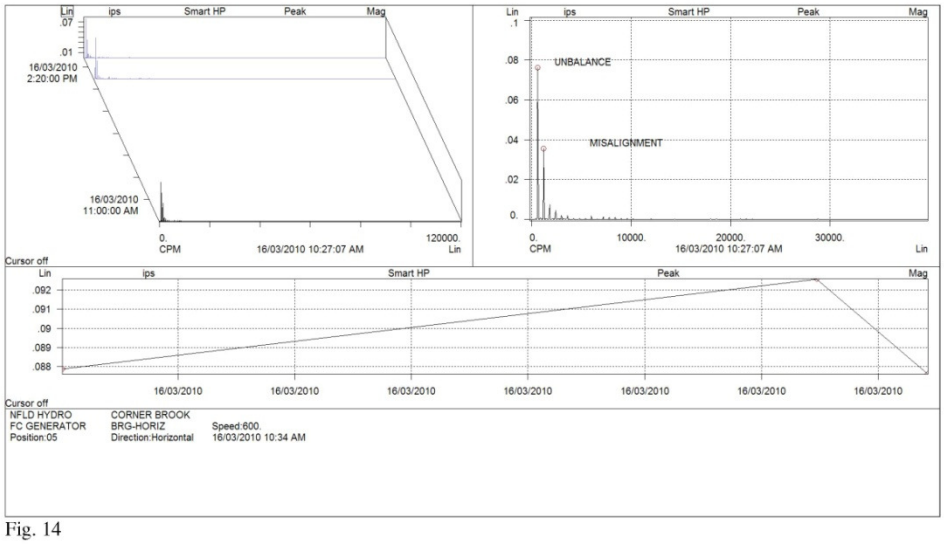

Fig. 14

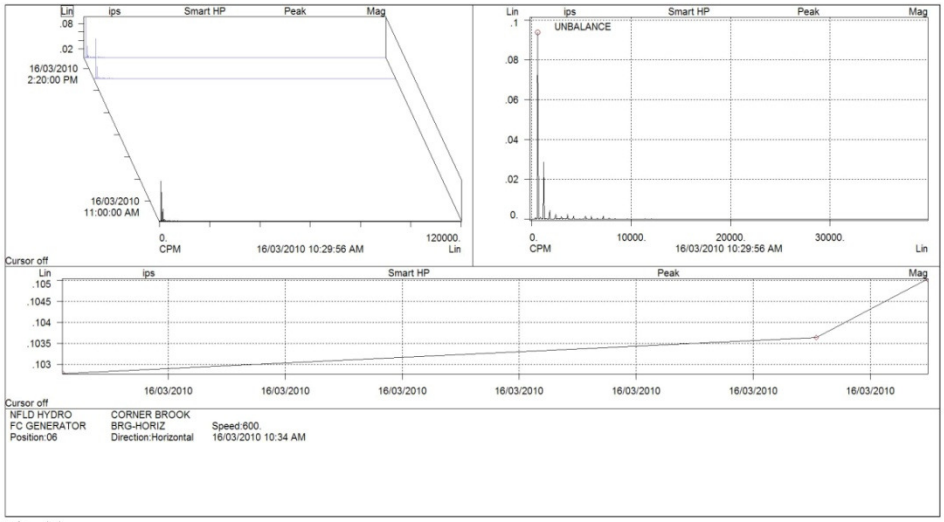

Fig. 15

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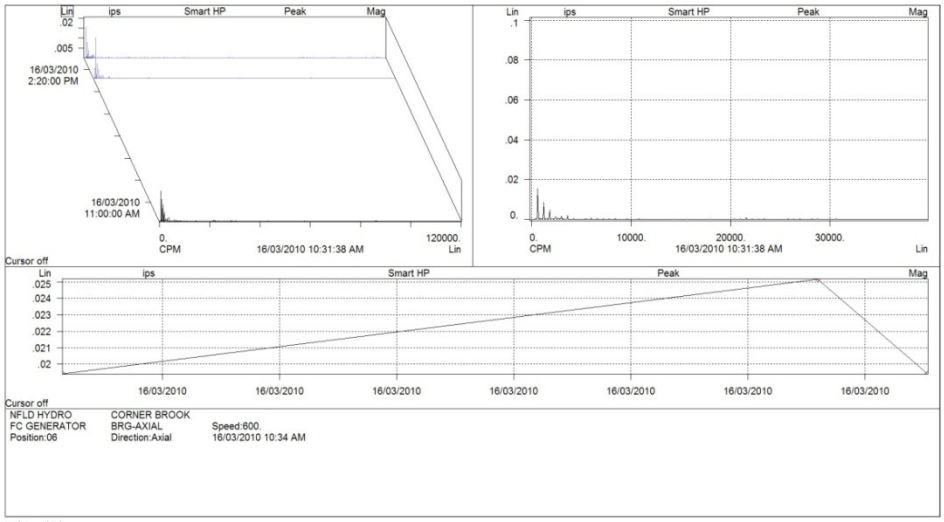

Fig. 16

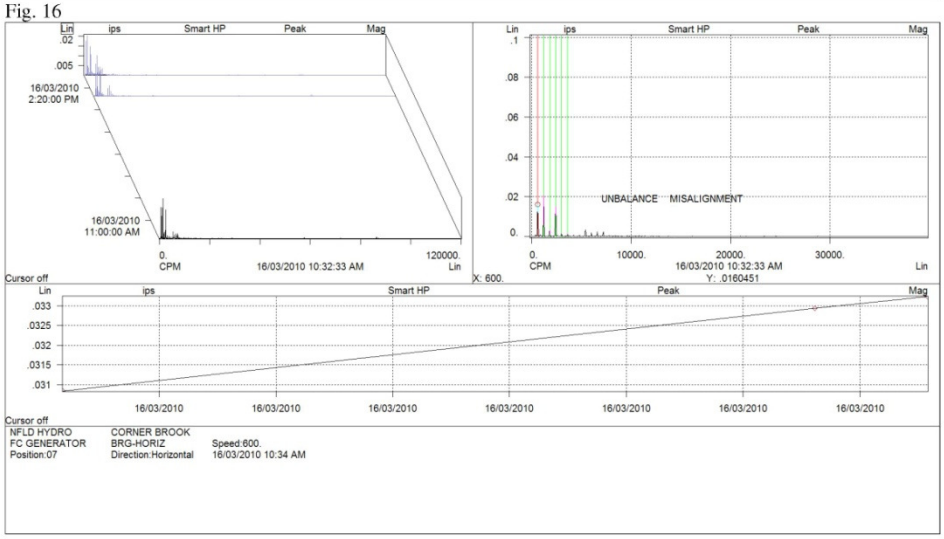

Fig. 17

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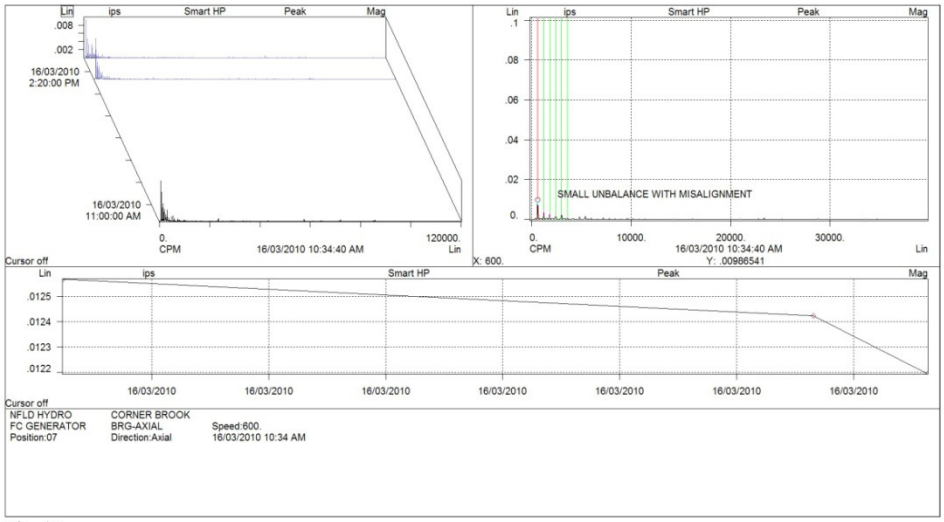


Fig. 17

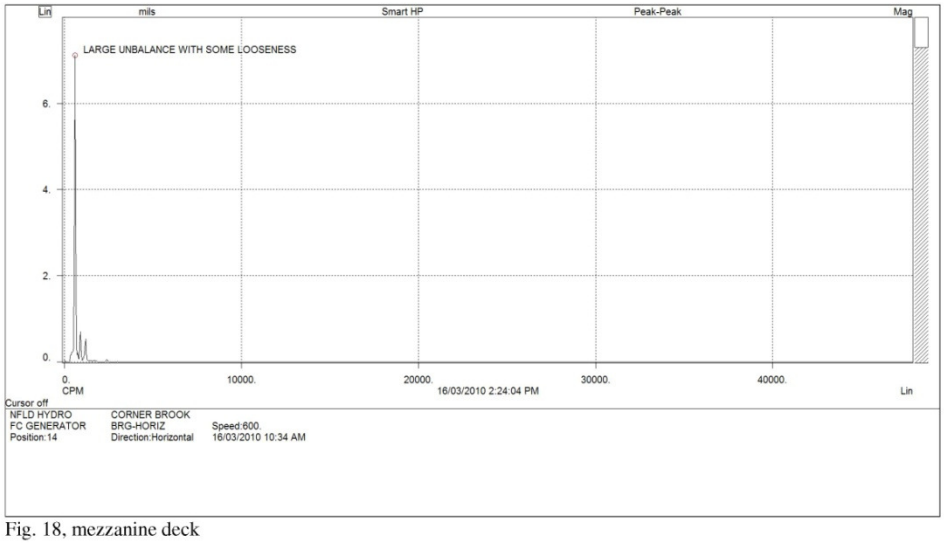


Fig. 18, mezzanine deck

Project Title: Install Additional Washrooms

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Type: Other

Classification: Normal

Project Description:

This is year one of a multi-year program to install additional washrooms in various Hydro site facilities. The washrooms are required to accommodate an increase in the number of female staff working in, what were once considered to be, non-traditional roles. Hydro presently employs approximately forty female employees in these non-traditional roles and given the ever changing workplace demographic, this number will increase in years to come. This budget proposal is requesting $250,000 for 2013 and is expected to form the first 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 site facilities prioritization list will be created to ensure that areas experiencing higher concentrations of female employees are the first to be completed. The intention is to complete the required upgrades at all Hydro remote site facilities, as female workers could be working out of any facility. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**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	16.7	0.0	0.0	16.7
Contingency	0.0	0.0	0.0	0.0
TOTAL	**250.9**	**0.0**	**0.0**	**250.9**

JUSTIFICATION

This project is required to provide additional washrooms in all of Hydro's remote site facilities which currently contain a single washroom. With the increasing presence of female employees in what

was once considered to be non-traditional roles, Hydro is seeing more females working and/or visiting field operating facilities. With this changing dynamic comes the requirement to provide separate female washroom facilities 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. 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 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 inclusion of female workers in these non-traditional roles and, as a result, there is a requirement for the addition of separate female washroom facilities.

This work will form the first 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.

Legislative or Regulatory Requirements

Section 61-2 (c) of the *Provincial Occupational Health and Safety Regulations, 2012* (OH&S), states that, "where both male and females are employed, separate toilets shall be provided and suitably identified for workers of each sex".

Hydro's remote site facilities are frequently visited by both male and female employees for the completion of routine maintenance tasks. While Hydro has adopted a new company policy for the inclusion of two gender specific washrooms in all new constructed facilities, the existing facilities contain a single washroom.

Safety Performance

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. This has been demonstrated through a Safe Work Place Observation (SWOP), submitted by a female employee in September 2011, noting that, "There are no designated washroom facilities in any substations on the east coast and according to the OH&S Act there should be both male and female washrooms"

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. The only available historical information consists of the inclusion of separate female washrooms in the control buildings for the newly constructed Quartzite and Vanier Terminal Stations in Labrador City. The cost to modify the original building layout to accommodate the additional washrooms was

$27,000 per building. It is important to note that no changes to the building structure were required in these two instances. It is anticipated that the inclusion of additional washrooms in the majority of Hydro's facilities will require a building extension.

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 and therefore 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 all of Hydro's remote site facilities.

CONCLUSION

Today's workplace has seen a significant influx in the number of females assuming what were once considered to be non-traditional roles. A proud promoter of workplace equality and diversification, 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 will ensure that Hydro meets the current industry standard, which is expected by today's employees, and satisfies any requirements of the Provincial Health and Safety Act.

Project Schedule

The anticipated project schedule is contained in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Project Design Transmittal and Scheduling	February 2013	March 2013
Tender/Award	Tender Preparation/Project Award	March 2013	April 2013
Construction	Install Additional Washroom Facilities	June 2013	August 2013
Commissioning	Final Inspection	-	August 2013
Closeout	Contract Closeout	-	October 2013

Project Title: Replace Recloser Control Panels

Location: Various Sites

Category: Transmission and Rural Operations - Distribution

Type: Pooled

Classification: Normal

Project Description:

The Recloser Control Panel Replacement Project is required to replace 50 aging recloser control panels. This is the sixth year of a seven-year program. In 2013, five recloser control panels will be replaced. The existing control panels are housed in steel enclosures which have deteriorated due to exposure 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 panel will also have remote control capability should a future telecommunications network be established at these sites. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	65.0	0.0	0.0	65.0
Labour	74.0	0.0	0.0	74.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	23.0	0.0	0.0	23.0
Interest and Escalation	15.3	0.0	0.0	15.3
Contingency	32.4	0.0	0.0	32.4
TOTAL	**209.7**	**0.0**	**0.0**	**209.7**

In 2013, five 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: 2013 Recloser Control Panel Replacements

Location	Type	Recloser ID	Installation Year
St. Anthony	Rack Mounted	SA2-R1	1980
St. Anthony	Rack Mounted	SA3-R1	1985
St. Anthony	Rack Mounted	SA1-R1	1986
L'Anse au Loup	Rack Mounted	LL1-R1	1975
L'Anse au Loup	Rack Mounted	LL1-R2	1968

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.

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 severe rusting of the recloser control panel.

Existing System:

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.

This project is to replace aging and weathered distribution recloser control panels on distribution feeders to ensure fault protection reliability is not compromised. Photos of rusted recloser control panels are shown in Figure 1 and Figure 2. These recloser panels are part of the approved 2012 replacement.

Figure 1: Hawkes Bay Recloser HB3-R1 Control Cabinet

Figure 2: Parson Pond Recloser PP1-R1 Control Cabinet

The existing recloser control panels are housed in a painted steel compartment, many of which are exposed to a highly corrosive coastal environment.

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 and/ 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 2007 to 2011 average SAIFI and SAIDI data by feeder and distribution system where the upgrades are proposed. The table also lists the 2007 to 2011 corporate value and the latest Canadian Electrical Association (CEA) five-year average (2006 to 2010) for comparison.

Table 3: Outage Statistics

Five Year averages (2007 to 2011)

SYSTEM	All Causes SAIFI	All Causes SAIDI	Defective Equipment SAIFI	Defective Equipment SAIDI
Northern Isolated	6.34	6.02	0.38	0.55
Northern Interconnected	4.43	9.86	0.43	0.99
Charlottetown Feeder 1	6.78	4.99	0.05	0.17
Mary's Harbour Feeder 1	12.22	8.15	0.34	0.62
Port Hope Simpson Feeder 1	7.02	4.58	0.21	0.05
St. Anthony System	5.55	13.72	0.80	2.61
St. Anthony Feeder 1	5.36	12.53	1.57	2.98
St. Anthony Feeder 2	5.89	11.12	0.22	0.03
St. Anthony Feeder 3	4.46	10.11	0.07	0.05
L'Anse au Loup System	4.48	5.30	0.51	0.55
L'Anse au Loup Feeder 1	4.42	5.14	0.46	0.60
L'Anse au Loup Feeder 2	4.52	5.42	0.54	0.52
Hydro Corporate	5.37	10.84	0.41	0.96
CEA Region 2 (2006-2010)	2.66	7.79	0.45	1.21

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.

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements with this project.

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, with the exception of one which is LL2-R1, have been tested and are below 1 parts per million (PPM) polychlorinated biphenyl (PCB) content. LL2-R1 will be tested in the near future.

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

A representative for Cooper Power Systems 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 out 3-6 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."
Note: 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 2013. 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)
2011	St Anthony Recloser SA1-R1	0.0	0.4	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
2008	St Anthony Recloser SA3-R1	0.5	1.2	1.7
2008	St Anthony Recloser SA1-R1	0.0	0.4	0.4
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	St Anthony Recloser SA2-R1	0.0	0.7	0.7
2007	St Anthony Recloser SA3-R1	0.0	1.4	1.4

Historical Information

Eight recloser control panel replacements completed in 2008 included 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 completed in 2009 included 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 to be replaced in 2010, eleven recloser control panels were completed in 2010 and five were completed in 2011. The replacements completed in 2010 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). The five replacements completed in 2011 were located at 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 were purchased. Due to resource issues, they will be installed and commissioned in 2012. The replacements will be located at Roddickton (RO1-R2, RO1-R3, RO3-R2, RO4-R1) and Main Brook (MB1-R2).

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
2012	202.3		5		
2011	231.9	178.4	7	25.49	2 completed and 5 recloser panels have been carried over into 2012 for installation and commissioning due to resource issues
2010	603.1	370.2	16	23.14	See Footnote [6]
2009	132.4	107.3	5	21.46	
2008	222.5	133.9	8	16.74	See Footnote [7]

[6] 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 $218,411. Resource issues in Rural Operations had pushed the schedule of 5 recloser panels into 2011.

[7] 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 to the project was $88,961.

Anticipated Useful life

The recloser control panel has an anticipated useful life of 20 years.

Forecast Customer Growth

Customer load growth does not affect this project.

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 noted in the Availability of Replacement Parts Section of this document and the enclosures are in a deteriorating condition.

Net Present Value

A net present value calculation was not performed in this instance, as there are no viable alternatives to replacing the control panels.

Levelized Cost of Energy

This project will have no effect on the levelized cost of electricity.

Energy Efficiency Benefits

There are no energy efficiency benefits associated with this type of project.

Economic Analysis

An economic analysis is not required as there are no quantifiable benefits.

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.

Status Quo

Maintaining the status quo will result in prolonged outages and by-passed protective devices due to the lack of 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 deteriorated 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 2013	January 2013
Design	Project Design	February 2013	April 2013
Procurement	Equipment Ordering	February 2013	April 2013
Construction	Field Construction and Installations	May 2013	October 2013
Commissioning	Commissioning after Installation	May 2013	October 2013
Closeout	Project Completion and Closeout	November 2013	November 2013

Future Plans:

Replacement of recloser control panels will be proposed as part of the 2014 Capital Budget Application.

APPENDIX A

Age of Assets

Recloser Panels

List of Recloser Panels to be Replaced

Location	Recloser ID	Asset #	Year Installed	Year Scheduled/Replaced
Hawke's Bay	HB3-R1	58178	1971	2012
Cow Head	CH1-R1	58187	1981	2012
Cow Head	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 Upgrades

Reclosers

Major Work and/or Upgrades

Date	Recloser	Major Work and/or 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

Five-year Maintenance History

Maintenance History

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2011	St Anthony Recloser SA1-R1	0.0	0.4	0.4
	Total 2011	**0.0**	**0.4**	**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	**9.3**	**0.0**	**9.3**
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**	**0.1**	**1.4**
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	**1.4**	**2.9**	**4.3**
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
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: Front End Engineering Design

Location: Hydro Place

Category: Administration

Type: Other

Classification: Normal

Project Description:

The project is to capitalize in 2013, Phase 1 - Front End Engineering Design associated with the preparation of the 2014 capital budget submission.

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

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	318.0	0.0	0.0	318.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	42.0	0.0	0.0	42.0
Interest and Escalation	40.1	0.0	0.0	40.1
Contingency	72.0	0.0	0.0	72.0
TOTAL	**472.1**	**0.0**	**0.0**	**472.1**

JUSTIFICATION

Ensuring that the preliminary engineering work is advanced during the capital budget preparation process enables more appropriate estimates and work plans. For the preparation of 2014 capital budget submission, it is intended that costs incurred in 2013 related to Phase 1, or front end engineering and design (FEED), will be capitalized in advance of the 2014 capital budget submission. These costs are defined as follows:

Phase 1 engineering includes all of the engineering design for an engineering project. It starts from the project brief and works through to the visualization, conceptualization and definition stages. It involves translating the project into a conceptual design and then a basic design. In order to prepare capital budget information, engineers must begin the front end engineering and design (FEED) phase of the projects. Completing the initial stages of FEED allows the engineers to

determine an estimate of costs attributable to the capital projects. Additional costs associated with compiling and reporting the capital budget are not directly attributable to bringing an asset into operation and as such would be considered an operating expense. Only FEED costs exceeding $1,000 per project have been capitalized.

FEED costs are considered to be part of the initial costs associated with bringing an asset to its intended location and condition and can be capitalized under International Financial Reporting Standards IAS 16 Property, Plant and Equipment. While some high level engineering work had been completed in the past prior to the filing of the capital budget submission, the Phase 1 engineering was often delayed until after the approval process by the Board. As a result, the necessary information for the preparation of a strong cost estimate for a project was received after the filing of the capital budget. The timing of this information often resulted in revisions being made to the project plans and budget estimates.

Should the Board subsequently disallow or reject any of the capital projects for which FEED costs relate, the costs associated with the Phase 1 engineering work will be expensed.

Existing System

Currently, Hydro expenses costs related to FEED that occurs before a project has been approved by the Board. The FEED costs will be captured by project so they can be added to the project total.

The following categories are not applicable to this project.

- Operating Experience
- Reliability Performance
- Outage Statistics
- Legislative or Regulatory Requirements
- Safety Performance
- Environmental Performance
- Industry Experience
- Vendor Recommendations
- Maintenance or Support Arrangements
- Maintenance History

- Anticipated Useful Life
- Forecast Customer Growth
- Development of Alternatives
- Evaluation of Alternatives
- Energy Efficiency Benefits
- Economic Analysis

HISTORICAL INFORMATION

Hydro has captured the FEED costs within each applicable 2013 capital project incurred in 2012 pertaining to the preparation of the 2013 Capital Budget proposals. These costs, by project, are listed on pages 14 and 15 of the 2013 Capital Projects Overview section.

CONCLUSION

FEED costs are eligible for capitalization under International Financial Reporting Standards. Allowing Hydro to capture these costs in advance of project approvals will assist Hydro in improving the quality of project estimates and schedules.

PROJECT SCHEDULE

The capturing of FEED costs for the 2014 capital projects will commence in January 2013 and be completed by June of 2013.

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 229 personal computers that were deployed in 2008 and 2009. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	288.7	0.0	0.0	288.7
Labour	30.0	0.0	0.0	30.0
Consultant	53.0	0.0	0.0	53.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	17.9	0.0	0.0	17.9
Contingency	74.3	0.0	0.0	74.3
TOTAL	**463.9**	**0.0**	**0.0**	**463.9**

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 over 1000 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.

Industry Experience

Hydro has a similar life cycle plan for computer equipment as other companies in the utility industry, including Newfoundland Power.

Maintenance or Support Arrangements

Hydro has purchased maintenance agreements with Lenovo Corporation, the manufacturer, that cover laptops for four years and desktops for five years.

Historical Information

Historical information on computer replacement over the last five years as well as those budgeted for 2012 is presented in Table 2.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2012B	490.6		183		
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	
2007	395.0	393.7	102	3.86	Laptops only replaced

Anticipated Useful Life

According to Gartner[8], 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.

[8] 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.

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 2013 and be completed before December 31, 2013.

Project Title: Upgrade Server Technology Program

Location: Various Sites

Category: General Properties - Information Systems

Type: Other

Classification: Normal

Project Description:

This project is a part of Hydro's evergreen program and involves the replacement, addition and upgrade of hardware components and software related to Hydro's shared server infrastructure and upgrades to the server-based office productivity tools.

Based on the age of existing servers, each year an appropriate number of servers will be refreshed. This infrastructure ensures that Hydro has a reliable secure infrastructure environment required to support efficient operations.

The scope of the proposed Server and Operating System Evergreen Program includes the replacement of 45 servers. There are 15 servers within the Energy Management System and 30 within the Hydro System. Some of these servers will be replaced with virtual machines[9].

The budget includes a higher than usual number of servers for replacement as a result of the specific systems which are due for replacement:

- Within Energy Systems, 10 of the 15 servers are all used in identical capacity within the Diesel Plants and were all acquired at the same time, therefore all expire at the same time.

- Within the Hydro System, 26 of the 30 servers are used in identical capacities to host corporate applications used on a daily basis by the entire organization. These systems are configured in an integrated set of hardware (running Citrix XenApp software) which should be maintained with common system, processor and memory configurations to provide consistent performance and system availability levels. These systems were also all acquired at the same time and therefore expire at the same time.

[9] A virtual machine (VM) is a software implementation of a machine (i.e. a computer) that executes programs like a physical machine.

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

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	369.0	0.0	0.0	369.0
Labour	35.0	0.0	0.0	35.0
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	14.6	0.0	0.0	14.6
Contingency	80.8	0.0	0.0	80.8
Sub-Total	**499.4**	**0.0**	**0.0**	**499.4**
Cost Recovery	**(131.8)**	**0.0**	**0.0**	**(131.8)**
TOTAL	**367.6**	**0.0**	**0.0**	**367.6**

JUSTIFICATION

The factors that are driving Hydro's proposal to replace/upgrade its server environment include:

- Addressing obsolescence/maintaining vendor support;
- Providing security/managing the infrastructure; and
- Supporting current versions of applications.

Addressing obsolescence/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 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.

Providing security/managing the infrastructure – As technology advances, there are built-in architectures and devices that improve the security of the servers and allow for better management of them.

Supporting current versions of applications – 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 Hyper-threading Technology.

Existing System

There are 174 physical servers and 66 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, and 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:

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 45 servers proposed for replacement:

Level 0

- None.

Level I

- 26 Citrix hosts provide the core business applications to users and are all aged five years
- One Automated Meter Reading server for billing industrial clients and is aged five years
- One GIS server for Woodpole Management and is aged five years

Level II

- Three TriGeo Security monitoring of the server environments and aged six years
- One Test server required for pre-validating changes and is aged six years

Level III

- Ten Diesel Plant monitoring servers (non control) and are all aged seven years
- Three Energy Management monitoring servers and are aged seven years

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. Hydro 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

IBM recommends 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 support for the 45 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 Gold Card 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 2012.

Table 2: Five-Year Historical Information

Year	Budget ($000)	Actual ($000)	Servers
2012B	171.7		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
2007	81.8	79.1	5

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 five to eight years. The average age is six 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 refresh program to maintain server performance. Future replacements and upgrades will be proposed in future budget applications.

Project Schedule

The project is scheduled to start in March 2013 and be completed by the end of November 2013.

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 initiated 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 2013-2017 is provided in Appendix A. Eighteen radomes are scheduled to be replaced in 2013. 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 2013. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	3.9	0.0	0.0	3.9
Labour	19.9	0.0	0.0	19.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	241.5	0.0	0.0	241.5
Other Direct Costs	1.1	0.0	0.0	1.1
Interest and Escalation	16.3	0.0	0.0	16.3
Contingency	53.3	0.0	0.0	53.3
TOTAL	**336.0**	**0.0**	**0.0**	**336.0**

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 shall be distributed as much as practical. The current schedule for the next five years is included in Appendix A.

The decision to distribute the replacement of radomes presents another obstacle: some radomes will be left in service for periods longer than recommended. In response to 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.

As this project is for the replacement of radomes, there is no relevant information for the following:

- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Losses during Construction.

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.

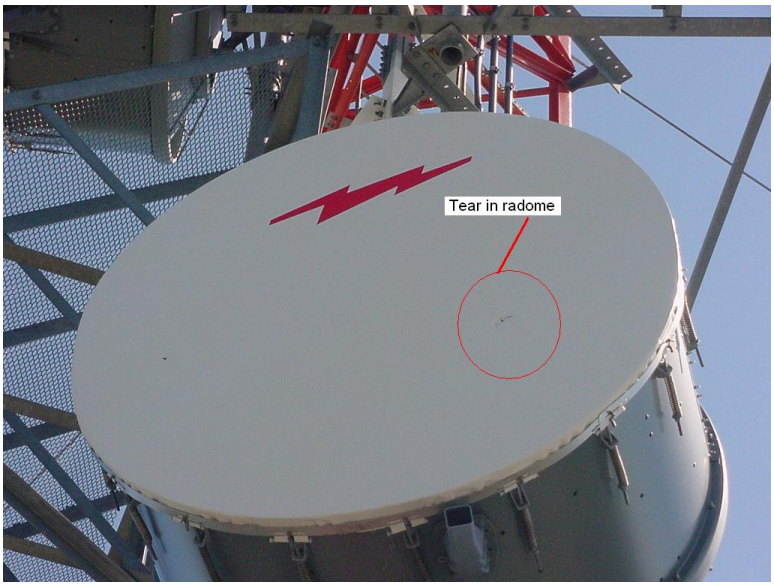


Figure 2: Tear in Radome

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 projectile 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.

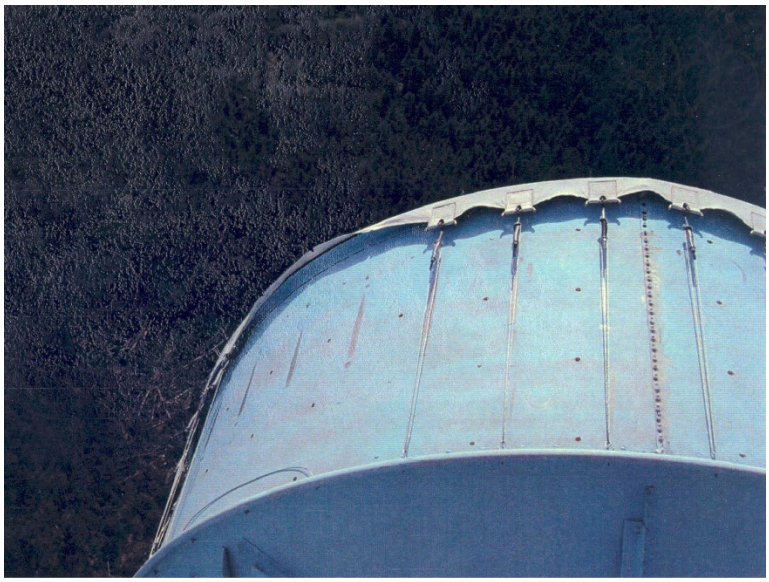


Figure 4: Missing Radome Mounts

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.

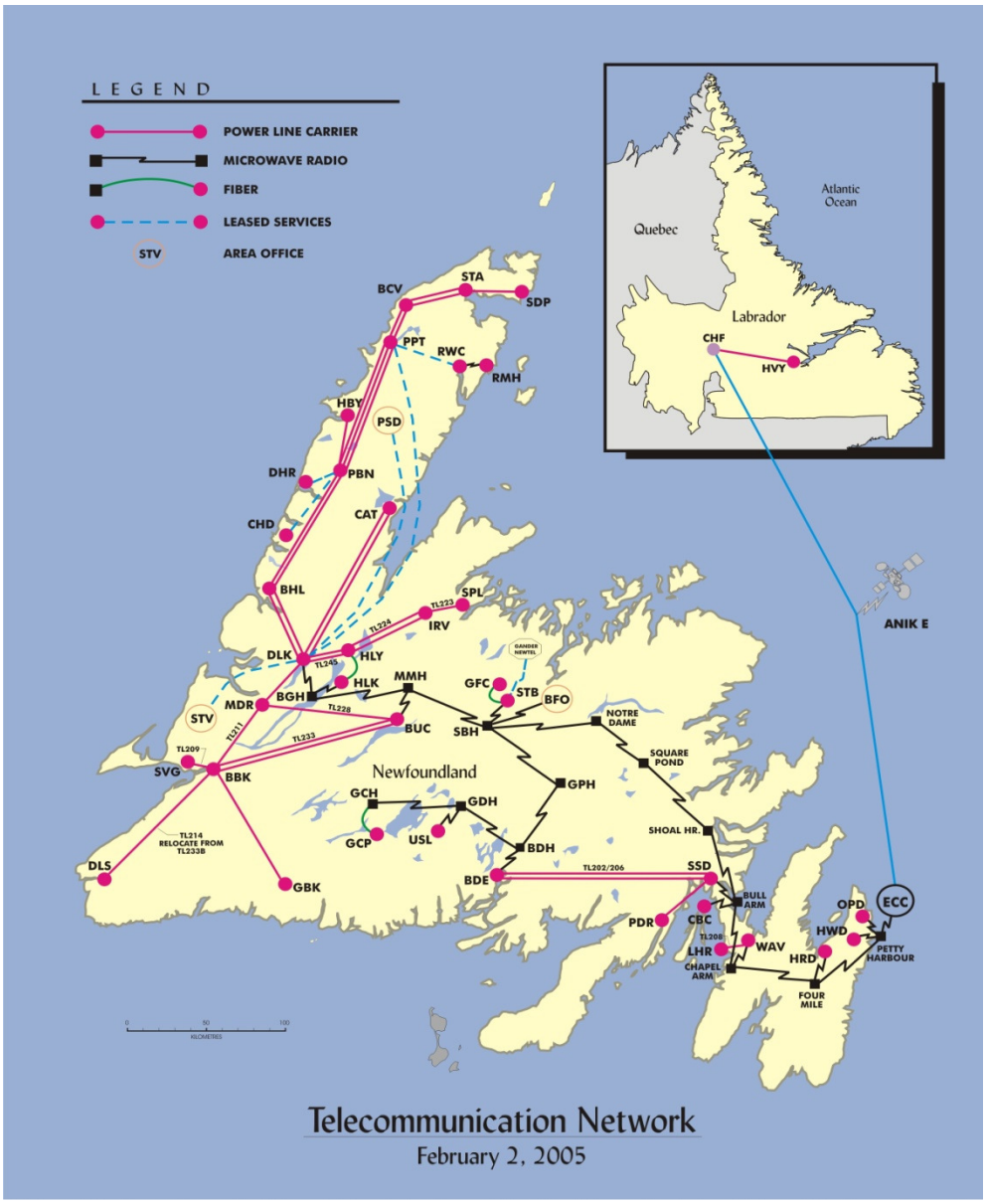


Figure 5: Location of Towers

Age of Equipment

Refer to the Last Replaced column of Appendix A for the ages of the radomes being replaced.

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.

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

Radome maintenance consists of inspection when the tower is inspected. Because radomes cannot be repaired, damaged radomes are replaced when identified.

Historical Information

Table 2 shows the five-year historical information for the Radome Replacement Program which commenced in 2007 as well as the 2012 budgeted amounts.

Table 2: Capital Budget and Expenditures for the Last Five Years

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2012B	172.0		14		
2011	195.9	101.7	11	9.3	
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	12.3	
2007	26.9	9.2	1	9.2	Labour only. No replacement.

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 2013.

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.

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 2013	February 2013
Design	Complete Tender Package	February 2013	March 2013
Procurement	Purchase Radomes	April 2013	April 2013
Installation	Install Radomes	May 2013	September 2013
Commissioning	Site Inspections	October 2013	October 2013
Closeout	Project Closeout	November 2013	December 2013

Future Plans

Future plans will be proposed in future capital budget applications. Radome replacements are planned for four of the next five years as listed in Appendix A of this report and shown in the five-year capital plan (2013 Capital Plan Tab, Appendix A).

APPENDIX A

Radome Replacement Schedule

2013 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
BFI	SBH	2.4m(8')	Andrew	HP8-71GE	June 1/2003
BGH	MMH	2.4m(8')	CW	DA8-71hp	April 1/1996
BGH	DLP	3.6m(12')	CW	DA12-71hp	2005
FMH	PHH (div)	1.8m(6')	Andrew	HP6-71E	Sept 1/2001
MMH	SBH	3.6m(12')	CW	DA12-71hp	April 1/1996
MMH	BGH	2.4m(8')	CW	DA8-71hp	April 1/1996
SBH	NDH (main)	3.6m(12')	Andrew	HP12-71E	June 1/2003
SBH	NDH (div)	3.0m(10')	Andrew	HP10-71D	June 1/2003
SBH	MMH	3.6m(12')	CW	DA12-71hp	Aug 12/2004
SBH	BFI	2.4m(8')	Andrew	HP8-71GE	June 1/2003
SHH	BAH (main)	2.4m(8')	Andrew	HP8-71GE	June 1/2003
SHH	BAH (div)	2.4m(8')	Andrew	HP8-71GE	June 1/2003
SHH	SPH (main)	3.6m(12')	Andrew	HP12-71E	June 1/2003
SHH	SPH (div)	3.6m(12')	Andrew	HP12-71E	June 1/2003
SPH	SHH (main)	3.6m(12')	Andrew	HP12-71E	June 1/2003
SPH	SHH (div)	3.6m(12')	Andrew	HP12-71E	June 1/2003
SPH	NDH (main)	3.6m(12')	Andrew	HP12-71E	June 1/2003
SPH	NDH (div)	3.6m(12')	Andrew	HP12-71E	June 1/2003

2014 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
BDE	BDH	1.8m(6')	CW	DA6-71hp	Feb 1/1997
BDH	GPH	2.4m(8')	Andrew	HP8-71D	April 1/1999
BDH	GPH	1.8m(6')	CW	DA6-71hp	Sept 30/2000
BDH	BDE	1.8m(6')	CW	DA6-71hp	Sept 30/2000
BDH	GDH	3.0m(10')	CW	DA10-71hp	Feb 1/1997
BUC	MMH	1.8m(6')	CW	DA6-71hp	Mar 26/2001

2015 Radome Replacements

None Required

2016 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
GPH	SBH (main)	3.6m(12')	Andrew	HP12-71E	April 1/1999
GPH	SBH (div)	3.6m(12')	CW	DA12-71hp	July/06/2001
GPH	BDH	2.4m(8')	Andrew	HP8-71D	April 1/1999
GPH	BDH	1.8m(6')	CW	DA6-71hp	Sept 30/2000
SBH	GPH	3.6m(12')	CW	DA12-71hp	Nov 12/2000
SBH	GPH	3.6m(12')	Andrew	HP12-71E	April 1/1999
SBH	MMH	3.0m(10')	Andrew	HP10-71D	April 1/1999
SBH	STB	1.8m(6')	CW	DA6-71hp	Oct 5/2000

2017 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
BAH	CAH	2.4m(8')	Andrew	HP8-71D	Sept 1/2001
BAH	CBC	1.8m(6')	Andrew	HP6-71E	Sept 1/2001
BAH	SSD	1.8m(6')	Andrew	HP6-71E	Sept 1/2001

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: 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 2013, this project will consist of the replacement of 16 Multi-Function Devices (MFDs) used for printing, copying, faxing and scanning, as well as 29 Laser Printers and smaller multi-purpose units. Ten MFDs are to be replaced at St. John's, one at Bishops Falls, one at Deer Lake, one at Happy Valley, two at Port Saunders, and one at Wabush. The location of the laser printers to be replaced are as follows: eight in Hydro Place, one in Deer Lake, three in Holyrood, one in Bay d'Espoir, five in Happy Valley-Goose Bay, one in St. Anthony, one in Whitbourne, six in Port Saunders, one in Bishop's Falls, one in Stephenville, and one at Wabush. In addition, this budget includes funds for replacement of eight projectors and one video conferencing unit. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	227.8	0.0	0.0	227.8
Labour	21.8	0.0	0.0	21.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	10.4	0.0	0.0	10.4
Contingency	49.9	0.0	0.0	49.9
TOTAL	**309.9**	**0.0**	**0.0**	**309.9**

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 2013 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 only 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 user needs. Continued review of the products lifecycle 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 and/or Upgrades.

Age of Equipment or System

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 product roadmap (new features like secure print and scanning will not be supported on older equipment);
- User 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 peripheral 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 only 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 the 2012 budget for the Peripheral Infrastructure Replacement Project.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per Unit[10] ($000)
2012B	327.5		45	
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
2007	139.0	139.0	10	13.9

Anticipated Useful Life

According to Gartner[11], the useful life for a color printer is three years while a black/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 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 2013 and be completed before December 31, 2013.

[10] The variability in unit costs are due to specifications of the printers being replaced such as pages per minute, memory, fax and scanning capability.

[11] 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: 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. As in the past three years, the value of this work is estimated to be approximately $250,000. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	80.0	0.0	0.0	80.0
Labour	98.0	0.0	0.0	98.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	34.0	0.0	0.0	34.0
Other Direct Costs	20.0	0.0	0.0	20.0
Interest and Escalation	18.5	0.0	0.0	18.5
Contingency	0.0	0.0	0.0	0.0
TOTAL	**250.5**	**0.0**	**0.0**	**250.5**

JUSTIFICATION

This project is required to provide a safe work environment for Hydro employees, contractors, visitors and the general public in compliance with the Occupational Health and Safety Regulations, 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 program 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 program, need to be immediately corrected to provide a safe work environment. Criteria for the selection of acceptable projects include SWOP identification.

Existing System

As part of Hydro's 2011 Capital Budget an amount of $252,400 was approved by Board Order P.U. 38 (2011) to address safety hazards in the workplace. Several potential safety hazards were identified through our SWOP program. Table 2 lists the projects completed in 2011 having a total expenditure of $239,924.

Table 2: Projects Completed

Location	Project	Costs
Various Sites	Highway signs to meet Occupational Health and Safety Traffic Control while working on highway	$144,317
Bay d'Espoir	Refurbish to bridge that crosses Burnt Canal	$20,468
Bay d'Espoir	Upgrade to Venam's Bight penstock access trail	$28,264
Bay d'Espoir	Replace public access stairway to Bay d'Espoir office/ powerhouse	$36,885
Holyrood	Install portable foam and dry chemical units for fire suppression	$9,990
	Total	$239,924

As this is an on-going program, safety hazards will be identified as they arise in 2013 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 identified through Hydro's SWOP Program 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 Regulated Operations 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.

<u>Legislative or Regulatory Requirements</u>

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 chronic 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 actual and budgeted expenditures for years 2010-2012.

Table 3: Capital Expenditure History

Year	Capital Budget ($000)	Actual Expenditures ($000)
2012B	249.1	
2011	252.1	239.9
2010	252.4	207.8

CONCLUSION

Unsafe conditions identified by employees, contractors and the public are recorded through the SWOP Program 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 Plan

Future safety hazards removal projects will be proposed in future capital budget applications. See five-year capital plan (Capital Plan 2013 Tab, Appendix A).

PROJECT DESCRIPTION	Expended to 2012	2013	Future Years ($000)	Total	Page Ref
GENERATION					
Install Automated Fuel Monitoring System - Upper Salmon		192.7		192.7	E - 2
Overhaul Unit 3 Boiler Feed Pump West - Holyrood		178.5		178.5	E - 11
Replace Cooling Water Pumps - Bay d'Espoir		175.4		175.4	E - 19
Replace Fall Arrest System on Surge Tank 2 - Bay d'Espoir		153.0		153.0	E - 22
Replace By-Pass Valves Units 3 and 4 - Bay d'Espoir		141.9		141.9	E - 26
Replace Condensate Polisher Annunciator Panels - Holyrood		123.5		123.5	E - 31
Overhaul Unit 2 Extraction Pump South - Holyrood		101.5		101.5	E - 34
Purchase Low Pressure Screw Compressor Set - Bay d'Espoir		97.3		97.3	E - 41
TOTAL GENERATION	0.0	1,163.8	0.0	1,163.8	
TRANSMISSION AND RURAL OPERATIONS					
Purchase Meters, Equipment and Metering Tanks - Various Sites		199.5		199.5	E - 45
Install Fall Protection Equipment - Various Sites		196.6		196.6	E - 64
Purchase 10 Position Meter Calibration Test Console - Hydro Place		192.5		192.5	E - 73
Replace Optimho Relays on TL242 - Holyrood to Hardwoods		189.2		189.2	E - 102
Legal Survey of Primary Distribution Line Right of Way - Various Sites		156.2	40.0	196.2	E - 113
Replace Surge Arrestors - Various Sites		121.3		121.3	E - 118
Install Transformer Fans - Conne River		114.9		114.9	E - 126
Replace 230 kV Breaker Controls - Bottom Brook		68.9		68.9	E - 129
TOTAL TRANSMISSION AND RURAL OPERATIONS	0.0	1,239.1	40.0	1,279.1	
GENERAL PROPERTIES					
Replace Network Communications Equipment - Various Sites		182.4		182.4	E - 133
Replace Telephone System - St. Anthony		135.4		135.4	E - 135
Upgrade Energy Management System - Hydro Place		129.9		129.9	E - 138
Upgrade Enterprise Storage Capacity - Hydro Place		124.7		124.7	E - 140
Replace Computer Room Air Conditioner - Hydro Place		83.2		83.2	E - 143
Perform Minor Application Enhancements - Hydro Place		81.1		81.1	E - 149
Replace Helpdesk Service Manager Application - Hydro Place		61.8		61.8	E - 151
TOTAL GENERAL PROPERTIES	0.0	798.5	0.0	798.5	
TOTAL PROJECTS OVER $50,000 AND UNDER $200,000	0.0	3,201.4	40.0	3,241.4	

Project Title: Install Automated Fuel Monitoring System

Location: Upper Salmon

Category: Generation - Hydraulic

Definition: Other

Classification: Justifiable

Project Description:

North 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 of 19 km 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 8,000 liter bulk tank and one 900 liter day tank.

This project is required to install an automated fuel monitoring system at the North 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 and the Ebbegunbaeg Control Structure in 2010 at a cost of $159,689. The cost of the proposed installation at North Salmon Dam and Spillway is approximately 20 percent higher due to increased travel since there are no accommodations at the site. These 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)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	26.0	0.0	0.0	26.0
Labour	116.0	0.0	0.0	116.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	9.0	0.0	0.0	9.0
Interest and Escalation	11.5	0.0	0.0	11.5
Contingency	30.2	0.0	0.0	30.2
TOTAL	**192.7**	**0.0**	**0.0**	**192.7**

Operating Experience:

The diesel fuel tanks are dipped monthly and physically inspected for leaks. Dipping is the process used in which 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 three 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. The current staffing model supports traditional monthly inspections. 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. This is a technology solution to address Hydro's 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 significant 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. 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, 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 auditor with QMI-SAI Global has documented these reoccurring issues and has advised that corrective actions are required as part of the Environmental Management System. Should corrective actions not be undertaken, it is within the rights of the auditor to revoke the ISO 14001 registration for Hydro Generation.

In addition, under GAP section 18, Hydro is required to report apparent losses, following the reconciliation, on a weekly basis; which is not presently attainable. Also, after a 26 week period, from January through July and then from July through January, Hydro is required to report semi-annual losses but these two sets of data from North Salmon Spillway are not available for this report.

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 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.

The following typical photos taken during the project work at Ebbegunbaeg show the before and after installation of fuel monitoring devices mounted on the main tank and the automation system components in a cabinet inside the diesel building.

Photo 1 - Main Fuel Tank before Monitoring Devices

Photo 2 - Main Fuel Tank with New Monitoring Devices

Photo 3 - Automated Fuel Monitoring System Cabinet (door closed)

Photo 4 - 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 as per Government Regulations for checking fuel. 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 Operations 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 $20 per day for round trip travel to North 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 damage.

Utilizing a 25 year study period for these two alternatives, the cumulative net present value for each alternative is as follows:

Alternative 1: $187,250

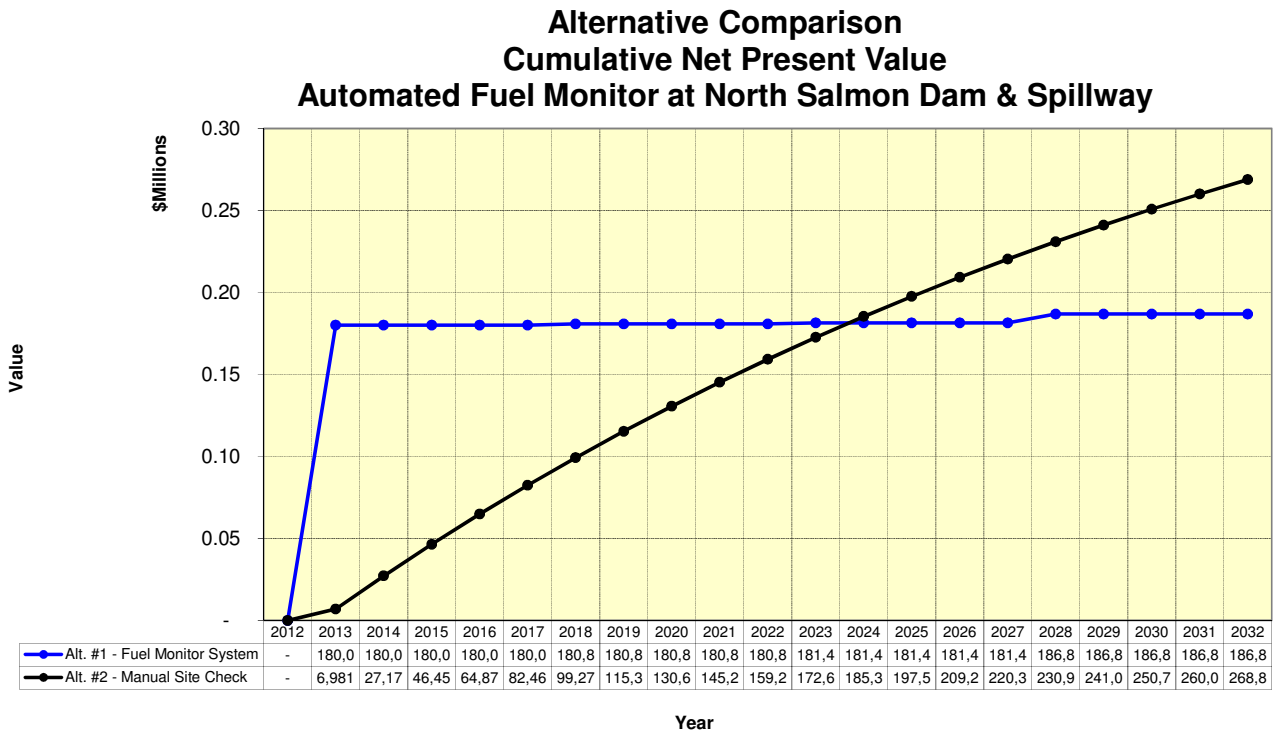
Alternative 2: $307,461

A savings of $120,211 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 Fuel Monitor at NSS		
Alternative Comparison *Cumulative Net Present Value* *To The Year* **2037**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Alt. 1 - Fuel Monitor System	187,250	0
Alt. 2 - Manual Site Check	307,461	120,211

Graph 1: Alternative Comparison



Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Prepare Project Design Transmittal Site visit to evaluate work	February 2013	March 2013
Design	Prepare Protection and Control Drawings Program PLC	March 2013	May 2013
Procurement	Order materials Order construction trailer rental	March 2013	March 2013
Construction	Install conduit and cables Install tank monitoring apparatus Install PLC Cabinet	June 2013	June 2013
Commissioning	Commission new monitoring system	June 2013	June 2013
Closeout	Drafting and Review of As-Built drawings Prepare Project Closeout documentation	July 2013	August 2013

Future Plans:

Installation of automated fuel monitoring systems will be proposed in future capital budget applications. See five year plan (2013 Capital Plan Tab, Appendix A)

Project Title: Overhaul Unit 3 Boiler Feed Pump West

Location: Holyrood

Category: Thermal Generation

Definition: Other

Classification: Normal

Project Description:

This project will involve a refurbishing of 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% capacity of the boiler. The boiler feed water pump draws water from the deaerator feed water tank located at the eighth floor. The pump has eleven stages of impellers and is driven by a 3,000 horse power motor. It 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;
- Examination of Components; and
- Re-Assembling the Pump

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	100.0	0.0	0.0	100.0
Labour	20.2	0.0	0.0	20.2
Consultant	20.0	0.0	0.0	20.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	10.3	0.0	0.0	10.3
Contingency	28.0	0.0	0.0	28.0
TOTAL	**178.5**	**0.0**	**0.0**	**178.5**

Operating Experience:

One boiler water feed pump is in service until 70 MW. A second boiler water feed pump is necessary if the load has to be increased above 70 MW.

Project Justification:

Two pumps are required to carry 100% boiler load. Loss of one pump restricts the load to 70 MW. The Unit 3 boiler feed water pump west was last overhauled in the year 2000. There had been two major expenses in pump repair in 2005 and 2006 amounting to $90,416 for a cartridge replacement and $52,806 for a casing leak respectively. It will be 13 years in 2013 since the pump was overhauled and in view of the two major repairs which had to be carried out in 2005 and 2006, there is a likelihood of other major repairs in the coming years. In order to provide a reliable pump it is necessary to have the pump overhauled in 2013.

Hydro has received recommendations from Flowserve regarding the optimal timelines for refurbishing the Unit 3 boiler feed pumps west. The recommendations state that the pump should receive an overhaul every 45,000 operating hours or ten years, whichever occurs first. The repairs in 2006 were not full overhauls and so the unit is now in excess of the ten year recommendation by Flowserve. The potential for major corrective repairs in the future if this overhaul is not completed is significant based on the recommendations of Flowserve.

Future Plans:

Other boiler feed pump overhauls will be proposed in future capital budget applications.

Photo 1: Unit-3 Boiler Feedwater Pump

Photo 2: Unit-3 Boiler Feedwater Pump Name Plate

Photo 3: Unit-3 Boiler Feedwater Pump West Motor Name Plate

APPENDIX A

Flowserve Review (May 24, 2011)

FLOWSERVE

Service/Repair 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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APPENDIX B

Flowserve Letter (June 26, 2012)

FLOWSERVE

ServiceRepair Division

June 26, 2012

Newfoundland Labrador Hydro
Holyrood G.S.

Attention: Mr. Brent Peddle

Dear Brent

By way of background information and Introduction I became Holyrood service engineer in 1994 following an agreement between Hydro and BWIP to service Units 1 and 2 Byron Jackson B.F. pumps. When the maintenance agreement with BWIP was signed in 1997 (which ran for two 5 years consecutive contracts) I continued as the service engineer. BWIP (formerly Byron Jackson) name changed to Flowserve in 1998. I have been employed by Holyrood as their service engineer to date. Under BWIP & Flowserve all 4000 volt pumps have been modified and upgraded for maximum life and performance.

Unit 3 Bingham B.F. Pump West
Starting in 1997 we have upgraded the pump with design changes to more reliable pump with an estimated 7 years of running time between maintenance. The risk factor in running more than 7 years of running time is barrel wash at the high pressure gasket of volute to barrel. This can result into costly field welding and machining to repair. For this reason I had Holyrood on a 7 year staggered change out cycle for all the units B.F. pumps. This cycle ended in 2008 with new station personnel. Unit 3 West B.F. Pump requires inspection and overhaul in 2013.

Unit 2 Extraction Pump South
In 1997 we spent days in Holyrood reviewing maintenance history on all the 4000 volt pumps and made recommendations. The units 1 and 2 extraction pumps had badly deteriorated at the stuffing box and the pump thrust bearing housing. Our recommendation was for new high thrust motors, eliminate the pump thrust bearing and convert to mechanical seal from packing. In the repair, the 1st stage impeller was badly cavitated in both eye inlets. To save the impeller as there were no spares we cut the eye vanes back 1.38" to remove most of the damage. The estimated average life is 10 years. Unit 2 Extraction Pump South is due for inspection and overhaul because it has been 12 years since it's last overhaul.

With regards to the Excel File containing Holyrood's repair schedule I do agree with the repair schedule set by Newfoundland Labrador Hydro.

Regards

Arnold Padgett P.Eng.

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Project Title: Replace Cooling Water Pumps

Location: Bay D'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is to replace cooling water pumps 2 and 4 in Powerhouse 1 at the Bay D'Espoir Hydroelectric Generation Station (Bay d'Espoir). The project will also include the replacement of associated piping, fittings, valves, strainers and electrical equipment as required. The removal of the old equipment and the installation of the new will be performed by Hydro internal labour.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	78.3	0.0	0.0	78.3
Labour	55.5	0.0	0.0	55.5
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	11.2	0.0	0.0	11.2
Contingency	27.4	0.0	0.0	27.4
TOTAL	**175.4**	**0.0**	**0.0**	**175.4**

Operating Experience:

The cooling water pumping configuration in Bay d'Espoir consists of a complete pump and strainer system for each unit. These systems are interconnected by a 10 inch diameter header, which supplies cooling water to each generating unit. The water is used to cool the generator by supplying water to the surface air coolers and to cool the generator bearing by providing water to the heat exchangers in bearing oil reservoir. There is also a small take off at the 10 inch diameter header to provide water for cooling the turbine bearing and to provide water to the shaft seal system in the turbine pit.

The cooling water system is designed to be operated with all units interconnected. Under normal tail water conditions, each pump will deliver about 20 percent more than the maximum

requirements of the unit. This configuration would allow at least one pump and strainer system to be on stand-by. The unit on stand-by is rotated to even out the running time on the pumps or for availability to perform maintenance.

Cooling water pumps 2 and 4 are original plant equipment installed in 1967. Four of the six cooling water pumps at Bay d'Espoir have been replaced in recent years due to age and condition. The reliability of pumps 2 and 4 is a concern given their age, high maintenance costs (Table 2), and increasing difficulty in sourcing replacement parts. As seen in Figure 1, cooling water pump 4 is leaking and the overall condition of the pump is poor as this pump has gone past its service life by about five years.

There have been numerous maintenance problems with these pumps and there are 14 and 40 corrective work orders recorded in the JD Edwards maintenance program on pumps 2 and 4 respectively. These work orders date back to 1994 and mainly include maintenance on the packing glands of the pump, pressure loss problems, and bearing noise reported. The most reoccurring issue is the packing glands in the pumps. The glands have been replaced so many times that the repair had no definite lasting time which is an indication that the pump is at the end of its service life.

Table 2: Cost of Corrective Maintenance on Cooling Water Pump[1]

Year	Pump 2 ($000)	Pump 4 ($000)
2011	0.1	0.7
2010	0.0	0.1
2009	6.1	0.4
2008	10.0	0.7
2007	1.6	5.1

Project Justification:

Cooling water pumps 2 and 4 are at the end of their serviceable life, which is 40 years. They were installed 45 years ago and parts are not readily available, maintenance costs are increasing, and reliability is down. This replacement will lower the risk of losing cooling capacity to key areas of a hydroelectric unit. Therefore, to ensure continued reliability of the cooling water system these pumps need to be replaced as the other four original cooling water pumps have been replaced in recent years.

[1] *Preventative maintenance (PM) cost is not provided as it is combined with overall cooling water system PM costs and is not broken out by pump.*

Figure 1: Cooling Water Pump No. 4

Future Plans:

None.

Project Schedule

The anticipated schedule for the cooling water replacement project is provided in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Review scope and budget Confirm schedule	April 2013	April 2013
Design	Submit transmittal	May 2013	May 2013
Procurement	Tender materials Confirm schedules Award tenders	Aug 2013	Aug 2013
Construction	Site safety tour Safety meetings Risk/change management	Sept 2013	Sept 2013
Commissioning	Safety meeting	Sept 2013	Sept 2013
Closeout	Financial close out Post implementation review	Nov 2013	Nov 2013

Project Title: Replace Fall Arrest System on Surge Tank 2

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project involves the removal of the existing ladder safety slide rigid rail system from surge tank 2 and the installation of a new Canada Standards Association (CSA) compliant rigid rail (Glideloc) system. CSA issued a safety alert which named the current rigid rail system among the fall arrest systems no longer considered compliant with CSA standards. In response, the manufacturer of the currently installed fall arrest system issued a bulletin instructing users to use a Y-Lanyard method of securing a climber to a structure. This method is not optimal for user efficiency and this project will replace the current non-compliant system with a CSA approved Glideloc system. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	44.1	0.0	0.0	44.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	70.0	0.0	0.0	70.0
Other Direct Costs	5.4	0.0	0.0	5.4
Interest and Escalation	9.5	0.0	0.0	9.5
Contingency	23.9	0.0	0.0	23.9
TOTAL	**153.0**	**0.0**	**0.0**	**153.0**

Operating Experience:

The surge tank was constructed in the mid 1960's and currently has the same rigid rail fall protection equipment installed on the tank ladder which is original to the tank installation. 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.

Currently workers preparing to climb the ladder on the surge tank are required to use a Y lanyard system for fall protection. See Figure 1 below.

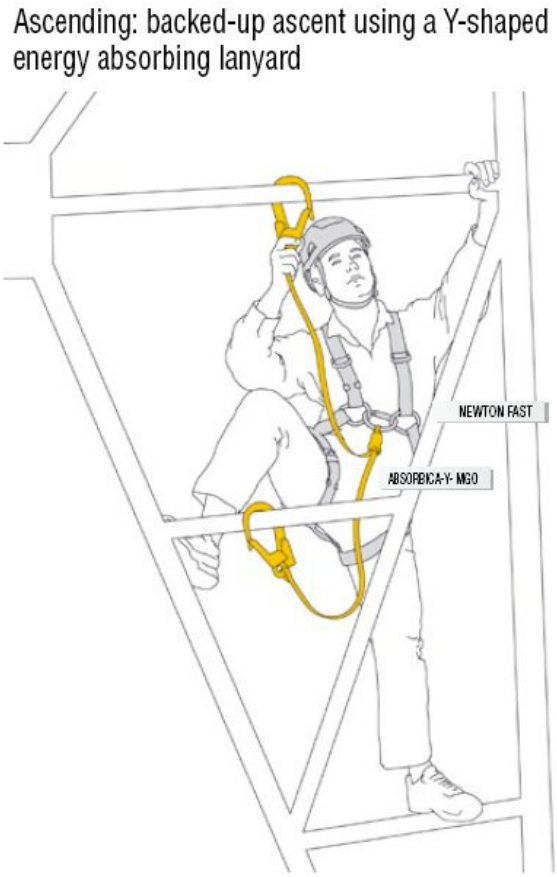

Figure 1: Worker using Y lanyard System

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 second 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.

Project Justification:

The CSA issued a product safety alert (see Appendix A) relating to Class FRL (Frontal-fixed Rail Ladder) fall protection system. 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, Appendix B, 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. As a result of this safety alert, the use of the existing North Safety Products Ltd. rigid rail system as fall protection while climbing the surge tank has been prohibited by Hydro and a new CSA compliant Glideloc rigid rail system is proposed.

The current method for climbing the surge tank is the Y lanyard method as outlined in Operating Experience section above and is intended only as a temporary measure. Once the climber has climbed the 368 foot ladder using the Y lanyard method, he has been physically taxed which makes completing the necessary work a challenge. With condition assessments indicating that the tank requires increased maintenance, more frequent climbing of the tank will be required and Hydro is interested in facilitating an improvement to 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. As such Hydro plans to replace the existing rigid rail system with a certified rigid rail system. A system such as SOLL Glideloc is currently certified by CSA as a safe Class FRL fall protection system.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Planning	February 2013	March 2013
Design	Specification development Tender	March 2013 April 2013	April 2013 May 2013
Construction	Contract completion	June 2013	July 2013
Commissioning	Commissioning	August 2013	August 2013
Closeout	Closeout	September 2013	September 2013

Future Plans:

None.

Project Title: Replace By-Pass Valves Units 3 and 4

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project will replace the spherical valve by-pass assemblies on Units 3 and 4 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 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 has to be flooded and pressurized to be near the pressure of the penstock 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 internal labour. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	35.0	0.0	0.0	35.0
Labour	70.6	0.0	0.0	70.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	3.8	0.0	0.0	3.8
Interest and Escalation	10.6	0.0	0.0	10.6
Contingency	21.9	0.0	0.0	21.9
TOTAL	**141.9**	**0.0**	**0.0**	**141.9**

Operating Experience:

The spherical valve by-pass valves and associated components are original plant equipment, 45 years old, installed in 1967 (Figure 1). This assembly provides pressurized water to allow for safe operation of the spherical valve by priming the scroll case before the spherical valve is opened, minimizing the pressure shock the scroll case would experience when the spherical valve is activated. The operation of the spherical valve is fully automatic and remotely activated from the

control room with a set of logic permissive controls in place. The logic permissive control system is where several conditions have to be met before the unit is allowed to start up. The priming of the scroll case is a critical step in the operation of the unit and is the first permissive that must be met for safe operation of the spherical valve. The set value of scroll case pressure is 100 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 (Figure 2). If the operation of the by-pass assembly does not meet the designed activation pressure, maintenance or operations technicians have to manually manipulate the valves in order to open or close them as internal components have become jammed or seized. If the technicians are unable to open the valves, this could lead to a forced unit outage until the issue is resolved, or if the time of the year was critical, such as in the winter time, then it would be possible to circumvent the pressure permissive and operate the spherical valve, with the understanding that the spherical valve is in higher risk of damage.

The by-pass assembly on Unit 4 is in worse shape compared to Unit 3, this is because Unit 3 is a station service unit and is not cycled off and on like Unit 4. The motorized valve on Unit 4 is in poor condition and there is usually water in it indicating that the internal components of the valve are damaged. Along with the valves, the piping in these assemblies is in degraded shape. Over the years the passing of high pressure water around the spherical value has caused wear on the piping lines and this wear is considered a frictional line loss which is contributing in the inability to meet the permissive pressure. The work associated with this upgrade would require the penstock to be dewatered, and since Unit 4 is in the worse condition, this will be the first unit done along with Unit 3 as both units share the same penstock. It is also in Hydro's best interest to complete the work all at once as the penstock is not always dewatered when a unit is taken down as this would require 2 unit outages.

Upon a review of corrective work orders in the past five years, there have been 30 corrective work orders on Unit 4 spherical valve while 15 on Unit 3 spherical valve. The majority of the corrective works for both spherical valves are issues with scroll case pressure or problems with the remote actuated valves in the by-pass assembly. The associated yearly maintenance costs are in Table 2. In addition to the corrective maintenance, there is regular preventative maintenance performed on the spherical valve by-pass valves, which is the same for all assemblies with the exception of Unit 4

which has had the regular greasing intervals being increased from monthly to twice a month.

Table 2: Yearly Spherical Valve Maintenance Costs

Year	Unit 3 Spherical Valve ($000)	Unit 4 Spherical Valve ($000)
2011	1.5	2.0
2010	5.9	5.9
2009	0.3	1.3
2008	0.3	0.3
2007	1.4	0.9

Project Justification:

Increased maintenance has been required on the spherical valve by-pass assemblies as they have aged. Currently, the spherical valve by-pass assemblies have been operating in an abnormal condition that is not in compliance with the basis of design for this system. In the current state, maintenance technicians are required to manually manipulate malfunctioning valves that were designed for remote activation. The by-pass assemblies are constantly being greased and man-handled in order for the spherical valve to operate. This method of maintenance will last only for so long until the by-pass assemblies fail and potentially inhibit the function of the spherical valve. There have been regular problems with the by-pass assemblies and in order to maintain a high level of reliability, and ensure proper operation of the generating units, they need to be replaced on Units 3 and 4.

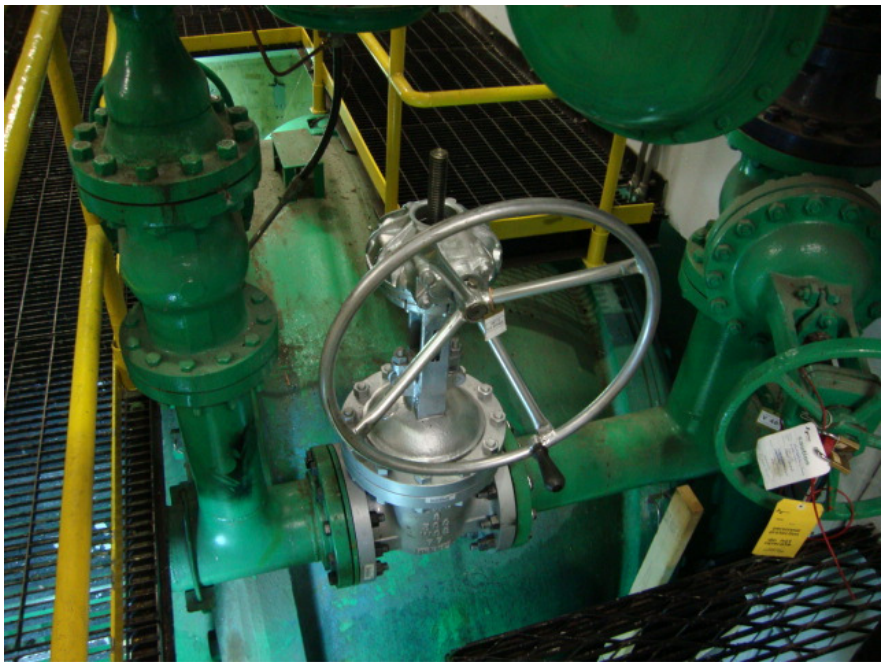

Figure 1: Spherical Valve By-Pass Assembly

Figure 2: By-Pass Valve with Disk Jammed in Half Open Position

Future Plans:

Future projects for spherical valve by-pass replacement will be proposed in future capital budget applications. See the five year capital plan (note: this would be a three year plan from 2013 – 2015).

Project Schedule

The following is the anticipated project schedule.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Review Scope Confirm Schedule Review Budget	March 2013	March 2013
Design	Submit design transmittal Risk workshop	March 2013	March 2013
Procurement	Confirm Schedule Tender materials / review tenders Award tender for supply	April 2013	April 2013
Construction	Safety meetings Schedule meetings Risk / Change management Site safety tour	July 2013	July 2013
Commissioning	Safety meeting Training	July 2013	July 2013
Closeout	Financial close out Post implementation review	October 2013	October 2013

Project Title: Replace Condensate Polisher Annunciator Panels

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the annunciator for the condensate polisher system on each of Units 1 and 2 at the Holyrood Thermal Generating Station. The annunciators will have the same capabilities and functionality as the existing annunciators. They will be installed at the present locations and will reuse the existing instrumentation wiring. A general alarm to the Plant Distributed Control System (DCS) will be provided for each annunciator. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	10.7	0.0	0.0	10.7
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	1.0	0.0	0.0	1.0
Interest and Escalation	7.7	0.0	0.0	7.7
Contingency	19.3	0.0	0.0	19.3
TOTAL	**123.5**	**0.0**	**0.0**	**123.5**

Operating Experience:

The condensate polisher system annunciator panel in each of Units 1 and 2 has worked well. There is no maintenance or failure data on record.

During the closed loop process of steam generation at Holyrood, supply water is fed through a boiler to create high pressure steam, which is used to drive a turbine that is directly coupled to an electrical generator. As the steam drives the turbine blades, it cools and condensate forms. This condensate is collected and then re-used as boiler feed water. Prior to re-use, the condensate must be purified or "polished" to remove impurities which have the potential to cause damage to equipment and piping. The condensate polishers serve this critical function of removing impurities.

Their annunciator panels provide status indication to the plant laboratory technicians, and provide alarm functionality if problem arises with this system.

Figure 1: Unit 2 Condensate Polisher Annunciator (Front)

Figure 2: Unit 2 Condensate Polisher Annunciator (Rear)

Project Justification:

The existing annunciators were installed in 1980 (32 years old), and are now obsolete. They have worked well in the past, but should a failure occur the condensate polisher system will have to be shut down.

The condensate polishers treat the supply water with both acidic and basic (caustic) chemicals to remove minerals and impurities. Due to the potentially harmful nature of the chemical treatments involved, it is critical that the annunciator panels for both Unit 1 and Unit 2 condensate polishers be reliable. Specific alarm indication for the condensate polishers is only available at these annunciators, with a general system alarm to the DCS.

While operational, the condensate polishers are locally controlled by a plant laboratory technician. Failure of an annunciator panel will prevent safe operation of the condensate polisher and render the system inoperable. If the system is bypassed completely, contaminated condensate will re-circulate throughout the system. All of the condensate should be treated to protect the boilers from corrosion, and prevent boiler tube failures. Spare parts for this system are not available.

Future Plans:

None.

Project Title: Overhaul Unit 2 Extraction Pump South

Location: Holyrood

Category: Thermal Generation

Definition: Other

Classification: Normal

Project Description:

Unit 2 condensate extraction pump south will undergo a complete pump overhaul consisting of:

- Removing the Pump;
- Dismantling the Pump;
- Examination of Components; and
- Re-Assembling the Pump .

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	40.0	0.0	0.0	40.0
Labour	20.0	0.0	0.0	20.0
Consultant	20.0	0.0	0.0	20.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	5.5	0.0	0.0	5.5
Contingency	16.0	0.0	0.0	16.0
TOTAL	**101.5**	**0.0**	**0.0**	**101.5**

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 incapable of being in service due to pump outage or maintenance.

Project Justification:

The condensate extraction pump is an important piece of equipment whose outage can cause a unit

to shut down. A sudden failure of the pump during unit operation can cause a sudden interruption of power production and consequent unit hot start up or back up gas turbine start up. In case of a pump failure, the loss of power production can be a maximum of 175 MW. A few gas turbines in other locations would have to be started up to compensate for this loss of production. There is also a possibility of destabilization of the island power system when a large amount of power supply is lost. It would be time consuming to re-stabilize the power system. Given the range of possible consequences, it is essential that the extraction pumps are maintained in good condition. This pump was last overhauled in 2001. In 2013 the pump would have been in service for 12 years and an asset review of preventative maintenance by pump experts 'Flowserve' recommend the overhaul of this pump in 2013. Please see Appendix B for Flowserve's letter detailing these recommendations.

Future Plans:

Other pump overhaul projects will be proposed in future capital budget applications.

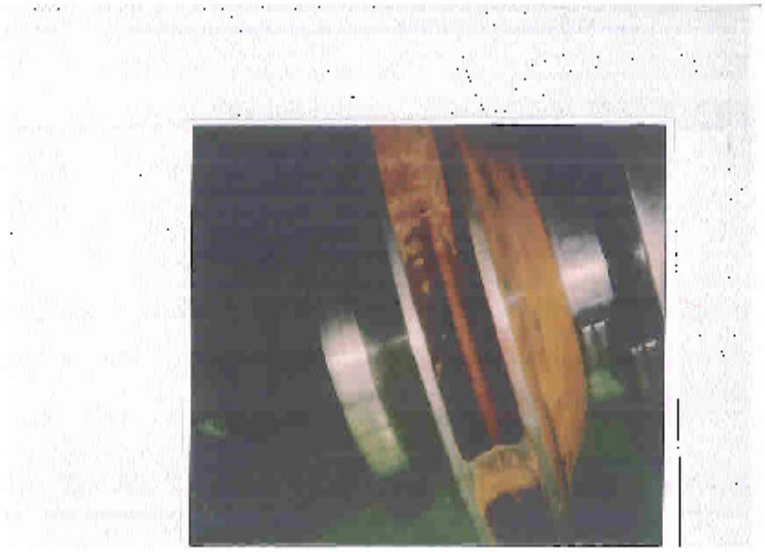

Photo 1: Pump Impeller

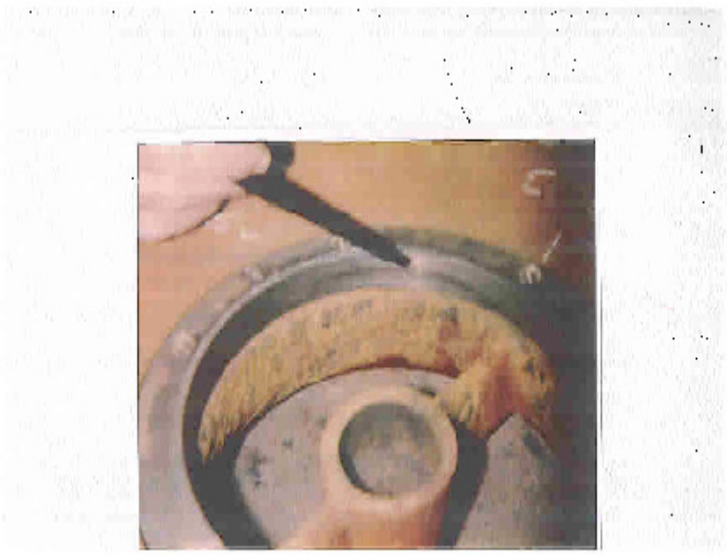

Photo 2: Impeller in the Casing

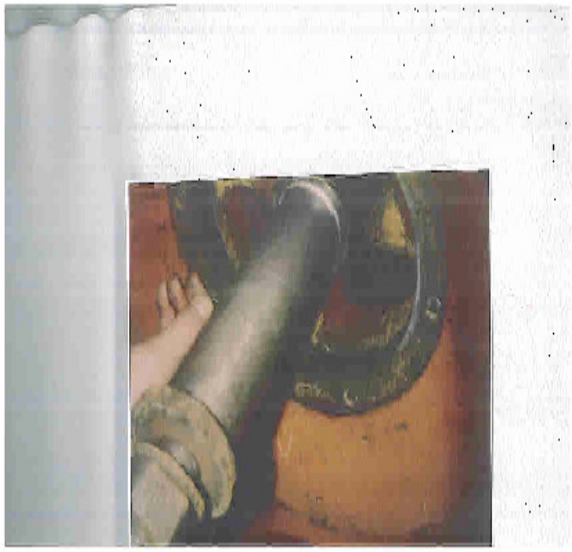

Photo 3: Pump Impeller with Pump Shaft

APPENDIX A

Flowserve Review (May 24, 2011)

FLOWSERVE

Service/Repair 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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APPENDIX B

Flowserve Letter (June 26, 2012)

FLOWSERVE

ServiceRepair Division

June 26, 2012

Newfoundland Labrador Hydro
Holyrood G.S.

Attention: Mr. Brent Peddle

Dear Brent

By way of background information and Introduction I became Holyrood service engineer in 1994 following an agreement between Hydro and BWIP to service Units 1 and 2 Byron Jackson B.F. pumps. When the maintenance agreement with BWIP was signed in 1997 (which ran for two 5 years consecutive contracts) I continued as the service engineer. BWIP (formerly Byron Jackson) name changed to Flowserve in 1998. I have been employed by Holyrood as their service engineer to date. Under BWIP & Flowserve all 4000 volt pumps have been modified and upgraded for maximum life and performance.

Unit 3 Bingham B.F. Pump West
Starting in 1997 we have upgraded the pump with design changes to more reliable pump with an estimated 7 years of running time between maintenance. The risk factor in running more than 7 years of running time is barrel wash at the high pressure gasket of volute to barrel. This can result into costly field welding and machining to repair. For this reason I had Holyrood on a 7 year staggered change out cycle for all the units B.F. pumps. This cycle ended in 2008 with new station personnel. Unit 3 West B.F. Pump requires inspection and overhaul in 2013.

Unit 2 Extraction Pump South
In 1997 we spent days in Holyrood reviewing maintenance history on all the 4000 volt pumps and made recommendations. The units 1 and 2 extraction pumps had badly deteriorated at the stuffing box and the pump thrust bearing housing. Our recommendation was for new high thrust motors, eliminate the pump thrust bearing and convert to mechanical seal from packing. In the repair, the 1st stage impeller was badly cavitated in both eye inlets. To save the impeller as there were no spares we cut the eye vanes back 1.38" to remove most of the damage. The estimated average life is 10 years. Unit 2 Extraction Pump South is due for inspection and overhaul because it has been 12 years since it's last overhaul.

With regards to the Excel File containing Holyrood's repair schedule I do agree with the repair schedule set by Newfoundland Labrador Hydro.

Regards

Arnold Padgett P.Eng.

Page 1 of 1

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Project Title: Purchase Low Pressure Screw Compressor Set

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Justifiable

Project Description:

This project is to add a low pressure air compressor to the existing compressed air system located in Powerhouse 1 of Bay d'Espoir Hydroelectric Generation Station (Bay d'Espoir). The project includes provision of a new compressor, air receiver tank, operating controls, concrete pad, electrical breaker and miscellaneous pipe, fittings and conduit. The installation of the equipment and concrete pad will be performed by Hydro internal labour.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	28.0	0.0	0.0	28.0
Labour	44.2	0.0	0.0	44.2
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	7.1	0.0	0.0	7.1
Contingency	15.0	0.0	0.0	15.0
TOTAL	**97.3**	**0.0**	**0.0**	**97.3**

Operating Experience:

Presently at Bay d'Espoir, there are two separate high pressure compressor stations. The first station includes high pressure compressors 1 and 2 which supplies air to receiver tank 1 at 360 psi. After the air leaves tank it is reduced to 230 psi for use in operating the switchgear breakers in the switchyard. The second station includes high pressure compressors 3 and 4 and supplies air to receiver tank 2 at 360 psi. Some of the air from tank 2 is supplied to the generator governor accumulator tanks at full 360 psi. The remainder of the air is reduced in pressure down to 115 psi for operation of the generator brakes, grease pumps, and general service. This project will add a new low pressure compressor to produce low pressure air at 115 psi in a more cost effective manner to

supply the generator brakes, grease pumps, and general service. The existing method of producing 115 psi air will remain in place to provide redundancy.

High pressure compressors 1 and 2 were installed in 2001 and compressors 3 and 4 were installed in 2000. Table 2 below provides the historic maintenance costs for the past five years.

Table 2: Historical Maintenance Costs ($000)

Year	Compressor 1	Compressor 2	Compressor 3	Compressor 4
2011	5.1	2.3	3.7	9.3
2010	3.1	3.5	3.8	6.5
2009[2]	3.1	1.3	1.7	0.0
2008	4.9	4.0	4.4	1.0
2007	5.8	1.1	1.7	2.4
Total	22.0	12.2	15.3	19.2

Bay d'Espoir Powerhouse 1 is Hydro's only hydroelectric powerhouse that uses high pressure compressors to produce high pressure air and then reduces the pressure for low pressure applications. Hydro's other plants have dedicated low pressure compressors for low pressure air requirements.

Project Justification:

The addition of a new low pressure air compressor is justifiable because the low pressure compressor will provide a more energy efficient service with reduced maintenance cost. Under the current operating conditions Bay d'Espoir is using high pressure compressors to provide both high and low pressure air requirements. However, high pressure compressors are designed to efficiently compress air at high pressures and low volumes, while low pressure compressors are designed to compress air efficiently at high volumes and low pressures. Using compressors 3 and 4 under the existing system configuration to produce low pressure air is inefficient as these high pressure compressors have to run longer and cycle on/off frequently which results in increased maintenance costs.

A cost benefit analysis was performed to determine the cost effectiveness of purchasing a low pressure compressor compared to continuing with the existing configuration. The analysis shows a

[2] *Compressor was off line for the majority of the year*

benefit in purchasing the low pressure compressor.

Cost Benefit Analysis:

A cost benefit analysis was completed with two alternatives analyzed as follows:

- Alternative 1: Purchase a new low pressure compressor to add to the compressed air system; or
- Alternative 2: Continue with the existing system (status-quo).

Assumptions:

- 40 year life cycle for a compressor; and
- Energy efficiency calculations are based on NLH Proxy Marginal Cost (note 2% increase was used after 2032 for the analysis).

The cost benefit analysis indicates that Alternative 1 is the least cost option for providing low pressure air. Table 3 provides the results of the analysis.

Table 3: Cost Benefit Analysis

BDE - Purchase LP Screw Compressor Set		
Alternative Comparison ***Cumulative Net Present Value*** ***To The Year*** **2052**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Add LP Compressor to system	201,391	0
Status Quo, Only HP Comp Configuration	215,211	13,820

Future Plans:

None.

Project Schedule:

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

Table 4: Project Schedule

Activity		Start Date	End Date
Planning	Review Scope Confirm Schedule Review Budget	April 2013	April 2013
Design	Submit design transmittal Risk workshop	April 2013	April 2013
Procurement	Confirm Schedule Tender materials / review tenders Award tender for supply	May 2013	May 2013
Construction	Safety meetings Schedule meetings Risk / Change management Site safety tour	June 2013	June 2013
Commissioning	Safety meeting training	June 2013	June 2013
Closeout	Financial close out Post implementation review	September 2013	September 2013

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 360 demand meters, 1000 residential meters and associated equipment for use in revenue metering applications which require replacement each year due to government retest, technology changes, or obsolescence. Also, Hydro will purchase six Dry-Type Metering Units (Meter Tanks) to replace existing aging and obsolete 2.5 element units. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	129.0	0.0	0.0	129.0
Labour	25.7	0.0	0.0	25.7
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	13.9	0.0	0.0	13.9
Contingency	30.9	0.0	0.0	30.9
TOTAL	**199.5**	**0.0**	**0.0**	**199.5**

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. They have been replaced by electronic meters.

There are 74 oil-filled metering tanks of which 36 are in service and 38 in storage as critical spares. These are all 2.5 element units, ranging in age from 22 to 41 years, and Measurement Canada no longer permits these units to be installed for new customer services. In recent years, there have been five tanks removed from service due to deterioration from environmental conditions or to failure of components. The most recent tank to be replaced was in November, 2011.

Project Justification:

Meters/metering equipment obsolescence and failure requires critical 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, Measurement Canada introduced a new compliance sampling procedure (S-S-06) on January 1, 2011 that can be used on a voluntary basis until fully implemented on January 1, 2014 (see Appendix A). Once implemented, fewer meters will be passing compliance testing due to more stringent guidelines related to compliance testing of electromechanical meters. Measurement Canada highly recommends that utilities manage their compliance sampling groups effectively to avoid a tsunami effect of failing meters that will occur if groups aren't properly managed. Measurement Canada acknowledges that many meters currently passing the old standard, LMG-EG-04, will not pass the new standard (S-S-06). 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 (see Appendix A, Section 3.0).

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 Canadian Electricity Association in 2001 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 and a number of recommendations were agreed on to reduce the impact of this potential error. Subsequently, effective April 2, 2003;

(a) All new; and

(b) All reconstruction of existing, 3-phase 4-wire wye configured metering installations shall use 3-element metering.

Furthermore, there is an environmental benefit of having dry-type metering units versus oil-filled units due to the fact that there is no potential for environmental hazards from oil leaks.

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Prepare order	January 2013	January 2013
Design	Prepare drawings	January 2013	January 2013
Procurement	Order meters and tanks	January 2013	March 2013
Construction	Install meters and tanks	May 2013	October 2013
Commissioning	Verify installations	May 2013	October 2013
Closeout	Close out projects	December 2013	December 2013

Future Plans:

Hydro's plan is to replace all electromechanical meters with electronic meters over a period of eight years and replace all metering tanks over a period of five years. This is the third year of that plan. See five-year capital plan (2013 Capital Plan Tab, Appendix A).

APPENDIX A

Measurement Canada / Mesures Canada
An Agency of Industry Canada / Un organisme d'Industrie Canada

Specifications

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	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.

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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.

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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.

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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.

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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) $c1 \leq Ac_{type\ 1}$
(ii) $c2 \leq Ac_{type\ 2}$

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.

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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.

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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.

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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).

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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

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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%

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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%

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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:	Bulletin:	Date:	Page:
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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

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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: 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 installing roof fall protection systems on the control buildings at the Bottom Brook, Sunnyside and Stony Brook Terminal Stations and on the William's Harbour Diesel Plant, anchor plates for transformers where needed and ladder cable systems for ladders where needed. The project estimate is $196,600, as shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**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	20.0	0.0	0.0	20.0
Other Direct Costs	34.7	0.0	0.0	34.7
Interest and Escalation	12.4	0.0	0.0	12.4
Contingency	0.0	0.0	0.0	0.0
TOTAL	**196.6**	**0.0**	**0.0**	**196.6**

Operating Experience:

Hydro initiated a program in 2005 to install fall protection systems on transformers, fuel tanks and roofs at its facilities. During the execution of the program, Hydro developed a comprehensive listing of all sites that required fall protection systems (see Appendix A). This is the ninth year of the program that started in 2005.

Below is a discussion of the three basic types of fall protection systems installed by Hydro. The photographs illustrate how each system is used.

Roof Fall Protection System

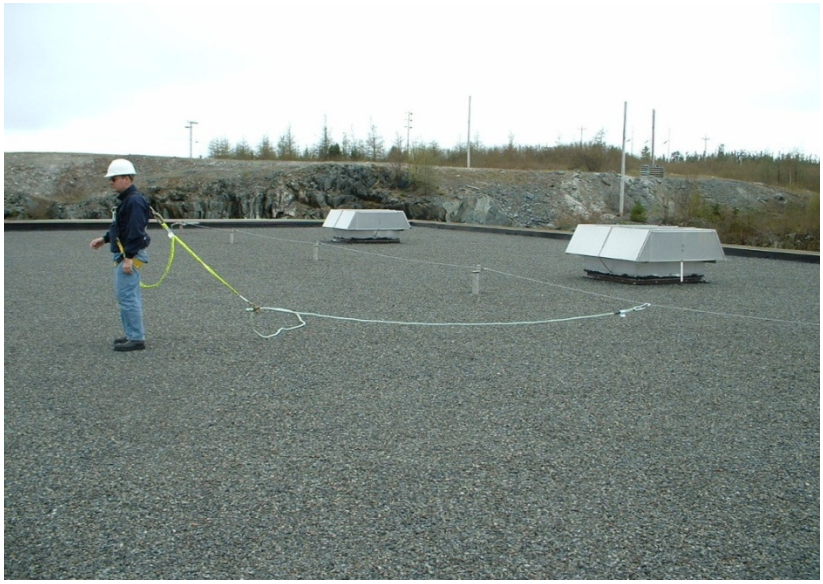

Figure 1: Roof Fall Protection System

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 Figure 2, that is attached to a cable grab which in turn rides on the cable. The cable

Figure 2: Ladder Fall Protection System

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.

Figure 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.

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 Section 60 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 Section 60 of the Occupational Health and Safety Regulations. The section "Safety Belts and Lifelines" states in part "the employer shall ensure that fall protection systems are used by all workers employed over pits, shafts or moving machinery and by all workers working at elevations greater than 3.05 meters above ground or floor level". The complete Section 60 regulations are presented in Table 3. Without proper fall protection systems in place, a worker can refuse to perform his/her assigned duties.

Table 2 presents annual capital budget and actual expenditures for years 2007 to 2011 and the budget for 2012.

Table 2: Capital Expenditure History

Year	Capital Budget ($000)	Actual Expenditures ($000)	Comments
2012B	199.2		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[3]	Tanks, transformers and roofs
2007	250.9	245.2	Tanks, transformers and roofs

In order to be compliant with Section 60 "Safety Belts and Lifelines" of the Occupational Health and Safety Regulations, this work must continue until all facilities are properly equipped with fall protection systems.

[3] *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.*

Table 3. Safety belts and lifelines from Occupational Health and Safety

60.	(1) Where it is impracticable to provide adequate work platforms or staging, the employer shall ensure that fall protection systems are used by all workers employed over pits, shafts or moving machinery and by all workers working at elevations greater than 3.05 metres above grade or floor level in accordance with current standards of the C.S.A. Code with respect to fall protection and fall protection systems. (2) Rep. by 23/99 s2 (2) (3) When a worker is employed under circumstances where he or she might become entrapped by material, or be overcome by another cause, he or she shall wear a safety-belt or safety-harness attached to a lifeline or other device attended by another worker who shall be stationed, equipped and capable of immediately effecting a rescue. (4) Safety-belts, safety straps, lifelines and all interconnecting parts shall be of sufficient strength to support before breaking a weight of 1134 kilograms. (5) All metal fittings used on or with safety-belts shall conform to the metallurgical strength requirement standards as specified by the Canadian Standards Association. (6) Permanent anchors to which safety straps or rope terminals may be attached shall conform to the requirements of subsections (4) and (5). (7) Rope used for lifelines or safety straps shall comply with the requirements of current C.S.A. Code standards with respect to fall protection. (8) When axes or other tools are used which are likely to sever, abrade or burn the lifeline or safety strap, a wire rope or wire cored fibre rope shall be used. (9) Where workers are engaged in work in proximity to energized electrical circuits where conductive safety straps cannot be used, 2 non-conductive safety straps shall be worn to provide the additional protection required. (10) The safety strap shall be so attached to the safety-belt that it cannot pass through the belt fittings should either end become loose from its anchorage. (11) Thimbles shall be installed to protect ropes from chafing at points of connection to eyes, rings and snaps. (12) Safety-belts, safety straps and lifelines shall be arranged to limit the free fall of a worker to 1.22 metres. (13) No more than one worker shall be attached to a lifeline. (14) Belts, straps, harnesses, lifelines and other similar devices shall be kept free from substances and conditions which could contribute to deterioration and this equipment shall be carefully inspected before use. (15) If an impairment of function is detected the defective part shall be removed from service.

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 2013 Tab, Appendix A).

APPENDIX A

Fall Protection Project List

Fall Protection Project List

Location	Description	Comment
Bay d'Espoir		
Cat Arm	Ladder system on powerhouse roof	Planned for 2012
General	Spillway Gate Handrails	Planned for 2012
	Platform Access to hoist control panel at Salmon Spillway	Planned for 2012
	Surge Tanks 1, 2 & 3 balcony gates	Planned for 2012
	Surge Tank #3 Fall Arrest System	Planned for 2012
Granite Canal	Install anchor points for changing lights	Planned for 2012
Powerhouse 1	PH1 Overhead crane ladder/support	Planned for 2012
	Fabricate/install Spherical valve platform #1	Planned for 2012
	Fabricate/install Spherical valve platform #2	Planned for 2012
	Fabricate/install Spherical valve platform #3	Planned for 2012
	Safe access to overhead cranes	Planned for 2012
	Access ladder attached to mobile crane	Planned for 2012
	Sump pit #1 ladder	Planned for 2012
	Sump pit #2 ladder	Planned for 2012
	Sump pit #3 ladder	Planned for 2012
Upcountry	Ladder system at Burnt Dam spillway	Planned for 2012
	Suitable access to aircraft warning lights at Salmon Spillway	Planned for 2012
Central		
Francois	Fall protection system on diesel plant roof	Planned for 2012
Massey Drive TS	Fall protection system on control building roof	Planned for 2012
Oxen Pond TS	Fall protection system on control building roof	Planned for 2012
St. Brendan's	Fall protection system on diesel plant roof	Planned for 2012
Various Transformers	Anchor plates for transformers	Ongoing
Western Avalon TS	Fall protection system on control building roof	Planned for 2012
Labrador		
Happy Valley	Sure-Track ladder system on North side plant ladder	Planned for 2012
Northern		
Various Transformers	Anchor plates for transformers	Planned for 2012
William's Harbour	Ladder station and fall protection system on diesel building roof	Planned for 2012

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 TS	Fall protection system on control building roof	Planned for 2013
Stony Brook TS	Fall protection system on control building roof	Planned for 2013
Sunnyside TS	Fall protection system on control building roof	Planned for 2013
Holyrood		
Holyrood TS	Fall protection system on control building roof	Planned for 2013
Holyrood	Four ladder cable systems for pumphouse	Planned for 2013

Location	Description	Comment
Bay d'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
General	Support for Oil Tank Rescue	Future projects
	Intake #4 gate control access rail	Future projects
	Access catwalk for installing stoplogs	Future projects
	Surge Tank #2 Fall Arrest System	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
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
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
Powerhouse 1	Fall arrest or restraint system when working atop overhead crane	Future projects
	Unit #1-6 Rotor/Stator access ladder	Future projects
	Unit #2 railing install toeboards	Future projects
	Unit #5 Spherical valve rail/ladder mod	Future projects
	Unit #6 Spherical valve rail/ladder mod	Future projects
	Grating unit #4 improvement	Future projects
	Grating unit #5 improvement	Future projects
	Grating unit #6 improvement	Future projects
	Overhead crane access ladder	Future projects
	Downstream Unit 5 ladder	Future projects
	Downstream Unit 6 ladder	Future projects

Location	Description	Comment
Bay d'Espoir		
Powerhouse 1	Cable tunnel shelter ladder	Future projects
Powerhouse 2	Railing to Fire Pump area	Future projects
	Sump pit ladder	Future projects
Up Country	Ladder to upper deck at Victoria Control Structure	Future projects
	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
Upper Salmon	Ladder cable system at North Salmon spillway roof	Future projects
	Ladder cable system at West Salmon spillway roof	Future projects
	Ladder cable system at warehouse roof	Future projects
	Intake ladder modification/safety slide-powerhouse	Future projects
	Diver access ladder at West Salmon Spillway	Future projects
	Install railing around unit-powerhouse	Future projects
Central		
Bishop's Falls	Lifelines on service building	Future projects
	Fall protection system on office building	Future projects
	Fall protection system on salvage stores	Future projects
Various Transformers	Anchor plates for transformers	Future projects

Project Title: Purchase 10 Position Meter Calibration Test Console

Location: Hydro Place

Category: Transmission and Rural Operations - Metering

Definition: Other

Classification: Normal

Project Description:

This project consists of purchasing a new fully automatic 10 position meter calibration test console compliant to Measurement Canada's standard S-E-01, Specifications for the Calibration, Certification and Use of Electricity Calibration Consoles (see Appendix A). The new test console will be capable of testing all electro-mechanical and electronic type meters that are used by electric utilities in today's revenue metering applications. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	155.0	0.0	0.0	155.0
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	6.5	0.0	0.0	6.5
Contingency	31.0	0.0	0.0	31.0
TOTAL	**192.5**	**0.0**	**0.0**	**192.5**

Operating Experience:

Hydro presently has a 34 year old 5 position meter calibration test console that was purchased in 1978 and a 25 year old 10 position meter calibration test console that was purchased in 1987, both of which are manually operated. Both test consoles have been maintained since original purchase and have received upgrades in 1998, 2003 and the latest upgrades were completed in 2009. The 5 position console currently meets Measurement Canada's specifications and is certified for testing and verifying revenue meters, but is limited to verifying only two of the nine types that Hydro is accredited to inspect. These restrictions are because of the limitations within the test console itself (i.e. one isolation transformer vs. five) and also in changes due to design of the new electronic meters (i.e. one test link vs. two). The 10 position console also meets Measurement Canada's specifications and presently is capable of testing all types of revenue meters, however Testcor Inc.,

the company that performed the latest software and hardware upgrades is no longer in business, consequently there is no software or hardware support. In December 2011, the 10 position console developed software and hardware problems and because there was no support available to help troubleshoot these problems, the test console was out of service for two months before the problems were found, components repaired, tested and put back in service. Also, the original manufacturer of these test consoles is no longer building test consoles and replacement parts are not readily available.

Project Justification:

This project is justified on the requirement to replace obsolete equipment along with the necessity to ensure that we have the capacity and reliability to meet our obligations as an accredited organization and also as an Authorized Service Provider. Hydro is the only Measurement Canada accredited organization in the Province and in 2011 Hydro entered into an agreement with Newfoundland Power as an Authorized Service Provider to provide testing, calibration and certification services for the sealing of revenue meters. This contract is based on cost recovery and is a benefit to the rate payer of the Province. Also, aside from the reliability and the capacity component, a fully automated test console eliminates the manual connections required to configure the voltage and current circuits for a given meter type. The operator simply identifies and selects the meter type through software and the system is ready to perform testing of standard or user defined test sequences. This capability provides benefits such as enhanced productivity due to the fact that the operator can perform other duties while the test console software automatically performs the test sequences, reduced learning curve because there is less to set up, and fault tolerant voltage and current sources to ensure that the operator, equipment and meters under test are protected from faults.

A new fully automatic 10 position meter calibration test console will ensure that Hydro can continue to function as an accredited organization and also as an Authorized Service Provider under Measurement Canada's Electricity and Gas Inspection Act and Regulations.

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Prepare order	January 2013	January 2013
Design	Consult with manufacturer	January 2013	January 2013
Procurement	Order Test Console	January 2013	February 2013
Construction	Four to Six months	February 2013	July 2013
Commissioning	Ensure compliance to S-E-01	July 2013	August 2013
Closeout	Close out project	August 2013	September 2013

Future Plans:

None.

APPENDIX A

Measurement Canada Mesures Canada

Specifications

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	Supersedes : **S-E-01 (rev. 2)**	

Specifications for the Calibration, Certification And Use of Electricity Calibration Consoles

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	Supersedes : **S-E-01 (rev. 2)**	

S-E-01 (rev. 3): Summary of Amendments to S-E-01 (rev.2)	
Section	**Description**
All	Reformatted to new formatting requirements.
5.2.6	This section was 5.2(d) in the previous revision. All of the subsections of 5.2(d), required information be provided in a specific format and were identified under the 20% reduction initiative for removal. The worksheets for the pre-evaluation of consoles will serve to provide all the information required for this specification.
6.1.2	This section has been revised to a minimum frequency of weekly as identified in the 20% reduction initiative.
6.3.1	Removed the requirement for the on state to be prominently illuminated. With the indicating instruments illuminated, there is no additional value in also requiring the master switch to have an on status illuminator.
6.3.8	This section has been removed. Section 6.3.8 "test links" was identified under the 20% reduction initiative for removal.
6.4.1.3	Section 6.4.1.3 has been removed. It was identified that other methods do not require the indicator, therefore the current indicator will also suffice for indication when a switch is used.
6.4.3.1(d)	Clarified that where a power standard is used for the setup of test loads, inspection of the indicating instrument is done during the accuracy testing of the test points for the standard.
7.1.2.1	Formula modified to reflect correct expression of test console error.

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Specifications for the Calibration, Certification and Use of Electricity Calibration Consoles

1.0 Scope

1.1 The scope of this document includes calibration, certification, and use of electricity calibration consoles. These specifications are intended for the certification or recertification of measuring apparatus consisting of calibration consoles and accessories thereto intended for the verification and/or reverification of single and/or polyphase energy and/or demand meters, including meter testing pursuant to the requirements of any Measurement Canada approved statistical sampling plan for the verification and reverification of electricity meters.

1.2 This document is supported by procedures set out in P-E-01: Procedures for Calibrating and Certifying Calibration Consoles Pursuant to the Requirements of S-E-01.

1.3 These specifications do not apply to calibration consoles used solely for the purpose of verifying the register ratios on electricity meters.

2.0 Authority

This document is issued pursuant to section 5 of the *Electricity and Gas Inspection Act* and Part I of the *Regulations* established thereto. It has been produced under the authority of the President of Measurement Canada for the purposes of setting out specifications for the calibration, certification and use of electricity measuring apparatus.

Alan E. Johnston
President

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3.0 Purpose

3.1 The purpose of this specification is to provide the requirements for calibration, certification and use of electricity calibration consoles.

4.0 Terminology

Burden
The load usually expressed in VA, which is placed on transformer secondaries by the associated meter coils, leads and other connected devices, at a specified test point and power factor.

Calibration
A comparison between the readings of two instruments, measuring devices, or standards, one of which is of known accuracy.

Calibration Console
Electricity Measuring Apparatus used for the verification and/or reverification of single phase and/or polyphase energy and/or demand meters.

Distortion
An undesired change in waveform which will result in a non-sinusoidal waveform.

Electromechanical Demand Meter
An electricity meter which measures demand power using a thermal element, or mechanical gearing from an electro-mechanical rotating energy disk.

Electronic Demand Meter
An electricity meter which measures demand power using solid state techniques such as digital sampling or Time Division Multiplication (TDM).

Fully Automatic Console
A console which is capable of setting and resetting all loads without direct operator intervention. (eg. RFL console).

Ground
A conducting connection between an electric circuit or equipment and earth.

Hybrid Demand Meter
An electricity meter which uses electronics to calculate demand power and other electrical quantities using input pulses from an electro-mechanical rotating energy disk.

Line Conditioner
A device used to minimize distortion to the input voltage and/or current supplying a calibration console.

Manual Console
A console which operates in a manner such that an operator is required to manually set and reset all loads.

Recti-thermal Demand Meter
An electricity meter which measures demand power by the use of a thermal element and an AC to DC rectifier circuit.

Reference Meter
A measuring instrument used to determine the error of a meter/device under test on a calibration console. The measuring instrument can be a stand alone device or an indicating device used in conjunction with a measuring device.

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Regulator
A device which operates to ensure that an electrical quantity which deviates from a set point or set load is brought back to that set point or set load.

Self Contained Meter
A meter designed to be connected directly in a power circuit without the use of external devices such as instrument transformers or shunts.

Semi-automatic Console
A console which is capable of setting and resetting loads after initial setting by operator. (eg. Multi-Amp console).

Significant Digits
The total number of digits beginning with the first non-zero digit to the left of the decimal point, or with the first digit after the decimal point if there is no non-zero digit to the left of the decimal point and ending with the last digit to the right.

Specifications
The Specifications For the Calibration, Certification, and Use of Electricity Calibration Consoles. (S-E-01)

Standard
A certified measuring instrument, having errors traceable to the National Research Council of Canada, that is used to calibrate a Calibration Console.

Test Load
Applied test voltage multiplied by the applied test current.

Transformer-type Meter
A meter designed to be used with instrument transformers.

5.0 Administrative Requirements

5.1 General

5.1.1 These specifications shall apply to all calibration consoles which are used for verification or reverification of meters as described in the scope. This includes meters which are tested for the purposes of performing a dispute investigation.

5.2 Roles and Responsibilities

5.2.1 Prior to the calibration of measuring apparatus, the person conducting the calibrations shall be responsible for ensuring that the following standards and measuring equipment to be used have been certified by Measurement Canada or the National Research Council of Canada.

(i) Energy, Demand and Phase standards

(ii) Voltage and Current standards, and Current Transformer if required

(ii) Distortion Analyzer

(iv) Level or inclinometer (angle gauge block)

NOTE: For the purpose of calibration, data included on the manufacturer's certificate for the angle gauge block is acceptable. To qualify the validity of the manufacturer's angle gauge block certificate, the gauge block shall be visually inspected each time it is used to identify any physical damage. Any evidence that the gauge block may not represent its original condition (i.e. damage, deterioration due to rust, etc.) will disqualify the use of the gauge block as equipment used for certification.

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5.2.2 Organizations authorized to re-certify calibration consoles on behalf of MC shall conduct that calibration in accordance with the procedures set out in P-E-01. Organizations that wish to use procedures that differ from the procedures set out in P-E-01 shall submit the relevant procedures and work instructions (if applicable) for review and acceptance by MC.

5.2.3 When an owner, (other than MC), requests console certification to be performed by Measurement Canada, the owner shall be responsible for providing all information required by these specifications.

5.2.4 For calibration consoles that have never been certified or have not had a valid certificate for at least three years, the owner shall ensure that the calibration console is fully compliant with all applicable requirements set out in these specifications prior to the calibration of the console.

5.2.5 For certified calibration consoles or calibration consoles that have expired certificates that are less than three years past expiry date, the owner shall ensure as a minimum, that the console is compliant with the requirements of sections 7.5, 7.6, and 7.8 as applicable. For the purpose of pre-testing to ensure compliance to section 7.8, the console shall be tested to the following requirements as a minimum.

(a) All test points pursuant to the requirements of section 7.8.2.1, 7.8.2.2 and 7.8.2.4 shall be evaluated as applicable.

(b) Consoles that are expected to be certified in accordance with requirement 7.8.2.3 may be evaluated using a reduced set of test points as determined below:

(i) One function shall be evaluated at the nominal voltage of the voltage tap that is used with the greatest number of current taps. At this voltage the maximum and minimum loads at unity power factor as well as all other power factor loads shall be evaluated for each current tap used to evaluate meters pursuant to section 5.2.6. At each of the other voltage taps required to be used to evaluate meters pursuant to section 5.2.6, one current tap shall be selected and the console shall be evaluated at the minimum and maximum loads, at unity, 0.5, and 0.866 power factors as applicable for the set voltage and current tap combination.

(ii) All other functions shall be evaluated at the minimum and maximum loads at three different current taps at each voltage at unity, 0.5 and 0.866 power factors as applicable.

(iii) If during the process of calibration console certification by Measurement Canada, a console fails any calibration test pursuant to section 7.8, the console shall be subject to a complete pre-test of all required calibration test points pursuant to section 7.8.

(iv) Compliance with section 7.8 may also be demonstrated by providing the results of the weekly accuracy tests performed on the calibration console since the last certification which indicate that the console has been verified at test points consistent with those that would be evaluated pursuant to the requirements of 5.2.5 (b)(I) and (ii) above.

5.2.6 The owner shall provide all information required to determine the manner in which the console will be used for verifying meters. Note: The worksheets (i.e. for pretesting) and procedure, P-E-01 include information needed for determination of the manner in which the console will be used for verifying meters.

5.2.7 The owner shall provide meters or burdens to perform all tests that require a burden.

5.2.8 The owner, (other than MC) shall notify the local district office of Measurement Canada if a calibration console is required to be used for verifying meters outside the scope of certification. The owner shall also request the additional inspection required to expand the scope of the certification as needed to permit the use of the console to inspect those meters.

5.2.9 The user of a calibration console shall be responsible for using the measuring apparatus in the manner for which it was intended in accordance with the requirements set out in these specifications and with any terms and conditions set out in the certificate.

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5.2.10 The owner shall retain copies of the calibration console worksheets and the calibration console certificate until the expiration of the calibration console certificate.

5.2.11 The owner shall ensure that the measuring apparatus is maintained in good repair and operating order.

5.2.12 The owner shall forthwith notify the local district office of Measurement Canada of any repair or adjustment to the measuring apparatus. The calibration console (including MC owned), shall not be used for verification or dispute testing until the declared repairs or adjustments have been evaluated by the Measurement Canada regional electricity specialist.

5.2.13 The owner shall notify the local district office of Measurement Canada, (which must notify the regional electricity specialist), prior to undertaking any modification or relocation of the measuring apparatus.

5.3 Markings and Documentation

5.3.1 Nameplate

Calibration consoles shall be fitted with a legible, readily accessible nameplate indicating:

(i) Name of manufacturer

(ii) Model number

(iii) Serial number

(iv) Supply voltage and configuration

5.3.2 Log Book or File

5.3.2.1A log book or file shall be maintained by the owner of the calibration console and kept readily available. The log book shall have recorded in it, the dates and details including identification of the person or persons performing all accuracy checks, adjustments, maintenance, repairs and modifications to the calibration console.

5.3.3 Operating Manuals and Schematics

5.3.3.1
The operating manuals and schematic drawings of the calibration console shall be readily available.

5.3.4 Calibration Console Markings

5.3.4.1
All controls, displays and switches shall be indelibly identified.

6.0 Technical Requirements

6.1 Use Requirements

6.1.1 General

6.1.1.1
Calibration consoles shall be used in accordance with the terms and conditions of their certificates.

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6.1.2 Accuracy Check

6.1.2.1
An accuracy check shall be conducted by an inspector or an accredited meter verifier, at least once per week during any week that the console is used to verify meters. The accuracy check shall be conducted at one different test point for each day the console was used, selected from the test points that were used to evaluate meters during the week. If this number of different test points were not used during the week, additional test points shall be selected from the test points used to evaluate meters as identified pursuant to section 5.2.6.

6.1.2.2
The accuracy check shall consist of, as a minimum, connecting a certified standard, certified reference meter, or meter of known accuracy in a meter-under-test position and comparing its registration with the results determined by the calibration console at the selected test point.

6.1.2.3
Where the error determined pursuant to the accuracy check differs from that appended to the certificate for the calibration console, by more than ± 0.2 percent, or exceeds the allowable tolerance specified in section 7.8, the calibration console shall not be used until the cause of the change in error has been investigated and corrected. All meters verified during the period since the last confirmed accuracy check shall be reverified on a different certified console with confirmed accuracy check or on the same console after the condition that caused the failed accuracy check has been corrected.

6.1.2.4
All accuracy check results shall be recorded in the log book.

6.1.3 Minimum Duration of Verification Tests

6.1.3.1
The minimum duration of any test performed on energy meters for the purposes of verification, or reverification, shall be such that meter test results are provided to a resolution of 0.1%. For the case of calibration consoles equipped with energy reference meters that emit pulses the minimum duration of tests shall be such that at least 1000 pulses are emitted by the energy reference meter.

6.2 Environmental Requirements

6.2.1 Temperature

6.2.1.1
The ambient temperature surrounding the calibration console shall be 23°C ± 5°C.

6.3 Mechanical Requirements

6.3.1 Master Control Switch and Indication of Energization

Calibration consoles shall have a master on/off control for switching off all power sources to the console. It shall be readily accessible and clearly marked.

6.3.2 Circuit Protection

6.3.2.1
The circuit protection features of the calibration console (e.g. fuses or breakers) shall be readily accessible.

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6.3.3 Grounding

6.3.3.1
The potential between any exposed metal panels of the calibration console and (earth) ground shall not exceed 1 Vrms.

6.3.3.2
Calibration consoles that are not grounded shall protect the operator from a shock hazard by use of a ground fault interrupting (GFI) circuit breaker. The device shall automatically protect the operator from any ground fault currents flowing between the console supply conductors(s) and ground which exceed 10 mA.

6.3.4 Isolation

6.3.4.1 Isolation from Ground

6.3.4.1.1
All test circuits of the calibration console shall be electrically isolated from ground such that the leakage current measured between any terminal and ground, does not exceed 1 mA rms when the console is energized at its maximum operating current and voltage, nor when it is energized at its maximum operating voltage and its minimum test current.

6.3.4.2 Isolation of Secondary Circuits From Primary Circuits

6.3.4.2.1
All secondary test circuits of the calibration console shall be electrically isolated from primary supply circuits.

6.3.5 Meter Mounting Arrangements

6.3.5.1
Calibration consoles shall have sufficient arrangements to allow for the mounting of all meter types identified in the information provided pursuant to section 5.2.6, such that the rotating disks of electromechanical integrating meters are within ±3.0° of true level once such meters are installed.

6.3.6 Operating Mode

6.3.6.1
Calibration consoles shall be capable of testing meters under single phase conditions with potential circuits connected in parallel and current circuits connected in series. A console that is capable of applying voltages and currents to the voltage and current circuits of a meter from independent sources shall be considered to meet this requirement if the applied voltages, currents, phase angles, and loads from each source are within the tolerances set out in Table 1 of section 6.4.3.2. The spread of the applied voltages, currents, phase angles, and loads, shall also be within the tolerances set out in Table 1 of section 6.4.3.2.

6.3.7 Individual Elements

6.3.7.1
Calibration consoles shall be capable of testing individual elements of meters.

6.3.7.2
Semi-automatic and fully automatic calibration consoles shall be capable of applying currents to individual elements of meters. The maximum spread of currents supplied, without operator intervention, when switching between the various elements of a meter, either individually or in series, shall not exceed 2.0% of the nominal current required to be supplied to any one element. If this tolerance cannot be met without operator intervention the console may only be certified for use as a manual console.

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6.3.7.3
Calibration consoles shall comply with this requirement at the highest test load current or 50 amps, whichever is lower, and at the lowest test load current used for verifying meters as specified in the information provided pursuant to section 5.2.6.

6.4 Electrical Requirements

6.4.1 Creep Switch

6.4.1.1
Where a calibration console incorporates a switch or other means intended to reduce the current supplied to the meter-under-test position(s) to zero, when the switch or other means has been activated with a standard in the meter-under-test position, and load voltage applied to each meter-under-test position, the energy recorded during a fifteen minute interval shall not be greater than 0.1% of the energy that would be delivered if the load current was set at the minimum current shown on the nameplate of the lowest rated meter included in the information provided pursuant to section 5.2.6 and the load voltage was set to the maximum voltage of the highest voltage rated meter included in the information provided pursuant to section 5.2.6.

6.4.1.2
Calibration consoles that do not meet the above requirement or do not have a creep switch may be certified for testing meter creep if they can be configured to remove the current supplied to the meter(s) under test.

6.4.2 Maximum Test Voltages and Currents

6.4.2.1
Calibration consoles shall be capable of continuously supplying the highest rated voltage and the largest test current used to verify the meters specified in the information provided pursuant to section 5.2.6.

6.4.3 Indicating Instruments

6.4.3.1
Calibration consoles shall be equipped with indicating instruments that are capable of displaying the quantities listed below:

(a) Voltage (volts)

(b) Current (amps)

(c) Phase angle (degrees) or power factor (Pf)

(d) Power (where a power standard is used to setup and monitor the power, it's accuracy is evaluated under the test points for the standard)

(i) Watt meter for the case of consoles used for watt or watt hour meter testing.

(ii) Volt ampere (average or rms as applicable) meter for the case of consoles used for va or va hour meter testing.

(iii) Var meter for the case of consoles used for var or var hour meter testing.

6.4.3.2
These instruments shall be capable of indicating their respective quantities to tolerances specified in Table 1, and shall be capable of indicating all values required for verifying all meters specified in the information provided pursuant to section 5.2.6. When setting any of the quantities above, the respective indicating instrument shall be readily accessible with an unobstructed view.

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TABLE 1

Required Indicator Accuracies

Quantity	Tolerances
Current	±2%
Voltage	±2%
Phase angle/power factor (at unity Pf)	±2.5°/±0.1%
Phase angle/power factor (at 0.5 Pf)	±1.0°/±3%
Power (active, reactive, or apparent)	±2%

6.4.3.3
The tolerances expressed in percentage are in percent of true value.

6.4.3.4
For the purpose of determining compliance with the above tolerances, the currents, voltages, phase angles, and loads shall be measured at a meter-under-test position using instrument transformers if necessary.

6.4.3.5
The requirements for power indicating instruments may be satisfied by calibration console reference meters that are also capable of displaying the power quantities set out in Table 1.

6.4.3.6
Calibration consoles intended to verify reactive meters shall be capable of meeting the above requirements with the exception that the tolerances for phase angle and power, at 0.5 power factor (60°) set out in Table 1, apply at 0.866 lagging power factor (30°) as well.

6.4.4 Accuracy and Repeatability of Calibration Consoles

6.4.4.1
Calibration consoles shall be capable of setting all currents, voltages, phase angles, and loads within the tolerances set out in Table 1 of section 6.4.3.2, for all meters required to be verified pursuant to section 5.2.6.

6.4.4.2
Calibration consoles which are capable of setting loads automatically, whether with, or without initial load setting by the operator, and which reset set loads without any further operator intervention shall meet the requirements of (i) and (ii) below:

(i) The calibration console shall set currents, voltages, phase angles, and loads within the tolerances set out in Table 1 of section 6.4.3.2. The console shall be capable of achieving required settings within one minute, of any change in setting.

(ii) The calibration console shall be capable of automatically setting and resetting the load determined pursuant to section 7.1.4 at least three successive times. The resulting current, voltage, phase angle and power observed at a meter-under-test position for the successive observations shall be within the tolerances set out in Table 1 of section 6.4.3.2 for the respective quantities.

6.4.4.3
Calibration consoles which do not meet requirements (I) and (ii) above, may only be certified for use as a manual console.

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6.4.5 Calibration Console Reference Meters

6.4.5.1
Calibration consoles intended to verify energy meters or calibration consoles which meet the requirements of section 6.4.9 and are intended to verify block interval demand meters shall be equipped by their owners with energy reference meter(s). Calibration consoles intended to verify exponential demand meters or calibration consoles intended to verify block interval demand meters and which do not meet the requirements of section 6.4.9 shall be equipped with demand (power) reference meter(s). Calibration consoles intended to verify average responding demand meters shall be equipped with average responding reference meter(s). Calibration consoles intended to verify demand meters with root mean square (rms) response shall be equipped with rms responding reference meter(s).

6.4.6 Energy Reference Meters

6.4.6.1
Calibration consoles which automatically determine and display meter-under-test errors and which are not equipped with energy reference meters that emit at least one pulse for every 0.00300 watt hours (or volt ampere hours, or var hours), shall display the errors to a resolution of at least two significant digits to the right of the decimal point when the console is undergoing calibration tests pursuant to these specifications. When the console is used for meter verification tests the displayed error shall be shown with a resolution of at least one significant digit to the right of the decimal point.

6.4.6.2
Calibration consoles which do not automatically determine and display meter-under-test errors shall be equipped with energy reference meters that emit at least one pulse for every 0.00300 watt hours (or volt ampere hours, or var hours) applied to the energy reference meter.

6.4.7 Demand Reference Meters

6.4.7.1
Calibration consoles intended to verify exponential demand meters or calibration consoles intended to verify block interval demand meters and which do not meet the requirements of section 6.4.9 shall be equipped with power meter(s) (i.e. watt, va, or var meter) which shall serve as the demand reference meter(s). The demand reference meter(s) shall be capable of displaying power to a resolution of 5 significant digits for the case of consoles used to verify electronic or hybrid demand meters, and 4 significant digits for the case of consoles used to verify electromechanical type, demand meters.

6.4.8 Control Circuits for Energy Meters

6.4.8.1
Calibration consoles intended to verify energy meters and which do not automatically determine and display meter-under-test errors shall have at least one meter-under-test position which is equipped with a device to automatically count the disk revolutions of an electromechanical meter or the test energy pulses provided by an electronic meter. Such consoles shall also be equipped with a device to predetermine the number of revolutions or pulses of a meter under test and to count the pulses emitted by the energy reference meter during the predetermined number of revolutions.

6.4.8.2
Calibration consoles equipped with devices that automatically detect the disk revolution of electromechanical energy meters or the test energy pulses provided by an electronic meter, shall be capable of doing so without error.

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6.4.9 Control Circuits for Demand Meters

6.4.9.1
Calibration consoles intended to verify block interval demand meters may be equipped to start and stop the accumulation of energy by an energy reference meter simultaneously with the start and stop of the demand interval(s). If such a device is not provided the console shall be equipped with a demand reference meter pursuant to section 6.4.7, and shall meet the regulation requirements of section 7.6.

6.4.10 Statistical Calculations

6.4.10.1
Calibration consoles or accessories thereto intended to perform statistical calculations of average error and standard deviation of a sample of meters, shall do so in accordance with the applicable requirements of Measurement Canada authorized statistical sampling plans for the verification and reverification of electricity meters.

7.0 Metrological Requirements

7.1 General

7.1.1 Manual Correction Factors

7.1.1.1
All tolerances for calibration consoles set out in this document shall be achieved without the manual application of correction factors.

7.1.2 Error Calculations - All Consoles

7.1.2.1
The error of a calibration console at any test point is the difference between the results obtained for the standard (and transformer combination) when its apparent error is measured on the calibration console, and the errors set out in the certificates for the standards.

At any test point.

Measuring apparatus error is equal to [Apparent error of standard (and transformers)] minus [Certified (or calculated) error of standard (and transformers)]

7.1.2.2
The apparent error of the standard (and transformer combination) is either read directly off the calibration console or calculated by the operator according to the operating principle of the console. The certified error of the standard is used if no instrument transformers are necessary. Where instrument transformers are necessary, the calculated error of the standard and transformer combination is determined according to the formula set out in section 7.1.2.2.5 of P-E-01: Procedures for Calibrating and Certifying Electricity Calibration Consoles Pursuant to the Requirements of S-E-01.

7.1.3 Minimum Duration of Accuracy Tests

7.1.3.1
The minimum duration of each accuracy test performed on calibration consoles intended to verify energy or block interval demand meters for the purpose of certifying the calibration console shall be as follows:

(a) For the case of consoles equipped with energy reference meters that emit pulses, at least 10 000 pulses shall be emitted by the energy reference meter.

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(b) For the case of consoles not equipped with reference meters that emit pulses, the tests shall be conducted for a period of time equivalent to the minimum duration required to verify a meter at the test load.

7.1.3.2
The minimum duration of accuracy tests performed on calibration consoles intended to verify exponential demand meters shall be the time required to record the necessary readings.

7.1.4 Test Positions and Test Loads

7.1.4.1
Unless otherwise stated, the conditions and requirements set out below shall apply to all Metrological Requirements in section 7.0.

(a) All tests of calibration console accuracy shall be conducted at one test load and at any one meter-under-test position.

(b) Console calibration tests shall be conducted with all current elements connected in series.

(c) For calibration consoles intended to verify self-contained single-phase meters only, the test load used shall correspond to the highest verification test point at 0.5 power factor indicated in the information provided pursuant to section 5.2.6; (e.g. 240 V, 50 A, 0.5 power factor for a watt hour console intended to verify 200 ampere meters).

(d) For consoles intended to verify transformer type meters, in addition to any other meter types, the test load shall be 120 V, 2.5 A, 0.5 power factor.

(e) For consoles intended to verify self contained single-phase and polyphase meters, or self contained polyphase meters only, and which are not intended to verify transformer rated polyphase meters, the test load shall be at 0.5 power factor at the rated voltage and 25% of the rated current of the meter which will be used as the burden determined pursuant to 7.1.5.1(c) below.

(f) For consoles that are not used to verify meters at 0.5 power factor the test load shall be set at unity power factor.

(g) Burdens which simulate meters under test shall be installed in the meter-under-test position(s). This includes placing a potential burden in the meter-under-test position in which the test socket and standard are connected.

(h) For calibration consoles having a potential selection switch, tests shall be conducted with the potential selection switch in the "parallel" position when isolation transformer(s) are out of the test circuit, and in the "multiple" position when isolation transformer(s) are in the test circuit.

7.1.5 Test Burdens

Conditions for Metrological Characteristics

7.1.5.1
Except as otherwise set out in these specifications, all metrological requirements shall be evaluated at the test load determined pursuant to section 7.1.4.1 above, with the burdens installed in the meter-under-test positions. The required test burden(s) shall be determined pursuant to the applicable sections below.

(a) For calibration consoles intended to verify self contained single-phase meters only, the voltage burden that causes the greater of the two errors determined pursuant to (I) and (ii) below, shall be used as the test burden.

> (i) The console shall be tested at the test load determined pursuant to section 7.1.4.1(c) with meters having the highest voltage burden identified in the information provided pursuant to section 5.2.6 installed in any one meter-under-test position.

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(ii) The console shall be tested at the test load determined pursuant to section 7.1.4.1(c) with meters having the lowest voltage burden identified in the information provided pursuant to section 5.2.6 installed in the meter-under-test position used above.

(b) For calibration consoles intended to verify polyphase transformer type meters in addition to any other meter types, the burden that causes the greater of the two errors determined pursuant to sections (i) and (ii) below shall be used as the test burden.

(i) The console shall be tested at the test load determined pursuant to section 7.1.4.1(d) with transformer type polyphase meters having the highest voltage burden identified in the information provided pursuant to section 5.2.6 installed in any one meter-under-test position.

(ii) The console shall be tested at the test load determined pursuant to section 7.1.4.1(d) with transformer type polyphase meters having the lowest voltage burden identified in the information provided pursuant to section 5.2.6 installed in the meter-under-test position used above. The lowest voltage burden may be represented by using zero burden. (ie: Shorting bars and no additional potential burden.)

(c) For calibration consoles intended to verify single phase and/or polyphase, self contained meters only, the burden that causes the greater of the two errors determined pursuant to sections (I) and (ii) below shall be used as the test burden.

(i) The console shall be tested at rated meter voltage and at 25% of rated meter current, with self contained polyphase meters having the highest voltage burden identified in the information provided pursuant to section 5.2.6 installed in any one meter-under-test position.

(ii) The console shall be tested at rated meter voltage and at 25% of rated meter current, with self contained polyphase meters having the lowest voltage burden identified in the information provided pursuant to section 5.2.6 installed in the meter-under-test position used above. The lowest voltage burden may be represented by using zero burden. (ie. Shorting bars without any additional potential burden.)

7.1.5.2
When calibrating calibration consoles which are equipped with 1:1 isolation transformers the test load shall be as determined pursuant to section 7.1.4.1(c) when the 1:1 isolation transformers are in the test circuit, and as determined pursuant to section 7.1.4.1 (d) or (e) when the 1:1 isolation transformers are not in the circuit.

7.1.5.3
When calibrating calibration consoles which are equipped with 1:1 isolation transformers the test burden shall be as determined pursuant to section 7.1.5.1(a) when the 1:1 isolation transformers are in the test circuit, and as determined pursuant to section 7.1.5.1 (b) or ©) when the 1:1 isolation transformers are not in the circuit.

7.2 Burden Effects

7.2.1 Maximum Permissible Errors

7.2.1.1
The change in calibration console error resulting from the installation of different voltage burdens equivalent to those of meters from the list of test points provided pursuant to section 5.2.6, shall not exceed 0.1%.

7.2.1.2
The calibration console error resulting from the installation of any voltage burden equivalent to that of a meter from the list of test points provided pursuant to section 5.2.6, shall not exceed the applicable tolerance set out in section 7.8.

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7.2.2 Conditions for Metrological Characteristics

7.2.2.1
All calibration consoles shall be tested for the effects of varying burden conditions.

7.2.2.2
Calibration consoles which are not equipped with 1:1 isolation transformers, or are equipped with 1:1 isolation transformers which are not in the test circuit, shall be evaluated for burden effects at any one meter-under-test position. The test shall be performed in accordance with section 7.1.5.1(b) above if the console is intended to be used to verify polyphase transformer type meters, or in accordance with section 7.1.5.1(c) above if the console is not intended to be used to verify transformer type meters.

7.2.2.3
Calibration consoles equipped with 1:1 isolation transformers which are in the test circuit shall be evaluated for burden effects at each meter-under-test position that has isolation transformers in the test circuit. The test shall be performed in accordance with section 7.1.5.1(a) of the Specifications.

7.3 Sensitivity to Number of Meters under Test

7.3.1 Maximum Permissible Errors

7.3.1.1
The change in calibration console errors, resulting from varying numbers of meters installed in the meter-under-test positions shall not exceed $\pm$0.1%.

7.3.1.2
Calibration console errors, resulting from varying numbers of meters installed in the meter-under-test positions shall not exceed the applicable tolerance set out in section 7.8.

7.3.2 Conditions for Metrological Characteristics

7.3.2.1
Calibration consoles shall be tested for sensitivity to the number of meters under test at the maximum test load for the burden that is applied pursuant to section 7.1.5 with all other meter-under-test positions empty. The calibration shall be repeated with the test burden determined pursuant to section 7.1.5 connected in each of the other meter-under-test positions.

7.4 Variations from Position to Position

7.4.1 Maximum Permissible Errors

7.4.1.1
The spread of errors from position to position on a calibration console shall not exceed 0.2 percent.

7.4.1.2
For calibration consoles that are certified at one meter-under-test position only, pursuant to the requirements of section 7.8.2.3 or 7.8.2.4, as applicable, the spread of errors from position to position shall not exceed 0.1 percent.

7.4.1.3
No position error shall exceed the applicable tolerance set out in section 7.8.

7.4.2 Conditions for Metrological Characteristics

7.4.2.1
Each meter-under-test position of calibration consoles shall be calibrated at the test load determined pursuant to section 7.1.4 with the test burden determined pursuant to section 7.1.5 connected in each of the other meter-under-test positions.

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7.5 Distortion

7.5.1 Maximum Permissible Errors

7.5.1.1
The distortion in either the current or voltage circuit of calibration consoles intended to verify thermal demand meters shall not exceed 3 percent.

7.5.1.2
The distortion in either the current or voltage circuit of calibration consoles intended to verify meters other than thermal demand meters shall not exceed 5 percent.

7.5.2 Conditions for Metrological Characteristics

7.5.2.1
The distortion in the current and voltage circuits of calibration consoles shall be measured with both circuits energized when conducting these tests. These tests shall be conducted with any regulators or line conditioners that are always in circuit while the console is being used. For the case of regulators or line conditioners that are switched in or out of circuit depending on the meters being verified, the tests shall be conducted once with these devices out of circuit and then repeated with the devices in circuit and turned on.

7.5.2.2
The following distortion tests shall be conducted as applicable at all power factors required for verification pursuant to section 5.2.6.

7.5.2.3 Recti-thermal Demand Meters

7.5.2.3.1
Calibration consoles intended for verifying recti-thermal demand meters, or other meters known to cause distortion, shall have such meters installed in all but one meter-under-test position. Distortion shall be measured at any meter-under-test position at 2.5 amperes and at the lesser of the maximum verification test current for the installed meters, or the maximum current rating of the distortion analyser used,

7.5.2.3.2
Distortion shall be measured at any meter-under-test position at 120 volts and at the lesser of the maximum voltage rating of the installed meters, or the maximum voltage rating of the distortion analyser used.

7.5.2.3.3
In addition, the distortion shall be measured with no meters installed in the meter-under-test positions at 2.5 amperes and at the lesser of the maximum test current used for verifying meters as specified in the information provided pursuant to section 5.2.6, or the maximum current rating of the distortion analyser used.

7.5.2.3.4
In addition, the distortion shall be measured with no meters installed in the meter-under-test positions, at 120 volts and at the lesser of the maximum test voltage used for verifying meters as specified in the information provided pursuant to section 5.2.6, or the maximum voltage rating of the distortion analyser used.

7.5.2.4 1:1 Current Transformers and/or Potential Transformers

7.5.2.4.1
Calibration consoles equipped with 1:1 current transformers and/or potential transformers equipped with multiple secondary taps shall be tested for distortion at any one meter-under-test position equipped with such circuits. The tests shall be conducted with the burden determined pursuant to section 7.1.5.1(a) installed at each meter-under-test position.

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7.5.2.4.2
Distortion shall be measured at 2.5 amperes and at the lesser of the maximum test current used for verifying meters that require the use of 1:1 transformers and/or multiple transformers, **or** the maximum current rating of the distortion analyser used.

7.5.2.4.3
Distortion shall be measured at 120 volts and at the lesser of the maximum test voltage used for verifying meters that require the use of 1:1 transformers and/or multiple transformers, **or** the maximum voltage rating of the distortion analyser used.

7.5.2.5 Other Meters

7.5.2.5.1
Calibration consoles intended for verifying meters other than those identified in 7.5.2.3 or 7.5.2.4 above, shall be tested for distortion with the burden determined pursuant to section 7.1.5.1(b) installed at each meter-under-test position.

7.5.2.5.2
Distortion shall be measured at any meter-under-test position at 2.5 amperes and at the lesser of the maximum test current used for verifying meters having the burden determined pursuant to section 7.1.5.1(b), or the maximum current rating of the distortion analyser used.

7.5.2.5.3
Distortion shall be measured at any meter-under-test position at 120 volts and at the lesser of the maximum test voltage used for verifying meters having the burden determined pursuant to section 7.1.5.1 (b), or the maximum voltage rating of the distortion analyser used.

7.5.3 Distortion shall be calculated according to the formula:

$$\% \text{ Distortion} = \left| \frac{\text{rms of harmonic}}{\text{rms of fundamental and harmonics}} \right| \times 100$$

7.6 Regulation

7.6.1 Calibration consoles intended to verify exponential demand meters, or calibration consoles intended to verify block interval demand meters which do not meet the requirements of section 6.4.9 shall meet the following requirements:

7.6.1.1
The calibration console shall be capable of maintaining test loads for a period of not less than 60 minutes, such that for a 60 minute period, the energy delivered shall be within ±0.25% of the energy that should have been delivered during that period, at the set load. The calibration console shall be allowed to warm up for up to one hour, if required, in order to meet this requirement. The calculation of the expected delivered energy shall be determined using the value of the load indicated on the reference meter following the warm-up period.

7.6.1.2
In addition to the above requirement, energy delivered during the 60 minute period above shall be monitored at nominally, one minute intervals. The duration of each one minute period shall be within ±0.05% of all other one minute intervals.

(i) For the case of consoles intended for verifying electronic or hybrid demand meters, the energy recorded during each one minute interval shall not exceed ±0.2% of the energy expected to be delivered in a one minute period at the load shown on the reference meter at the start of this test.

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(ii) For the case of consoles intended for verifying electromechanical demand meters only, the energy recorded during each one minute interval shall not exceed ±0.3% of the energy expected to be delivered in a one minute period at the load shown on the reference meter at the start of this test.

(iii) The energy monitored in section 7.6.1.1 and 7.6.1.2 shall be in watt hours. Calibration consoles shall be evaluated for compliance to the requirements of section 7.6.1.1 and 7.6.1.2 at the test load determined pursuant to section 7.1.4 with the burden determined pursuant to section 7.1.5 and at the test load determined pursuant to section 5.2.6 with the burden equivalent to the meter that is verified at this test load.

7.7 Current Switching Effects

7.7.1 Maximum Permissible Errors

7.7.1.1
Current switching effects in semi-automatic and automatic consoles shall not introduce error changes greater than 0.2%.

7.7.1.2
Any error resulting from current switching shall not exceed the applicable tolerance set out in section 7.8.

7.7.2 Conditions for Metrological Characteristics

7.7.2.1
Semi-automatic and automatic calibration consoles which have current, potential and/or 1:1 isolation transformers connected between the reference meter and the meter-under-test position(s) shall be tested for current switching effects. Such consoles shall be calibrated at all applicable test loads with the applicable test burdens determined pursuant to sections 7.1.4 and 7.1.5. Using the normal operating mode of the console, the current shall be switched to 10 percent of the test current determined pursuant to section 7.1.4, and back to its original value.

7.7.2.2
The console shall then be recalibrated. This test shall be conducted five times. If the normal operating procedure for the console requires that the load be removed when switching from one setting to another, then this shall be done when conducting this test.

7.8 Console Calibration

7.8.1 Maximum Permissible Errors

7.8.1.1
Calibration consoles intended to verify energy meters, including the energy reference meter with which the console is equipped and any other reference meters that may simultaneously be in circuit while the console is used for verifying meters, shall not exhibit an error greater than ±0.2 percent of reading at any test point.

7.8.1.2
Calibration consoles intended to verify electronic or hybrid demand meters, including the demand reference meter with which the console is equipped and any other reference meters that may simultaneously be in circuit while the console is used for verifying meters, shall not exhibit an error greater than ±0.2 percent of reading at any test point.

7.8.1.3
Calibration consoles intended to verify electromechanical demand meters, including the demand reference meter with which the console is equipped and any other reference meters that may simultaneously be in circuit while the console is used for verifying meters, shall not exhibit an error greater than ±0.5 percent of reading at any test point.

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7.8.2 Conditions for Metrological Characteristics

The errors of calibration consoles shall be determined as follows:

7.8.2.1
Calibration consoles equipped with 1:1 isolation transformers which may be switched in or out of the test circuit during tests shall be calibrated with the isolation transformers in the test circuit, at each meter-under-test position, at each test point for which 1:1 isolation transformers are needed to verify meters as indicated in the information provided pursuant to section 5.2.6.

7.8.2.2
Calibration consoles equipped with 1:1 isolation transformers which are designed to be in the test circuit at all times shall be calibrated at each meter-under-test position, at each test point which will be used to verify meters as indicated in the information provided pursuant to section 5.2.6.

7.8.2.3
Calibration consoles which have current and/or potential transformers connected between the reference meter(s) and the meter-under-test position(s) and which are not equipped with 1:1 isolation transformers or which are equipped with 1:1 isolation transformers which may be switched out of the test circuit, shall be calibrated at any one meter-under-test position with the isolation transformers switched out of the test circuit. The calibration shall be at each combination of voltage and current tap, and selector switch setting at the maximum, and minimum test loads (i.e. test voltage multiplied by test current) for the respective voltage and current tap and selector switch combination used to verify meters as indicated in the information provided pursuant to section 5.2.6. The calibration at these test loads shall be conducted at all power factors used to verify meters as indicated in the information provided pursuant to section 5.2.6.

7.8.2.4
Calibration consoles which:

(i) do not have current and/or potential transformers connected between the reference meter(s) and the meter-under-test position(s); and,

(ii) are not equipped with 1:1 isolation transformers, or are equipped with 1:1 isolation transformers which may be switched out of the test circuit; and,

(iii) have reference meters which have valid certificates of calibration (with traceability to the standards of the National Research Council of Canada) that have expiry dates at or later than, the expiry date of the certificate of calibration for the console, at unity power factor at the maximum and minimum test currents at each test voltage as well as at all test loads at other than unity power factor as indicated in the information provided pursuant to section 5.2.6;

shall be calibrated with the isolation transformers switched out of the test circuit, at any one meter-under-test position, at the minimum, median and maximum test loads(i.e. test voltage multiplied by test current) of the range of loads at unity power factor as well as at all other power factors to be used to verify meters included in the list provided pursuant to section 5.2.6.

7.8.2.4.1
The errors of the calibration console (E_{cons}) at each of the test loads shall be calculated according to equation 1 of section 7.9. If the error of the console at each of the test points is not greater than ±0.1 percent, and all errors are within 0.05 percent of each other, the errors of the console at the other test points shall be calculated by averaging the values of (E_{cons}) at the three test points, and summing the resulting value with the known errors of the reference meter(s).

7.8.2.4.2
Calibration consoles which meet the foregoing requirements except that they do not have valid certificates of calibration as described in (iii) above, or which have errors (E_{cons}) which do not meet the criteria set out in the paragraph above, shall be calibrated at any one meter-under-test position, at the minimum, median, and maximum test currents at each test voltage at unity power factor as well as all other power factors which will be used to verify meters indicated in the list provided pursuant to section 5.2.6.

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7.8.2.5
For calibration consoles which have position to position errors pursuant to section 7.4, less than 0.1%, the errors determined in 7.8.2.3 and 7.8.2.4 above shall be applicable for each meter-under-test position. Calibration consoles which have a position to position error spread between 0.1% and 0.2% pursuant to section 7.4, shall have calibrations of 7.8.2.3 and 7.8.2.4 above, performed at each meter-under-test position.

7.8.2.6
For all of the tests set out in 7.8.2.1 through 7.8.2.4 above, the test burden determined pursuant to section 7.1.5 shall be connected in each meter-under-test position except the position with the standard (and transformer combination); this position shall have the applicable voltage burden connected in parallel with the standard. In the case where the test load exceeds the voltage or current rating of the meters used to burden the meter-under-test position, higher rated meters shall be used to burden the meter-under-test positions.

7.8.2.6.1
If the errors determined in any of the tests pursuant to the applicable subsections of section 7.2 differ by 0.05 percent or less, then the meter-under-test position with the standard does not require a burden for the purposes of performing the tests set out in 7.8.2.3 and 7.8.2.4 above.

7.8.2.6.2
If the errors determined pursuant to section 7.3 differ by 0.05% or less, then test burdens are not required to be placed in any of the other meter-under-test positions not containing the standard for the purposes of performing the tests set out in 7.8.2.3 and 7.8.2.4 above.

7.8.2.7
Calibration consoles which are equipped with more than one reference meter shall be calibrated with all reference meters which will be in circuit simultaneously while the console is used for verification of meters. Calibration consoles that will be used with more than one reference meter either in or out of circuit, shall be calibrated for all combinations of reference meters that will be in circuit simultaneously while the console is being used for verifying meters.

7.8.2.8
Where a console is used with variable combinations of reference meters in or out of circuit, the console shall be calibrated at the test load and test burden pursuant to sections 7.1.4 and 7.1.5 for each combination of reference meter in or out of circuit. The console shall be deemed acceptable for use for each combination of reference meter in or out of circuit that results in errors that are within 0.05% of each other.

7.8.2.9
The certificate of errors for the calibration console shall indicate which reference meters are in circuit for the errors set out in the certificate. The certificate shall also indicate all certified combinations of reference meters used with the console.

7.9 Interchangeability of Console Reference Meters

7.9.1 Energy and/or demand reference meters may be interchanged under the following conditions:

7.9.1.1
A reference meter of one make, type or model shall not be substituted for a reference meter of another make, type or model unless the calibration console has been calibrated and certified for use with reference meters of each make, type and model.

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7.9.1.2
All reference meters intended to be interchanged shall have certificates of calibration (with traceability to the standards of the National Research Council of Canada) that have expiry dates at or later than, the expiry date of the certificate of calibration for the console. The certificate of calibration for the interchangeable reference meters shall be for calibration of the reference meter at each test point which would be used to calibrate the calibration console pursuant to the applicable portions of section 7.8.

7.9.1.3
The combined error, calculated from equations 1 and 2 below, of the calibration console and each reference meter intended to be interchanged, at each test point which would be used to calibrate the console pursuant to section 7.8, shall be not greater than those specified in sections 7.8.1.1 and/or 7.8.1.2.

7.9.2 The error of the console without a reference meter shall be determined from the following formula:

$$E_{cons} = E_{cons\&refA} - R_{cor} \quad (1)$$

Where:

E_{cons}	=	Error of console without reference meter.
$E_{cons\&refA}$	=	Error of console including reference meter (determined pursuant to section 7.8).
R_{cor}	=	Reference meter % correction $\Rightarrow$ (- E_{refA}).
E_{refA}	=	Certified error of original interchangeable console reference meter, traceable to the National Research Council of Canada.

7.9.3 The console errors including interchanged reference meter shall be determined from the following formula:

$$E_{cons\&refB} = E_{cons} + R_{cor} \quad (2)$$

Where:

E_{cons}	=	Error of console without reference meter, determined using equation (1) above.
$E_{cons\&refB}$	=	Error of console with new interchangeable reference meter.
R_{cor}	=	Reference meter % correction $\Rightarrow$ (- E_{refB})
E_{refB}	=	Certified error of new interchangeable console reference meter, traceable to the National Research Council of Canada.

7.9.4 The owner shall append the console errors of the console plus the interchanged reference meter to the original calibration certificate issued for the console. The date and time of installation and removal of any reference meter shall be recorded.

7.10 Pulse Counters and Generators

7.10.1 Maximum Permissible Errors

7.10.1.1
Internal or external pulse counters and pulse generators utilized with calibration consoles, which are intended to be used for verifying devices to be used for revenue metering, shall not exhibit errors exceeding plus or minus one count.

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7.10.2 Conditions for Metrological Characteristics

7.10.2.1
Internal or external pulse counters and pulse generators utilized with calibration consoles, which are intended to be used for verifying devices to be used for revenue metering shall be tested by connecting them to an appropriate pulse generator in accordance with Appendix B. For example, a test time of two minutes and the pulse generating speed shall be the maximum pulse rate specified pursuant to section 7.2.6 for meters with pulse outputs. For testing pulse counters, a constant uniform pulse train of sufficient duration and frequency to register a minimum of 1000 pulses shall be used. The duration of tests shall be such that at least 1000 pulses are registered.

7.11 Rangeability

7.11.1 Maximum Permissible Errors

7.11.1.1
The errors of calibration consoles or accessories thereto which automatically calculate meter errors shall not exceed the tolerances set out in section 7.8 throughout the ranges identified below.

7.11.2 Conditions for Metrological Characteristics

7.11.2.1
Calibration consoles or accessories thereto which automatically calculate meter errors shall be capable of accurately performing such calculations over a range of errors suitable for the intended purpose of the calibration console.

9.0 Revision

The purpose of revision 1 is to format document to the new format for Specifications.

The purpose for revision 2 is to remove the specific format for providing the required information and clarify that completed worksheets of the pre-evaluation testing will serve to address this requirement.

The purpose of revision 3 is to reduce the minimum frequency of the accuracy checks to weekly.

The purpose of revision 4 is to remove the requirement, for the "on state" of the master control switch to be prominently illuminated.

The purpose of revision 5 is to remove the "test links" requirement.

The purpose of revision 6 is to remove the requirement for an "on status indicator" for the creep switch.

The purpose of revision 7 is to clarify that this test is not required, where the power standard is used to setup the test loads.

The purpose of revision 8 is to modify the formula to reflect the correct expression of the test console error.

Project Title: Replace Optimho Relays on TL242

Location: Holyrood to Hardwoods

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This is a project to replace the existing Optimho relays on the 230 kV system east of Bay d'Espoir with modern microprocessor relays. The relay replacement in 2013 will involve the evaluation and selection of the appropriate relay for the application. The Optimho relays used on TL242 between Holyrood and Hardwoods terminal stations are to be replaced in this project. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	42.0	0.0	0.0	42.0
Labour	77.0	0.0	0.0	77.0
Consultant	25.0	0.0	0.0	25.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.7	0.0	0.0	2.7
Interest and Escalation	13.2	0.0	0.0	13.2
Contingency	29.3	0.0	0.0	29.3
TOTAL	**189.2**	**0.0**	**0.0**	**189.2**

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. Line protective relays detect fault conditions on the protected line such as a defective line, line contact between conductors, conductor to ground, or lightning strikes to conductors. 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[4] at each end of the transmission line will

[4] *Circuit breaker is a device to isolate apparatus in the power system. It acts like a switch to stop the current flow to the isolated apparatus.*

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 Electirc) ceased production of the Optimho relays in 2002. A protection consultant (Henville Consulting Inc.) reviewed the protection on all ten 230 KV lines east of Bay d'Espoir Generating Station: five lines were reviewed in 2010 and the remaining five lines in 2011. Historical performance of the protection on the lines was reviewed and actual faults that had occurred in the past were analyzed. Detailed reviews of the settings for each line were also competed. The final report 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 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.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Planning Initiation	January 2013	January 2013
Design	Project Design	February 2013	April 2013
Procurement	Equipment Ordering	February 2013	April 2013
Construction	Field Installation	July 2013	September 2013
Commissioning	Commissioning after Installation	July 2013	September 2013
Closeout	Project Completion and Closeout	October 2013	November 2013

Future Plans:

Future proposals to replace the Optimho relays on the other nine lines east of Bay d'Espoir station will be followed. The plan is to do two lines each year in the following years.

APPENDIX A

Recommendations on Page 3 of consultant final review report

by Henville Consulting Inc.

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.

APPENDIX B

Recommended Protection Upgrade Report

by Henville Consulting Inc.

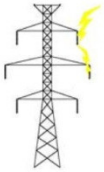
Newfoundland and Labrador Hydro

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

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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.

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.

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

Project Title: Legal Survey of Primary Distribution Line Right Of Way

Location: Various Sites

Category: Transmission and Rural Operations - Properties

Definition: Other

Classification: Normal

Project Description:

Hydro owns and operates approximately 2,370[5] 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 2011, a total of 835 km of distribution line has been surveyed and is being processed through the Department of Environment and Conservation, Lands Division (Crown Lands). In 2012, approximately 150 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 approximately 150 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.

[5] *In early 2011, Hydro re-examined its distribution systems single line drawings and discovered that an additional 120 km of distribution lines were located on Crown lands. The adjusted total length of lines is 2,370 km from previously reported 2,250 km.*

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

Table 1: Budget Estimates

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	3.2	2.5	0.0	5.7
Labour	9.0	9.0	0.0	18.0
Consultant	112.0	20.0	0.0	132.0
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	6.0	0.0	31.0
TOTAL	**156.2**	**40.0**	**0.0**	**196.2**

Operating Experience:

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 and 2012 were contracted out and it is planned that Hydro will continue this practice to contract out this work in 2013 and beyond.

This capital budget has been adjusted based on the cost quotes received from the bids on the 2011 surveys. The cost per km received from those bids range 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 project completion now being 2021.

Table 2: Length of Lines Surveyed

Year	Length (km)	Comments
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 2011 and the budget for 2012.

Table 3: Budget History

Year	Budget ($000)	Actual ($000)
2012B	197.9	
2011	78.7	78.7
2010	65.4	65.4
2009	56.0	54.5
2008	52.0	54.0
2007	50.8	47.9

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 2012, 985 kilometers of distribution line will have been surveyed. The legal surveys are being completed and obtaining title is currently in progress for these surveyed lines.

Project Justification:

The distribution lines occupy Crown land without title, contrary to the Crown Lands Act. Lack of adequate title is a risk to the operation of the lines should competing requirements for the lands arise. In addition, maintenance and upgrading of the lines could be cumbersome and costly without appropriate legal easements when these lands become privately owned. Property owners are reticent to have Hydro accessing their land. The sole purpose of these surveys is to obtain easements over Crown land to prevent other parties from getting title to the land, thereby potentially complicating maintenance of the 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 Hydro to 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 1,385 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)
2013	196.2	151	1,234
2014	197.0	152	1,082
2015	199.4	153	929
2016	197.3	154	775
2017	197.3	155	620
2018	197.3	155	465
2019	197.4	155	310
2020	197.4	155	155
2021	197.4	155	0

Future projects for legal surveys will be proposed in future capital budget applications. See five-year plan (2013 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 2013	February 2013
Prepare survey scope of work and plan Field Work	February 2013	March 2013
Complete surveying	April 2013	September 2013
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 2013 September 2013 January 2014	November 2013 December 2013 May 2014
Close out and documentation	December 2014	December 2014

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 replacement 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)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	41.7	0.0	0.0	41.7
Labour	50.0	0.0	0.0	50.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.1	0.0	0.0	2.1
Interest and Escalation	8.7	0.0	0.0	8.7
Contingency	18.8	0.0	0.0	18.8
TOTAL	**121.3**	**0.0**	**0.0**	**121.3**

The surge arresters target for replacement in 2013 is:

- Three 69 kV and three 25 kV rated surge arresters on transformer T1 at the Coney Arm terminal station;
- Three 138 kV and three 66 kV rated surge arresters on transformer T1 at the Deer Lake terminal station;
- Three 66kV and three 25 kV rated surge arresters on transformer T1 at the Glenburnie terminal station; and
- Three 230 kV and three 138 kV rated surge arresters on transformer T7 at the Holyrood 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 lightning strikes and switching surges. The wide variety of operating environments across the system make 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 40 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. 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 will result in major system disturbances which could result in 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 2013	January 2013
Design	Design transmittal, project work package and commissioning procedures	February 2013	March 2013
Procurement	Material requisition, specification and procurement. Coordinate material delivery. *(4 month lead time)*	February 2013	June 2013
Construction	Deliver surge arresters to designated TS, perform outage including required permits, install surge arresters	July 2013	September 2013
Commissioning	Initial surge arrester commissioning procedures	July 2013	September 2013
Closeout	Project close-out	October 2013	October 2013

Future Plans:

Future replacements will be proposed in future capital budget applications. Surge arrester replacements are planned for the next five years. Please see five-year capital plan in Appendix A.

APPENDIX A

Five-Year Plan For

Surge Arrester Replacements

TABLE A1 – 2013 SURGE ARRESTER REPLACEMENT PLAN

Target Year	Terminal Station Location	Asset Description
2013	Coney Arm	CAM – T1 H1
2013	Coney Arm	CAM – T1 H2
2013	Coney Arm	CAM – T1 H3
2013	Coney Arm	CAM – T1 X1
2013	Coney Arm	CAM – T1 X2
2013	Coney Arm	CAM – T1 X3
2013	Deer Lake	DLKTS – T1 H1
2013	Deer Lake	DLKTS – T1 H2
2013	Deer Lake	DLKTS – T1 H3
2013	Deer Lake	DLKTS – T1 X1
2013	Deer Lake	DLKTS – T1 X2
2013	Deer Lake	DLKTS – T1 X3
2013	Glenburnie	GLB – T1 H1
2013	Glenburnie	GLB – T1 H2
2013	Glenburnie	GLB – T1 H3
2013	Glenburnie	GLB – T1 X1
2013	Glenburnie	GLB – T1 X2
2013	Holyrood	GLB – T1 X3
2013	Holyrood	HRD – T7 H1
2013	Holyrood	HRD – T7 H2
2013	Holyrood	HRD – T7 H3
2013	Holyrood	HRD – T7 X1
2013	Holyrood	HRD – T7 X2
2013	Holyrood	HRD – T7 X3

TABLE A2 – 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	Grand Falls Frequency Converter	GFC – T1 H1, H2, H3 OVERALL
2014	Hawkes Bay	HBY – T2 H1
2014	Hawkes Bay	HBY – T2 H2
2014	Hawkes Bay	HBY - T2 H3
2014	Hawkes Bay	HBY - T2 X1
2014	Hawkes Bay	HBY - T2 X2
2014	Hawkes 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	Massey Drive	MDRTS – T3 XO
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 A3 – 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	Grand Falls Frequency Converter	GFC – T2 H1, H2, H3 OVERALL
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 A4 – 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	Hawkes Bay	HBY – T3 H1
2016	Hawkes Bay	HBY – T3 H2
2016	Hawkes 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 A5 – 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 TOP
2017	Stony Brook	STB – T2 H1 MID
2017	Stony Brook	STB – T2 H1 BOT
2017	Stony Brook	STB – T2 H1 OVERALL
2017	Stony Brook	STB – T2 H2 TOP
2017	Stony Brook	STB – T2 H2 MID
2017	Stony Brook	STB – T2 H2 BOT
2017	Stony Brook	STB – T2 H2 OVERALL
2017	Stony Brook	STB – T2 H3 TOP
2017	Stony Brook	STB – T2 H3 BOT
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

Project Title: Install Transformer Fans

Location: Conne River

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

The scope of work includes the installation of four new cooling fans on transformer T1 in Conne River Terminal Station. The fans will increase the rating of the transformer from 2,500 kVA to 3,333 kVA. The project requires the installation of the fans, the installation of fan power supplies and control systems, testing, and commissioning. The installation of a portable transformer is also required to supply the community of Conne River during the execution of the project. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	0.5	0.0	0.0	0.5
Labour	56.3	0.0	0.0	56.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	26.0	0.0	0.0	26.0
Other Direct Costs	9.2	0.0	0.0	9.2
Interest and Escalation	4.4	0.0	0.0	4.4
Contingency	18.4	0.0	0.0	18.4
TOTAL	**114.9**	**0.0**	**0.0**	**114.9**

Operating Experience:

This proposal is driven by load growth and is not associated with the age or condition of equipment. The existing transformer at Conne River was installed in 1976 and has been operated without incident since that time. A condition assessment of the transformer indicates that the unit is in acceptable condition, with only minor rust on the radiators. The expected lifespan of this transformer is beyond 2017, as documented in the “Upgrade Power Transformers” Capital Project Proposal.

Project Justification:

At present, Conne River Terminal Station is supplied entirely by transformer T1. Based on the

forecast presented in Table 2 below, it is estimated that the total available capacity of 2500 kVA will be exceeded in 2014. Continued operation in an overloaded state will result in the loss of transformer life and premature failure. Hydro's criterion for its major power transformers is to add capacity before transformers reach overload. This is consistent with industry standards.

An alternative to the installation of the transformer fans is to replace the Conne River Transformer T1 in 2013 rather than 2017 or later. Based upon recent purchases of similar units, the expected in service cost of a new 5 MVA transformer is approximately $700,000. The cumulative net present value of the advancement of such a project would be higher than that of the fan installation by approximately $50,000. This is illustrated in Table 3.

Table 2: Conne River Energy and Demand Forecast

2012-2032				
	Customer Sales	Distribution Losses	Deliveries	
Year	MWh	MWh	MWh	kW
2012	10,040	930	10,970	2,385
2013	10,480	970	11,450	2,495
2014	10,880	1,005	11,885	2,585
2015	11,200	1,035	12,235	2,660
2016	11,400	1,055	12,455	2,710
2017	11,600	1,075	12,675	2,760
2018	11,760	1,090	12,850	2,795
2019	11,920	1,105	13,025	2,835
2020	12,080	1,115	13,195	2,870
2021	12,220	1,130	13,350	2,905
2022	12,340	1,140	13,480	2,930
2023	12,440	1,150	13,590	2,960
2024	12,540	1,160	13,700	2,980
2025	12,640	1,170	13,810	3,005
2026	12,740	1,180	13,920	3,030
2027	12,820	1,185	14,005	3,050
2028	12,900	1,195	14,095	3,065
2029	12,980	1,200	14,180	3,085
2030	13,040	1,205	14,245	3,100
2031	13,120	1,215	14,335	3,120
2032	13,200	1,220	14,420	3,135

Notes: 1. Energy sales include domestic, general service, and lighting
2. Energy losses based on Hermitage system historical losses
3. Demands based on recloser readings using 98.5% power factor

Table 3: Cumulative Net Present Value Analysis

Conne River Capacity Increase Alternative Comparison *Cumulative Net Present Value* *To The Year* 2032		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Install Transformer Fans Replace Transformer	603,580 654,206	0 50,626

Project Schedule:

The anticipated project schedule is shown in Table 4.

Table 4: Project Schedule

Activity		Start Date	End Date
Project Management	Scope, schedule, cost, risk, quality and communication planning. Also involves monitoring and controlling project activities.	January 2013	August 2013
Design	Site visits, engineering and design of transformer power supply drawings, coordination and review of consultants design, issue for construction work package.	January 2013	August 2013
Procurement	Scope of work and technical specification for third party contract work for design, supply and installation transformer fans. Purchase of miscellaneous materials.	February 2013	April 2013
Construction	Installation of transformer fans and associated power and control cabling, including Owner Site Representative.	October 2013	October 2013
Commissioning	Testing and commissioning operation of the transformer with new fans.	October 2013	October 2013
Closeout	As built drawing review. Procurement contract close out, project financial close out and post implementation review.	November 2013	November 2013

Future Plans:

None.

Project Title: Replace 230 kV Breaker Controls

Location: Bottom Brook

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the existing electromechanical controls on two 230 kV circuit breakers; L11L33 and L09L33 at the Bottom Brook Terminal Station. The work will involve purchasing and installing a Programmable Automation Controller for each breaker to operate in the same manner as the existing controls. The existing controls will be removed, replaced with the new controller and tested to ensure proper functionality. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	9.3	0.0	0.0	9.3
Labour	42.8	0.0	0.0	42.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.0	0.0	0.0	2.0
Interest and Escalation	4.0	0.0	0.0	4.0
Contingency	10.8	0.0	0.0	10.8
TOTAL	**68.9**	**0.0**	**0.0**	**68.9**

Operating Experience:

Circuit breakers at terminal stations are protection devices that interrupt the flow of power when an electrical disturbance such as a fault occurs. An electrical fault occurs when there is a malfunction in an electrical circuit that causes current to flow to ground or between conductors if they come into contact with each other. This current is sufficiently high to cause damage to electrical equipment in the terminal station. Circuit breakers react to this high current by acting like a switch to stop the current flow. Circuit breakers are complex mechanisms that have control devices that allow them to operate in a predefined manner to provide the required protection. When a fault occurs on a transmission line, circuit breakers at the terminal stations react by tripping or switching off the transmission line so that no damage occurs. Often the fault is cleared immediately. The breaker

control will react in a timely fashion, usually within seconds, to automatically reclose the associated breaker to minimize the transmission line outage. If the fault is not cleared, the breaker control allows the circuit breaker to take the transmission line out of service to avoid damage.

The 230 kV breaker controls on L09L33 and L11L33 are obsolete and are no longer available from manufacturer. As indicated in Table 3, they are in excess of 34 years old and have exceeded their useful lives of 30 years. Table 3 also lists other 230 kV circuit breakers that have had upgraded controls since 2000. The controls on 230 kV breakers L09L33 and L11L33 consist of electromechanical relays and timers that operate the tripping and reclosing circuits of the breaker. The controls for the two breakers are comprised of discontinued electromechanical relays. Figure 1 represents a typical example of an obsolete system.

Figure 1: Discontinued Breaker Control Package

Project Justification:

This project is justified on the need to continue supplying reliable electrical power. The two 230 kV breaker controls are composed of outdated and discontinued electromechanical relays. Current automation technology allows for replacements with less hardwiring and the benefit of self-diagnostic testing and expansion of functionality for future considerations. If a failure occurs, it is anticipated that prolonged system outage or system instability could result if the breaker does not reclose normally. This project is required to continue the ongoing work to upgrade the breaker controls systems to current technology as anticipated in Table 2 below. Figure 2 is an example of a microprocessor based relay that was recently installed at the Buchans Terminal Station.

Figure 2: Microprocessor Based Relay

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Planning Initiation	January 2013	January 2013
Design	Project Design	February 2013	May 2013
Procurement	Equipment Ordering	February 2013	May 2013
Construction	Field Installation	June 2013	July 2013
Commissioning	Commissioning after Installation	June 2013	July 2013
Closeout	Project Completion and Closeout	August 2013	September 2013

Future Plans:

Future replacements will be planned as necessary on the basis of age and performance.

Table 3: 230kV Breaker Controls with Single Pole Reclosing

Station	Breaker	Details
STB - Stony Brook	L05L35	Upgraded 2000 with PLC
STB - Stony Brook	B1L31	Upgraded 2001 with PLC
STB - Stony Brook	B2L04	Upgraded 2001 with PLC
BUC - Buchans	B1L05	Upgraded 2002 with PLC
BDE - Bay D'Espoir	B4B5	Upgraded 2002 with PLC
SSD - Sunnyside	B1L03	Upgraded 2003 with PLC
SSD - Sunnyside	L06L07	Upgraded 2003 with PLC
HRD - Holyrood	B1L17	Upgraded 2004 with PLC
WAV - Western Avalon	B1L17	Upgraded 2004 with PLC
MDR - Massey Drive	B1L28	Upgraded 2005 with PLC
BBK - Bottom Brook	B1L11	Upgraded 2005 with PLC
BDE - Bay D'Espoir	B3B4	Upgraded 2006 with SEL-2411
BUC - Buchans	L05L33	Upgraded 2006 with SEL-2411
OPD - Oxen Pond	B1L36	Upgraded 2008 with SEL-2411
SSD - Sunnyside	L03L06	Upgraded 2008 with SEL-2411
WAV - Western Avalon	L01L03	Upgraded 2008 with SEL-2411
WAV - Western Avalon	L03L17	Upgraded 2008 with SEL-2411
OPD - Oxen Pond	B1L18	Upgraded 2009 with SEL-2411
BDE - Bay D'Espoir	B5B6	Upgraded 2009 with SEL-2411
BDE - Bay D'Espoir	L06L34	Upgraded 2009 with SEL-2411
MDR - Massey Drive	B5L11	Upgraded 2010 with SEL-2411
BUC - Buchans	L28L32	Upgraded 2010 with SEL-2411
BUC - Buchans	B1L28	Upgraded 2010 with SEL-2411
BBK - Bottom Brook	L11L33	Proposed to be upgraded in 2013, age 34 years
BBK - Bottom Brook	L09L33	Proposed to be upgraded in 2013, age 39 years
BBK - Bottom Brook	B1L09	Relays; age 34 years
DLK - Deer Lake	B3L48	Relays; age 29 years
DLK - Deer Lake	B3L47	Relays; age 27 years
HWD - Hardwoods	B1L36	Relays; age 26 years
SSD - Sunnyside	L03L06	Relays; age 22 years
SSD - Sunnyside	B1L02	Relays; age 22 years
HRD - Holyrood	B2L42	Old relays, no clear evidence of age but older than 28 years
HRD - Holyrood	B12L42	Old relays, no clear evidence of age but older than 28 years
HRD - Holyrood	B12L17	Old relays, no clear evidence of age but older than 28 years
HWD - Hardwoods	B1L01	Old relays, no clear evidence of age but older than 28 years

The proposed two circuit breakers are located in the Bottom Brook 230kV ring bus. As a result of this inherent flexibility in station layout for system reliability, outages to the breakers for installation and commissioning of the new controls will not require outages to the transmission lines or customers.

Project Title: Replace Network Communications Equipment

Location: Various Sites

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This project is to replace firewalls (10) and switches (3) at Hydro Place, Holyrood Plant, and the Backup Control Center at Holyrood which are nearing obsolescence. A detailed list by location is provided in the following table.

Table 1: Equipment to be Retired

Location	Current Device	Date Acquired	End of Life
Hydro Place	Juniper Netscreen 208 Firewall	2005/01/02	2013
Holyrood	Cisco PIX 506E Cisco Firewall	2004/09/24	2013
Holyrood	Cisco PIX 506E Cisco Firewall	2003/09/24	2013
Hydro Place	Cisco PIX 506E Cisco Firewall	2004/11/08	2013
Hydro Place (EMS Level 2)	2950-24 Cisco Switch	2006/12/01	2013
Hydro Place (Test FW)	PIX 506E Cisco Firewall	2006/04/03	2013
EMS Computer Room	PIX 506E Cisco Firewall	2005/01/01	2013
EMS Computer Room	PIX 506E Cisco Firewall	2005/01/01	2013
EMS Computer Room	PIX 525 Cisco Firewall	2005/08/09	2013
EMS Computer Room	PIX525 Cisco Firewall	2005/08/09	2013
Holyrood (BCC)	PIX525 Cisco Firewall	2005/08/09	2013
Hydro Place	2950-24 Cisco Switch	2005/08/09	2013
Hydro Place	2950-24 Cisco Switch	2005/08/09	2013

The budget estimate for this project is shown in Table 2:

Table 2: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	82.2	0.0	0.0	82.2
Labour	59.1	0.0	0.0	59.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.7	0.0	0.0	0.7
Interest and Escalation	12.0	0.0	0.0	12.0
Contingency	28.4	0.0	0.0	28.4
TOTAL	**182.4**	**0.0**	**0.0**	**182.4**

Operating Experience:

Vendor support and security updates for the equipment being replaced will not be available after 2013.

Project Justification:

The project is required in order to ensure the reliability and fitness for use of Hydro's Administrative, Energy Management System (EMS), Backup Control Center (BCC), and Supervisory Control and Data Acquisition (SCADA) networks. Critical networking components must be replaced at or before obsolescence since vendor support, replacement parts, and security updates are not available for obsolete devices. Networking devices and infrastructure must often be upgraded or replaced in order to support the evolving needs of the organization such as increasing headcount and traffic.

Future Plans:

Future communication equipment replacements will be proposed in future capital budget applications. See Five-Year Capital Plan (2013 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	Complete a detailed schedule and budget with resource assignments.	January 2013	March 2013
Design	Complete a detailed design with all items and outages identified.	April 2013	May 2013
Procurement	Complete all ordering and detailed schedules for delivery.	May 2013	June 2013
Install First Set of Firewalls	Install the smaller firewalls and switches.	July 2013	August 2013
Install the Internet Firewall	Install and commission the replacement for the Juniper Netscreen 208 Firewall with an outage.	September 2013	September 2013
Closeout	Complete all drawings, configuration and release management, and project closeout.	November 2013	December 2013

Project Title: Replace Telephone System

Location: St. Anthony

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This project consists of replacing the existing Nortel Norstar telephone system at Hydro's St. Anthony office with an Avaya Private Branch Exchange (PBX) system and expanding the new system to include the St. Anthony Diesel Plant. 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)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	40.1	0.0	0.0	40.1
Labour	52.9	0.0	0.0	52.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	12.4	0.0	0.0	12.4
Interest and Escalation	8.9	0.0	0.0	8.9
Contingency	21.1	0.0	0.0	21.1
TOTAL	**135.4**	**0.0**	**0.0**	**135.4**

Operating Experience:

The telephone system was originally installed in the 1980s by Newtel Communications and rented by Hydro. In 1995 Hydro purchased the system and all maintenance since this date has been performed by Hydro's internal personnel. This system has performed well with minimal failures; however it has reached its capacity and cannot meet Hydro's current needs. The existing system can support 24 telephone lines of which 22 are in usage. There is now a need for 27 lines to incorporate the four separate lines currently in the diesel plant and to add one extra line for the office area boardroom. The diesel plant's telephone system is segmented from the administrative and maintenance facilities not allowing for efficient business communications among the three facilities such as local voice mail, call display and paging. The proposed new system which can

accommodate 32 lines and is expandable up 190 lines will bring the St. Anthony telephone system up to the standard of other Hydro facilities.

Also, the existing systems are manufacturer discontinued with no further support or parts available. The telephone system has an anticipated useful life of ten years. Hydro has installed similar systems in Happy Valley (2009), Ramea (2010), Wabush (2011) and Port Saunders and Whitbourne planned for 2012.

Project Justification:

The existing telephone system has a fixed capacity, cannot be expanded and is not supported because of obsolescence and the original provider, Nortel is no longer in business. The new system has voice mail capabilities and automated attendant features such as routing calls to the appropriate persons. Specifically, this system will allow voice communications within the office and to external warehouses, garages, line depots and the diesel plant to remain functional in the event of a loss of service from the telephone service provider. This added capacity provides for safe and efficient office operation.

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 2013	February 2013
Design	Prepare design brief; make hardware selection; prepare dial plans, technical and functional design.	February 2013	March 2013
Procurement	Prepare and review technical specifications for tender; Award tender.	April 2013	May 2013
Construction	Model entire system in Hydro's lab to verify configuration and system functionality, performance and features.	May 2013	June 2013
Commissioning	Travel to site to install new telephone system paging speakers and test and verify customer acceptance.	August 2013	September 2013
Closeout	Complete as build diagrams and finalize technical documentation, lessons learned and project closeout and completion certificate.	October 2013	October 2013

Future Plans:

Similar replacements are proposed for the Stephenville Office in 2014 and the Deer Lake Office in 2015. See the Five-Year Capital Plan (2013 Capital Plan Tab, Appendix A)

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)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	19.2	0.0	0.0	19.2
Consultant	85.0	0.0	0.0	85.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	4.9	0.0	0.0	4.9
Contingency	20.8	0.0	0.0	20.8
TOTAL	**129.9**	**0.0**	**0.0**	**129.9**

Operating Experience:

The Monarch Energy Management System (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 2012. 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:

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 March 2013 and end in July 2013.

Project Schedule:

This project will be started in April 2013 and completed by the end of July 2013.

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 (2013 Capital Plan Tab, Appendix A).

Project Title: Upgrade Enterprise Storage Capacity

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

This project is to provide an additional 60 TB of disk storage to the V7000 SAN to serve the Intel Enterprise Servers. The DS4700 SAN (installed in 2007), DS4800 SAN (installed in 2008) and the V7000 (installed in 2011) provide disk storage for the corporate Intel Enterprise Servers. This project will give Hydro the capacity to anticipate and mitigate the data growth imposed by large scale projects in the future.

34TB of this storage will cover growth of existing file systems, establish 30% reserve capacity, provide replacement storage for the DS4700 SAN that is retiring in 2013 and support increased requirement for GIS storage.

The remaining 26TB represents additional storage being acquired in 2013 to contribute toward future storage requirement in 2014 for decommission of the DS4800 SAN in that year.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	133.0	0.0	0.0	133.0
Labour	17.5	0.0	0.0	17.5
Consultant	6.3	0.0	0.0	6.3
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	6.7	0.0	0.0	6.7
Contingency	31.4	0.0	0.0	31.4
Sub-Total	194.9	0.0	0.0	194.9
Cost Recoveries	(70.2)	0.0	0.0	(70.2)
TOTAL	**124.7**	**0.0**	**0.0**	**124.7**

Operating Experience:

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 up. Due to the growing need for storage, it is imperative that we have ample reserve storage.

When calculating disk requirements, there is a 25 percent overhead of storage space which is consumed in providing redundancy to the data; Example:

1 TB of useable space with failure redundancy requires 1.25 TB of disk

Additionally, Hydro keeps approximately 30 percent unallocated disk in reserve to satisfy growth resulting from such activities as large volumes of data being brought into the system by a project or business unit. These additional quantities of storage are included in the final storage estimates required to maintain a healthy system able to respond to business demands; Example:

1 TB of useable space with failure redundancy requires 1.25 TB disk
+ 30 percent reserve (1.25TB * 130 percent)
= 1.625 TB total disk

Support and Maintenance on these systems is generally purchased at acquisition for a five year period, with one year of additional support purchased for the sixth year, which is the standard lifetime of the hardware. Beyond 6 years, the maintenance programs become increasingly more expensive as the hardware become less reliable and parts in shorter supply.

Project Justification:

The servers that are attached to the storage area network are used by Hydro employees in running the business on a daily basis. Loss of production processing on these servers due to disk space unavailability would have a negative effect on employee productivity and customer service. The existing Enterprise Storage systems have approximately 17 percent reserve storage combined, which is insufficient to meet anticipated storage requirements for 2013.

The DS4700 SAN (approximately 20TB) is due for retirement in 2013. GIS Data requirements have

increased (additional 5TB in storage in 2013), and the natural growth of data and storage for increasing numbers of virtualized servers (replacing physical servers where possible) requires additional storage in the V7000 SAN.

The V7000 SAN was previously purchased (2011) to replace aging SAN units and provide the required storage for business use. A total of 34TB of additional storage is required in 2013 to accommodate natural growth, new GIS requirements, and retirement of the DS4700.

Future Plans:

The future plan for Enterprise Storage is to manage the disk capacity on our SANs to operate a healthy and responsive enterprise storage system able to meet the data storage demands of the business.

In 2013 we will begin to consolidate our older storage systems onto the current generation of storage technology (V7000 SAN). New storage will now be placed on the V7000 system whenever possible.

A further 26TB of additional storage will be purchased in 2013 in preparation for retirement of the DS4800 SAN in 2014. This represents approximately 30% of the required storage purchases for the V7000 in preparation for DS4800 retirement in 2014.

By the end of 2014 (with additional V7000 disk purchases in 2014) we will have reduced the current number of SANs providing corporate data services by consolidating to the V7000 SAN and migrating data from the DS4700 and DS4800 systems.

Therefore, 60 TB (34TB + 26TB) will be required to cover current and future storage requirements in 2013.

Project Title: Replace Computer Room Air Conditioner

Location: Hydro Place

Category: General Properties - Administrative

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the computer room air conditioner. The existing air conditioner has been in service since 1989 and is not reliable in cooling the computer room. The current air conditioner will be replaced with a Liebert 12-ton DS precision cooling system, with an outdoor air cooled condensing unit. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	40.0	0.0	0.0	40.0
Labour	21.4	0.0	0.0	21.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	45.0	0.0	0.0	45.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	2.3	0.0	0.0	2.3
Contingency	21.3	0.0	0.0	21.3
Sub-Total	130.0	0.0	0.0	130.0
Cost Recoveries	(46.8)	0.0	0.0	(46.8)
TOTAL	**83.2**	**0.0**	**0.0**	**83.2**

Operating Experience:

The air conditioners have been in service since their installation in 1989 when Hydro Place was originally built. One computer room air conditioner will be replaced in 2012. The replacement is not due to the cooling load increase and is a like for like replacement. The computer room requires two air conditioners to cool the equipment and if one unit fails the other air conditioner cannot sustain the cooling requirements for the room. The computer room houses all the computer servers that are used by staff in carrying out their day to day work. The servers provide the business functions for the company such as General Ledger, Accounts Payable, Accounts Receivable, Fixed Assets, Job Costing, Purchasing, Inventory, Human Resources, Payroll, Plant Equipment Management, Work Orders, and Customer Services and Corporate Email.

Project Justification:

Failure of the air conditioners puts the computer equipment at risk of malfunctioning as the temperature will rise above the operating temperatures tolerated by the equipment. This will negatively affect Hydro's operation as the computer systems are used in day to day operations and business functions.

A report by IBM in 2009 recommended the air conditioners be replaced in two to three years before they became too unreliable. Refer to Appendix A: NL Hydro – Energy & Health Check Report.

This project will start in March 2013 and end in September 2013.

Future Plans:

None.

APPENDIX A

NL Hydro – Energy & Health Check Report

Mechanical Systems

Computer Room Air Conditioning

The temperature and humidity levels in the computer room are controlled by two Liebert precision air conditioning units. Each unit is rated at 10-tons (nominal). The following table lists the capacities and readings for each of these units:

Table 17: Air Conditioner Inventory

Model Information			Sensible Rating		Temperature (°F)			Humdification (RH)			Fan		Vane
Unit #	Model Number	Manu. Date	BTU	Tons	Reading	Set	Sens	Reading	Set	Sens	HP	CFM	Y/N
AC-10	Liebert FH114A-B00	Jun 1989	115,600	9.63	74	70	3	41%	45%	3%	1.5	4,650	N
AC-11	Liebert FH114A-B00	Jun 1989	115,600	9.63	71	71	1	48%	45%	3%	1.5	4,650	N
	TOTALS		231,200	19.3								9,300	

The air conditioning units in the computer room were manufactured in 1989. While these units are capable of operating beyond 20 years of age, it should be expected that reliability may become an issue as the years progress. There are previous service records left inside the AC units that indicate the units are maintained regularly. Other customers have reported to IBM that getting replacement parts for units of this age is becoming more difficult. NL Hydro has reported that it may not be possible to replace these units for another 2-3 years.

The AC units run autonomously. Each unit controls its own particular part of the room without regard to the operating status of the other unit. As such, it was not uncommon to observe one unit humidifying the room, while the other was de-humidifying. The heating circuit of one AC unit may be engaged while the other unit is simultaneously attempting to cool the room. The cooling load in the room (9.8 tons) is slightly above the total sensible capacity of either of these AC units. Redundancy may only be possible in limited circumstances. The unit that is closest to the IT equipment racks likely absorbs most of the workload. The other AC unit next to the operator's station probably does not see the same workload. Anecdotal evidence seems to confirm that only the AC unit next to the operator's station can realistically be removed from service for any length of time without adversely affecting the IT equipment. The same cannot be said of the other AC unit.

The set-points that have been selected for the AC units are 2-3°F higher than the AC units in the EMS room. The sensitivity range (or dead-band) of AC-10 is set higher as well. This, combined with its proximity to a majority of the IT equipment heat load, explains why the return air temperature (74°F) is higher. Despite these differences, temperature control at the face of the IT equipment rack was relatively stable and within the recommended ranges.

A temperature logger was installed at mid-point at the face of two equipment racks (PROD-3 and PROD-6) to determine how well temperatures are being controlled at the face of the racks. The results indicate that air temperature for both racks falls within the recommended temperature range of 64°F-80°F (see appendix). Albeit, these temperatures were at the lower end of the recommended range, indicating that some efficiency gains can still be made.

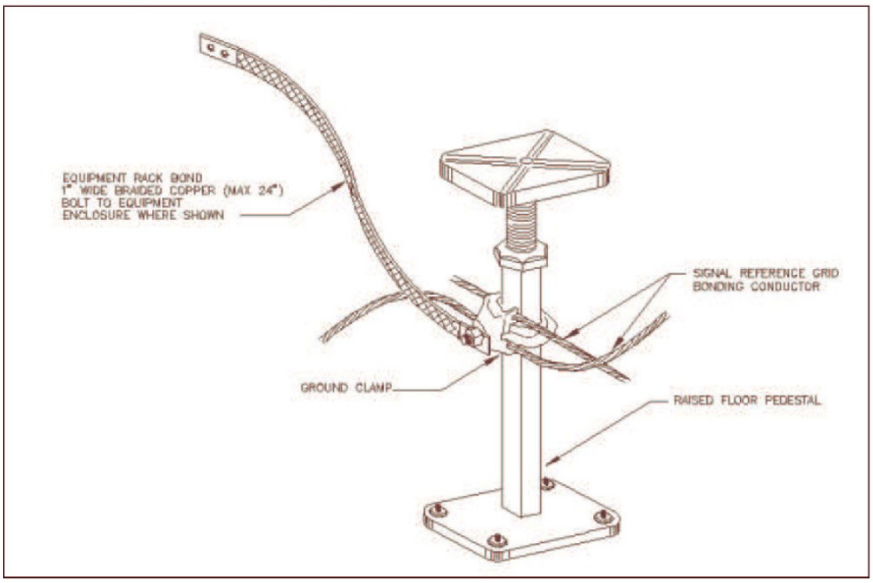
Humidity levels in the ADMIN computer room appeared to be influenced by external migration of outdoor moisture. There were no observed vapour barriers installed in the walls of the computer room. On the day of the initial site inspection, the weather was extremely rainy. As a result, humidification cycles (and de-humidification cycles) alternated between each AC unit, sometimes operating at cross-purposes simultaneously. Despite this, however, humidity levels at the rack faces were controlled to within the recommend range (see appendix).

- It is not currently possible to identify which IT servers or devices are connected to which circuit breaker. A method of cross-referencing this information should be created. In this way, it will be a simple matter to know which IT devices are implicated by any circuit overloads or planned service actions.
- Branch circuit labelling should be consistently administered at each receptacle and at the breaker panels. Receptacles should be labelled at their faceplates with a mechanically created label. Up to date panel schedules should be kept with each circuit breaker panel. The names of the circuits servicing each IT equipment rack should be posted on the rack itself.

Grounding

- Grounding in the EMS computer room has not been installed as per the Canadian Electrical code or the IEEE-1100 grounding guidelines. The raised access floor must be bonded to ground. Individual IT equipment racks should also be bonded to the signal reference grid created by the floor ground. This also applies to air conditioning units, PDUs, circuit breaker panels, LAN racks, and any other device mounted on the raised floor.

Figure 18: Typical Rack Grounding Method



Mechanical Systems

AC Systems

- The age of the AC units will likely require NL Hydro to replace them within the next two to three years. Hopefully these units will not become totally unreliable before that time. The AC units that will ultimately replace the existing units should have some features included that are not currently installed on the existing units. These features include:

- Un-loader technology, variable speed fans, and/or digital scroll compressor technology to accommodate lightly loaded room conditions.
- Web/SNMP connection capability to allow the new AC units to communicate directly to a monitoring system and/or internal LAN.
- Inter-unit communications capability to allow AC units to operate collaboratively within each room. Various control scenarios should be explored to understand which will work best for each room (teamwork mode vs. standby mode vs. cascade mode)
- Ducting capability to allow the ceiling plenum space to be used as a hot air return.

- In the interim, the existing AC units can be configured to use less energy. There is no need to run both AC units in the EMS room simultaneously. An auto-changeover controller could be installed that would cycle each of these units on and off according to a set schedule. The position of the AC units in the room with respect to the orientation of the IT equipment racks will likely require the units to be ducted into the ceiling so that the ceiling plenum space can be used as a hot air return. Zinc whisker contamination issues in the ceiling space will first need to be addressed.
- In the ADMIN room, it will still be necessary to run both units simultaneously. However, some set-point adjustments could still be made if the air flow patterns in the room can first be improved. Again, ducting of the AC units will help to improve hot air return. When the time comes to replace these AC units, more advantageous positioning of the new units and some strategic baffling under the raised floor may permit a "standby" mode to be used in this room as well. This would allow the AC units to take turns controlling the room instead of both units running simultaneously. However, careful planning should be done before this is attempted. CFD modeling of the space would likely be necessary to ascertain where the units should best be positioned in the room, if under-floor baffling provides an advantage, and if a single AC unit can maintain the environment under present and future design loads.
- The temperature set-points and sensitivity ranges should be standardized on each AC unit. If air flow improvements can be made to each room, it will be possible to raise the set points of each AC unit. This will have a significant and direct impact on energy consumption and efficiency.
- Water leak dams or pans should be installed below the AC units to channel possible leaks towards leak detectors that will need to be installed under the raised floor inside the water dams.
- The water leak detection system should be extended to include the drains that are present under the raised floor, especially in the ADMIN room. Each drain should be provided with a back-flow prevention device.

Air Flow

- Many cable cut-outs in the rear of equipment racks have not been properly sealed to prevent loss of air pressure under the floor. This also promotes air "bypass" problems for the air conditioning units. An example of a device that will greatly reduce this air leakage is shown at right. A "split" version of the device is available that will allow it to be installed over existing floor penetrations without disturbing the cables. There are also fire-rated memory-foam pillows that can be used to achieve the same effect. However, these devices are dependent on users replacing them back into the holes if they are removed, and do not absolve NL Hydro from also sealing the exposed wood-core cuts in the floor tiles with a fire-rated grommet.

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)*	**2013**	**2014**	**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	5.5	0.0	0.0	5.5
Contingency	11.0	0.0	0.0	11.0
Sub-Total	126.8	0.0	0.0	126.8
Cost Recoveries	(45.7)	0.0	0.0	(45.7)
TOTAL	**81.1**	**0.0**	**0.0**	**81.1**

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 2011, the most recent year for which actual data is available, the following application enhancements were made:

- Upgrades to corporate reporting systems; and

- Upgrade to TRIM document management systems.

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 upgrades that have occurred from 2007-2012B.

Table 2: Application Enhancements

Year	Budget ($000)	Actual ($000)	Comments[6]
2012B	123.4[7]	0.0	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
2007	148.5	148.5	Upgrade

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning	January 2013	April 2013
Design	February 2013	June 2013
Procurement	March 2013	August 2013
Construction	March 2013	November 2013
Commissioning	May 2013	November 2013
Closeout	May 2013	December 2013

Future Plans:

Future enhancements will be proposed in future capital budget applications. Also see five-year capital plan (Capital Plan 2013 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: Replace Helpdesk Service Manager Application

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

The project will replace the existing helpdesk application for the information system department which has received an end of support notice from the manufacturer. The Helpdesk tool is used to record incidents and requests that are received at the information systems helpdesk. The software allows for a standard process to record all requests and changes and help provide better customer service to the information systems users. The budget estimate for this project is shown in Table 1. The cost recovery is based on a 36% ratio which is utilized when the software implemented is used by all divisions.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	24.2	0.0	0.0	24.2
Labour	16.8	0.0	0.0	16.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	36.0	0.0	0.0	36.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	4.1	0.0	0.0	4.1
Contingency	15.4	0.0	0.0	15.4
Sub-Total	96.5	0.0	0.0	96.5
Cost Recoveries	(34.7)	0.0	0.0	(34.7)
TOTAL	**61.8**	**0.0**	**0.0**	**61.8**

Operating Experience:

The existing helpdesk application was put into service in 2005. The application is used to record service requests from approximately 1200 employees. The service requests are then assigned to second tier support staff when the request can not be resolved during the initial phone call. The application tracks who is responsible for the service request and its status.

Project Justification:

The existing product is no longer supported by its vendor.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning Activity	March 2013	April 2013
Design Activity	March 2013	April 2013
Procurement	May 2013	May 2013
Construction Activity	June 2013	August 2013
Commissioning	September 2013	September 2013
Closeout Activity	September 2013	September 2013

Future Plans:

The replacement application will be used by helpdesk staff and upgraded on a regular basis to keep up with vendor support.

PROJECT DESCRIPTION	Expended to 2012	2013	Future Years	Total	PUB Approval	Ref. No.
			($000)			
Replace Static Excitation Systems - Upper Salmon, Holyrood and Hinds Lake	1,813.9	2,295.2		4,109.1	P.U. 38 (2010) 2011 Capital Budget	1
Replace Emergency Diesel Generator - Bay d'Espoir	611.4	282.7		894.1	P.U. 2 (2012) 2012 Capital Budget	2
Rewind Generator Units 1 and 2 - Holyrood	112.2	1,107.6	10,681.4	11,901.2	P.U. 5 (2012) 2012 Capital Budget	3
Replace Fuel Oil Heat Tracing - Holyrood	1,474.3	1,413.9		2,888.2	P.U. 5 (2012) 2012 Capital Budget	4
Replace Compressed Air Piping - Buchans	28.4	278.3		306.7	P.U. 2 (2012) 2012 Capital Budget	5
Upgrade Distribution Lines - Bay d'Espoir, Parsons Pond and Plum Point	1,385.2	1,110.5		2,495.7	P.U. 2 (2012) 2012 Capital Budget	6
Upgrade JD Edwards - Hydro Place	187.4	387.8		575.2	P.U. 2 (2012) 2012 Capital Budget	7
Upgrade Electrical Equipment - Holyrood	209.6	212.1		421.7	P.U. 38 (2010) 2011 Capital Budget	8
Perform Grounding Upgrades - Various Sites	645.2	329.0	682.5	1,656.7	P.U. 38 (2010) 2011 Capital Budget	9
Replace Guy Wires TL215 - Doyles to Grand Bay	606.8	350.1	530.0	1,486.9	P.U. 38 (2010) 2011 Capital Budget	10
Voltage Conversion - Labrador City	8,430.8	969.5		9,400.3	P.U. 1 (2010) 2010 Capital Budget	11
Upgrade L2 Distribution Feeder - Glenburnie	2,960.1	596.6		3,556.7	P.U. 1 (2010) 2010 Capital Budget	12
Perform Arc Flash Remediation - Various Sites	809.8	391.0	814.9	2,015.7	P.U. 38 (2010) 2011 Capital Budget	13
Install Automated Meter Reading - Plum Point and Bear Cove	379.6	287.7		667.3	P.U. 2 (2012) 2012 Capital Budget	14
Replace Off Road Track Vehicles - Flower's Cove and Cow Head	482.5	395.6		878.1	P.U. 2 (2012) 2012 Capital Budget	15
Replace Vehicles and Aerial Devices (2012-2013) - Various Sites	1,711.4	1,218.8		2,930.2	P.U. 2 (2012) 2012 Capital Budget	16

1. Replace Static Excitation Systems – Upper Salmon, Holyrood and Hinds Lake

The initial project schedule and estimated cost are listed in the table below.

Year	Activity	Cost ($000)
2011	Design and Installation of the Static Excitation System – Upper Salmon	1,214.3
2012	Design and Installation of the Static Excitation System – Holyrood Unit 3	1,528.0
2013	Design and Installation of the Static Excitation System – Hinds Lake	1,366.8
	Total	4,109.1

The intent was to tender for all three excitation systems and install one in Upper Salmon in 2011. There was insufficient time allotted for design, procurement, delivery and installation in 2011. In addition, the Hinds Lake exciter has experienced four failures in 2011 (one each in March, April, May and June); therefore it has become the first priority for replacement. In 2011, the annual budgets were adjusted with the bulk of the expenditures occurring in 2012 due to Hinds Lake and Holyrood Unit 3 installations occurring in the same year. Hydro has decided to defer installation of the exciter at Holyrood from 2012 to 2013. This schedule change followed a constructability review of all planned and carried over capital projects for Holyrood Unit 3 in 2012 and 2013. The decision to defer the exciter installation allows Hydro to better distribute the level of activity on Unit 3 over the two years and alleviated the impact of an unexpected, temporary shortage in plant electrical and instrumentation resources in 2012. The project schedule and cost have been adjusted to reflect the necessary changes. There has been no change to the overall project cost as shown in the table below. This is also reflected in the 2013 Capital Budget Application.

Year	Activity	Cost ($000)
2011A	Design and tender for all three excitation systems.	16.8
2012	Install Excitation Systems – Hinds Lake	1,797.1
2013	Install Excitation System – Upper Salmon and Holyrood Unit 3	2,295.2
	Total	4,109.1

The scope for this project remains unchanged and the project is expected to be completed within budget.

2. Replace Emergency Diesel Generator

This project is required to replace the emergency diesel generator, control panel and associated auxiliary equipment in Powerhouse No. 1 at the Bay d'Espoir Generating Station.

The project cost by year is shown in the table below.

Year	Cost ($000)
2012	611.4
2013	282.7
Total	894.1

The scope for this project remains unchanged and the project is expected to be completed within budget.

3. Rewind Generator Units 1 and 2

This project consists of the replacement of the stator windings for Unit 1 and Unit 2 thermal generating units at the Holyrood Thermal Generating Station (Holyrood). Along with the replacement of stator windings, the project would include an upgrade to the generator protection and remediation of asbestos from the stator windings. Hydro intends to replace the stator winding in Unit 2 in 2014 and Unit 1 in 2015.

The project cost by year net of cost recoveries is shown in the table below.

Year	Cost ($000)
2012	112.2
2013	1,107.6
2014	4,885.7
2015	5,795.7
Total	11,901.2

The scope for this project remains unchanged and the project is expected to be completed within budget.

4. Replace Fuel Oil Heat Tracing

This project is a two-year plan to replace the electric heat tracing system on the fuel oil delivery pipeline at the Holyrood Thermal Generating Station. The existing copper mineral insulated electric heat tracing cables will be replaced with new stainless steel electric heat tracing cable. This project was approved in 2012 however, Hydro is not permitted to recover the costs of this project unless otherwise ordered by the Board.

The project cost by year is shown in the table below.

Year	Cost ($000)
2012	1,474.3
2013	1,413.9
Total	2,888.2

The scope for this project remains unchanged and the project is expected to be completed within budget.

5. Replace Compressed Air Piping and Install Dew Point Monitor

The aging compressed air distribution piping at the Buchans Terminal Station will be replaced under this project. A new compressed air dew point monitoring system and back-up compressed air dryer will also be installed.

The project cost by year is shown in the table below.

Year	Cost ($000)
2012	28.4
2013	278.3
Total	306.7

The scope for this project remains unchanged and the project is expected to be completed within budget.

6. Upgrade Distribution Lines

The Upgrade Distribution Line project will upgrade the existing infrastructure in the distribution systems of Bay d'Espoir, Parsons Pond and Plum Point. Upgrades to distribution systems of Bay d'Espoir and Parsons Pond will be completed in 2012 with only the Plum Point portion of this project to be completed in 2013.

The project cost by year is shown in the table below.

Year	Cost ($000)
2012	1,385.2
2013	1,110.5
Total	2,495.7

The scope for this project remains unchanged and the project is expected to be completed within budget.

7. Upgrade JD Edwards

The JD Edwards (JDE) suite of applications has been used by Hydro since 1998 to manage data entry and reporting for all business and computer service processes within the company. This project is required to upgrade the software applications to the latest supported release from the vendor.

The project cost by year is shown in the table below.

Year	Cost ($000)
2012	187.4
2013	387.8
Total	575.2

The scope for this project remains unchanged and the project is expected to be completed within budget.

8. Upgrade Electrical Equipment – Holyrood

This is a three year project to replace the circuit protection equipment in six motor control centers (MCCs) located in the Holyrood plant powerhouse and to replace one MCC and items of the electrical switchgear in the Gas Turbine building.

The project consists of a complete replacement of the protection equipment in each motor starter for the six MCCs that are located in the plant. The new protection will be in the form of thermal magnetic circuit breakers to replace the existing fuses. The new breakers will enable better coordination with the protective equipment to interrupt the electrical faults that could cause damage to the equipment or present safety hazards to workers.

The MCC refurbishments planned for 2011 were completed. A portion of this project was to perform electric upgrades to the Holyrood Gas Turbine however that work has been cancelled. The remainder of MCC refurbishments will be completed in 2013.

The project cost by year is shown in the table below.

Year	Budgeted Cost ($000)	Revised Cost ($000)
2011	188.0	179.6 A
2012	206.3	30.0
2013	284.5	212.1
Total	678.8	421.7

9. Perform Grounding Upgrades – Various Sites

This is a five year project to upgrade terminal station and distribution substation grounding. The table below shows the original project schedule and budget estimates for each of the five years.

Year	Activity	Cost ($000)
2011	Step and touch potential analysis of 18 terminal stations and 3 distribution substations Grounding grid upgrades at 10 terminal stations Gradient control mat survey of 156 mats in 22 terminal stations	321.2
2012	Step and touch potential analysis of 4 terminal stations and 15 distribution substations Grounding grid upgrades at 12 terminal stations	324.0
2013	Step and touch potential analysis of 14 terminal stations and 15 distribution substations Grounding grid upgrades at 13 terminal stations and 1 distribution station	329.0
2014	Grounding grid upgrades at 11 terminal stations and 10 distribution substations Upgrade of 32 gradient control mats	337.1
2015	Grounding grid upgrades at 6 distribution substations Upgrade of 313 gradient control mats	345.4
	Total	1,656.7

Even though the total budgeted amount of this project remains the same, there have been adjustments to the work performance each year as shown in the table below.

Year	Activity	Cost ($000)
2011A	Step and touch potential analysis of 1 terminal station Ground grid upgrades at 1 terminal station Upgrade of 97 gradient control mats Gradient control mat survey of 11 mats in 2 terminal stations	287.6
2012	Step and touch potential analysis of 17 terminal stations Ground grid upgrades at 6 terminal stations Upgrade of 65 gradient control mats	357.6
2013	Step and touch potential analysis of 16 terminal stations Ground grid upgrades at 8 terminal stations Upgrade of 42 gradient control mats	329.0
2014	Step and touch potential analysis of 9 terminal stations Ground grid upgrades at 11 terminal stations Upgrade of 31 gradient control mats	337.1
2015	Step and touch potential analysis of 0 terminal stations Ground grid upgrades at 12 terminal stations Upgrade of 50 gradient control mats	345.4
	Total	1,656.7

10. <u>Replace Guy Wires TL215 – Doyles to Grandy Bay</u>

This is a four-year project to replace the existing guy wire arrangement on TL215 with an assembly that helps reduce the fatigue problem on the existing pre-form grips. A single year project was completed in 2010 which replaced guy wires on approximately 20 percent of the line. This project will replace the guy wires on the remainder of the line with approximately 20 percent being replaced each year. The cash flow estimate by year is shown in the table below.

The project cost by year net of cost recoveries is shown in the table below.

Year	Budgeted Cost ($000)	Revised Cost ($000)
2011	288.8	447.6 A
2012	318.0	159.2
2013	350.1	350.1
2014	530.0	530.0
Total	1,486.9	1,486.9

The scope for this project remains unchanged and the project is expected to be completed within budget. Extra costs were incurred in 2011 due to future work and material procurement being advanced from future years into 2011, to take advantage of savings related to bulk minimum quantity orders, and to complete full sections of line in some areas.

11. <u>Voltage Conversion – Labrador City</u>

This is a four year project, to complete the voltage conversion on the existing Labrador City distribution system from 4.16 kV to 25 kV. The existing distribution line components, currently rated for a nominal voltage of 4.16 kV cannot operate at 25 kV.

The project schedule, budget estimate and revised estimate are listed in the table below:

Year	Activity	Budgeted Cost ($000)	Revised Cost ($000)
2010	Field Assessment/Engineering Design	1,088.9	1,524.6 A
2011	Material Procurement/Installation	3,501.2	2,825.0 A
2012	Installation	3,840.7	4,081.2
2013	Installation	969.5	969.5
	Total	9,400.3	9,400.3

The first year of this project, 2010, was designated for the ordering of materials and the upgrade of the Harrie Lake Trailer Court area to be 25 kV ready. The cost estimate for this project was created prior to an assessment of the line being performed. Once the assessment of the line was completed late in 2009, it was discovered that dual voltage distribution transformers were required to allow for the Harrie Lake 25 kV conversion. Some of the additional expenditures in 2010 included material

costs which were originally expected to be incurred in 2011 (essentially transferring 2011 costs into 2010). Although there is an over expenditure for the budget year 2010, offset by the under expenditure in 2011, the four-year project is expected to be completed within budget overall.

12. Upgrade L2 Distribution Feeder – Glenburnie

This is a four year project for the design, supply and construction of an 18.5 kilometer (km) three phase distribution line from the Tablelands area to Trout River. It will also include the replacement of approximately 20 deteriorated poles located within the first 5.5 km from the Glenburnie Terminal Station.

The original project schedule, budget estimate and revised estimate are listed in the table below.

Year	Activity	Budgeted Cost ($000)	Revised Cost ($000)
2010	Line/Environmental Assessment	267.3	109.9 A
2011	Field Assessment / Line Design	578.2	402.4 A
2012	Material Order/ Procurement/Installation	2,114.6	2,447.8
2013	Environmental	596.6	596.6
	Total	3,556.7	3,556.7

The overall budget and schedule are expected to remain the same.

The original project scope allowed for the completion of a technical and environmental assessment as well as the purchase of a limited amount of material in 2010 and 2011. The assessments are completed, but the material was ordered early in 2012.

13. Perform Arc Flash Remediation – Various Sites

This project is a five year program to upgrade facilities to reduce the arc flash levels on electrical equipment throughout the Hydro system.

The budget estimate and revised estimate by year is shown in the table below.

Year	Budgeted Cost ($000)	Revised Cost ($000)
2011	429.5	103.5 A
2012	380.3	706.3
2013	391.0	391.0
2014	401.8	401.8
2015	413.1	413.1
Total	2,015.7	2,015.7

The scope for this project remains unchanged and the project is expected to be completed within budget.

Three sites were completed in 2011. The primary reasons for the variance are related to less work being completed and savings realized on the work that was completed by coordinating arc flash upgrades with other planned work.

14. <u>Automated Meter Reading</u>

This project is required to implement Automated Meter Reading (AMR) in Hydro's customer service areas of Rocky Harbour and Glenburnie. Hydro has changed the location of the installation to Plum Point and Bear Cove. The original location proposed was based on a meter reader position becoming vacant. This did not occur, however, as the meter reader for Plum Point and Bear Cove did retire. The budget for installation of AMR remains the same since the number of meters to be replaced is similar (1,842 for Rocky Harbour and Glenburnie versus 1,912 meters for Plum Point and Bear Cove). A revised Cost Benefit Analysis shows that the project is still justified.

The project cost by year is shown in the table below.

Year	Cost ($000)
2012	379.6
2013	287.7
Total	667.3

15. Replace Off-Road Track Vehicles

This project involves the replacement of V7734 (Flower's Cove), a 1993 heavy-duty off-road track vehicle, and V7846 (Cow Head), a 1994 heavy-duty off-road track vehicle.

The project cost by year is shown in the table below.

Year	Cost ($000)
2012	482.5
2013	395.6
Total	878.1

The scope for this project remains unchanged and the project is expected to be completed within budget.

16. Replace Vehicles and Aerial Devices

This project proposes the replacement of 34 light-duty vehicles and nine heavy-duty vehicles.

The budget estimate by year is shown in the table below.

Year	Cost ($000)
2012	1,711.4
2013	1,218.8
Total	2,930.2

The scope for this project remains unchanged and the project is expected to be completed within budget.

PROJECT DESCRIPTION	Expended to 2012	2013	Future Years	Total	Definition
			($000)		
MANDATORY PROJECTS					
Perform Grounding Upgrades - Various Sites	645.2	329.0	682.5	1,656.7	Pooled
TOTAL MANDADORY PROJECTS	645.2	329.0	682.5	1,656.7	
NORMAL PROJECTS					
Rewind Generator Units 1 and 2 - Holyrood	112.2	1,107.6	10,681.4	11,901.2	Other
Additions for Load Isolated Generation Stations - Various Sites		2,040.2	9,357.9	11,398.1	Pooled
Voltage Conversion - Labrador City	8,430.8	969.5		9,400.3	Other
Upgrade Distribution Systems - Various Sites		1,940.1	3,995.5	5,935.6	Pooled
Replace Stator Windings Unit 1 - Bay d'Espoir		5,663.5		5,663.5	Other
Provide Service Extensions - All Service Areas		5,006.0		5,006.0	Pooled
Replace Static Excitation Systems - Upper Salmon,Holyrood and Hinds Lake	1,813.9	2,295.2		4,109.1	Pooled
Replace Instrument Transformers - Various Sites		593.2	3,074.8	3,668.0	Pooled
Upgrade L2 Distribution Feeder - Glenburnie	2,960.1	596.6		3,556.7	Other
Additions for Load Distribution Systems - Various Sites		3,114.7		3,114.7	Other
Replace Vehicles and Aerial Devices (2012-2013) - Various Sites	1,711.4	1,218.8		2,930.2	Other
Replace Fuel Oil Heat Tracing - Holyrood	1,474.3	1,413.9		2,888.2	Other
Upgrade Distribution Systems - All Service Areas		2,790.0		2,790.0	Pooled
Upgrade Circuit Breakers - Various Sites		2,785.3		2,785.3	Pooled
Upgrade Distribution Lines - Bay d'Espoir, Parsons Pond and Plum Point	1,385.2	1,110.5		2,495.7	Pooled
Perform Wood Pole Line Management Program - Various Sites		2,466.7		2,466.7	Pooled
Replace Compressed Air Systems - Sunnyside and Stoney Brook		303.0	2,105.9	2,408.9	Other
Perform Arc Flash Remediation - Various Sites	809.8	391.0	814.9	2,015.7	Other
Replace Vehicles and Aerial Devices (2013-2014) - Various Sites		1,302.3	679.2	1,981.5	Other
Upgrade Terminal Station - Wiltondale		697.7	1,173.3	1,871.0	Other
Upgrade Power Transformers - Various Sites		1,621.1		1,621.1	Pooled
Replace Guy Wires TL215 - Doyles to Grand Bay	606.8	350.1	530.0	1,486.9	Other
Replace Off-Road Track Vehicles - Whitbourne, Happy Valley and Port Saunders		416.8	1,054.1	1,470.9	Pooled
Upgrade Governor Controls on Units 1 and 2 - Holyrood		1,455.5		1,455.5	Other
Replace MDR4000 Microwave Radio (West) - Various Sites		539.0	706.9	1,245.9	Other
Upgrade Gas Turbine Controls - Happy Valley		61.4	1,128.6	1,190.0	Other
Complete Condition Assessment Phase 2 (Year 2) - Holyrood		1,170.2		1,170.2	Other
Upgrade Microsoft Products - Various Sites		420.3	589.0	1,009.3	Other
Overhaul Unit 3 Turbine Valves - Holyrood		993.9		993.9	Other
Overhaul Diesel Units - Various Sites		977.8		977.8	Pooled
Install Backup System for Raw Water Supply and Clarifier - Holyrood		955.6		955.6	Other
Replace Emergency Diesel Generator - Bay d'Espoir	611.4	282.7		894.1	Other
Upgrade Burnt Dam Spillway - Bay d'Espoir		885.8		885.8	Other
Replace Off Road Track Vehicles - Flower's Cove and Cow Head	482.5	395.6		878.1	Pooled
Replace Battery Banks and Chargers - Various Sites		782.0		782.0	Other
Upgrade Fuel Oil Day Tank - Holyrood		584.2		584.2	Other
Upgrade JD Edwards - Hydro Place	187.4	387.8		575.2	Other
Automate Generator Deluge Systems Units 5 and 6 - Bay d'Espoir		532.0		532.0	Other
Upgrade Vibration Monitoring Equipment - Holyrood		519.9		519.9	Other
Upgrade Business Intelligence Software - Hydro Place		369.2		369.2	Other
TOTAL NORMAL PROJECTS	20,585.8	51,506.7	35,891.5	107,984.0	
JUSTIFIABLE PROJECTS					
Install Variable Frequency Drives on Forced Draft Fans - Holyrood		697.6	2,659.7	3,357.3	Other
Install Automated Meter Reading - Plum Point and Bear Cove	379.6	287.7		667.3	Other
Install Automated Meter Reading - Various Sites		397.9	258.8	656.7	Other
TOTAL JUSTIFIABLE PROJECTS	379.6	1,383.2	2,918.5	4,681.3	

PROJECT DESCRIPTION	Expended to 2012	2013	Future Years	Total	Definition
			($000)		
MANDATORY PROJECTS					
Replace North End Equipment Door - Bay d'Espoir		265.5		265.5	Other
TOTAL MANDATORY PROJECTS	0	265.5	0.0	265.5	
NORMAL PROJECTS					
Install Cold-Rehead Condensate Drains and High Pressure Heater Trip Level Unit 3 - Holyrood		50.0	448.1	498.1	Other
Replace Disconnects - Various Sites		492.6		492.6	Other
Upgrade Generator Bearings - Bay d'Espoir		480.9		480.9	Pooled
Replace Light Duty Mobile Equipment - Various Sites		476.5		476.5	Other
Replace Insulators - Various Sites		187.1	287.9	475.0	Pooled
Front End Engineering Design - Hydro Place		472.1		472.1	Other
Replace Personal Computers - Various Sites		463.9		463.9	Other
Install Automatic Sprinkler System - Bay d'Espoir		429.9		429.9	Other
Upgrade Electrical Equipment - Holyrood	209.6	212.1		421.7	Pooled
Install Online Vibration Monitoring System - Corner Brook Frequency Converter		382.8		382.8	Other
Upgrade Server Technology Program - Hydro Place		367.6		367.6	Other
Replace Radomes - Various Sites		336.0		336.0	Pooled
Replace Automatic Transfer Switches - Hinds Lake		314.7		314.7	Other
Replace Peripheral Infrastructure - Various Sites		309.9		309.9	Other
Replace Compressed Air Piping - Buchans	28.4	278.3		306.7	Other
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir		298.1		298.1	Pooled
Replace MicroSCADA Computers - Granite Canal		297.4		297.4	Other
Install Fire Protection Upgrades - Holyrood		267.2		267.2	Other
Replace Auto Greasing Systems Units 1 and 3 - Bay d'Espoir		260.1		260.1	Other
Install Additional Washrooms - Various Sites		250.9		250.9	Other
Remove Safety Hazards - Various Sites		250.5		250.5	Other
Overhaul Turbine/Generator Units - Bay d'Espoir and Cat Arm		428.1		428.1	Other
Replace Recloser Control Panels - Various Sites		209.7		209.7	Other
TOTAL NORMAL PROJECTS	238.0	7,516.4	736.0	8,490.4	
JUSTIFIABLE PROJECTS					
				0.0	
TOTAL JUSTIFIABLE PROJECTS	0.0	0.0	0.0	0.0	

PROJECT DESCRIPTION	Expended to 2012	2013	Future Years	Total	Definition
			($000)		
MANDATORY PROJECTS					
Install Fall Protection Equipment - Various Sites		196.6		196.6	Pooled
TOTAL MANDATORY PROJECTS	0.0	196.6	0.0	196.6	
NORMAL PROJECTS					
Purchase Meters, Equipment and Metering Tanks - Various Sites		199.5		199.5	Other
Legal Survey of Primary Distribution Line Right of Way - Various Sites		156.2	40.0	196.2	Other
Purchase 10 Position Meter Calibration Test Console - Hydro Place		192.5		192.5	Other
Replace Optimho Relays on TL242 - Holyrood to Hardwoods		189.2		189.2	Other
Replace Network Communications Equipment - Various Sites		182.4		182.4	Other
Overhaul Unit 3 Boiler Feed Pump West - Holyrood		178.5		178.5	Other
Replace Cooling Water Pumps - Bay d'Espoir		175.4		175.4	Other
Replace Fall Arrest System on Surge Tank 2 - Bay d'Espoir		153.0		153.0	Other
Replace By-Pass Valves Units 3 and 4 - Bay d'Espoir		141.9		141.9	Other
Replace Telephone System - St. Anthony		135.4		135.4	Other
Upgrade Energy Management System - Hydro Place		129.9		129.9	Other
Upgrade Enterprise Storage Capacity - Hydro Place		124.7		124.7	Other
Replace Condensate Polisher Annunicator Panels - Holyrood		123.5		123.5	Other
Replace Surge Arrestors - Various Sites		121.3		121.3	Other
Install Transformer Fans - Conne River		114.9		114.9	Other
Overhaul Unit 2 Extraction Pump South - Holyrood		101.5		101.5	Other
Replace Computer Room Air Conditioner - Hydro Place		83.2		83.2	Other
Perform Minor Application Enhancements - Hydro Place		81.1		81.1	Other
Replace 230 kV Breaker Controls - Bottom Brook		68.9		68.9	Other
Replace Helpdesk Service Manager Application - Hydro Place		61.8		61.8	Other
TOTAL NORMAL PROJECTS	0.0	2,714.8	40.0	2,754.8	
JUSTIFIABLE PROJECTS					
Install Automated Fuel Monitoring System - Upper Salmon		192.7		192.7	Other
Purchase Low Pressure Screw Compressor Set - Bay d'Espoir		97.3		97.3	Other
TOTAL JUSTIFIABLE PROJECTS	0.0	290.0	0.0	290.0	

Type	Number	($000)
Clustered	0	0.0
Pooled	20	49,467.4
Other	71	76,851.9
Total	**91**	**126,319.3**

* *Includes multi-year projects but excludes contingency fund*

2013 LEASING COSTS

THERE ARE NO ITEMS FOR THIS SECTION

	ACTUALS				BUDGET					
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
GENERATION	13,703	9,592	16,337	13,131	34,980	23,134	40,149	38,943	39,589	19,362
TRANSMISSION AND RURAL OPERATIONS	24,711	32,988	28,681	41,251	44,695	34,629	64,027	85,611	86,428	123,855
GENERAL PROPERTIES	7,832	11,572	10,535	8,734	8,131	8,382	7,506	10,670	10,083	10,105
TOTAL CAPITAL EXPENDITURES	46,246	54,152	55,553	63,116	87,806	66,145	111,682	135,224	136,100	153,322

	Expenditures Prior To 2012	PUB Approved Budget 2012	2012 Expenditures To June 30	Expected Total Expenditures 2012	Var. from Approved to Expected Expenditures
GENERATION	4,973.8	30,374.7	6,139.9	29,114.1	(1,260.6)
TRANSMISSION	9,593.7	16,101.2	5,684.8	17,118.0	1,016.8
RURAL SYSTEMS	6,394.5	24,365.3	7,484.5	25,395.5	1,030.2
GENERAL PROPERTIES	2,100.9	8,044.5	2,200.3	8,131.0	86.5
MAJOR OVERHAUL AND INSPECTIONS	0.0	6,839.5	2,579.4	6,948.4	108.9
CONTINGENCY FUND	0.0	1,000.0	387.1	1,000.0	0.0
PROJECTS APPROVED BY PU BOARD	0.0	0.0	0.0	0.0	0.0
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	0.0	99.2	71.1	99.2	0.0
TOTAL CAPITAL BUDGET	23,062.9	86,824.4	24,547.1	87,806.2	981.8

2012 Capital Budget Approved by Board Order No. P.U. 2 and 5 (2012)	76,992.3
Carryover Projects 2011 to 2012[1]	9,755.9
2012 New Projects under $50,000 Approved by Hydro	76.2
TOTAL APPROVED CAPITAL BUDGET	86,824.4

[1] *The carryover amount has been adjusted from $9,083 due to a restatement of expenditures in 2011 resulting from the conversion to the International Financial Reporting Standards (IFRS).*

	Expenditures Prior To 2012	PUB Approved Budget 2012	2012 Expenditures To June 30	Expected Total Expenditures 2012	Var. from Approved to Expected Expenditures
GENERATION					
HYDRO PLANTS	262.4	10,723.8	3,118.1	9,647.9	(1,075.9)
THERMAL PLANT	2,316.8	14,932.6	2,722.5	14,747.9	(184.7)
GAS TURBINES	2,394.6	4,718.3	299.3	4,718.3	0.0
TOTAL GENERATION	4,973.8	30,374.7	6,139.9	29,114.1	(1,260.6)
TRANSMISSION					
TERMINAL STATIONS	9,146.1	13,375.7	5,134.9	14,392.5	1,016.8
TRANSMISSION	447.6	2,725.5	549.9	2,725.5	0.0
TOTAL TRANSMISSION	9,593.7	16,101.2	5,684.8	17,118.0	1,016.8
RURAL SYSTEMS					
DISTRIBUTION	5,157.6	19,279.7	6,290.7	20,182.3	902.6
GENERATION	578.8	1,901.9	305.6	2,029.5	127.6
PROPERTIES	4.5	639.8	85.1	639.8	0.0
METERING	228.0	692.5	124.7	692.5	0.0
TOOLS AND EQUIPMENT	425.6	1,851.4	678.4	1,851.4	0.0
TOTAL RURAL SYSTEMS	6,394.5	24,365.3	7,484.5	25,395.5	1,030.2

	Expenditures Prior To 2012	PUB Approved Budget 2012	2012 Expenditures To June 30	Expected Total Expenditures 2012	Var. from Approved to Expected Expenditures
GENERAL PROPERTIES					
INFORMATION SYSTEMS	**(1.8)**	**2,391.8**	**1,227.0**	**2,391.8**	**0.0**
TELECONTROL	**1,850.0**	**2,815.0**	**474.0**	**2,901.5**	**86.5**
TRANSPORTATION	**252.7**	**2,457.0**	**456.8**	**2,457.0**	**0.0**
ADMINISTRATIVE	**0.0**	**380.7**	**42.5**	**380.7**	**0.0**
TOTAL GENERAL PROPERTIES	**2,100.9**	**8,044.5**	**2,200.3**	**8,131.0**	**86.5**
MAJOR OVERHAUL AND INSPECTIONS	**0.0**	**6,839.5**	**2,579.4**	**6,948.4**	**108.9**
CONTINGENCY FUND	**0.0**	**1,000.0**	**387.1**	**1,000.0**	**0.0**
PROJECTS APPROVED BY PU BOARD	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
PROJECTS APPROVED FOR LESS THAN $50,000	**0.0**	**99.2**	**71.1**	**99.2**	**0.0**
TOTAL CAPITAL BUDGET	**23,062.9**	**86,824.4**	**24,547.1**	**87,806.2**	**981.8**

	Expenditures Prior To 2012	PUB Approved Budget 2012	2012 Expenditures To June 30	Expected Total Expenditures 2012	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
HYDRAULIC PLANT						
Replace Fire Alarm System - Hinds Lake	20.2	88.9	80.2	88.9	0.0	
Replace Static Excitation Systems - Upper Salmon, Holyrood and Hinds Lake	16.8	2,873.0	403.9	1,797.1	(1,075.9)	1
Upgrade Generating Station Service Water System -Cat Arm	0.0	451.1	10.5	451.1	0.0	
Upgrade Burnt Dam Spillway Structure - Bay d'Espoir	154.8	103.0	16.1	103.0	0.0	
Purchase Spare Disconnect - Bay d'Espoir	70.6	62.1	43.8	62.1	0.0	
Upgrade Intake Gate Controls - Bay d'Espoir	0.0	495.4	143.0	495.4	0.0	
Rewind Stators Units 1, 3 and 4 - Bay d'Espoir	0.0	4,953.8	2,250.5	4,953.8	0.0	
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir	0.0	48.3	16.4	48.3	0.0	
Replace Emergency Diesel Generator - Bay d'Espoir	0.0	611.4	36.8	611.4	0.0	
Replace Fuel Tank at Burnt Dam - Bay d'Espoir	0.0	207.5	20.0	207.5	0.0	
Replace Rip Rap - Bay d'Espoir	0.0	199.1	19.2	199.1	0.0	
Upgrade Burnt Dam Spillway - Bay d'Espoir	0.0	523.8	52.9	523.8	0.0	
Purchase Tools and Equipment Less than $ 50,000	0.0	106.4	24.8	106.4	0.0	
TOTAL HYDRAULIC PLANT	**262.4**	**10,723.8**	**3,118.1**	**9,647.9**	**(1,075.9)**	

	Expenditures Prior To 2012	PUB Approved Budget 2012	2012 Expenditures To June 30	Expected Total Expenditures 2012	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
THERMAL PLANT						
Replace Steam Seal Regulator Unit 1 - Holyrood	321.3	337.6	181.0	337.6	0.0	
Replace Steam Seal Regulator Unit 2 - Holyrood	51.6	743.0	103.6	743.0	0.0	
Replace Relay Panels Unit 3- Holyrood	134.2	696.5	102.0	696.5	0.0	
Rewind Generator Units 1 and 2 - Holyrood	0.0	112.2	26.3	112.2	0.0	
Upgrade Stack Breaching Units 2 - Holyrood	0.0	1,505.1	30.2	1,505.1	0.0	
Upgrade Stack Breaching Unit 1 - Holyrood	0.0	1,522.3	78.7	1,522.3	0.0	
Replace Programmable Logic Controllers - Holyrood	0.0	743.3	15.9	743.3	0.0	
Replace Pumphouse Motor Control Centres - Holyrood	640.0	(0.9)	96.9	(0.9)	0.0	
Replace Diesel Fire Pump - Holyrood	177.8	197.4	(7.4)	197.4	0.0	
Upgrade Hydrogen System - Holyrood	270.5	1,721.8	806.7	1,721.8	0.0	
Upgrade Electrical Equipment - Holyrood	179.6	214.7	22.3	30.0	(184.7)	2
Upgrade Forced Draft Fan Ductwork Unit 1 - Holyrood	400.4	1,097.6	23.3	1,097.6	0.0	
Upgrade Synchronous Condenser Unit 3- Holyrood	141.4	747.6	627.1	747.6	0.0	
Replace Fuel Oil Heat Tracing - Holyrood	0.0	1,474.3	12.6	1,474.3	0.0	
Upgrade Forced Draft Fan Ductwork Units 2 - Holyrood	0.0	928.6	45.6	928.6	0.0	
Replace Beta Attenuation Monitoring Analyzers - Holyrood	0.0	160.9	116.8	160.9	0.0	
Refurbish Fuel Storage Facility - Holyrood	0.0	2,641.2	440.9	2,641.2	0.0	
Purchase Tools and Equipment Less than $ 50,000	0.0	89.4	0.0	89.4	0.0	
TOTAL THERMAL PLANT	**2,316.8**	**14,932.6**	**2,722.5**	**14,747.9**	**(184.7)**	
GAS TURBINES						
Upgrade Glycol Systems - Stephenville	521.2	597.0	38.9	597.0	0.0	
Upgrade Gas Turbine Plant Life Extension - Hardwoods	1,873.4	4,121.3	260.4	4,121.3	0.0	
TOTAL GAS TURBINE PLANTS	**2,394.6**	**4,718.3**	**299.3**	**4,718.3**	**0.0**	
TOTAL GENERATION	**4,973.8**	**30,374.7**	**6,139.9**	**29,114.1**	**(1,260.6)**	

	Expenditures Prior To 2012	PUB Approved Budget 2012	2012 Expenditures To June 30	Expected Total Expenditures 2012	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
TERMINAL STATIONS						
Voisey's Bay Nickel - Long Harbour Power Supply	11,186.0	2,868.9	1,957.0	2,868.9	0.0	
Cost Recovery - Vale Inco	(11,186.0)	(2,868.9)	(1,957.0)	(2,868.9)	0.0	
Perform Grounding Upgrades - Various Sites	0.0	357.6	36.4	357.6	0.0	
Replace Compressed Air System - Bay d'Espoir	83.7	563.8	40.8	1,221.1	657.3	3
Replace Digital Fault Recorder - Bay d'Espoir	69.1	99.5	67.2	99.5	0.0	
Replace 230 kV Circuit Breaker - Sunnyside	7.3	624.1	3.0	624.1	0.0	
Install Alternate Station Services - Stony Brook and Massey Drive	5.5	189.7	12.8	189.7	0.0	
Replace Compressor, Dryer and Air Piping Header System - Corner Brook Frequency Converter Station	141.8	138.4	19.9	138.4	0.0	
Upgrade Circuit Breakers - Various Sites	0.0	1,677.3	68.8	1,677.3	0.0	
Replace Surge Arrestors - Various Sites	0.0	75.7	43.2	75.7	0.0	
Replace Instrument Transformers - Various Sites	0.0	452.4	136.2	452.4	0.0	
Upgrade Power Transformers - Various Sites	0.0	1,246.3	281.0	1,246.3	0.0	
Replace Disconnects - Various Sites	0.0	351.8	233.4	351.8	0.0	
Replace Compressed Air Piping and Install Dew Point Monitor - Buchans	0.0	28.4	0.0	28.4	0.0	
Replace Insulators - Various Sites	0.0	411.6	47.6	411.6	0.0	
Upgrade Terminal Stations to 25 kV - Labrador City	8,008.0	4,642.0	3,372.5	4,642.0	0.0	
Upgrade Substation - Wabush	13.8	1,071.9	258.0	1,071.9	0.0	
Replace 69 kV SF6 Breakers - St. Anthony Airport	480.5	299.3	34.8	299.3	0.0	
Upgrade Station Reliability and Safety - Rocky Harbour	5.2	789.7	318.9	1,149.2	359.5	
Replace Breaker, Structures and Disconnects - Hawke's Bay	331.2	356.2	160.4	356.2	0.0	
TOTAL TERMINAL STATIONS	**9,146.1**	**13,375.7**	**5,134.9**	**14,392.5**	**1,016.8**	

	Expenditures Prior To 2012	PUB Approved Budget 2012	2012 Expenditures To June 30	Expected Total Expenditures 2012	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
TRANSMISSION						
Replace Guy Wires TL-215 - Doyles to Grand Bay	447.6	159.2	67.2	159.2	0.0	
Install Ice Monitoring Equipment - Various Sites	0.0	47.0	0.0	47.0	0.0	
Perform Wood Pole Line Management Program - Various Sites	0.0	2,519.3	482.7	2,519.3	0.0	
TOTAL TRANSMISSION SECTION	**447.6**	**2,725.5**	**549.9**	**2,725.5**	**0.0**	
TOTAL TRANSMISSION	**9,593.7**	**16,101.2**	**5,684.8**	**17,118.0**	**1,016.8**	
DISTRIBUTION						
Replace Substation Infrastructure- Burgeo	6.9	488.9	101.8	488.9	0.0	
Replace Recloser Control Panels - Various Sites	0.0	202.3	6.0	202.3	0.0	
Voltage Conversion - Labrador City	4,349.6	4,081.2	1,047.2	4,081.2	0.0	
Upgrade L2 Distribution Feeder - Glenburnie	512.3	2,447.8	409.9	2,447.8	0.0	
Provide Service Extensions - All Service Areas	0.0	4,172.0	2,342.9	4,172.0	0.0	
Upgrade Distribution Systems - All Service Areas	0.0	2,508.0	1,731.1	2,875.0	367.0	4
Upgrade Distribution Lines - Roddickton and Makkovik	132.8	666.8	37.8	666.8	0.0	
Upgrade Distribution Systems Francois, Rigolet and Happy Valley	121.6	1,045.0	171.4	1,580.6	535.6	5
Upgrade Distribution Lines - Bay d'Espoir,Parsons Pond and Plum Point	0.0	1,385.2	144.0	1,385.2	0.0	
Install Voltage Regulators - Conne River and L'Anse au loup	34.4	110.4	60.8	110.4	0.0	
Distribution Systems Additions - Various Sites	0.0	2,172.1	237.8	2,172.1	0.0	
TOTAL DISTRIBUTION	**5,157.6**	**19,279.7**	**6,290.7**	**20,182.3**	**902.6**	

	Expenditures Prior To 2012	PUB Approved Budget 2012	2012 Expenditures To June 30	Expected Total Expenditures 2012	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
GENERATION						
Replace Diesel Unit 2001 and Engine 566 - Francois	458.0	160.4	65.6	160.4	0.0	
Perform Arc Flash Remediation - Various Sites	103.5	706.3	15.6	706.3	0.0	
Perform FEED for Diesel Plant Remediation - Various Sites	0.0	110.4	0.0	110.4	0.0	
Replace Mini Hydro Turbine - Roddicton	10.7	311.5	92.4	439.1	127.6	6
Install Sequence of Events Monitor in Diesel Plant -	6.6	148.2	27.9	148.2	0.0	
Replace Fuel Storage Tanks - St. Lewis	0.0	465.1	104.1	465.1	0.0	
TOTAL GENERATION	578.8	1,901.9	305.6	2,029.5	127.6	
PROPERTIES						
Install Fall Protection Equipment - Various Sites	0.0	199.2	10.1	199.2	0.0	
Upgrade Mechanical Workshop - St. Anthony	0.0	87.0	2.5	87.0	0.0	
Install Waste Oil Storage Tank - L'Anse au Loup	0.0	81.5	50.8	81.5	0.0	
Legal Survey of Primary Distribution Line Right of Way - Various Sites	4.5	74.2	21.7	74.2	0.0	
Legal Survey of Primary Distribution Line Right of Ways - Various Sites	0.0	197.9	0.0	197.9	0.0	
TOTAL PROPERTIES	**4.5**	**639.8**	**85.1**	**639.8**	**0.0**	

	Expenditures Prior To 2012	PUB Approved Budget 2012	2012 Expenditures To June 30	Expected Total Expenditures 2012	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
METERING						
Purchase Meters, Equipment and Metering Tanks - Various Sites	0.0	190.4	0.8	190.4	0.0	
Install Automatic Meter Reading - Labrador City	228.0	122.5	42.8	122.5		
Install Automatic Meter Reading - Plum Point and Bear Cove	0.0	379.6	81.1	379.6	0.0	7
TOTAL METERING	**228.0**	**692.5**	**124.7**	**692.5**	**0.0**	
TOOLS AND EQUIPMENT						
Replace Light Duty Mobile Equipment - Various Sites	22.1	14.5	57.5	14.5	0.0	
Replace Light Duty Mobile Equipment - Various Sites	0.0	400.6	87.1	400.6	0.0	
Replace Excavator - L'Anse au Loup	0.0	120.0	0.0	120.0	0.0	
Replace Off Road Track Vehicles - Bishop's Falls and Fogo	403.5	427.5	424.7	427.5	0.0	
Replace Off Road Track Vehicles - Flower's Cove and Cow Head	0.0	482.5	0.0	482.5	0.0	
Tools and Equipment Less than $ 50,000	0.0	406.3	109.1	406.3	0.0	
TOTAL TOOLS AND EQUIPMENT	**425.6**	**1,851.4**	**678.4**	**1,851.4**	**0.0**	
TOTAL RURAL SYSTEMS	**6,394.5**	**24,365.3**	**7,484.5**	**25,395.5**	**1,030.2**	

	Expenditures Prior To 2012	PUB Approved Budget 2012	2012 Expenditures To June 30	Expected Total Expenditures 2012	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
INFORMATION SYSTEMS						
SOFTWARE APPLICATIONS						
New Infrastructure						
Perform Minor Application Enhancements - Hydro Place	0.0	123.4	70.3	123.4	0.0	
Cost Recoveries	0.0	(41.9)	(23.9)	(41.9)	0.0	
Implement Work Protection Safety Code Application - Hydro Place	0.0	115.6	62.7	115.6	0.0	
Upgrade of Technology						
Corporate Application Environment - Upgrade Microsoft Products	0.0	684.1	546.5	684.1	0.0	
Cost Recoveries	(1.8)	(164.9)	(162.7)	(164.9)	0.0	
Upgrade JD Edwards - Hydro Place	0.0	284.0	64.5	284.0	0.0	
Cost Recoveries	0.0	(96.6)	(21.9)	(96.6)	0.0	
Upgrade Energy Management System - Hydro Place	0.0	117.8	45.6	117.8	0.0	
Upgrade Microsoft Project - Hydro Place	0.0	91.3	5.2	91.3	0.0	
Cost Recoveries	0.0	(31.0)	(1.6)	(31.0)	0.0	
Upgrade Creditron System - Hydro Place	0.0	37.5	39.0	37.5	0.0	
TOTAL SOFTWARE APPLICATIONS	**(1.8)**	**1,119.3**	**623.7**	**1,119.3**	**0.0**	
COMPUTER OPERATIONS						
Infrastructure Replacement						
Replace Personal Computers - Various Sites	0.0	490.6	300.6	490.6	0.0	
Replace Peripheral Infrastructure - Various Sites	0.0	327.5	7.6	327.5	0.0	
Upgrade Enterprise Storage Capacity - Hydro Place	0.0	306.3	253.2	306.3	0.0	
Cost Recoveries	0.0	(104.1)	(86.1)	(104.1)	0.0	
New Infrastructure						
Upgrade of Technology						
Upgrade Server Technology Program - Hydro Place	0.0	202.6	150.8	202.6	0.0	
Cost Recoveries	0.0	(30.9)	(22.8)	(30.9)	0.0	
Upgrade Computer Room - Hydro Place	0.0	122.0	0.0	122.0	0.0	
Cost Recoveries	0.0	(41.5)	0.0	(41.5)	0.0	
TOTAL COMPUTER OPERATIONS	**0.0**	**1,272.5**	**603.3**	**1,272.5**	**0.0**	
TOTAL INFORMATION SYSTEMS	**(1.8)**	**2,391.8**	**1,227.0**	**2,391.8**	**0.0**	

	Expenditures Prior To 2012	PUB Approved Budget 2012	2012 Expenditures To June 30	Expected Total Expenditures 2012	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
TELECONTROL						
NETWORK SERVICES						
Infrastructure Replacement						
Replace MDR 6000 Microwave Radio (West) - Various Sites	26.4	728.9	19.5	728.9	0.0	
Upgrade Communication Services - Paradise River	0.0	97.5	5.3	97.5	0.0	
Replace Radomes - Various Sites	0.0	172.0	6.9	258.5	86.5	
Public Address System - Holyrood	1,823.6	83.1	3.6	83.1	0.0	
Purchase Tools and Equipment less than $50,000	0.0	85.3	0.0	85.3	0.0	
Network Infrastructure						
Replace Battery Banks and Chargers - Various Sites	0.0	880.8	232.9	880.8	0.0	
Replace Network Communications Equipment - Various Sites	0.0	521.6	87.2	521.6	0.0	
Upgrade of Technology						
Replace Telephone Systems - Port Saunders and Whitbourne	0.0	199.3	118.4	199.3	0.0	
Upgrade Site Facilities - Various Sites	0.0	46.5	0.2	46.5	0.0	
TOTAL TELECONTROL	**1,850.0**	**2,815.0**	**474.0**	**2,901.5**	**86.5**	

	Expenditures Prior To 2012	PUB Approved Budget 2012	2012 Expenditures To June 30	Expected Total Expenditures 2012	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
TRANSPORATION						
Replace Vehicles and Aerial Devices (2011-2012) - Various Sites	252.7	745.6	369.6	745.6	0.0	
Replace Vehicles and Aerial Devices (2012-2013) - Various Sites	0.0	1,711.4	87.2	1,711.4	0.0	
TOTAL TRANSPORATION	**252.7**	**2,457.0**	**456.8**	**2,457.0**	**0.0**	
ADMINISTRATION						
Remove Safety Hazards - Various Sites	0.0	249.1	0.0	249.1	0.0	
Purchase Tools and Equipment less than $50,000	0.0	131.6	42.5	131.6	0.0	
TOTAL ADMINISTRATION	**0.0**	**380.7**	**42.5**	**380.7**	**0.0**	
TOTAL GENERAL PROPERTIES	**2,100.9**	**8,044.5**	**2,200.3**	**8,131.0**	**86.5**	

	Expenditures Prior To 2012	PUB Approved Budget 2012	2012 Expenditures To June 30	Expected Total Expenditures 2012	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
MAJOR OVERHAULS AND INSPECTIONS						
Condition Assessment and Life Extension Phase 2 - Holyrood	0.0	1,215.7	17.7	1,215.7	0.0	
Overhaul Turbine Unit 1 - Holyrood	0.0	4,193.1	1,874.8	4,193.1	0.0	
Overhaul Diesel Units - Various Sites	0.0	974.1	686.9	1,083.0	108.9	8
Overhaul Turbine/Generator Units - Granite Canal and Upper Salmon	0.0	456.6	0.0	456.6	0.0	
TOTAL MAJOR OVERHAULS AND INSPECTIONS	**0.0**	**6,839.5**	**2,579.4**	**6,948.4**	**108.9**	
CONTINGENCY FUND						
Contingency Fund	0.0	1,000.0	0.0	1,000.0	0.0	
Black Tickle Plant Rehabiliation	0.0	0.0	387.1	0.0	0.0	
TOTAL CONTINGENCY FUND	**0.0**	**1,000.0**	**387.1**	**1,000.0**	**0.0**	
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO						
Replace Engine # 2062 - Grey River	0.0	49.2	21.4	49.2	0.0	
Purchase Diesel Plant Property - English Harbour West	0.0	50.0	49.7	50.0	0.0	
TOTAL PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	**0.0**	**99.2**	**71.1**	**99.2**	**0.0**	

1. Replace Static Excitation System – Upper Salmon, Holyrood and Hinds Lake

Please see page F - 2 of Section F: Multi-Year Projects.

2. Upgrade Electrical Equipment – Holyrood

Please see page F - 6 of Section F: Multi-Year Projects.

3. Replace Compressed Air System – Bay d'Espoir

The increase in costs for the replacement of the compressed air system is due to tendered bids for construction that were approximately $600,000 greater than the estimated amount of $300,000.

4. Upgrade Distribution Systems – All Services

The budget for distribution upgrades is based on a five-year average. The increase in expected costs compared to budget is due to a transformer failure in Paradise River as well as a larger than normal replacement of voltage regulators and porcelain cut-outs.

5. Upgrade Distribution Systems - Francois, Rigolet and Happy Valley

The increase in costs for this project is due to contract bids that were approximately $400,000 and $200,000 greater than budgeted for Francois and Rigolet respectively.

6. Replace Mini Hydro Turbine - Roddickton

The increase in costs compared to budget is due to a scope change to include a generator replacement. The rotor shaft of the Roddickton Mini Hydro generator failed in 2010 due to misalignment. This failure occurred after the proposal was submitted for approval.

7. Automated Meter Reading

Please see page F - 10 of Section F: Multi-Year Projects.

8. Overhaul Diesel Units – Various Sites

There was a change to the scope of the project to include the replacement of Cartwright Diesel Engine 2061 as opposed to an overhaul. Unit 2061 failed on April 10, 2012 and a failure analysis was completed by Toromont in May 2012. As a result of the failure analysis, a tear down of the engine was completed which revealed the majority of internal components were not reusable including the block and crank shaft. The estimate to overhaul this unit, due to the damage, was estimated to be $196,000. Through further discussion with Toromont, an identical replacement unit was identified to be available from Toromont in St John's, and estimated at $156,000 installed. It is also important to note that Unit 2061 is also a mobile unit that can be used elsewhere on the system. With Unit 2044 (another 600 kW mobile) currently being installed at Mary's Harbour due to a generator failure on Unit 2083, it is critical to have Unit 2061 ready for service when required.

Plan of Projected Operating

Maintenance Expenditures

2013 - 2022

For Holyrood Generating Station

Newfoundland and Labrador Hydro

July 2012

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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, and vary from year to year.

This report addresses the identified and expected maintenance expenditures for the years 2013 to 2022 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 is in excess of 30 years old, along with its associated equipment, including the other two main fuel storage tanks. 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 which may trigger a revision of the maintenance plan to control unforeseen events. Even though expenditures for major overhauls are included in capital rather than operating budgets with the adoption of International Financial Reporting Standards (IFRS), 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."**

In 2007, an Asset Maintenance Review (AMR) was undertaken by Project Execution and Technical Services as a means to streamline, make uniform and permit the continual improvement of a maintenance program that could be applied company wide. Since that time the Asset Management Review process has been progressing on the assets of Holyrood Thermal Generating Station (Holyrood) where information regarding past asset maintenance, both preventative and corrective, is being compared with recommended practices, manufacturer or industry standard, in order to establish best practice.

The entire maintenance effort can be seen as a means to mitigate failure and its consequences. All failures have a cost and, to varying degrees, hinder progress in meeting the corporate goals and objectives, whether they are impediments to safety and health, environmental protection, production or financial performance. But recognizing there is a trade-off between the cost of failure and the cost of preventing failure, Hydro must make clearly guided decisions on the type and amount of preventive action to undertake. Such decisions are made within the confines of the following basic framework: philosophy - strategy - tactic.

It would be useful to first review the three main types or categories of maintenance undertaken at Holyrood:

1) Preventive Maintenance

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, in its specific sense, comprises routine inspections, 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, 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. These include repairs to equipment as it fails or reaches the point where preventive maintenance has identified that the equipment is approaching the end of its useful service life. Examples include wear and tear on pumps, pipes and valves in the main and auxiliary systems and motor rewinds due to failed or deteriorated winding insulation. Corrective maintenance conditions may also arise as a result of adverse conditions (humidity, salt laden atmosphere), or replacement of corroded piping equipment. In 2003, Unit 2 suffered three superheater tube failures and the analysis indicated a common tube failure problem had developed. An approved capital budget proposal saw the replacement of Unit 2 boiler superheater tubes in September 2007. Likewise, Unit 1 boiler superheater tubes were replaced in 2008.

3) <u>Projects</u>

Operating projects are those major cost repairs and inspections that are required to return structures and equipment to their original or near original condition, to maintain structural integrity, possibly extend plant life, improve efficiency, improve availability and prevent or reduce environmental risks. Such projects include repairs to building structural steel, roof repairs or replacement, fuel oil

tank and pipeline inspection and coating, replacement of equipment or components no longer supported by the original manufacturer. A major asbestos abatement program commenced in 2005 and was completed over a three-year period. Due to the significant cost ($11.3M), Hydro was given approval to treat this as an extraordinary repair, which will mean an annual cost will be recovered over an additional five years, bringing the total cash flow period to eight years, 2005 to 2012.

In 2006 a major failure of Unit 2 boiler waterwall tubing resulted in three months of unexpected down time plus extensive repairs that cost $2.5 million. This cost was amortized over a five year period (2007-2011) within the plant operating budget. A root cause analysis was conducted by an external consultant whose findings identified one of the major contributions to this failure as insufficient boiler chemical cleaning frequency (current industry practice is eight-ten years, regardless of tube loading condition). To perform future chemical cleaning of the Holyrood boilers, operating projects have been identified starting with Unit 2 in 2016, Unit 1 in 2017 and Unit 3 in 2018 with individual cost of approximately 380k.

In 2007 a major failure of the Unit 2 nozzle block assembly steam turbine resulted in two months of extended forced outage plus extensive repairs that cost $2.4 million. With the full adoption of the IFRS standard commencing in 2013, it is expected many of the projects that would involve significant overhaul will now be submitted as part of future capital submissions.

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. These changing demands give rise to changes in wear rates, the majority of which cannot be monitored close enough for reasonably accurate prediction, without incurring excessive inspection costs. Excessive inspection may in itself introduce increased risk of failure and thus additional cost, so all must be considered in balancing the most appropriate amount of inspection with accepted levels of failure. These costs however, generally balance from one year to another.

Similarly, (but to a lesser extent with adoption of the IFRS) major operating projects, because of their extended maintenance intervals (years) or non-repeatability also add to the annual fluctuations of the system equipment maintenance costs and have to be executed when plant conditions allow. 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 System Equipment Maintenance (SEM) costs for the years 2013 to 2022. Appendices B to D, inclusive, show the expected SEM costs categorized according to Preventive, Corrective, Overhauls and Major 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 may change as a result of the proposed Labrador Interconnection. This significantly impacts cost and activity levels for Holyrood and for the purposes of this analysis it does not reflect project sanction on the Muskrat Falls. The section entitled Holyrood Thermal Generating Station Requirements 2012 -2021 in the 2013 Capital Plan section of this application, summarizes Hydro's approach to planning for Holyrood during this period. The context and approach outlined in the section are reflected in the judgment used to prepare this ten-year plan.

This plan was prepared using the 2012 preventive, corrective and overhaul data and the current 2013 to 2017 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 2011 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	2013	2014	2015	2015	2017	2018	2019	2020	2021	2022
%	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 2013 to 2022 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 Major 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 preventative maintenance work orders performed on plant equipment annually. Corrective items include a large number of low cost jobs and some moderately expensive ones as well, 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 2012 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

APPENDIX A

TOTAL HOLYROOD 10 YEAR SEM[1] EXPENDITURES

($000)

	Base Year 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
UNIT #1 Total SEM	$1,904	$1,091	$2,001	$2,050	$1,175	$2,155	$2,209	$1,265	$2,320	$2,378
UNIT #2 Total SEM	$1,064	$1,952	$2,001	$1,146	$2,102	$2,155	$1,235	$2,263	$2,320	$1,329
UNIT #3 Total SEM	$1,904	$1,952	$1,118	$2,050	$2,102	$1,205	$2,209	$2,263	$1,296	$2,378
Common Equipment Total SEM	$1,690	$1,732	$1,776	$1,820	$1,865	$1,912	$1,960	$2,009	$2,059	$2,111
Buildings and Grounds Total SEM	$390	$400	$410	$420	$430	$441	$452	$464	$475	$487
WT Plant Total SEM	$104	$107	$109	$112	$115	$118	$121	$124	$127	$130
WWT Plant Total SEM	$21	$22	$22	$23	$23	$24	$24	$25	$26	$26
Environmental Monitoring Total SEM	$162	$166	$170	$174	$179	$183	$188	$193	$197	$202
Total Operating Projects	$72	$455	$575	$332	$831	$1,210	$833	$408	$666	$386
Total Holyrood SEM	$7,311	$7,877	$8,182	$8,128	$8,823	$9,402	$9,230	$9,014	$9,487	$9,428

[1] **System Equipment Maintenance**

APPENDIX B

10 YEAR SEM[1] EXPENDITURES FOR GENERATING UNITS

($000)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Unit No. 1										
Preventive – Yearly	532	$545	$559	$573	$587	$602	$617	$632	$648	$664
Corrective – Yearly	317	$325	$333	$341	$350	$359	$368	$377	$386	$396
Boiler Annual Overhaul	$1,055	$221	$1,109	$1,136	$238	$1,194	$1,224	$256	$1,286	$1,318
Operating Projects										
Boiler Chemical Clean						$463				
Projects – Lump Sum for Future Years		$42	$43	$44	$45	$46	$48	$49	$50	$51
Total – Unit No. 1	$1,904	$1,133	$2,044	$2,094	$1,220	$2,664	$2,256	$1,314	$2,370	$2,430
Unit No. 2										
Preventive – Yearly	$532	$545	$559	$573	$587	$602	$617	$632	$648	$664
Corrective – Yearly	$317	$325	$333	$341	$350	$359	$368	$377	$386	$396
Boiler Annual Overhaul	$215	$1,082	$1,109	$232	$1,165	$1,194	$250	$1,254	$1,286	$269
Operating Projects										
Boiler Chemical Clean					$452					
Projects – Lump Sum for Future Years		$42	$43	$44	$45	$46	$48	$49	$50	$51
Total – Unit No. 2	$1,064	$1,994	$2,044	$1,190	$2,599	$2,201	$1,282	$2,312	$2,370	$1,380
Unit No. 3										
Preventive – Yearly	$532	$545	$559	$573	$587	$602	$617	$632	$648	$664
Corrective – Yearly	$317	$325	$333	$341	$350	$359	$368	$377	$386	$396
Boiler Annual Overhaul	$1,055	$1,082	$226	$1,136	$1,165	$244	$1,224	$1,254	$262	$1,318
Operating Projects										
Boiler Chemical Clean							$475			
Projects – Lump Sum for Future Years			$13	$13	$14	$14	$14	$15	$15	$15
Total – Unit No. 3	$1,904	$1,952	$1,131	$2,064	$2,116	$1,219	$2,698	$2,278	$1,312	$2,394

[1] **System Equipment Maintenance**

APPENDIX C

APPENDIX C

10 YEAR SEM[1] EXPENDITURES FOR ANCILLARY UNITS

($000)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Common Equipment										
Preventive - Yearly	$1,533	$1,571	$1,611	$1,651	$1,692	$1,734	$1,778	$1,822	$1,868	$1,915
Corrective - Yearly	$157	$161	$165	$169	$173	$178	$182	$187	$191	$196
Operating Projects										
Pipe Surveillance		$57	$58	$60	$61	$63	$64	$66	$68	$69
Plant Color Coding		$16	$16	$17	$17	$18	$18	$19	$19	$19
Total Common Equipment	$1,690	$1,805	$1,850	$1,897	$1,944	$1,993	$2,042	$2,094	$2,146	$2,200
Buildings Grounds										
Preventive - Yearly	$338	$346	$355	$364	$373	$382	$392	$402	$412	$422
Corrective - Yearly	$52	$53	$55	$56	$57	$59	$60	$62	$63	$65
Operating Projects										
Exhaust Stack Repair and Maintenance			$250			$269			$290	
Total - Buildings and Grounds	$390	$400	$660	$420	$430	$710	$452	$464	$765	$487
Water Treatment Plant										
Preventive - Yearly	$20	$21	$21	$22	$22	$23	$23	$24	$24	$25
Corrective - Yearly	$84	$86	$88	$90	$93	$95	$97	$100	$102	$105
Operating Projects										
Resin Replacement	$72	$74	$76	$78	$79	$81	$83	$86	$88	$90
Total Water Treatment Plant	$176	$180	$185	$190	$194	$199	$204	$209	$214	$220

[1] **System Equipment Maintenance**

APPENDIX D

APPENDIX D

10 YEAR SEM[1] EXPENDITURES FOR ANCILLARY UNITS

($000)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Environmental Monitoring										
Preventive - Yearly	$86	$88	$90	$93	$95	$97	$100	$102	$105	$107
Corrective - Yearly	$76	$78	$80	$82	$84	$86	$88	$90	$93	$95
Operating Projects										
Emissions Monitoring		$50	$51	$53	$54	$55	$57	$58	$59	$61
Stack Emissions Testing and Dispersion Modelling		$116				$128				
Tube Bundle Replacement-All units		$35			$38			$41		
Total Environmental Monitoring	$162	$367	$221	$227	$271	$366	$244	$292	$257	$263
Waste Water treatment Plant										
Preventive - Yearly	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Corrective - Yearly	$20	$21	$21	$22	$22	$23	$23	$24	$24	$25
Operating Projects										
WWTP Periodic Basin Cleaning & Inspection		$23		$24		$26		$27		$28
WWTP Continuous Basin Clean-Out			$24		$25		$26		$27	
Total - Waste Water Treatment Plant	$21	$45	$46	$47	$48	$50	$50	$52	$53	$54

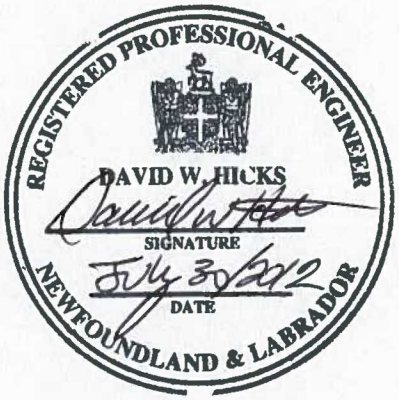
[1] **System Equipment Maintenance**

	2011	2010[1]
Capital Assets	2,191,991	2,136,058
Less:		
Accumulated Depreciation	707,241	669,742
Contributions in Aid of construction	98,054	97,257
Asset Retirement Obligations[2]	19,126	11,395
Asset Retirement Obligation Accumulated Amortization	(1,149)	-
Net Capital Assets	1,368,719	1,357,664
Net Capital Assets, Previous Year	1,357,664	1,353,625
Unadjusted Average Capital Assets	1,363,192	1,355,645
Less:		
Average Net Assets Not In Service	423	777
Average Capital Assets	1,362,769	1,354,868
Cash Working Capital Allowance	4,626	3,093
Fuel Inventory	33,680	29,908
Supplies Inventory	24,096	24,089
Average Deferred Charges	68,047	71,924
Average Rate Base	1,493,218	1,483,882

[1] *Certain of the 2010 comparative figures have been reclassified to conform with the 2011 presentation. Also, 2010 has been restated to exclude average net assets not in service from the average rate base. The impact of the adjustment to the average rate base is $777,000.*

[2] *The asset retirement obligation is comprised of $16,963,000 (2010 - $11,395,000) related to the Holyrood Generating Station and $2,163,000 (2010 – nil) related to the disposal of Polychlorinated Biphenyls (PCB).*

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES



Electrical
Mechanical
Civil
Protection & Control
Transmission & Distribution
Telecontrol
System Planning

Replacement of Stator Windings

Bay d'Espoir Hydroelectric Generating Station

May 2012

newfoundland labrador hydro
a nalcor energy company

SUMMARY

The replacement of stator windings on Unit 1 is a continuation of the stator winding replacement projects previously completed on Unit 2 in 2010 and presently being completed on Unit 4.

Unit 1 stator windings have similar visual indicators of deterioration as Units 2 and 4 did before their replacements. Along with the physical issues of the stator, recent direct current (DC) step potential testing completed in 2012 has confirmed that the stator winding insulation has reached a level where a high probability of failure during unit operation is present. A replacement in 2013 is recommended.

The replacement of the stator windings will include the removal, purchase, installation and commissioning work on Unit 1. This replacement project will also include: the identification and abatement of any asbestos as required; the refurbishment of rotor components and upgrades to generator protection.

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APPENDIX A A1

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 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 all have a similar design and functionality. The focus of this report is the replacement of stator windings on Unit 1. The nameplate ratings[1] for Units 1, 2, 3 and 4 is 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 & Asphalt)
Insulation Class of Fielding Windings	Class B (Shellac & Asphalt)
Shaft Position	Vertical
Number of Slots	360
Commissioning Year – Units 1, 2 and 3	1967
– Unit 4	1968

The physical dimension of Unit 1 is approximately three meters high with an approximate diameter of six meters. A generator, such as Unit 1, 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 series of copper coils that as a complete unit form the stator

[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", pg. 1.

windings. 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 1 have an asphalt 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 this amount of electrical protection from the insulation is known as the dielectric strength. Because of age, the asphalt tape insulation on the stator coils has 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 winding is quite complex and involves the removal of approximately 25 additional coils due to the inter-twining winding design of the stator winding and its coils. Due to aging and the brittle nature of the coils, any attempted stator winding 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.

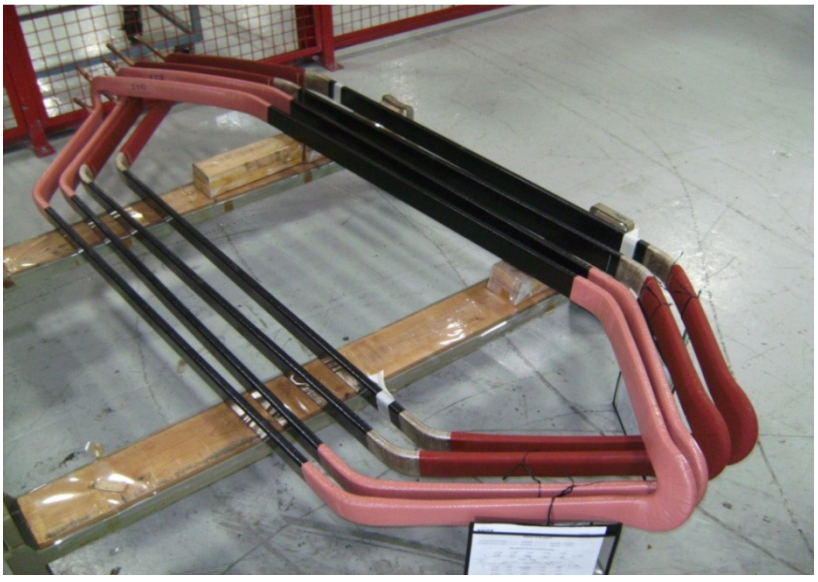

Figure 1: Stator Coils (4 individual coils are shown)

Based on previous stator winding replacements on Units 2 and 4, the operating lifecycle of Unit 1 is known. The physical condition of the stator windings for Unit 1 is showing similar indicators of deterioration as with Units 2 and 4 at this period of their lifecycle. This

deterioration would include cracking in the winding and asphalt seeping from within the windings, all of which are indicators of the breakdown in the insulation. The Unit 1 stator windings are assessed to have reached the end period of its serviceable life and is at risk of failure. Hydro is preparing this proposal to be proactive in replacing the stator windings before a failure occurs.

The complete rewind of the Unit 2 stator in Bay d' Espoir is shown in Figure 2, this work was completed in 2010.

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 an approval from the Board, under PUB Order No. P.U. 1 (2010) to replace the stator windings on Unit 2, this work was completed in 2010. In 2011, to provide further justification for the replacement of stator windings with the remaining three units, AMEC Americas Limited, an engineering consultant, was engaged to prepare a condition assessment report for the Bay d'Espoir Generator Units 1, 3 and 4. This assessment stated the need for an immediate replacement of Unit 4, and under PUB Order No. P.U.2 (2012) this work is being completed in 2012. The 2012 PUB Order also stated for Hydro to reapply each year for the remaining two units. This proposal is seeking the approval to complete the work on Unit 1 in 2013.

2 PROJECT DESCRIPTION

This proposal is a continuation of the stator replacement work that was completed on Units 2 and 4 in 2010 and 2012 respectively. This proposal is a one-year project to complete the rewind of the Unit 1 stator and purchase a complete spare set of stator windings in 2013. Hydro plans to submit a subsequent proposal to install the spare windings in Unit 3 as part of the 2014 application which is not part of this proposal.

The stator windings on Unit 1 in the Bay d'Espoir Generating Station was installed in 1967 and is approximately 45 years old. The lifecycle of an asphalt type winding is generally accepted by the utility industry to be 40 years. AMEC stated in its 2011 report[2] "According to industry experiences, the asphalt mica winding insulation on these three units has a life expectancy of 40 to 45 years." As such, the stator windings on Unit 1, which is of the asphalt type, is considered to be at the end of its useful life. This information combined with the poor to marginal maintenance test results has formed the basis for replacement of stator windings on Unit 1.

It is important to understand the components of a stator winding, its installation and the technical terms used. Stator windings have a series of tensioning components known as the packing system. This packing system is used to mount and secure the stator coils against the stator core. It is in this packing system where asbestos is suspected to be located.

As asbestos is sometimes present in this vintage of stator, its identification and abatement is part of the scope of this project. Generally, asbestos is located in the center stick and side packing of the stator winding. An overview of the packing system for one section 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.

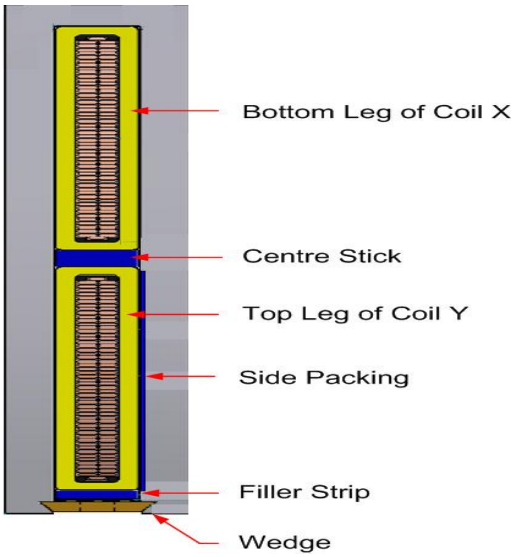

Figure 3: Overview of Packing System on One Section of Stator Winding

In 2007, High Potential (hipot) Testing or more particularly, a DC Voltage Step Test was completed on Unit 1 which showed weakness in the winding. As the DC voltage was increased from 15 kV to 27 kV the plotted line's slope increased considerably and at a faster rate of rise than the slope generated from the lower DC voltages. In 2012, the hipot testing on Unit 1 had to be abandoned at the 18 kV level as the leakage current and the slope were increasing at such a rate that the risk actually causing coil failure was present. This voltage level of 18 kV at hipot is marginally higher than the operating voltage level of the generator at 13.8 kV. As such, coil failure is becoming increasingly likely. A failed hipot test is an indication of a weakening dielectric level with the winding insulation.

Unit 1, as with the other seven generating units at Bay D'Espoir is critical to the Island Interconnected System. Unit 1 and Unit 3 also provide station service power in the Bay d'Espoir Generating Station. The loss of either Units 1 or 3 would reduce the overall reliability of the powerhouse and the Island Interconnected System.

The 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 in a suitable operating condition. Hydro and its consultant, AMEC have determined that Unit 1 has the highest probability of a winding failure of the existing units

in Bay d' Espoir and should have its stator windings replaced in 2013. AMEC states "The Unit 1 generator should be rewound as soon as possible."[3]

Another area of concern involves the work previously completed on the removal of the stator windings from Unit 2, where the stators were found to have its stator core slots migrating or moving out of alignment. The stator core is a mechanical structure compiled of a series of steel laminations that physically supports the stator coils in slots. With the removal of Unit 2, it was discovered that the laminations have shifted and are slowly moving out of alignment. The concern with stator core migration is that the stator core slots contain tightly packed stator windings and with the misalignment of the steel laminations tension begins between the steel lamination and stator windings. Thus, the laminations begin to cut into the stator windings creating a condition whereby if allowed to continue, could create an electrical fault and failure of the windings. 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 1 is similar in age and construction and would be expected to exhibit similar issues.

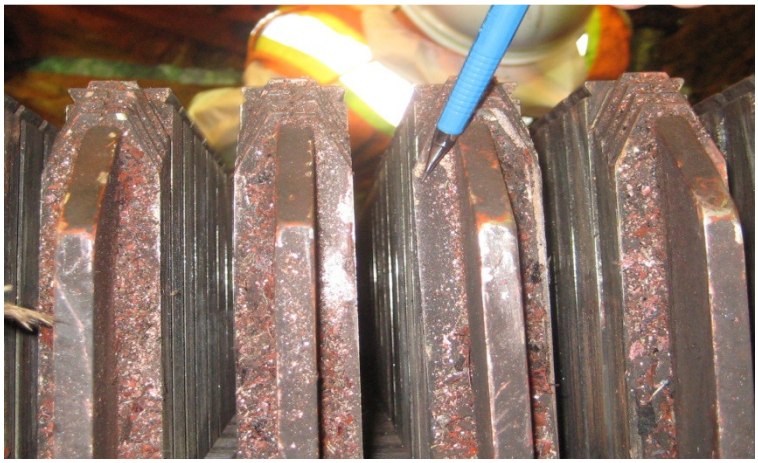

Figure 4: Migration of Stator Core Laminations–Looking Downward with Stator Winding Removed

[3] Bay d'Espoir Generating Station Powerhouse No.1 Unit Generators 1 and 3 Condition Assessment Follow-up Report, AMEC Americas Limited, May 8, 2012, pg 4.

The replacement of the stator windings will involve the removal of the existing stator windings along with the purchase, installation and commissioning of new stator windings. The removal of the existing windings will include the determination of asbestos in the stator and if present; its abatement. The scope of work is to have the work completed by a contract manufacturer, including abatement if required, as was previously done on Units 2 and 4. The work would also include an upgrade to the generator protection and the refurbishment of rotor components. This work is required to ensure the new stator will operate to its full capability.

3 JUSTIFICATION

The need for replacement of Unit 2 stator windings was evident during the completion of regular preventative maintenance work. Signs of deterioration, that include brittle insulation as shown in Figure 5 and seeping liquid asphalt were becoming present in many locations of the windings indicating the increased wear and near end of serviceable life of these windings. Subsequent testing for electrical partial discharge and DC Voltage Step produced results that indicated Unit 2 was trending to failure. The Unit 2 stator windings were removed and replaced in 2010. During this work, other signs of deterioration were found including stator core laminations that had migrated into some of the stator coils. This caused concern as the movement would eventually lead to insulation failure. One additional item found during the removal of Unit 2 was the presence of broken rotor bus bars, this deterioration which eventually lead to insulation damage of the stator windings. Both of these conditions are major issues and cannot be detected without a major rebuild, so Hydro's concern was heightened as to the level of deterioration, which could also be present on Unit 1, as it is of a similar vintage. The project is justified based on the minimization of impacts to system performance and additional costs should a unit suffer damage as a result of the failure of the stator windings.

The reliability of Unit 1 is critical to the Island Interconnected System and maintaining its reliability will follow a similar justification as was presented for the replacement of stators on Units 2 and 4. Hydro must maintain the reliability of each generating unit before a failure occurs. Should a stator fail during operation it would cause significant damage to the stator and its rotor. Based on 2010 figures, repair work for such a failure would cost $450,000 and require 100 days of effort. Thus, failure to replace the stator windings on Unit 1 would impair Hydro's ability to provide least-cost, reliable electricity.

As presented in the 2012 budget proposal for the Unit 4 stator winding replacement, AMEC recommended further testing in 2012 on Unit 1 to determine if the deterioration had worsened since its last testing in 2007. AMEC states "Follow up testing should be

performed annually …"[4] In 2012, the DC voltage step test or High Potential testing had to be abandoned for risk of damage or the complete failure of the stator windings. The results of the hipot test were stopped at the 18 kV level due to the rate of rise in the leakage current with each voltage step increase. AMEC states about Unit 1 "The condition of this unit's stator winding insulation indicates that there is a high risk of an in-service failure."[5] To reference both AMEC reports for review of the full results see Appendix A.

Figure 5: Existing Stator Windings

To ensure improved functionality of all generator components, the generator protection equipment should be upgraded from electro-mechanical relaying to electronic relaying. In the event of an electrical fault, the speed of operation for a protection relay is directly proportional to the level of damage mitigation on a faulted generating unit. With modern

[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 8, 2012, pg 4.

electronic relaying having response times approximately 10 times faster than the existing electro-mechanical relays and considering the asset cost of new stator windings, it would be prudent to upgrade the generator protection with the replacement of a stator windings.

As previously discussed in the project description in Section 2, the stator core migration issue demonstrates it was difficult to verify the level of all issues on Unit 2 and what may be present on the remaining units including Unit 1. This migration of the stator core is particularly troublesome as the risk of failure is increasing 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 windings present a risk of imminent failure to Unit 1. 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 to each other. The existing electro-mechanical protection equipment cannot prevent this potential damage and must be upgraded. AMEC states[6] "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."

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 concern from this workplace.

3.1 Existing System

Unit 2 is a 45 year old hydro generator that had signs of reduced insulation levels through visual testing. Similarly, Unit 1 has insulation on its stator with similar characteristics including: insulation that is physically cracking and brittle when dry and once heated has insulation that begins to drip liquid asphalt, reducing the insulation or dielectric properties

[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.

and physically covering the surrounding area in asphalt. Both visual results are indicators that the insulation is degrading and losing its dielectric strength.

Unit 1 is designed for continuous operation with varying loads to meet system requirements. With the exception of maintenance outages, this unit has been operating continuously, within its design capabilities, since it was commissioned in 1967.

Since its installation in 1967, Unit 1 has had minimal preventive maintenance costs related to its stator windings. 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, some stator related corrective maintenance repairs include: repairs to a loose V-block shim, the cleaning of the stators from dripping asphalt and the replacement of loose wedges that are used to mechanically secure the stator coils in place.

As listed in Table 2, Unit 1 has had several major upgrades since its installation in 1967.

Table 2: Major Work and/or Upgrades

Year	Major Work and/or Upgrade
2007	Unit 1 – Replace Slip Rings
2001	Unit 1 - Repair of Stator Windings
2000	Unit 1 – Repair Field Leads and Shims Between Poles 18 and 19.
1999	Unit 1 – Replace Loose Wedges
1998	Unit 1 - DC Exciter Replacement
1993	Unit 1 - Stator Re-wedging

3.2 Operating Experience

The stator windings on Unit 1 in the Bay d'Espoir Hydroelectric Generating Station are 45 years old and are operating beyond its expected useful service life. Inspections and testing have confirmed that a coil or complete winding could fail at any time. Therefore the status quo of operating without a replacement plan is not an option.

3.2.1 Environmental Performance

As part of the stator windings 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, multi-turn coil stator windings were manufactured by General Electric (GE) between the years 1930 and 1968 and is called a Class B winding. This was a common design and is used in most hydroelectric generators built during this period.

Multi-turn coil windings with asphalt insulation have varying service lives, which are dependent on operating conditions and regular maintenance. Generally this type of coil, operating under normal conditions will need to be rewound within 40 years. GE has indicated that the majority of generators of this type throughout the world have already undergone a stator rewind.

3.2.3 Vendor Recommendations

GE is the manufacturer of the Unit 1 stator windings and has participated in various inspections throughout its lifecycle. The latest inspection for Unit 1 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 windings.

GE halted production of these particular types of windings in 1969, shortly after Unit 1 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.

3.3 Development of Alternatives

The only viable alternative for Unit 1 stators are its replacement. Maintaining the status quo would expose the Unit to the likelihood of damage and failure due to the deterioration of the stator windings.

3.4 Evaluation of Alternatives

The justification for the replacement of Unit 1 stator windings is based on the history of the previous replacements on Units 2 and 4 and the current test results for Unit 1 which show the insulation resistance or dielectric strength is reducing to a level that has a high probability of failure during operation.

Generating Units 1 through 4 in the Bay d'Espoir Generating Station were all manufactured, installed and commissioned by GE in 1967 and 1968 using a similar design and functionality. Units 2 and 4 have been approved by the Board for replacement and Unit 1 is showing comparable indications of deterioration.

The Unit 1 asset has also reached its end of serviceable life based on the utility accepted life of 40 years for this model of stator windings. The DC Voltage Step or hipot testing was attempted on Unit 1 in 2012 but had to be abandoned at 18 kV before completion at 30 kV as the insulation's leakage current was trending to failure of the stator under test conditions. The 18 kV voltage level is slightly above the operating voltage of 13.8 kV for the generating unit. This situation for Unit 1 results in it having a high probability of failure under operation.

Unit 1 stator windings have reached its end of service and must be replaced.

4 CONCLUSION

Unit 1 at the Bay d'Espoir Hydroelectric Generating Station has been in service since its commissioning in 1967. The stator windings on Unit 1 has now exceeded the end of its useful service life of 40 years. The stator windings are showing indication of increased physical deterioration and electrical testing is producing results that show that if Unit 1 is left in service it has a high probability of failure during operation. This failure will likely damage the stator core and the rotor. Hydro and its consultant AMEC agree that the Unit 1 stator winding must be replaced in 2013 or sooner.

4.1 Budget Estimate

The budget estimate for the replacement of the stator windings on Unit 1 is $5.6 million in 2013. The budget estimate is shown in Table 3.

Table 3: Project Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	307.9	0.0	0.0	307.9
Labour	535.1	0.0	0.0	535.1
Consultant	14.0	0.0	0.0	14.0
Contract Work	3,453.2	0.0	0.0	3,453.2
Other Direct Costs	103.0	0.0	0.0	103.0
Interest and Escalation	367.7	0.0	0.0	367.7
Contingency	882.6	0.0	0.0	882.6
TOTAL	**5,663.5**	**0.0**	**0.0**	**5,663.5**

4.2 Project Schedule

The anticipated schedule for this project is shown in Table 4 below.

Table 4: Project Schedule for Unit 1 in 2013

Activity		**Start Date**	**End Date**
Planning	Outage Request and Project Planning for Unit 1	January 2013	March 2013
Procurement	Tendering, Equipment Ordering and Delivery for 2013 FAT Testing	April 2013	May 2013
Construction	Removal of Unit 1, Determine Asbestos Requirements, Install Stator Winding, Rotor Upgrades, Generator Protection on Unit 1	May 2013	September 2013
Commissioning	Commissioning Unit 1	October 2013	October 2013
Closeout	Project Closeout Unit 1	November 2013	December 2013

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

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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

REV.	DATE	REVISION(S)	PREPARED BY	CHECK	APP	CLIENT
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	

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BAY D'ESPOIR GENERATING STATION POWERHOUSE NO. 1

AMEC JOB NO. 168688

REPORT NO. 168688 | REV. 1

PAGE 1 OF 1

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ENF.04 Rev. 2

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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 90^{th} 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

Bay D'Espoir Generating Station Powerhouse No. 1
Unit Generators #1, #3 and #4 Condition Assessment Report
Prepared for: Newfoundland and Labrador Hydro

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.

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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.

Wednesday, July 6, 2011

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.

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July 29, 2011
Page 4

Thursday, July 7, 2011

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.

Attachments:
Table 1
Table 2
Photos

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BAY D'ESPOIR WINDING ASSESSMENTS

Information Collected During Site Visit

Table 1

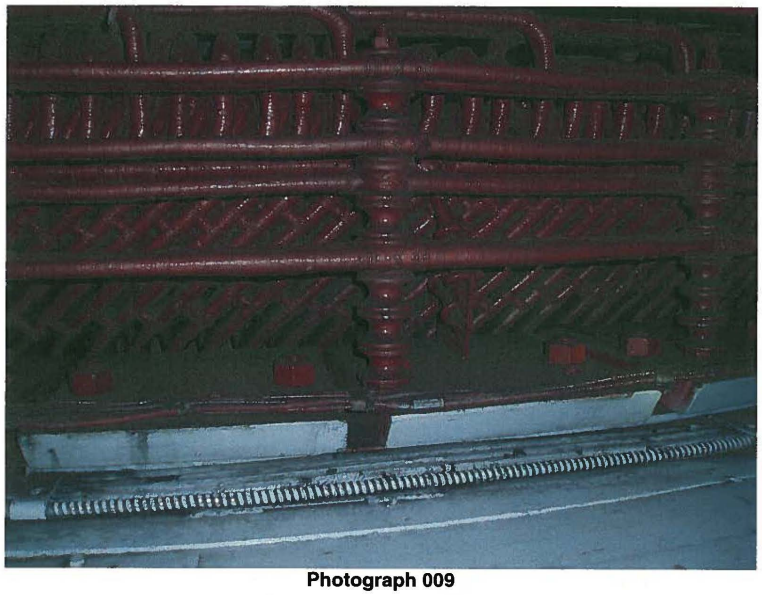
Description	Common	Unit 1	Unit 2	Unit 3	Unit 4
Bay D'Espoir Operating History	×				
Operation Records	×				
Stator Winding Temp, Trending	×				
Generator Plan and Sections	×				
Winding Details	×				
Unit 4, 3-Line Diagram	×				
Voith Unit 2 Rewind Final Documentation			×		
Voith Unit 2 Rewind OM Manual			×		
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

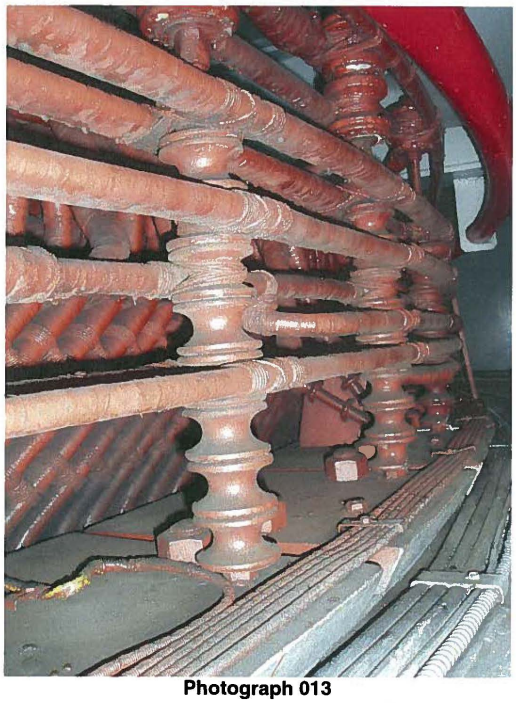
Information to be sent by Nalcor after Site Visit

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



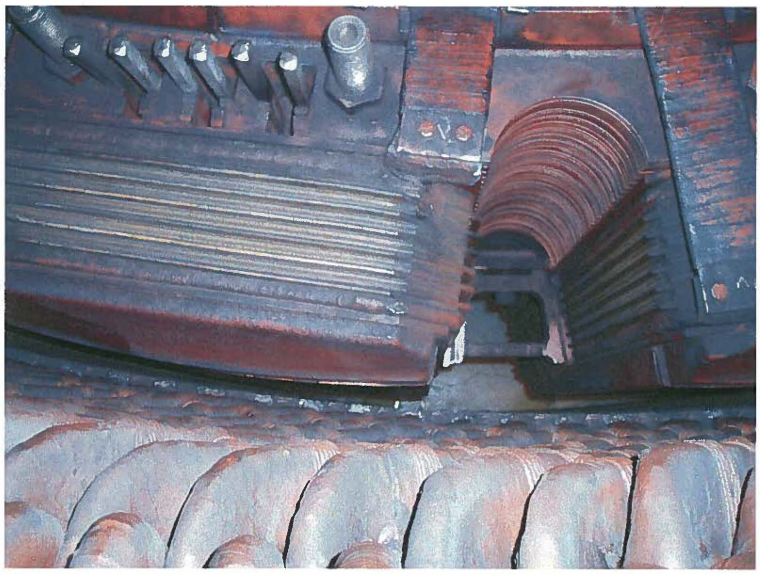
Photograph 009



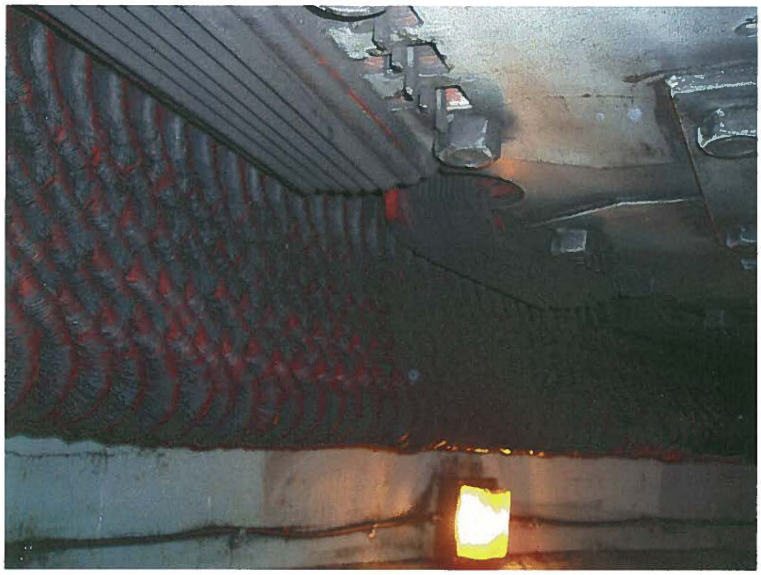
Photograph 013

Photograph 016

Photograph 020

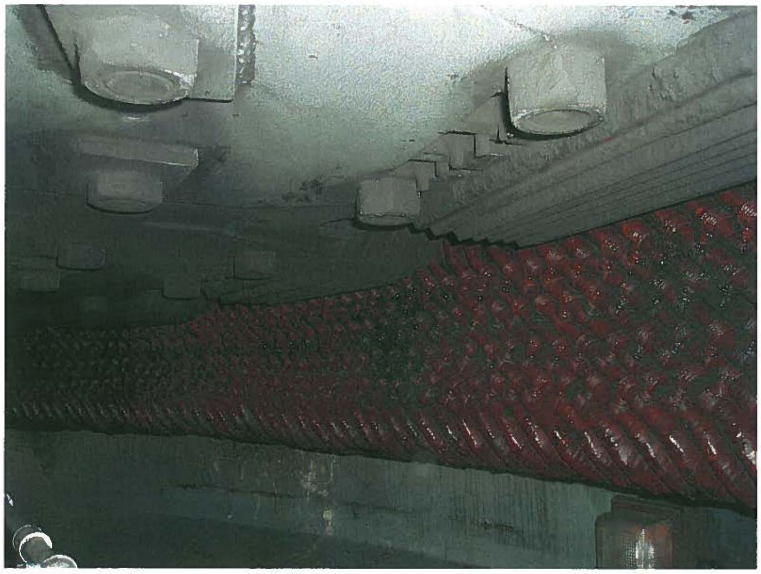


Photograph 023



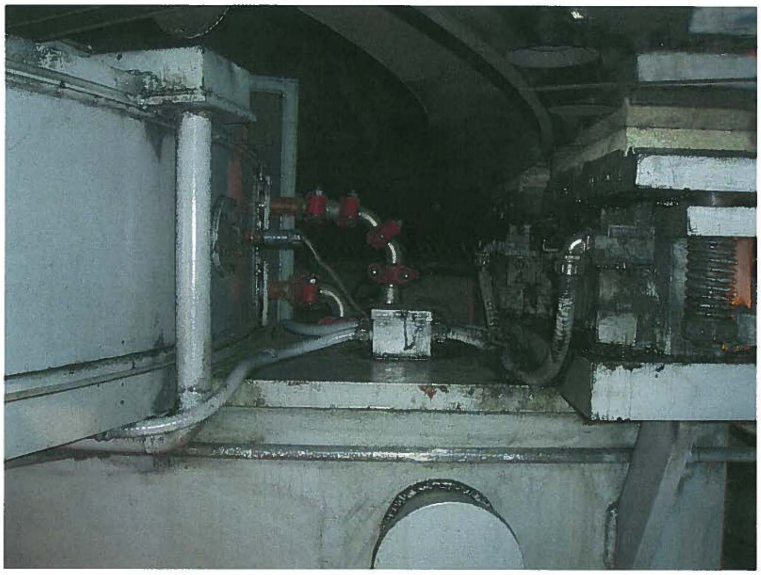
Photograph 036

Photograph 041



Photograph 046

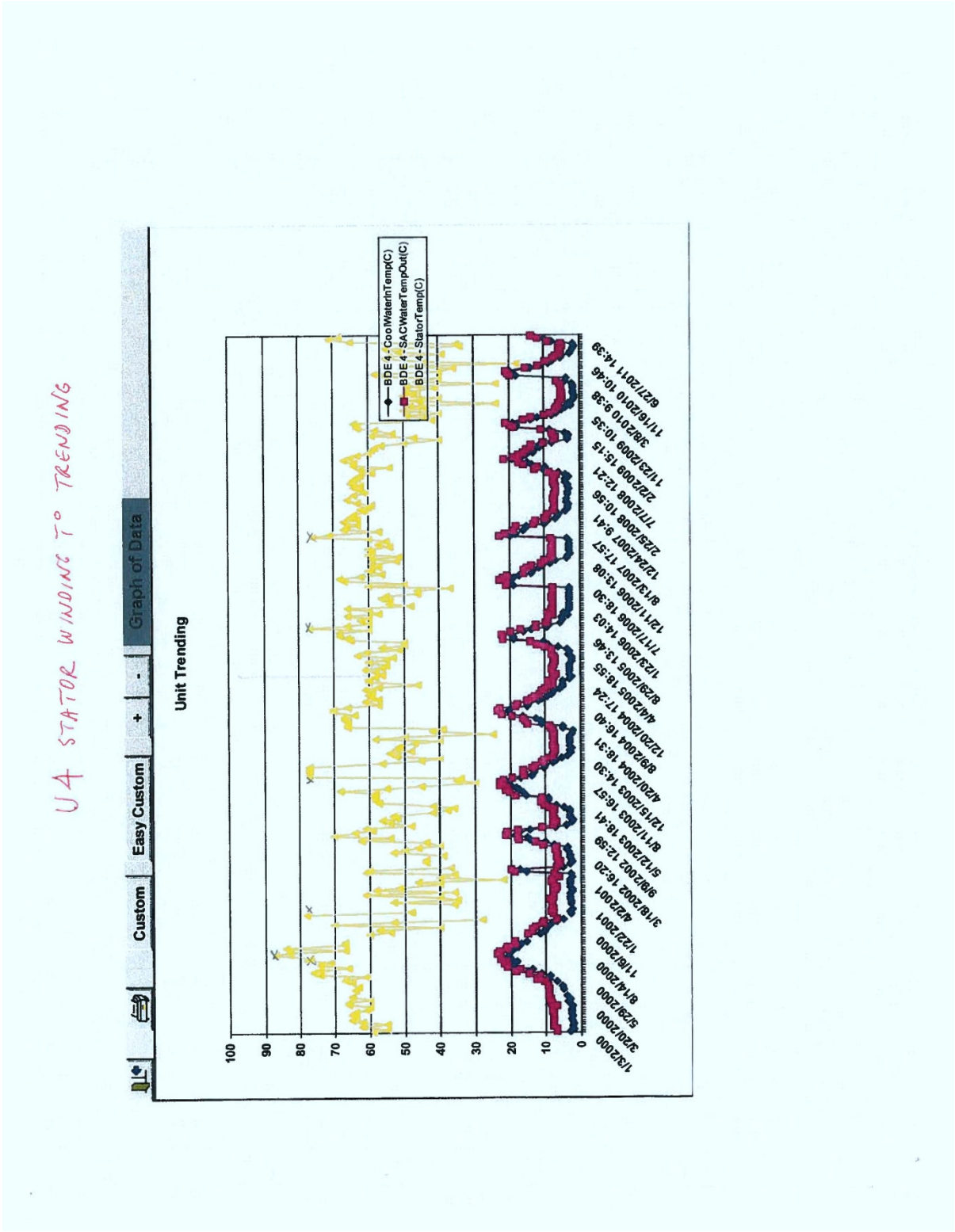
Photographs 047



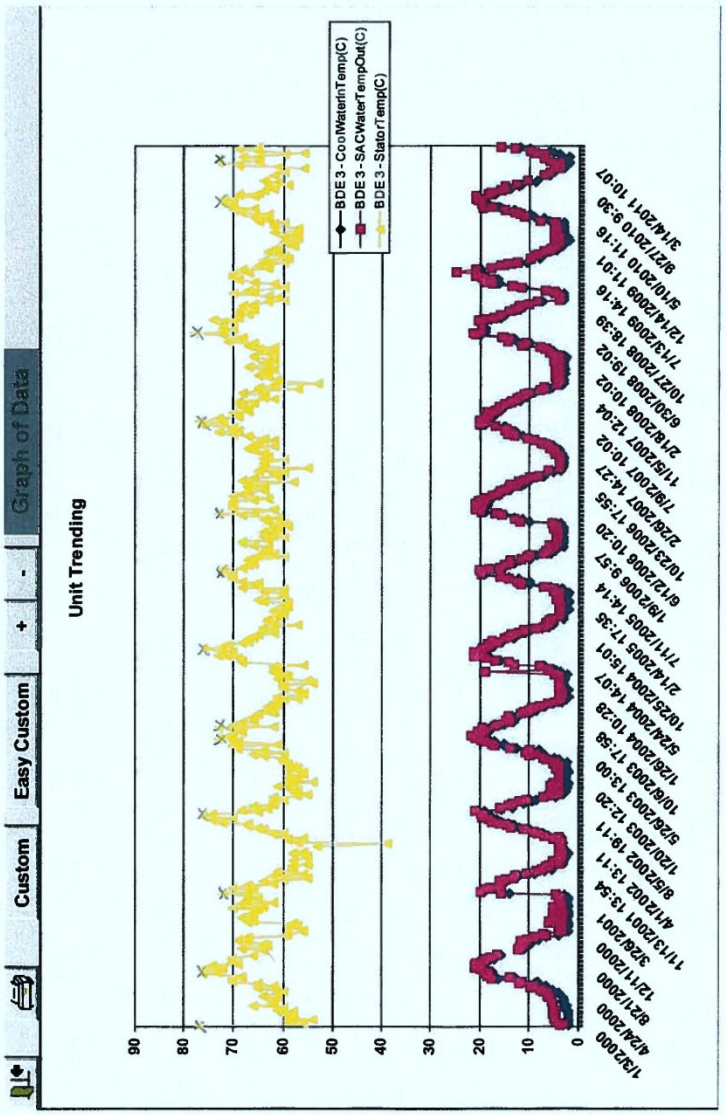
Photograph 050

Appendix B: Operating Temperature

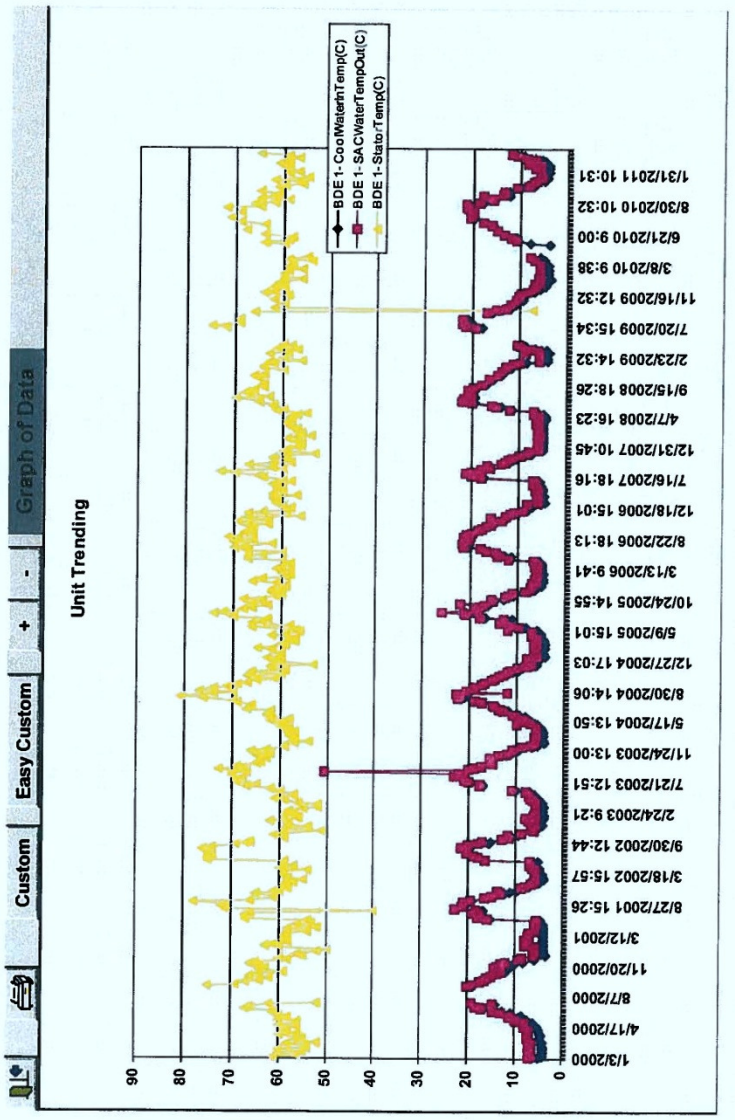
U4 STATOR WINDING T° TRENDING



UNIT 3 STATOR WINDING T° TRENDING



UNIT 1 STATOR WINDING T° TRENDING



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.

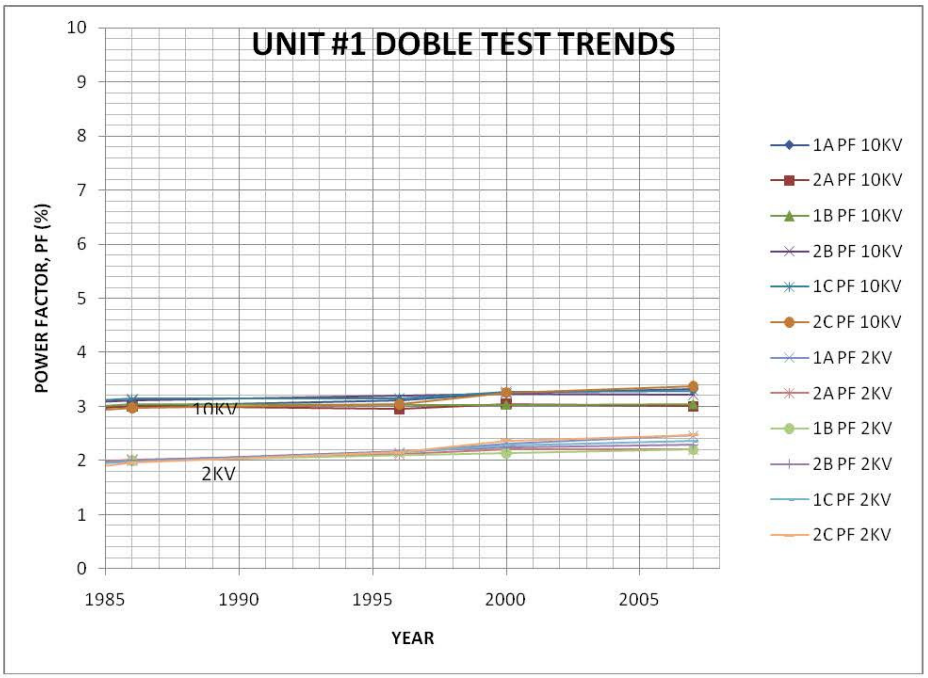
Unit #1 holds a consistent power factor of 3% at a test voltage of 10kV and as well at a test voltage of 2kV with a power factor a little above 2%.

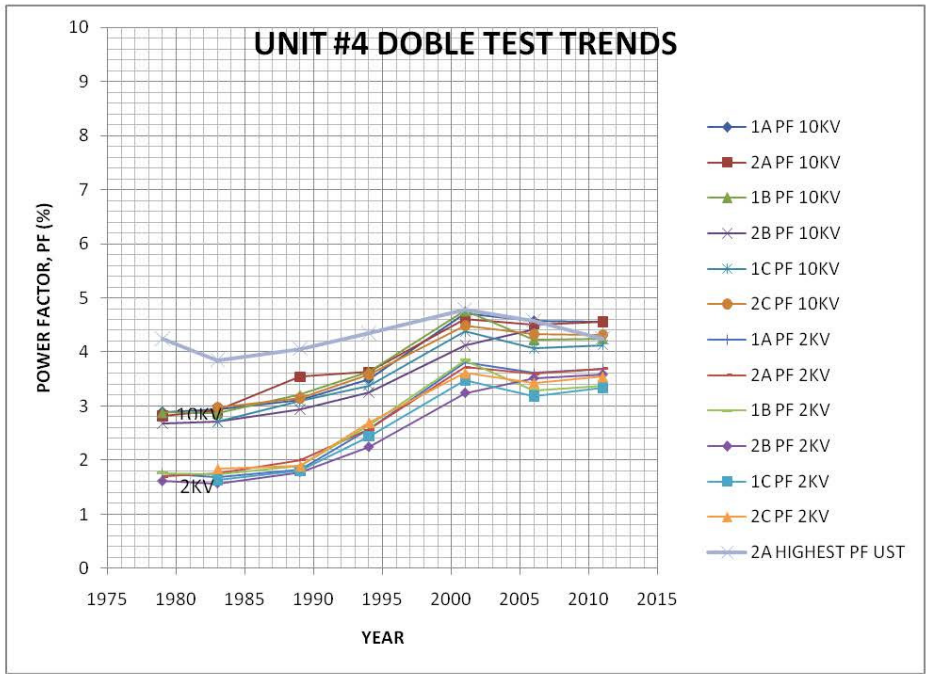
Unit #3 follows a similar trend to Unit #1 until the later tests where the slope is gradually increasing.

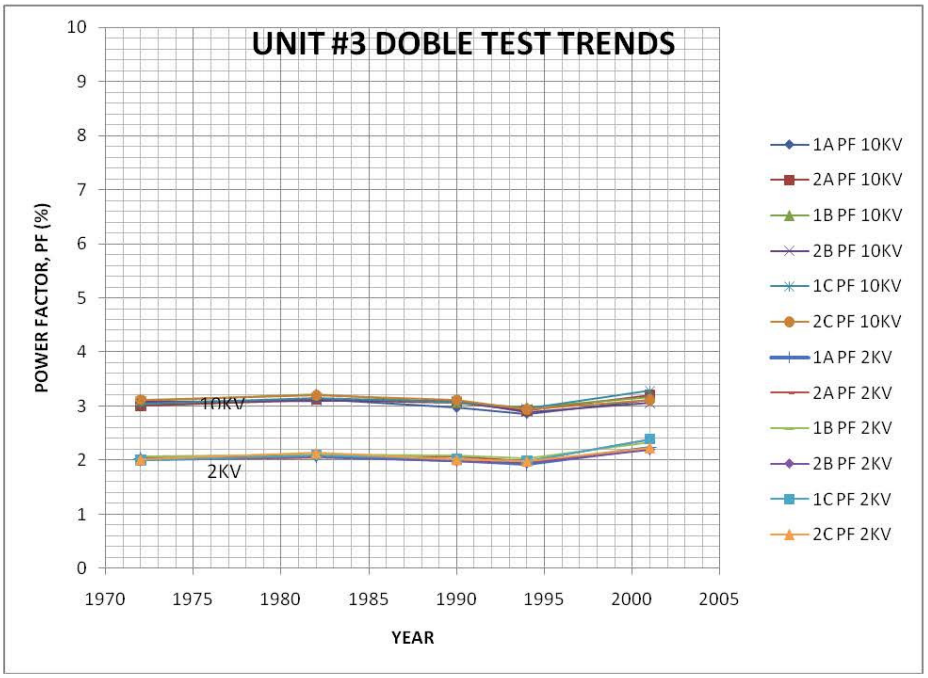
Unit #4 follows consistently linear trends until 1989 when all three phases had similar power factors of 2 and 3 percent at their respective test voltages of 2kV and 10kV. From the most current tests the second coil in Phase A reaches a power factor of 4.6% at a test voltage of 10kV and a power factor 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
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
0
1
2
3
4
5
6
7
8
9
10
1970
1975
1980
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

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.

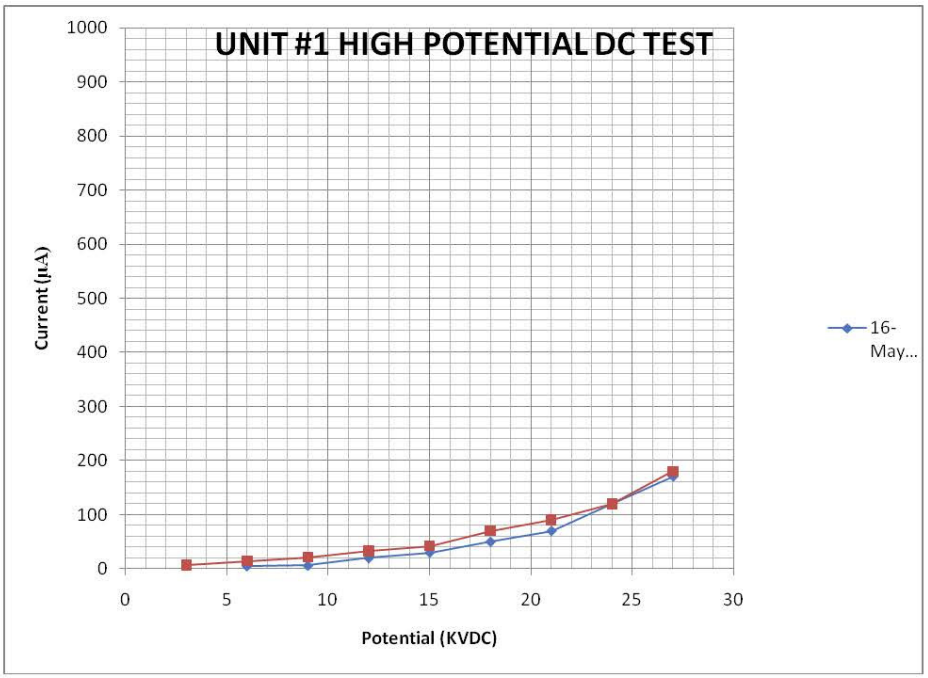
The only hypot tests provided on Unit #1 were completed in 2007, before and after cleaning in May and July respectively. Both tests follow similar a trend, gradually increasing slope with higher test voltages. Significant increases in slope begin to arise at 15kV, increasing by twice the slope in May 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.

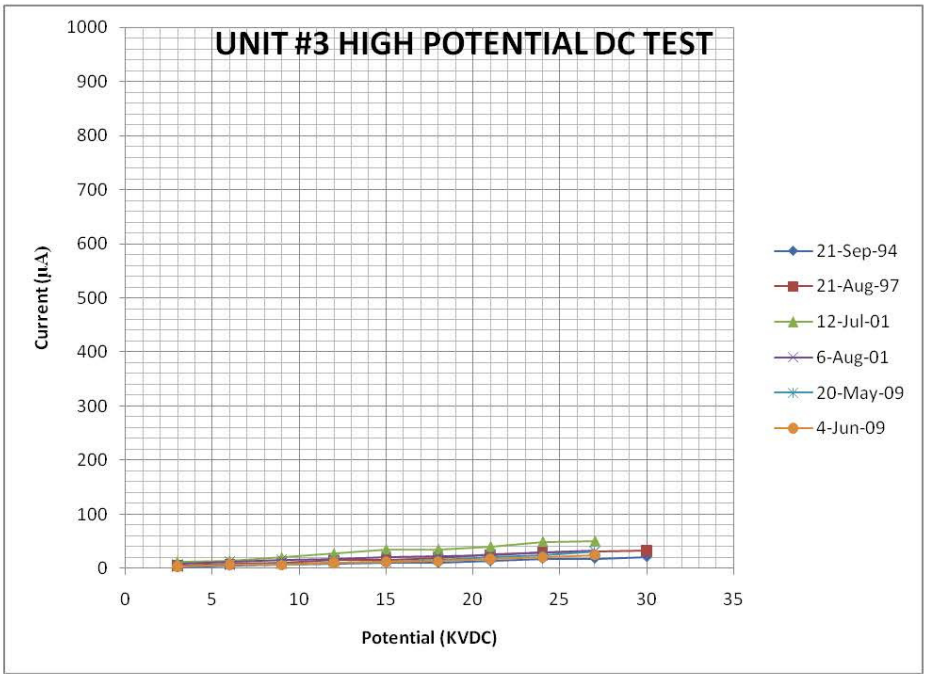
All tests completed on Unit #3 show consistently linear trends which is a good indication of acceptable test results.

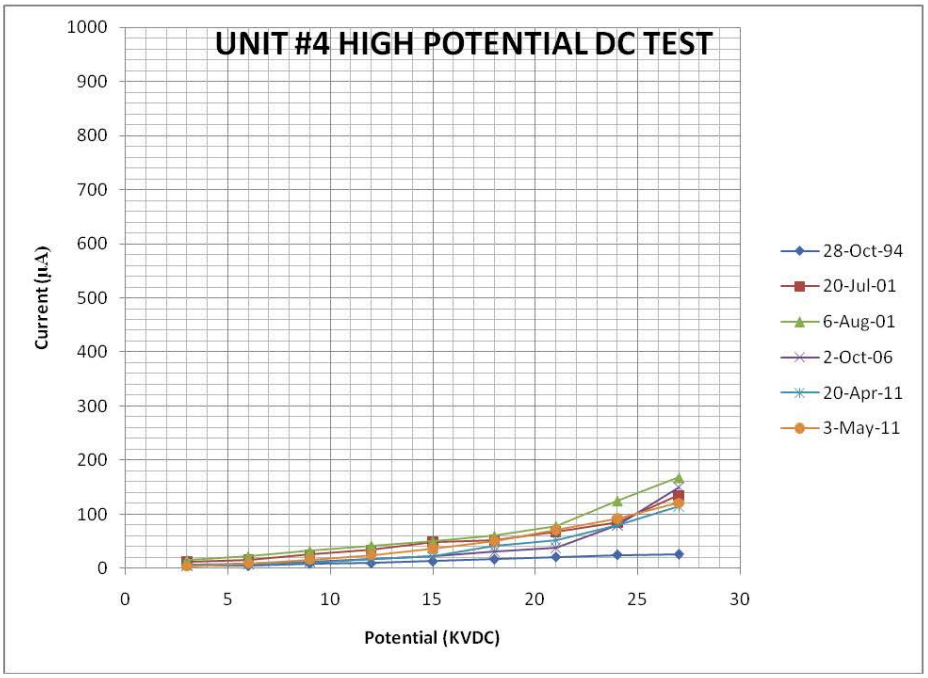
The first hypot test, done on Unit #4 in 1994, follows a linear trend with very small amounts of leakage current. Conversely, the five tests done within the last ten years show results that are not as desirable. The trends seem to remain consistently linear until a test voltage of 15kV when they begin 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)
1000
900
800
700
600
500
400
300
200
100
0
0
5
10
15
20
25
30
16-May...


UNIT #3 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
35
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)
Potential (KVDC)
0
100
200
300
400
500
600
700
800
900
1000
0
5
10
15
20
25
30
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

	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		

Deviation = (1-(Voltage/Mean))*100%

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

	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		

Deviation = (1-(Voltage/Mean))*100%

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

	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		

Deviation = (1-(Voltage/Mean))*100%

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

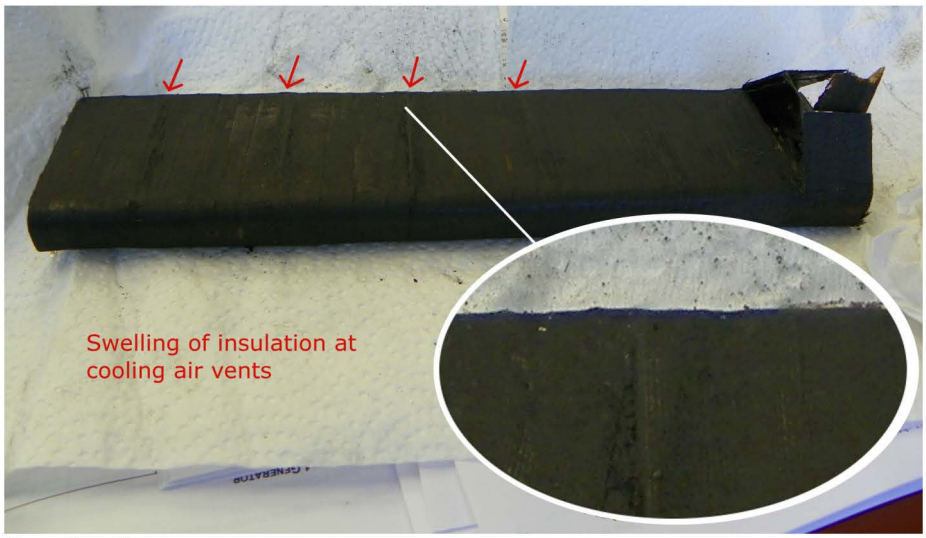
	UNIT #1	UNIT #3	UNIT #4
1967	Commissioned	Commissioned	
1968			Commissioned
1991		Stator re-wedged with piggyback wedges	
1992			Wedge inspection Stator re-wedged with piggyback wedges Generator trip (ground fault on phase A), problem found to be a fault on one of the main leads, the bus was reinsulated 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)

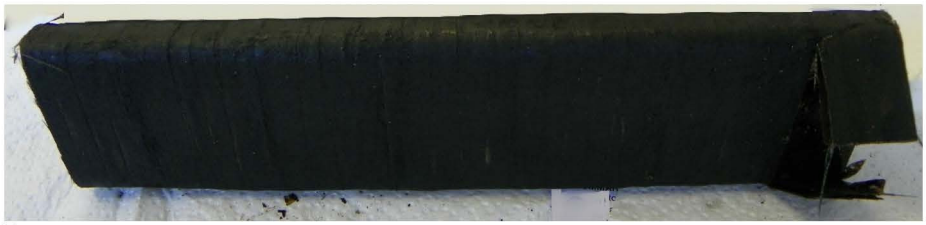
2005	PM6 - PI test(3.33, after 10min 1500MΩ)	PM6 - PI test(3.46, after 10min 2250MΩ)	
2006	PM6 - PI test(5.3, after 10min 800MΩ, still hot) PM9, PDA couplers checked	PM6 - PI test(3.28, after 10min 2300MΩ) Start up inspection	PM6 - PI test in October, before cleaning (2.5, after 10min 1100MΩ), after 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



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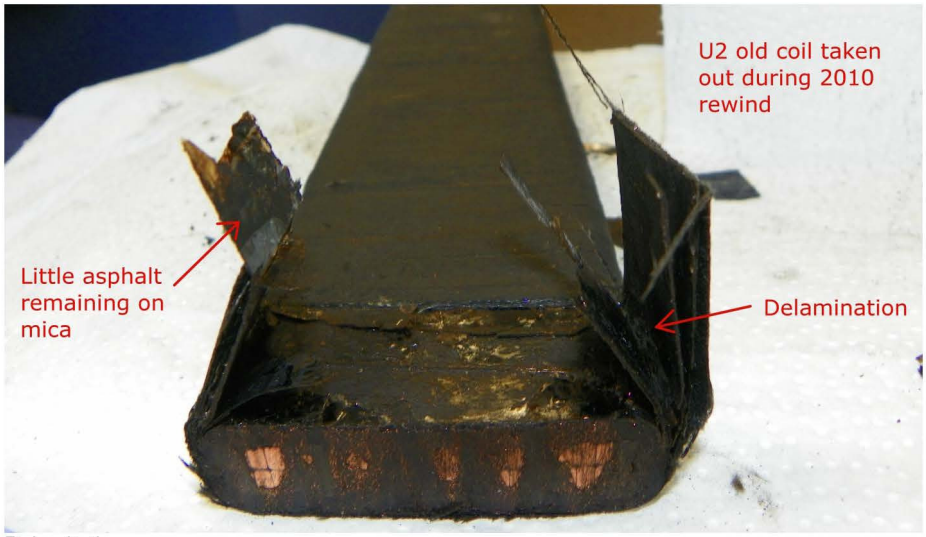


Delamitation

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.

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

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.

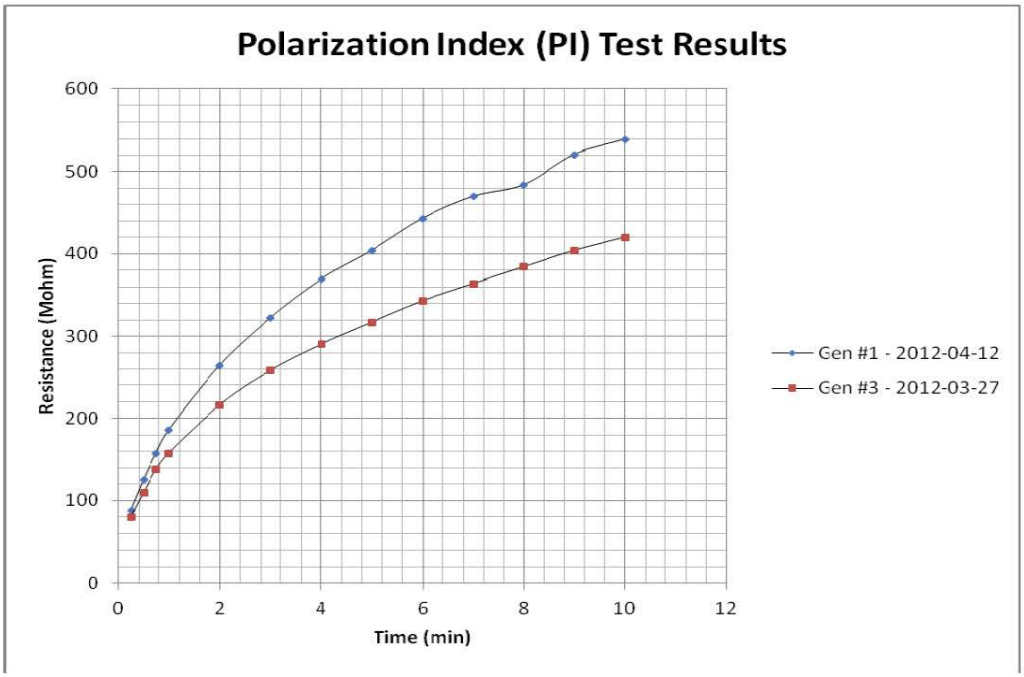
We strongly recommend the following actions:

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.

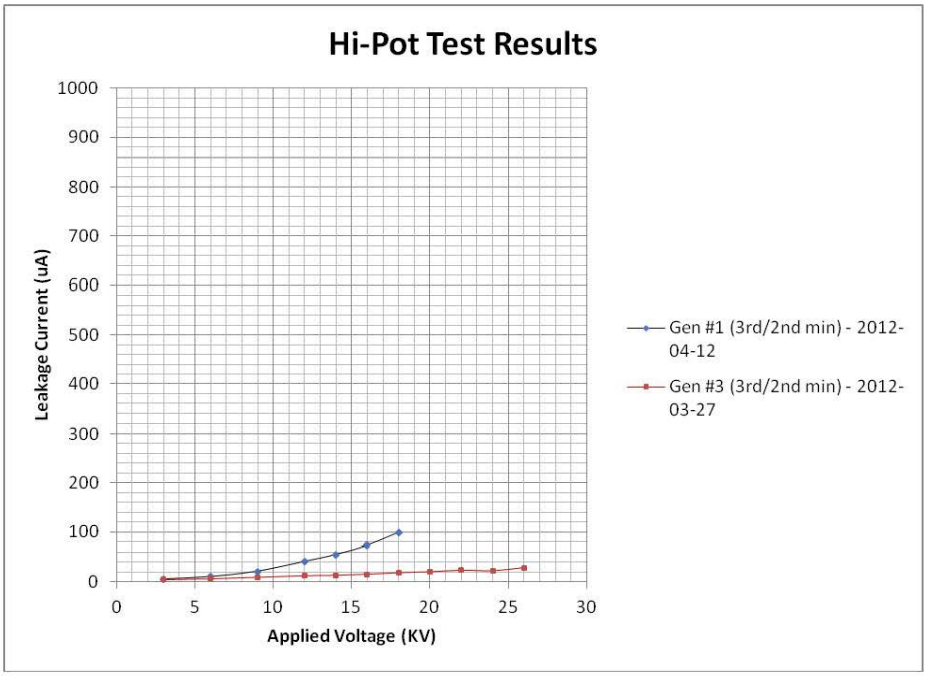
4.2. The Unit #3 generator stator insulation is in a deteriorated condition but the danger of an in-service failure is not as great as that of Unit #1. The Unit #3 rewind should therefore be planned to be completed after Unit #1 has been rewound. We suggest that this should occur no later than Spring 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.

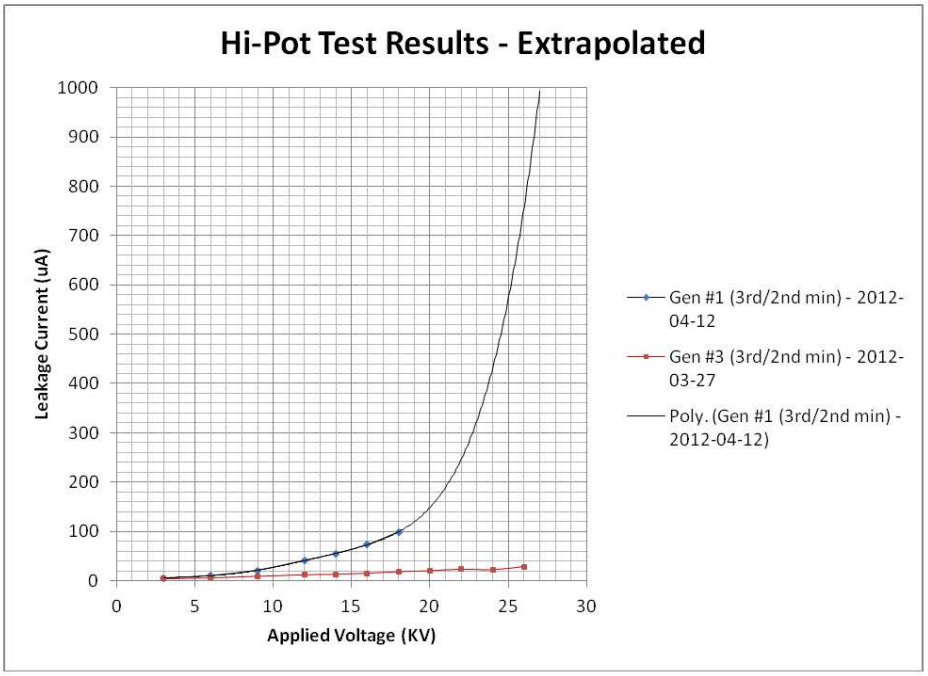
4.4. The Bay D'Espoir generating station auxiliary station services are provided by Unit #1 and Unit #3. During the rewind of the generator of either Unit #1 or Unit #3, there will be no redundancy for the station services for the Plant. It would be worthwhile to consider an alternate power source to 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

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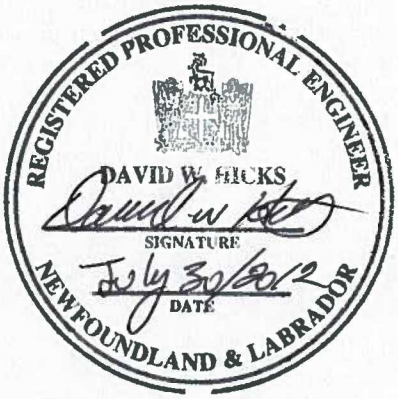
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES



Electrical
Mechanical
Civil
Protection & Control
Transmission & Distribution
Telecontrol
System Planning

Install Variable Frequency Drives on Forced Draft Fans

Holyrood Generating Station

June 2012

newfoundland labrador hydro
a nalcor energy company

SUMMARY

The installation of variable frequency drives (VFD) onto the forced draft fan motors at the Holyrood Thermal Plant will yield significant energy and cost savings for Hydro. These savings are achieved by allowing the forced draft fan motors to operate at varying speeds which align with the intake air requirements of the generating units. Currently, the motors operate at a constant speed (1,189 RPM) and energy usage (1,120 kW) which is independent of the air requirements of the generating units. Airflow to the boilers of the generating units is regulated via a mechanical inlet vane which restricts the amount of air pushed in by the fans. The intake fan motors remain at maximum speed but the inlet vane controls the air flow to ensure an appropriate volume of air is supplied to the generating unit.

This project will yield an annual savings of $2.2 million while the Holyrood plant is generating electricity when compared to the status quo of constant speed fan motors. The project will cost $3.4 million and will commence in 2013 and be completed in 2014. A detailed Cost Benefit Analysis shows that the project will pay for itself in less than one year of being put into service in 2015.

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1 INTRODUCTION

The Holyrood Generating Station is a thermal generating plant with three generating units which produce 500 MW for the Island Interconnected System. The thermal generating system uses many systems and sub-systems to generate electricity using the force of high pressure steam to rotate each generator's turbine and generator.

This steam is produced inside an oil-fired boiler which uses a combustion reaction to superheat water. This combustion reaction requires specific amounts of fuel and air. The air supply system for the Holyrood oil-fired boilers is comprised of intake fans powered by 4,160 V motor units which pull air in from outside, ductwork to transport the air to the boiler, and an inlet vane to control the volume of air entering the boiler.

The intake fans are connected to 4,160 V motor units which operate at a constant speed. Operating these motors at a constant speed results in a constant energy usage from each motor as their speeds cannot be adjusted. If a generating unit requires less than 100 percent airflow the inlet vane is adjusted to limit the airflow from the intake fans into the ductwork and boiler. This results in the 4,160 V motors operating at full capacity in situations when maximum airflow is not required by the generating units. For example, if a generating unit required 50 percent airflow the intake motors would continue to run at 100 percent while the inlet vane would be placed into the 50 percent airflow position. These motors consume 1,120 kW of energy when they are operated. Currently at the Holyrood Thermal Plant there are two 4,160 V motors for each of the three generating units for a total of six motors.

There are motor drive units available which can vary their operating speed to directly match the needs of a system. These motor drive units are known as VFD and they are more energy efficient than constant speed motors as they can lower their operating speed to match system needs. A lower operating speed will lower the energy usage of the motor which can

yield significant savings when compared to constant speed motors. Constant speed motors can be converted to variable frequency operation with the installation of a VFD.

This project will involve the design, procurement, installation, and commissioning of six VFD units to the existing system at Holyrood. This will enable the six intake fan motors to directly adjust the airflow into the boilers as necessary. This work will require adding structural enhancements to mount the 3,800 kg VFD equipment to the existing motors. The ability to directly manipulate the airflow will remove the need for the inlet vanes so they will be removed as well. It will also require programming the Foxboro control system to utilize the new variable speed capabilities of the motors.

The reduction in energy usage from installing VFDs with the intake fan motors at Holyrood will yield a cost savings to Hydro. These savings will be presented in this proposal.

2 PROJECT DESCRIPTION

This project will procure and install VFD on each existing forced draft fan motor at the Holyrood Thermal Plant. The VFD units to be installed weigh 3,800 kg and will require appropriate structural enhancements at the plant. The six inlet vanes in the current system will be removed. Finally, the Foxboro control system will be configured to properly utilize the VFD-enhanced motors.

Six VFDs will be procured and installed at the Holyrood Thermal Plant. The minimization of downtime for the generating units will be a priority during project execution. Each generating unit will require two VFDs (one for each forced draft fan motor) and therefore the project will install the VFDs in sets of two per unit.

3 JUSTIFICATION

At the Holyrood Thermal Plant there are a number of support systems which are used in the generating of electricity. These support systems consume electricity themselves. The forced draft fan motors are one of these support systems.

The current configuration for these forced draft fan motors involves their operating at maximum output whenever the generating unit they are connected to is in operation. There are a number of instances throughout the year when the generating unit is not operating at its maximum capacity rating (MCR). If a generating unit is operating both forced draft fan motors connected to it are operating at maximum speed. If the generating unit is not operating at 100 percent MCR then there is wasted production from the forced draft fan motors as they are constant operating speed motors.

Upgrading the forced draft fan motors with VFDs will yield operational savings based on the motors directly matching the air intake requirements of the generating units which will reduce the amount of energy used by the forced draft fan motors. These savings are discussed in Section 3.4.2.

3.1 Existing System

As discussed previously, the supply of air to the boilers of the generating units at the Holyrood Thermal Plant is a key part of the generation process. The current system has six intake fans driven by 4,160 V constant speed motors. Each generating unit has two forced draft fans. These fans supply air to the oil-fired boiler which produces steam for the generating units.

These fan motors operate at a constant speed of 1,189 RPM and consume 1,120 kW of energy. The supply of air to the boiler is controlled via inlet vanes which control the amount of air being supplied by the intake fans. Each intake fan has a corresponding inlet vane

connected to it. The forced draft motors on Units 1 and 2 were replaced in 1991 and Unit 3 has the original motors from 1977. All motors currently installed are constant speed motors.

3.2 Operating Experience

The Hydro methodology for the Island Interconnected System is to operate its hydraulic units on the island at maximum capacity and import as much power as possible to the Avalon Peninsula. Due to transmission line limits and other factors, the level of imported power is not adequate to meet the full load requirements of the Avalon Peninsula. Holyrood units are placed online for operation to meet this deficiency and to meet any peak loading requirements that occur throughout each day. As the ramp-up time on a thermal generating unit is slow, thermal units are base loaded at 40 percent of their MCR to ensure they are ready and available when needed while minimizing ramp-up time.

The generating units at Holyrood have a capability range of operation between 20 to 105 percent of their MCR. Generally, the units are not operated below 40 percent as these operating levels are highly inefficient. The following table describes the typical operating levels for the generating units at Holyrood.

Table 1: Generating Unit Operating Levels

Operating Level (% MCR)	Amount of Time at this Level Per Year
Offline	10%
40	50%
50	10%
60	10%
70	10%
>80	10%

As a generating unit nears 100 percent of its MCR, the efficiency of the constant speed fan motors becomes higher. However, it is clear that a majority of the year is spent with the generating units operating at loading levels which are less than its maximum. Regardless of operating level, the forced draft fan motors are operating at full speed (1,189 RPM) and consuming the full 1,120 kW of energy on a continuous basis.

3.2.1 Environmental Performance

This project will not alter the environmental performance of the Holyrood Thermal Plant. Installing VFDs will result in the motors not using as much energy throughout the year, but will not impact the consumer demand for energy from the generating units.

3.2.2 Industry Experience

The installation of variable frequency drives on large voltage motors is an established industry practice.

3.2.3 Anticipated Useful Life

The anticipated useful life of the forced draft fans and motors is for the remaining life of the plant. This VFD system will be used as long as the plant is used to generate electricity. The manufacturer of the variable speed drives will support the VFD equipment for 20 years.

3.3 Development of Alternatives

This proposal will analyze two alternatives. The first alternative is for the forced draft fan motors to remain at status quo. The second alternative is the installation of six variable frequency drives along with the removal of the inlet vane control from each intake fan system.

3.4 Evaluation of Alternatives

The time period considered for the evaluation of these alternatives is from 2013 to 2016. For the status quo, the energy and maintenance costs of the fan motors are considered for two years. For the installation of VFDs the new system is assumed to be placed in service at the end of 2014.

The cost of energy of operating the existing constant speed fan motors for four years was calculated to be $10.3 million. This represents the status quo cost. The cost for the same period of time for the VFD upgrade was calculated to be $5.9 million and this assumes the

VFD upgrades come online in January of 2015.

The difference in favor of the VFD upgrade is $4.3 million. This savings is realized in two years (2015 and 2016) for an average annual savings of $2.2 million. These figures are presented in Section 3.4.2.

3.4.1 Energy Efficiency Benefits

This project will yield energy efficiency benefits primarily through the reduction in energy usage by operating constant speed fan motors at full capacity even when the generating units do not require full capacity airflow. VFDs will operate the fan motors at the precise level required to supply sufficient air to the boilers of the generating units.

3.4.2 Economic Analysis

The analysis conducted for this proposal is a present value calculation for the period ranging from the estimated in-service date of the VFD system (January 2015) until the assumed in-service date of the Labrador Infeed (2017). This present value analysis shows an anticipated difference of $4.3 million for the two alternatives of status quo and the addition of VFDs.

The analysis involves an improvement in the efficiency of the forced draft fan systems. The VFD based system will consume less energy than the existing system. Energy consumption numbers for both systems were received from Siemens. The cost of consumed energy is calculated based on the amount of fuel consumed at Holyrood. The cost is calculated based on the formula:

Cost = MW * hours * barrels of oil/MWh * cost per barrel of oil

The analysis also uses a projection of production at Holyrood from the 2012 System Operation Holyrood Production Forecast. The cost of a barrel of oil is based on the Nalcor

Energy Corporate Planning Forecast from January 2012. The summary of this analysis is shown in Table 2.

Table 2: Net Present Value Analysis

Install Variable Frequency Drives on Six Forced Draft Fans		
Alternative Comparison ***Cumulative Net Present Value*** ***To The Year*** **2016**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Status Quo	10,278,019	4,343,355
VFD	5,934,664	0

To test the results of the present value analysis a sensitivity analysis was conducted for two factors. The assumed price of fuel and the energy consumption rate of the VFDs were tested independently to discover what the values for each would have to be to make status quo the preferred alternative. The cost of fuel at Holyrood would have to be less than 40 percent of the forecasted value for the status quo to become the preferred alternative. The energy improvement of the VFDs would have to be less than 40 percent of the value provided by Siemens for the preferred alternative to shift to the status quo.

The projected budget for this work is presented in Section 4.1 and is $3.4 million. Once operational the VFDs will yield an average annual fuel savings of $4.7 million to Hydro while the Holyrood Thermal Plant is generating electricity. The project pays for itself less than one year of being put into service.

4 CONCLUSION

The installation of VFDs on the forced draft fan motors at the Holyrood Thermal Plant will reduce energy costs and yield operational savings of $4.7 million per year. The payback period for the $3.4 million project budget is less than one year.

4.1 Budget Estimate

The budget estimate for this project is shown in Table 3.

Table 3: Project Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	453.9	1,285.0	0.0	1,738.9
Labour	53.9	43.4	0.0	97.3
Consultant	21.0	0.0	0.0	21.0
Contract Work	90.0	523.0	0.0	613.0
Other Direct Costs	37.7	25.5	0.0	63.2
Interest and Escalation	41.1	276.1	0.0	317.2
Contingency	0.0	506.7	0.0	506.7
TOTAL	**697.6**	**2,659.7**	**0.0**	**3,357.3**

4.2 Project Schedule

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

Table 4: Project Schedule

Activity		**Start Date**	**End Date**
Planning	Determine Outage Period, Gather Equipment Data	January 2013	March 2013
Design	Design Structural Components, VFD parameters	April 2013	July 2013
Procurement	Tender and Procure Structural Work Tender and Procure VFD Equipment Tender and Award Electrical Contract	July 2013 May 2013 October 2013	September 2013 June 2013 December 2013
Construction	Install Structural Components	October 2013	November 2013
	Install VFD, Remove Inlet Vane	May 2014	July 2014
Commissioning	Foxboro Tuning, VFD Operation	July 2014	August 2014
Closeout	Documentation Closeout	September 2014	December 2014

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Electrical
Mechanical
Civil
Protection & Control
Transmission & Distribution
Telecontrol
System Planning

Upgrade Governor Controls Units 1 and 2

Holyrood Thermal Generating Station

May 2012

newfoundland labrador hydro
a nalcor energy company

SUMMARY

This report addresses the need to upgrade the existing General Electric Mark V governor control system for Units 1 and 2 to the General Electric Mark VIe model. This project will require a migration of the existing circuit boards and controllers to the present technology of the Mark VIe control. The existing Mark V controller will enter Phase 5, Obsolete, of its Life cycle Plan, in 2014. The upgrade should be completed before the components enter into the obsolescence phase of the Life Cycle Plan so that the governor control system for Units 1 and 2 is not put at risk if a component failed and spare parts or repairs are not available.

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APPENDIX A A1

1 INTRODUCTION

The Holyrood is an essential part of the Island Interconnected System, with three units providing a total capacity of 490 MW. The generating station was constructed in two stages. In 1971, Stage I was completed bringing on line two generating units, Units 1 and 2, capable of producing 150 MW each. In 1979, Stage II was completed bringing on line one additional generating unit, Unit 3, capable of producing 150 MW. In 1988 and 1989, Units 1 and 2 were up-rated to 170 MW. Holyrood represents approximately one third of Hydro total Island Interconnected generating capacity.

The three main components of each generating unit are the boiler, turbine, and generator. For Units 1 and 2, application of load, turbine over speed protection, thermal stress protection and automatic run-up and synchronizing capabilities are provided by a General Electric (GE) Mark V governor control system. As per the GE Proposal SF59949 presented for the migration solution and given in Appendix A the Mark V was designed in 1990 as a dedicated turbine controller with embedded control, protection, and monitoring. Its hardware, software, and network designs reflected the 1990 controls technology when it began service in 1991 and completed production in 2003. The Mark V controller will enter the obsolescence life cycle phase (Phase 5) in 2014.

It will be necessary to have a solution in place to ensure that the turbine controllers for Units 1 and 2 at the Holyrood Thermal Generating Station (Holyrood) are supported by the manufacturer.

2 PROJECT DESCRIPTION

The scope of the work is to upgrade the existing GE Mark V turbine controller on Units 1 and 2 at Holyrood to the modern GE Mark VIe turbine controller.

GE offers a migration of the Mark V controller to the Mark VIe controller. This will bring the older technology up to the standards of today. Modern circuit boards and controllers using state of the art Mark VIe technology will be used. Engineering design, hardware, software and field services to migrate to the Mark VIe controller will be provided by GE.

The migration program allows for minimal downtime and site disruption with no impact to field wiring, turbine devices or the location of the existing Mark V controller cabinet. The Mark V application software will be translated by GE to the Mark VIe software as part of the engineering phase.

This upgrade will address the obsolescence of the Mark V controller in 2014 as stated by GE. The migration solution will provide a modern turbine controller, Mark Vie, supported by GE to 2026 and it will have the least impact on outage schedule and installation resources. The Mark VIe will be provided by GE so there will be familiarity with the use of the system.

3 JUSTIFICATION

The GE Mark V turbine controller on Units 1 and 2 will enter Phase 5, Obsolete, of the Life Cycle Plan in 2014 as stated by GE. In Phase 5, as per GE, "the product is no longer supported, and is not recommended for continued use in a machinery protection application." The definitions for the different phases of the Life Cycle Management and a letter from GE concerning the Mark V Product Transition are given in Appendix A. The turbine controller is used for application of load, turbine over speed protection, thermal stress protection and automatic run-up and synchronizing capabilities. It is critical for operation of the units and the failure of a component without the proper part or support would prevent the unit from operating.

GE offers a migration solution to move the hardware and software to the Mark VIe modern turbine controller. With the migration there is no disruption to the field wiring, turbine devices or the existing cabinet location. The migration can be done with minimal disruption and downtime.

If the project is not undertaken and one of the components fails the unit would be out of service until a replacement part or new system was installed. The turbine controller is essential for operation of the units.

3.1 Existing System

The Mark V turbine controller was installed on Unit 1 in 2003 and on Unit 2 in 1999. It was installed as a replacement for the original GE Mark II control system which had been in service since 1971.

The Mark V turbine controller consists of a single cabinet containing the hardware components. There is also a Human Machine Interface (HMI) situated in the control room for the operators' use. The Mark V control configuration consists of the control module, the

protection module and the common input/output module. The inside of the Mark V cabinet showing the hardware components is given in Figure 1.

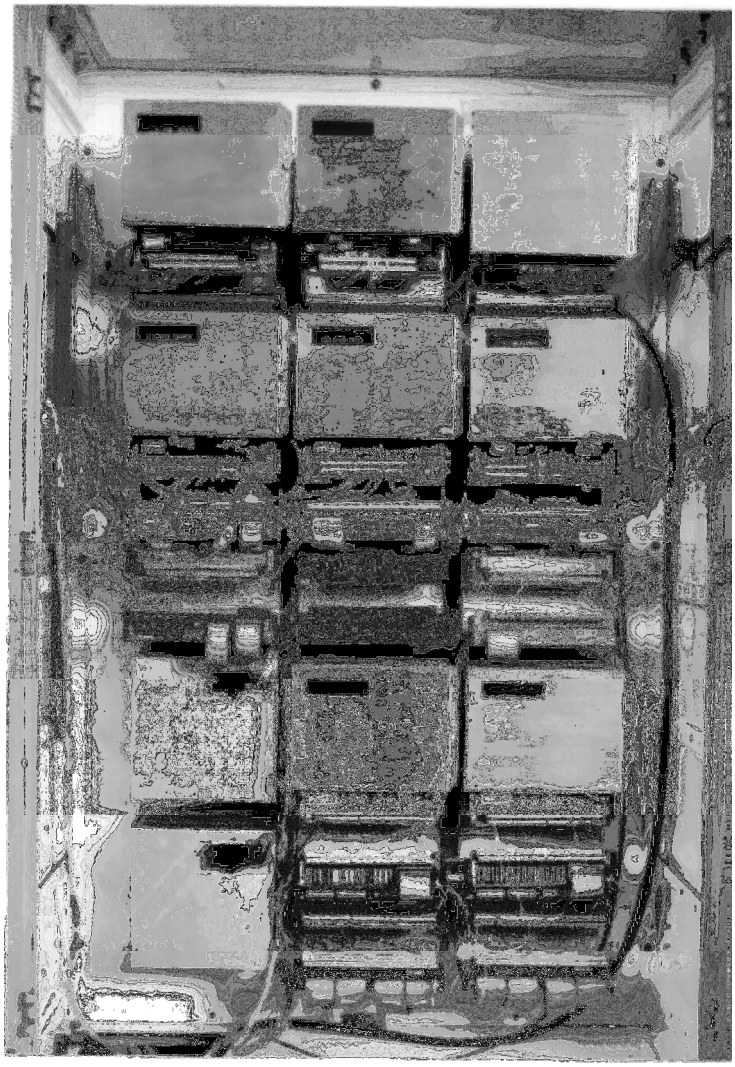

Figure 1: Mark V Showing Hardware

The Mark V turbine controller is a simplex version meaning it has only one control module which performs all of the critical control algorithms, protective functions and sequencing. It also acquires the data needed to generate outputs to the turbine. A triple redundant system is also available but was not specified for Holyrood. The protective functions are passed through a protection module that has triple redundant processors which provide independent protection functions for critical functions such as over speed. The input/output

module monitors non critical inputs and outputs. The Simplex Control Configuration is shown in Figure 2.

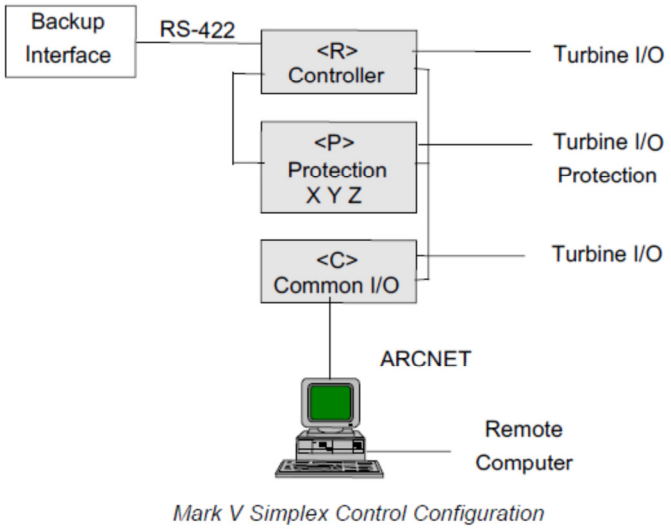

Figure 2: Mark V Simplex Control Configuration

The quantities of spare parts at Holyrood for the existing Mark V systems for Units 1 and 2 are as follows:

Table 1: On Site Spare Parts

Description	Part Number	Quantity
Drive Control	GE DS200SDCCG4A	2
TC2000 Common Analog I/O	GE DS200TCCAG1B	1
Emergency Over speed	GE DS200TCEAG1B	2
Common Expanded I/O	GEDS200TCEBG1B	1
DC Input Power Supply	GEDS200TCPSG1A	1
Analog I/O (RST)	GEDS200TCQAG1B	1
Overflow (RST)	GEDS200TCQCG1B	1
Relay Board c/w relays	GEDS200TCTSG1A	1
Power Distribution	GEDS200TCPDG1B	1

The Mark V turbine controller has operated well since its installation. The major work or upgrades are given in Table 2.

Table 2: Major Work and/or Upgrades

Year	Major Work and/or Upgrade	Comments
2005	Firmware Upgrade	GE recommended action
2010	Auto synchronizing added	Enables automatic startup

3.2 Operating Experience

The Mark V turbine controller will enter Phase 5, Obsolete, of the Life Cycle Plan in 2014. Phase 5, as per GE, means that "the product is no longer supported and is not recommended for continued use in a machinery protection application." The Mark V controller for Unit 1 has been in service since 2003 and the controller for Unit 2 has been in service since 1999.

The Mark V turbine controller for Units 1 and 2 has worked well since its installation. However, it has to be migrated to a newer version turbine controller, Mark VIe model, so that parts and full support from the manufacturer will be available after the Mark V becomes obsolete in 2014.

3.2.1 Reliability Performance

The existing Mark V turbine controllers have performed well. Reliability performance is not a basis for this proposal.

3.2.1.1 Outage Statistics

Outages on the Mark V turbine controller are primarily forced shutdowns to reset the communications core when the communications card locked up. The summary of outages is given in Table 3.

Table 3: Outages due to Mark V Turbine Controllers on Units 1 and 2

Date	Description	Action
2004-10-17	Unit 1 tripped (30 MW)	Reset Mark V
2004-10-18	Unit 1 offline	To reset Mark V
2004-11-08	Unit shutdown	To install software changes
2004-12-07	Unit load reduced	Problem on Mark V
2004-12-07	Unit 1 offline	To reset Mark v
2005-03-20	Unit 1 offline	Problem with Mark V
2005-03-21	Unit 1 shutdown	Rest Mark V
2006-01-06	Unit 1 load reduced	To reset Mark V
2006-11-30	Unit 2 reducing load	Planned outage, Mark V checks

3.2.2 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements related to this proposal.

3.2.3 Safety Performance

There are no safety performance issues related to this proposal.

3.2.4 Environmental Performance

There are no environmental performance issues related to this proposal.

3.2.5 Industry Experience

The Mark V turbine controller was introduced by GE in 1991 and there is an installed base of 3000 plus units.

3.2.6 Vendor Recommendations

GE recommends the migration of the Mark V turbine controller to the Mark VIe controller due to the obsolescence of the Mark V controller in 2014. The following is taken from a Proposal SF59949 (See Appendix A) submitted by GE.

"Mark V End of Life

As previously communicated by GE, the Mark V Control enters the obsolescence life cycle phase in 2014.

Migrating your Mark V with the Mark VIe Control will ensure that GE's long-term support for your critical control system asset will be extended for a minimum of 15 years, through 2026."

3.2.7 Maintenance or Support Arrangements

Repair or exchange of components is available until 2014. Support beyond 2014 in the obsolescence phase is, as per GE, "dependent upon numerous items, including supplied parts and components, design automation tools, test equipment, technical expertise, and manufacturing facility." Refer to Appendix A, Mark V/EX2000 to Mark Vie/EX2100 Control Product Transition letter. There is no maintenance agreement in place with GE. Maintenance is done by internal plant resources.

3.2.8 Maintenance History

The five-year maintenance history for the Mark V turbine controllers is shown in the following table:

Table 4: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2012	0.0	26.6	26.6
2011	0.0	2.4	2.4
2010	0.0	0.8	0.8
2009	0.0	3.9	3.9
2008	0.0	12.3	12.3

3.2.9 Historical Information

This is not a recurring project.

3.2.10 Anticipated Useful Life

The new turbine controller has an estimated service life of 15 years.

3.3 Forecast Customer Growth

This project is not needed for customer growth.

3.4 Development of Alternatives

The project is based on using the GE migration platform to move from the Mark V controller to the Mark Vie controller. As per the Proposal SF59949 from GE, Appendix A, the migration strategy has the following benefits.

The innovative Mark V Migration technology has been introduced to bring the older generation, digital control system technology up to today's standards. Each of the control, digital, and protection cores of the existing Mark V Control has been updated with modern circuit boards and controllers containing GE's state of the art Mark VIe Control technology.

Benefits for this Migration include:

- Minimum down time and less site disruption: Modernize in as few as five outage days with no impact to field wiring, turbine devices, or the existing Mark V Control system footprint;
- Reduced solution scope and risk at lower total cost, direct translation of as-running software;
- Increased computational power and I/O expandability enabling new features to improve turbine performance, reliability and operability;
- Conversion of 16 bit integer data format to 32 bit floating point resulting in a major improvement in programming flexibility;
- A new and improved Windows® based software suite, ToolboxST™, with modern features to simplify maintenance. Examples include:
    - drag-and-drop type editors,
    - trending with video type forward reverse-freeze capability, and
    - code-compare tools.
- Many new I/O types to choose from and distributable in any configuration;
- Elimination of single-point communication failures within the control and options for cost-effective network redundancy between controls and HMI's. Replacing ARCNET®

based Stage Link with an Ethernet® LAN conforming to modern IEEE 802.3 standards;

- The existing Mark V processor boards with their 196 CPUs are replaced with new boards containing Mark VIe processors. Elimination of customizable/programmable PROMs;
- Ease of operation with improved graphics, alarm/event management, trending;
- More efficient maintenance with one modern software tool for configuration of networks, processors and I/O boards, along with editors, block libraries, and diagnostics;
- Compatible with current programs for compliance with cyber security standards, maintenance;
- programs, and remote monitoring and diagnostics; and
- Backward compatibility with many of your existing spares.

For more information on the benefits of the migration strategy see Appendix A for a Fact Sheet from GE concerning the Mark VIe Control Migration from Mark V Control

An alternative would be to replace the Mark V turbine controller with a controller manufactured by another company. However, this would require more extensive engineering, testing, installation and outage duration to implement as it would involve the complete replacement of the existing Mark V turbine controller and field wiring. The benefits of using the existing field wiring, cabinet footprint and in house experience with the GE turbine controller would not be applicable.

3.5 Evaluation of Alternatives

No alternatives were evaluated. The migration solution offered by GE was selected based on the reduced field wiring, reduced engineering, installation time and outage duration.

3.5.1 Energy Efficiency Benefits

Not applicable.

3.5.2 Economic Analysis

Not applicable

4 CONCLUSION

This turbine controller for Units 1 and 2 needs to be upgraded because the existing Mark V controller will enter Phase 5, Obsolescence of its Life Cycle Plan in 2014. Phase 5 means that "the product is no longer supported and is not recommended for continued use in a machinery protection application." Support and repair services will be limited by availability.

Migration to the Mark VIe controller is required to ensure that full support is available form the manufacturer beyond 2014.

4.1 Budget Estimate

Table 5: Project Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	346.0	0.0	0.0	346.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	774.3	0.0	0.0	774.3
Other Direct Costs	19.1	0.0	0.0	19.1
Interest and Escalation	88.2	0.0	0.0	88.2
Contingency	227.9	0.0	0.0	227.9
TOTAL	**1,455.5**	**0.0**	**0.0**	**1,455.5**

4.2 Project Schedule

Table 6: Project Schedule

Activity		**Start Date**	**End Date**
Planning	Review existing Mark V logic Prepare design transmittal	January 2013	February 2013
Design	Update applicable drawings Prepare contract for supply	February 2013 February 2013	April 2013 March 2013
Procurement	Issue contract	April 2013	April 2013
Construction	Migrate to Mark Vie Unit 1 Migrate to Mark Vie Unit 2	July 2013 September 2013	August 2013 October 2013
Commissioning	Commissioning Unit 1 Commissioning Unit 2	August 2013 October 2013	September 2013 November 2013
Closeout	Project closeout documentation As built drawings	November 2013	December 2013

APPENDIX A

Correspondence from General Electric

GE Energy
Measurement & Control Solutions

Mark* VIe Control
Migration from Mark V Control

fact sheet

You can now elegantly modernize your legacy Mark V control system to GE's most advanced control platform, the Mark VIe, through a simple plug-and-play exchange of the electronic modules. With no change to site wiring, panel terminations, turbine field devices, or panel size, the migration significantly expands your system's capabilities while completely addressing all obsolescence issues. The solution ensures continued OEM support and the ability to grow and do more with your control system. It is designed to replace all Mark V control systems, except for those on LM (aeroderivative) turbines.

Benefits of Migrating Your Mark V to Mark VIe

- A complete control upgrade with reduced scope, risk, site disruption, cycle, and cost, installed in as few as five outage days
- Reset the clock on life cycle support – ensure availability of spare parts and OEM engineering support
- Increase turbine performance – substantially increased computer power and easily expandable I/O with many new types, enables incorporation of GE's many advanced turbine offerings such as Autotune, Turndown, Cooling Optimization, TILs, advance DLN, and more
- Increased reliability and availability through:
  - Increased communications availability: eliminates single-point communication failures within the control and provides options for cost-effective network redundancy between controls and HMIs
  - Increased electrical surge and noise immunity
  - Reduced time and effort to replace cards online with auto configuration
  - Card diagnostic LEDs replaced with HMI diagnostics
  - Advanced diagnostic/trending software tools with 1ms SOE on all discrete I/O, configurable before and after commissioning on a point by point basis, with no rewiring
  - Ability to incorporate proactive diagnostic devices and tools with the easily expandable I/O
  - Identify false open contact readings through optional open wire detection for both cabinet and field wiring
  - Available optional pluggable terminations on terminal boards
- Lower cost of ownership and maintenance with:
  - Backward compatibility of many existing Mark V controller spares
  - Single, powerful, easy-to-use software tool for plant operation, maintenance, diagnostics, and configuration of HMI application, networks, processors, and I/O boards
  - Replacement of proprietary maintenance software, GUI, and networks with easy-to-use industry standards
  - Elimination of jumpers and pluggable PROMs

fact sheet

New Technology

The Mark VIe platform offers many new features and capabilities, enhanced reliability, and greater availability. It also enables incorporation of many advanced control and turbine operability enhancements, such as the GE Suite of OpFlex offerings, TILs, and advanced Dry Low NOx. Existing Mark V processors are replaced with state-of-the-art Mark VIe processors, substantially increasing computational power. The ARCNET* communication is upgraded to redundant 100 MB Ethernet® for both the I/O network and external communications, while maintaining the ARCNET communication to the EX2000 where applicable. New operator stations communicate directly to the redundant controllers <R> <S> <T>, not through the Mark V <C> module, eliminating a single point failure and the need for a backup display.

The new network provides high speed, peer-to-peer communications among other Mark control systems and the ability to add redundant networks without requiring a Mark V gateway module <D> in the system.

For sites with EX2000 generator excitation systems, an ARCNET-to-Ethernet gateway is provided, or the control section of the exciter can be upgraded with a new Digital Front End (DFE) using the EX2100e platform. This upgrade allows seamless integration with the same ControlST software configuration, diagnostics tool, and networks as your new Mark VIe system.

Operator and Maintenance Software

Existing operator and maintenance stations are replaced with GE's current Proficy* HMI/SCADA CIMPLICITY* graphics system with improved graphics, screen navigation, alarm/event management, and trending tools. If you have an original <I> station, this also gives you a Windows* operating system with modern client/server networking capability. GE still supports your existing Modbus® and TCP/IP GSM links to plant controls, and complements these with OPC and HMI Client-to-PI server interfaces.

GE uses proven automation tools, ensuring that your existing application software, with its tens of thousands of attributes, is accurately translated to a modern 32-bit floating-point data format. All I/O scaling, alarms, and point names are retained. This new software environment is part of the ControlST software suite.

It offers major enhancements and a focus on ease-of-use over your current tools, including drag-and-drop type editors, math blocks, macros, trending with video-type forward/reverse/freeze capability, watch windows, code-compare tools, etc. Also, changes can be downloaded online without rebooting the new controllers.

I/O Interface

The elegance of the modernization is that the Mark VIe control system maintains the existing cabinet, high density of I/O, all cabinet and field terminations, and turbine devices, with no update to site drawings required. This is the key to reducing outage time from weeks to a few days.

Your new Mark VIe provides complete flexibility to add and distribute additional Mark VIe I/O as needed. Additional flexibility is gained though the diverse number of Mark VIe I/O types available, which continues to grow. Mark VIe I/O supports a variety of busses, including HART*, PROFIBUS-DP, and FOUNDATION Fieldbus.

GE also offers:

- Ribbon Cable Replacement Service Option
- Upgraded terminal boards with:
  - Optional pluggable terminations to ease maintenance
  - Increased protection from voltage spikes, including those caused by lightning
  - Both field and ribbon cable open-circuit detection on all digital I/O

Above all, migration of your Mark V control system to the Mark VIe platform gives you a clear path for future enhancements and life cycle support.

For more information, please contact your nearest GE Sales or Service office, or an authorized GE Sales representative.

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*Ethernet is a registered trademark of Xerox Corporation.
*HART is a registered trademark of HART Communication Foundation.
*Modbus is a registered trademark of Schneider Automation.
*Windows is a trademark of Microsoft Corporation.
*Mark, ControlST, CIMPLICITY, and Proficy are trademarks of the General Electric Company.

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GEA18405 (10/2010)

Life Cycle Management

Our newest life cycle support program provides comprehensive parts support, service support and upgrade services to extend the life of your systems. We'll let you know when product enhancements are available, and in later stages you'll be notified of last time to buy opportunities well in advance of parts and services no longer being offered for sale.

How well you plan the maintenance, upgrade and evolution of your control systems can impact your O&M budget and profitability. That's why a well-conceived life cycle support program is essential. Proper planning and cost-effective services can help you extend the life of your control systems and avoid undue risk and cost brought on by obsolescence.

Life Cycle Phases

GE's product life cycle support program for control systems addresses every phase of your system's life - from the development and deployment of system enhancements following initial release, to comprehensive parts and service support as your system matures; and ultimately a clear migration path to a new platform when your enterprise requires a level of performance only available in newer technologies. GE's lifecycle phases for control systems are defined as follows.

Phase 1 – Product Release
The product is released to market with full support including enhancements, custom modifications, new spare parts and full repair services.

Phase 2 – Mature Product
Full system support continues; however, new enhancements are no longer offered. A notice of last time to buy new systems is issued approximately six months before transitioning to Phase 3.

Phase 3 – Stop Sale
The product is no longer offered for new installations. Comprehensive support services continue with new spare parts; and repair, exchange, and remanufacture services through designated repair centers in Louisville Kentucky or Carrol Stream Illinois. Custom modifications are no longer offered. A notice of last time to buy spare parts is issued approximately six months before transitioning to Phase 4.

Phase 4 – After Market
New spare parts are no longer available and support is limited to repair, exchange or remanufacture - subject to availability. A notice of last date to repair is issued approximately six months before transitioning to Phase 5.

Phase 5 – Obsolete
At this point the product is no longer supported, and is not recommended for continued use in a machinery protection application.

Download

GE Industrial Systems

Mark V / EX2000 to Mark VI / EX2100^{tm} Control Product Transition

The Mark V turbine and EX2000 exciter controls complete many years of successful service as GE's main-line turbine / generator controls on March 30, 2004 with the End-of-Production announcements. Introduced in the '90s, they have controlled and protected a wide range of turbine / generators around the world.

GE continues to invest in new technology to keep pace with the growing demand for increased performance and reliability. This new technology is reflected in the next generation of controls, the Mark VI, Mark VIe and EX2100 series.

The Mark VI and EX2100 product platforms already have an experience base of hundreds of turbines / generators. The Mark VI, Mark VIe, and EX2100 support additional advanced applications and DCS controls for combined cycle power plants. The GE platform's flexible architecture, on-board I/O processors, networks, versatile programming libraries, and many other features offer significant advancements over past controls to drive lower life cycle costs. They provide a common control platform to directly monitor the unique sensors and actuators on the rotating machinery, communicates peer-to-peer with other GE sub-systems (i.e. PLC, protection relays) and controls the balance of plant equipment. Therefore, they simplify operation and reduce spare parts, training, and maintenance.

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September 9, 2003

GE Industrial Systems

SPEEDTRONIC™ MARK V TURBINE CONTROL
END-OF-PRODUCTION

GE Drives and Controls, Inc. will cease normal production of the SPEEDTRONIC™ Mark V Turbine Control system on March 31, 2004. As with many products, and particularly with electronics, the Mark V will eventually exceed its supportable life as parts and components become unavailable and technology resources become scarce. This makes it increasingly difficult to guarantee timely availability /reparability of parts for an extended period of time.

In order to address this issue and support customer initiatives, GE has established the following guidelines to help customers as they develop their plans to purchase and retire equipment and to minimize their costs through the Mark V's end-of-life stages.

Product End of Life

Once production of Mark V control systems ceases, its end-of-life process will have begun. During this process, the Mark V will be supported by renewal parts and technical support for 10 years, or as long as feasible. The length of time for continued support after obsolescence is dependent upon numerous items, including supplied parts and components, design automation tools, test equipment, technical expertise, and manufacturing facility. A product end-of-life team reviews the status of each product annually to determine its current status and future plans for continued support.

Renewal Parts End of Life

A renewal parts end-of-life planning team will determine the support strategy for parts, which will be coded to identify their availability and stage of support as follows:

RTS&S (Refer to Sales & Service):
"RTS&S" is temporarily assigned due to part problems, including cost, availability, quality, test equipment, technical expertise, EHS concerns, and low volume. The part will be reviewed for availability at the time of request.

OBS - No Replacement (Obsolete - No Replacement):
"OBS - No Replacement" is assigned to designate parts that GE Industrial Systems can no longer manufacture or obtain from suppliers, and for which no replacement part is available.

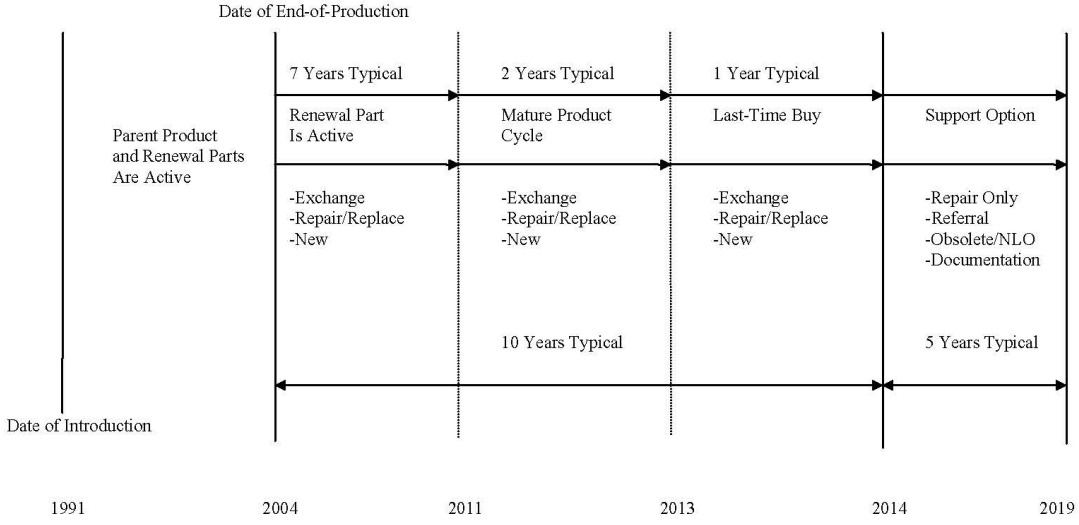
1

OBS - USE _xxxx_ (Obsolete - Use _xxxx_):
"OBS-USE" is assigned to designate parts that GE Industrial Systems can no longer manufacture or obtain from suppliers, but has assigned a replacement.

NLO (No Longer Offered):
"NLO" is assigned to designate parts that GE Industrial Systems can no longer offer.

The life cycle stage of parts will be identified on the current order/quote system, along with the date that they entered each life cycle stage. The stages of the part's life cycle are shown in the following table.

TYPICAL RENEWAL PARTS LIFE CYCLE MODEL



Mark V Timeline Overlay

Rev. released 09-05-03

2

GE Industrial Systems

EX2000 EXCITATION CONTROL
END OF PRODUCTION

GE Drives and Controls, Inc. will cease normal production of the EX2000 Excitation Control system effective March 30, 2004. As with many products, and particularly with electronics, the EX2000 will eventually exceed its supportable life as components become unavailable and technology resources become scarce. This makes it increasingly difficult to guarantee timely reparability of parts for an extended period of time.

In order to address this issue and support customer initiatives, GE has established the following end-of-life guidelines to help customers as they develop their plans to purchase and retire equipment and to minimize their costs through the EX2000's end-of-life stages.

Product End of Life

Once normal production of EX2000 control systems ceases, its end-of-life process will have begun. During this process, the EX2000 will be supported by renewal parts and technical support for 10 years, or as long as feasible. The length of time for continued support after normal production ceases is dependent upon numerous items, including supplied parts and components, contractual requirements, design automation tools, test equipment, technical expertise, and manufacturing facility. A product end-of-life team reviews the status of each product annually to determine its current status and future plans for continued support.

Renewal Parts End of Life

A renewal parts end-of-life planning team will determine the support strategy for parts, which will be coded to identify their availability and stage of support as follows:

RTS&S (Refer to Sales & Service):
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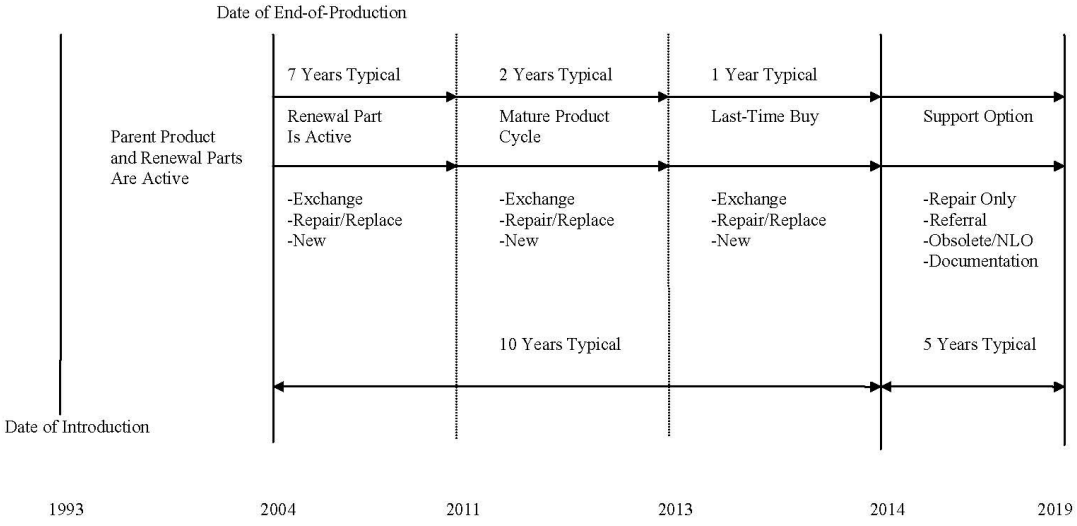

EX2000 Timeline Overlay

Rev. release 09-05-03

2

GE Energy

Measurement and Control Solutions

Newfoundland and Labrador Hydro, Holyrood Generating Station

Mark VIe Control: Migration from Mark V Control

Proposal Number: SF59949

Revision: 2

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GE Energy

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April 2, 2012

Newfoundland and Labrador Hydro
Holyrood Generating Station
Canada

For the attention of: Mr. Rick Leggo/ Manager, Protection, Control,& Communications Engineering

Proposal No: SF59949 Rev 2
Subject: Mark VIe Turbine Control Upgrades

Dear Rick,

GE Energy is pleased to provide this budgetary quotation to Newfoundland and Labrador Hydro for the supply of the items listed herein, in response to your recent enquiry.

We look forward to the opportunity to discuss our solution for your facility. Should you have any questions or require any additional information please do not hesitate to contact me.

Yours Sincerely,

Antonio Santangelo

Eastern Canada Sales Manager
GE Energy

GE Energy

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imagination at work

GE Energy

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GE Energy

Executive Summary

GE Energy

1. EXECUTIVE SUMMARY

1.1 OVERVIEW

This quotation is for the purpose of providing quantity two (2) Mark*V to Mark*VIe Controls Migrations to **Newfoundland and Labrador Hydro, Holyrood Generating Station.**

The units to be retrofitted are identified as turbine serial numbers **940310 (Unit #1) and 940311 (Unit #2).**

Pricing is for the purchase of both units.

Mark V Introduced 1990

The Mark V was designed in 1990 as a dedicated turbine controller with embedded control, protection, and monitoring. It's hardware, software, and network designs reflected the 1990 controls technology when it began service in 1991 and completed production in 2003. GE supports the installed-base of 3,000+ Mark V units with modifications, spare parts, and field service.

During this 12 year production period, many customers have requested new functionality expanded I/O and that requires more compute power, I/O, and communications that is currently not available in the Mark V platform.

Mark V End of Life

As previously communicated by GE, the Mark V Control enters the obsolescence life cycle phase in 2014. Migrating your Mark V with the Mark VIe Control will ensure that GE's long-term support for your critical control system asset will be extended for a minimum of 15 years, through 2026.

Mark VIe Control; Migration from Mark V Control Benefits

The innovative Mark V Migration technology has been introduced to bring the older generation, digital control system technology up to today's standards. Each of the control, digital, and protection cores (<R>, <S>, <T>, <C>, <D> (if applicable), <P>, <QD>, <CD>, and <DD> (if applicable) cores) of the existing Mark V Control has been updated with modern circuit boards and controllers containing GE's state of the art Mark VIe Control technology.

Benefits for this Migration include:

- Minimum down time & less site disruption: Modernize in as few as five outage days with no impact to field wiring, turbine devices, or the existing Mark V Control system footprint.
- Reduced solution scope and risk at lower total cost, direct translation of as-running software.
- Increased computational power and I/O expandability enabling new features to improve turbine performance, reliability and operability.
- Conversion of 16 bit integer data format to 32 bit floating point resulting in a major improvement in programming flexibility.
- A new and improved Windows® based software suite, ToolboxST™, with modern features to simplify maintenance. Examples include: drag-and-drop type editors, trending with video type forward-reverse-freeze capability, code-compare tools, etc.
- Many new I/O types to choose from and distributable in any configuration.
- Elimination of single-point communication failures within the control and options for cost-effective network redundancy between controls and HMI's. Replacing ARCNET® based Stage Link with an Ethernet® LAN conforming to modern IEEE 802.3 standards.
- The existing Mark V processor boards with their "196 CPUs" are replaced with new boards containing Mark VIe processors.

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- Elimination of customizable/programmable PROMs.
- Ease of operation with improved graphics, alarm/event management, trending, etc.
- More efficient maintenance with one modern software tool for configuration of networks, processors, and I/O boards, along with editors, block libraries, and diagnostics.
- Compatible with current programs for compliance with cyber security standards, maintenance programs, and remote monitoring & diagnostics.
- Backward compatibility with many of your existing spares.

GE's commitment to the continued success of controls is evident in the development and growth of our controls organization.

Product Support - Over 200 design and development engineers are available to support all Mark VIe applications. Also, Mark VIe simulation labs in Salem, Virginia and Schenectady, New York can test new applications and can be used to duplicate and troubleshoot field problems.

Field Engineering Services - GE can provide full scope, on-site power equipment maintenance; repair and upgrade services to meet all scheduled and unscheduled maintenance, repair and upgrade requirements. A worldwide network of field engineers backs our on-site services.

It is our goal to provide the highest level of advanced technology materials, design and manufacturing practices, installation services and overall project management available in the industry today.

As the world's leading manufacturer of turbines and the manufacturer of the turbines at this site, GE has the engineering experience, access to original design data, documentation, and long-term commitment, unmatched by any competitor, to support this project. We look forward to continuing our support of your turbine by implementing the controls upgrade with the GE Mark VIe Control; Migration from Mark V Control Upgrade. GE appreciates the opportunity to provide this proposal, and welcomes further discussions regarding our offering.

1.2 HMI CAP PROGRAM

GE Energy Control Solutions Inc. is pleased to offer a free one year HMI Cyber Asset Protection (HMI CAP) for the HMI(s) supplied with this control system upgrade. As a critical asset of your control system, it is essential that the Human Machine Interface (HMI) has the best and most up-to date security software protection to preserve the system's functionality and the integrity of its data. GE's HMI CAP program is a security solution for HMIs, COIs, Historians and RSGs. HMI CAP is designed to keep HMI operator stations and communications operating at peak performance and assists customers in meeting mandatory and emerging cyber-security requirements and guidelines.

1.2.1 HMI CAP Program Overview and Benefits

The Human Machine Interface (HMI) is the current GE operator / maintenance station for data acquisition and control equipment. It integrates the features and functions needed for real-time control, monitoring, and maintenance of turbo-machinery, processes, and auxiliary equipment in one powerful, flexible, and user-friendly package. The HMI has a real-time client-server based operating system, with potential vulnerabilities specific of an HMI in a Turbine Control Role. Current and developing cyber security regulations and best-practices require maintenance of these 'critical-to-infrastructure' assets. This includes a rigorous process for upgrading and installing current operating system security updates, antivirus definitions and related software upgrades to avoid down time due to a virus, denial-of-service attack, worms, Trojans or other malware that could lead to costly downtime and government assessed fines.

The HMI core-load is tested and deployed as a complete system. Compatibility of the original commercial and GE Proprietary packages loaded on your HMI were verified with years of validation and testing though

a rigorous NPI process. New Operating System and third-party software patches and Antivirus upgrades are released in generic / validated packages. These software packages could be incompatible with the customized versions of software that have evolved over years on your HMI. GE's HMI CAP software validation process verifies the integration of these packages with the specific configuration of your HMI. This includes selection of specific security code and extracting unnecessary code. Software upgrades are packaged with site-specific performance enhancements as required and implemented with a 'wizard' on an installation DVD.

Benefits:

- Intrusion detection, alarming and logging of events
- GE software service packs and updates as required
- Antivirus signatures and virus definition updates
- Microsoft® XP or Microsoft® 7 operating system service packs and fixes
- Microsoft Office and Adobe patches
- Pre-tested/validated software minimizes risk to the Control system environment
- Critical updates and compliance documentation installed via DVDs included in the CAP Program Binder
- Enhanced backup/restore capabilities
- 24/7 Web Access and 9/5 Eastern Standard Time (U.S.) phone support
- Pre-tested software from the validation program minimizes risk
- GE's experience from over 3,000 HMI's in service provides a solid knowledge base for the best implementation of security protection
- Microsoft Office patches and critical updates
- Adobe Reader and Flash Player patches and updates
- All associated records to document applicability and validation of patch releases within the update period

1.3 QUALITY

GE's commitment to Quality and process improvement is renowned around the world. While the Six Sigma™ tools we use are well-recognized, it is the dedication of our team that truly makes the difference. We empower our people to make customer-focused quality the highest priority in everything they do to ensure that we're delivering quality every day. We also attain external quality certification. Our manufacturing and Test facilities in Minden, NV; Longmont, CO; Budapest, Hungary; Salem, VA; and Bracknell, UK are certified to the ISO 9001 standard.

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Workscope

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2. WORKSCOPE

2.1 BASE SCOPE OF SUPPLY

The following detailed scope of supply covers the Hardware, Software and Engineering required to perform the Mark VIe Control; Migration from Mark V Control upgrade. It should be noted that this listing may not be "all inclusive" and further discussions along with a site visit by our project team may be required to ensure the completeness of our offering.

The equipment listed below is per unit. The Bill of Material is for Unit 2, which is a TMR controller. The equipment provided for Unit 1 which is a Simplex controller will not include <S> & <T> cores.

2.1.1 Bills of Material - each

Description	Qty

Mark VIe Control: Migration from Mark V Control
 	
Includes:
• <R> Core Hardware (<S> and <T> Cores for TMR)
  ○ (1) UCSA Mark VIe Controller
  ○ (1) UCSA Mark VIe IO Pack
  ○ (1) MVRA IO Processor Card A
  ○ (1) MVRB/F IO Processor Card B/F (unit dependent 'B' or 'F')
  ○ (1) PIOA Arcnet to Ethernet Stagelink Comm Pack (if applicable, redundant Stagelink only)
  ○ (1) MVRP Power Supply and Board
  ○ (1) JPDV Power Distribution Card
  ○ (1) IO Net Switch (16 port)
• <C> Core Hardware
  ○ (1) UCSA Mark VIe IO Pack
  ○ (1) MVRC IO Processor Card C
  ○ (1) PIOA Arcnet to Ethernet Stagelink Comm Pack (if applicable)
  ○ (1) MVRP Power Supply and Board
  ○ (1) JPDV Power Distribution Card
  ○ (1) IO Net Switch (8 port) (if applicable, unit with <D> core only)
• <P> Core Hardware
  ○ (3) PMVE Protection IO Module
• <QD1> Core Hardware
  ○ (3) PMVD Digital IO Module
• <QD2> Core Hardware (If Applicable)
  ○ (3) PMVD Digital IO Module
• <CD> Core Hardware
	1 Unit

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Description	Qty
○ (1) PMVD Digital IO Module • <DD> Core Hardware (If Applicable) ○ (2) PMVD Digital IO Module • Internal Cabinet wiring and Misc Hardware – i.e. Ethernet Cables, mounting hardware, labels, etc. • Turbine Control System Application Software Translation	
Human Machine Interface and Network Communications	
HP Z400 Convertible Minitower Workstation PC • Intel Xeon Processor W3505, 2.53 GHz, 4MB cache 1066 memory, 4.8 GT/s QPI, Dual-Core • 6 GB (3x2GB) DDR3-1333 ECC Un-buffered RAM-CPU • Qty 2 - 500GB SATA 7200 rpm 3Gb/s 3.5" HDD in Raid1 (mirrored) configuration • HP 16X DVD+-RW SuperMulti SATA Drive • NVIDIA Quadro NVS 295 256MB PCIe Graphics Card • High Definition Integrated Realtek ALC262 Audio • 475W, 85% efficient Power Supply • Standard Keyboard US and 2-Button Optical Scroll Mouse • Broadcom NetXtreme Gigabit Ethernet Plus NIC (PCIe) • OEM Windows® 7 Ultimate 64-bit Operating System License • GSM protocol for DCS interface	2
• VLAN Network Communications Switches	4
• 50 ' Ethernet cable (over 300' requires fiber optic)	2
• 22" LCD Widescreen Desktop Monitor	2
• Cyber Asset Protection - (1) year	Lot

2.1.2 Project Management – for both units

Upon receipt of an order, GE will assign a Project Manager who will be the Buyer's single point of contact to ensure that the scope and delivery requirements are satisfied.

GE utilizes a cross-functional project management team to manage every aspect of a project. A Project Manager is assigned prior to the receipt of a contract or purchase order and continues with the project until the end of the contract. In order to achieve Buyer satisfaction, GE uses suitably qualified personnel for execution of the project and gets them involved as early as possible. A strong focus is placed on understanding the Buyer's goals and expectations.

2.1.3 Engineering Design – each unit

As part of the Migration project, the GE Engineering Design will include the following:

- Updates to Existing Mark V drawings (CL – Case Layout & WD – Case Wiring)
- Network Topology Drawing

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- Mark VIe Auxiliary Case (Layout, Outline, & Wiring) – when applicable
- Translation of Mark V Application Software to Mark VIe ControlST
- Development of HMI Operator Graphic Screens – GE standard designs
- System Manual / Product Documentation

2.1.4 Installation and Start-up Services – each unit

Field Services for the installation for the Mark V Migration have been included in the base scope of supply and is summarized in the following sections.

A GE Field Engineering or Service Technician will perform the following installation Tasks at the customer site:

- Inventory the GE supplied Mark V Migration and HMI Equipment
- Remove the existing Mark V Hardware and cables identified for replacement
- Install new Mark VIe Control; Mark V Migration Hardware and cables
- Setup/Configure HMI's (Local and Control Room) and Network Switches for the new conversion.
- Install local, Ethernet cables from Network Switches to HMI's.
- Install local power cables for HMI PC and Monitors to customer supplied AC outlets/receptacles
- Power-up Mark VIe Control and HMI's
- Install Mark VIe Control unit application software and HMI operator graphics package
- Perform Mark VIe Control System Check-out (per GE standards)
- Perform Turbine Start-Up & Commissioning Tests (per GE standards)

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2.2 Optional Items

2.2.1 Re-Purchase of Mark V Hardware Credit – Core Charge

As part of the Migration package, GE offers a customer credit for the return of all Mark V hardware removed from the panel as part of this project, and the associated customer owned spare parts. Parts removed from the panel will be collected and packaged for shipment to a GE facility by the GE Field Engineer. The Customer will be responsible for collecting any Mark V spares that are no longer applicable to the Mark VIe Control, and providing them to the GE representative for shipment.

2.2.2 Spare / Replacement Parts - Option

GE recommends the following Spare Parts be maintained by the Customer in the unlikely event that a failure occurs. This list of parts is intended to complement any remaining spare parts currently on-hand for legacy Mark V components that remain in the system. Replacement hardware for the legacy components, now fully supported with the Mark VIe platform, is also available if the existing inventory of parts has been depleted or not previously renewed. Those parts have not been included in this listing.

Description	Qty
○ (1) UCSA Mark VIe IO Pack (PMVE) / Mark VIe Controller ○ (1) MVRA IO Processor Card A ○ (1) MVRB/F IO Processor Card B/F (unit dependent 'B' or 'F') ○ (1) MVRC IO Processor Card C ○ (1) PIOA Arcnet to Ethernet Stagelink Comm Pack (if applicable, redundant Stagelink only) ○ (1) MVRP Power Supply Distribution Board ○ (1) JPDV Power Distribution Card ○ (1) IO Net Switch (16 port) ○ (1) PMVP Protection IO Module ○ (1) PMVD Digital IO Module ○ (1) Mark V Migration Field Service Kit ○ (1) Compact Flash Memory Module ○ (1) 28 VDC Power Supply – Core ○ (10) Fuse (5.0A) 5mm x 20 mm	1 LOT

2.2.3 Software Acceptance Test- Option

Description	Qty
1-day software acceptance test at a GE Facility. The software acceptance test is intended to be a review of all aspects of the control system's operation and operator interface. Testing will include system software only.	1 LOT

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NOTES:	
1. The simulated environment for this test is intended to show the functionality of the software, but is not intended to fully replicate the environment or interrelated systems where it will eventually be installed, nor is the test intended to serve as training for Buyer's employees. 2. The Buyer is responsible for all travel and living expenses incurred to witness the testing.	

2.2.4 MarkV to MarkVIe Migration Maintance & Operator Training – Option

2.2.4.1 Mark V to Mark Vie Migration : CONTROLS (Silver)- Five (5) DAYS

This program is intended for all control technicians and engineers of existing, installed turbines (steam or gas) on which a Mark* V control to Mark* VIe control migration has taken place. It is expected that the technicians will have hands-on experience with their turbine systems. This training will familiarize them the hardware and software components of the Mark* VIe control system, changes to the HMI, and the overall control system architecture. It will develop skills in process alarm troubleshooting and analysis of the control code. Additional instruction will include introduction to LVDT calibration. Depending on time opportunities, there may be limited discussion on subjects such as control code analysis, Cimplicity software programming, sequence editing or advanced data collection techniques. These topics will be agreed upon based on discussions with the instructor and the equipment owner.

Please note: The training equipment will not run the site software. It will operate on generic machine software not turbine specific. If the site software is available at the time of the training, it will be used to illustrate various aspects of the training material, but it will not be loaded on the training equipment.

I. INTRODUCTION
A. Instructor Background
B. Course Outline
II. EQUIPMENT REVIEW
A. Turbine
B. Systems
C. Controls
III. DOCUMENTATION
A. GE Documentation Conventions
B. Manual
C. Control Specs / Schematics
IV. PANEL / NETWORK LAYOUT
V. PANEL HARDWARE
VI. HMI / CONTROLLER FILE STRUCTURE
VII. INTRODUCTION TO TOOLBOX-ST (SOFTWARE VIEWER / EDITOR)
A. Blockware Descriptions
B. Finder (software search engine) (exercises)

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C. Forcing / Control Constants
D. Introduction to Sequencing
E. Alarm Troubleshooting (exercises)
F. LVDT Calibration
G. Diagnostic Alarms
H. Circuit Board, Terminal Board and Component Replacement
I. As time allows some of the following topics will be discussed (based on the needs of the attendees):
    1. Sequence Editing (exercises)
    2. Trending / Trips / DDR / Watch Windows (exercises)
    3. Compiling and Downloading
    4. Introduction to EGD / OPC
    5. Card Flashing
    6. Introduction to HMI Device configuration
    7. Introduction to Cimplicity

2.2.4.2 Mark V to Mark Vie Migration : OPERATORS (Silver) - ONE (1) DAY

This program is intended for all operators of existing, installed turbines (steam or gas) on which a Mark* V to Mark* VIe control migration has taken place. It is expected that the operators will have operational experience with their turbine systems. The training will offer the attendees the knowledge to work with the Mark* VIe migrated control system in application with their turbine. This training will familiarize them with any hardware upgrades on the turbine in association with the upgraded control package. It will develop skills in process alarm troubleshooting and an understanding of the operator control interface. Additional training will cover the details of the interface between the control system and the turbine's support systems.

Please note: The training equipment will not run the site software. It will operate on generic machine software not turbine specific. If the site software is available at the time of the training, it will be used to illustrate various aspects of the training material but it will not be loaded on the training equipment.

I. INTRODUCTION
A. Instructor Background
B. Course Outline
II. EQUIPMENT REVIEW
A. Turbine
B. Systems
C. Controls
III. DOCUMENTATION
A. GE Documentation Conventions
B. Manual
IV. REVIEW OF OPERATOR INTERFACE (CIMPLICITY) SCREENS
V. SYSTEM ALARMS
VI. SYSTEMS INTERFACE

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Technical Description

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3. TECHNICAL DESCRIPTION

3.1 EQUIPMENT DESCRIPTION

3.1.1 Introduction

GE now offers a migration solution of the Mark V to the modern Mark VIe. The migration solution utilizes the current I/O interface including field wiring terminations and turbine devices to minimize installation and commissioning time.

A software translation tool is used to automate the conversion of Mark V application software to the 32 bit floating point data format and block libraries used in Mark VIe. This also reduces in-house engineering time and risk associated with the conversion. ToolboxST* configuration and diagnostic tools are now used for everything from the I/O devices, to the Controllers, to new / upgraded HMI's. The Mark V's ARCNET Stage Link is replaced with Ethernet complying with standard IEEE networking practices. Since Mark V's share the same vintage of technology as EX2000 generator excitation controls, an ARCNET-to-Ethernet gateway is provided. If an older exciter is present on site, the existing interface will be retained. If the project includes a Digital Front End (DFE) upgrade of the EX2000, the communication will be upgraded to an Ethernet connection on GE's Unit Data Highway.

The project will include engineering design, hardware, software, and field services to migrate the existing Mark V. Software functionality will be based on current operating software in the Mark V. The diagrams below graphically illustrate the conversion modifications between today's Mark V electronic hardware and the Mark V Migration panel electronic hardware packages (unit-specific configurations may deviate from the following generic illustrations and tables).

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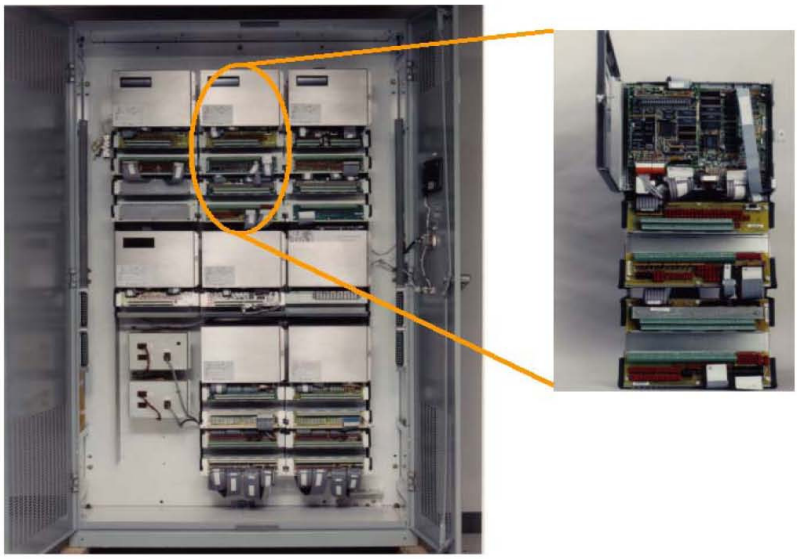
3.1.2 Control System Hardware

Today's Mark V Electronic Hardware Structure (Typical)



Major Components Removed:	Core
SDCC Main Controller	R, C, D (as applicable)
SLCC IO Controller	R, C, D (as applicable)
TCQA Analog I/O Processor Card	R
TCQB / F Multifunction I/O Processor Card (LVDT, MAO, PROX)	R
TCCA Analog I/O Processor Card (TCs, RTDs, MAIs, SV, CJ)	C, D (as applicable)
TCCB Analog I/O Processor Card (RTDs, MAIs)	C
TCCP Analog I/O Processor Card	D
TCPS Power Supply	R, C, D (as applicable)
TCEA TC200 Emergency Over-speed card	P
TCDA Digital I/O card	QD1, QD2, CD, DD (as applicable)

imagination at work

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GE Proprietary Information

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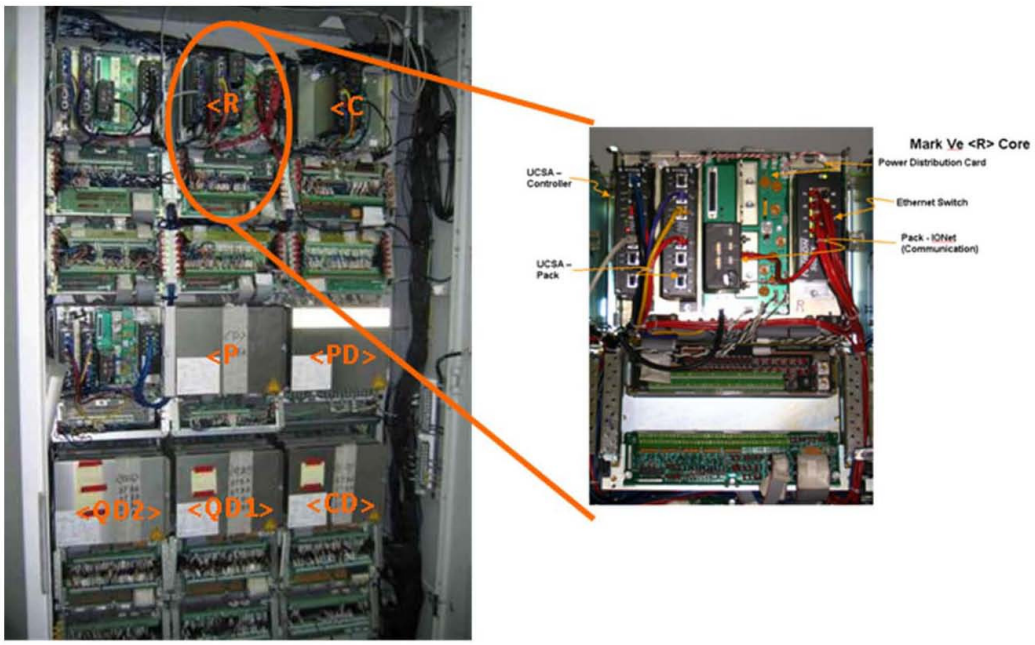
Tomorrow's Mark VIe Control: Mark V Migration Hardware Structure (Typical)



Major Components Added:	Core
UCSA Main Controller	R, S, T
UCSA IO Processor Pack	R, S, T, C, D (as applicable)
MVRA MkV Migration Multi I/O Processor Card A (replaces TCQA)	R, S, T
MVRB/F MkV Migration Multi I/O Processor Card B (replaces TCQB/F)	R, S, T
MVRC MkV Migration IO Processor C (replaces TCCA, TCCB)	C
PMVD MkV Migration Digital I/O Card (replaces TCDA)	QD1, QD2, CD, DD (as applicable)
PMVE MkV Migration Protection Card (replaces TCDE)	P
PIOA Serial to Ethernet IONet Comm Pack	R, S, T, C, D (as applicable)
PIOA Arcnet to Ethernet Stagelink Comm Pack	C (and R if Redundant Stagelink)
MVRP ACRO Power Supply & MVRP Power Board (replaces TCPS)	R, S, T, C, D (as applicable)
JPDV Power Distribution Card	R, S, T, C, D (as applicable)
Ethernet Switch (16 port)	R, S, T, C, D (as applicable)

imagination at work

Customer: Newfoundland and Labrador Hydro Page 19

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GE Proprietary Information

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3.1.3 Turbine Control Software

As part of the migration, the as-running Mark V software will be obtained from the unit and converted to a 32-bit floating-point data format with automation tools. Conversion of the existing software ensures the transition to the new control will be seamless and accurate. This new software environment is part of the GE ControlST software suite with major enhancements over the current Mark V tools, including: drag-and-drop type editors, math blocks, macros, trending with video type forward-reverse-freeze capability, watch windows, code-compare tools, etc.

3.1.4 I/O Enhancements

No changes are needed with the existing field wiring or turbine devices. The I/O interface to the field cabling remains as is. The current I/O capacity also remains unchanged, but the ability will now exist to expand the I/O capability either locally or remotely via Mark VIe I/O hardware blocks, and will communicate 100MB Ethernet via category 5 or fiber optic cable.

3.1.5 Operator Interface and Maintenance Software

Mark V's have an <I> operator station or a HMI with a CIMPLICITY® graphics package. In either case, an upgrade is needed to a current HMI package.
Existing operator and maintenance stations are replaced with our current Proficy HMI/SCADA graphics with vastly improved graphics, screen navigation, alarm/event management, and trending tools. For the <I> operator interfaces, it also provides a new modern hardware platform (Workstation PC and Monitor) with a Windows operating system with modern client/server networking capability. The new HMI also includes a replica of any Modbus® or GSM TCP-IP protocols currently being used for DCS communications. If a VAX-based historian is at the site, it will be replaced with either an OSI PI historian or a Proficy™ Historian from the GE Fanuc family of products.
The communications interface between the turbine controller(s) and the HMI can be provided in a simplex or redundant architecture. GE will provide the necessary network switches, Workstation PCs, and monitors based on the selected architecture and the requested quantity (and location) of HMI workstations.

3.1.6 Reliability

The same control and protection philosophy that has provided reliable running and tripping reliability all these years in the Mark V will be retained. With the new Ethernet network that is provided, the operator stations will communicate directly with the upgraded controller <R> and not through the Mark V <C> module, thereby eliminating a single point failure along with the need for a backup display on the door. This new network also provides high-speed peer-to-peer communications between the Mark VIe controller and the ability to add redundant networks without the need for a <D> module.

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Installation, Checkout, Start Up, and Commissioning

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4. INSTALLATION AND START-UP SERVICES

Field Services for the installation for the Mark V Migration have been included in the base scope of supply and is summarized in the following sections.

A GE Field Engineering or Service Technician will perform the following installation Tasks at the customer site:

- Inventory the GE supplied Mark V Migration and HMI Equipment
- Remove the existing Mark V Hardware and cables identified for replacement
- Install new Mark VIe Control; Mark V Migration Hardware and cables
- Setup/Configure HMI's (Local and Control Room) and Network Switches for the new conversion.
- Install local, Ethernet cables from Network Switches to HMI's.
- Install local power cables for HMI PC and Monitors to customer supplied AC outlets/receptacles
- Power-up Mark VIe Control and HMI's
- Install Mark VIe Control unit application software and HMI operator graphics package
- Perform Mark VIe Control System Check-out (per GE standards)
- Perform Turbine Start-Up & Commissioning Tests (per GE standards)

The following **Unit** schedule is intended as an aid for preliminary planning only. The final schedule and pricing will vary depending on as-sold equipment, other work to be performed during the outage, execution of responsibilities, etc.

Item	Description	Typical Schedule
A.	Mobilization and Site Prep	2 days, 10 hours per day, single shift
B.	Controls Conversion	3 days, 12 hours per day, single shift
C.	Checkout and Calibration	1 day, 12 hours per day, single shift
D.	Turbine Start-up	2 days, (depending on complexity of unit, etc.) 12 hours per day, single shift
E.	Completion	3 days, 8 hours per day, single shift

Please note, if any additional field engineer time above what is specified in the above table is needed to complete this item, they will be provided on a time and material basis per the GE Energy Control Solutions Inc. Services Rate Schedule in effect at the time if the work in lieu of any pre-existing agreements.

This above schedule is a preliminary schedule only to be used only for planning purposes for the controls related installation activities. It is not intended to be used as a firm schedule for the overall project. The final schedule will be determined after the kick-off meeting.

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Proposal Basis

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5. PROPOSAL BASIS

5.1 EXCLUSIONS / EXCEPTIONS / COMMENTS & ASSUMPTIONS

The proposed scope of supply is based upon the Buyer's requirement, preliminary discussions with Buyer and Seller's knowledge of the existing installation at the Site.

1. Seller believes that this Proposal meets the intent of the Buyers request for Proposal and will be the document of reference in any resulting contract.
2. All demolition/installation/commissioning manpower and materials not mentioned in this Proposal are not part of the Seller's scope of work.
3. The proposed Bill of Material is an estimate based on Seller's knowledge of these units at the time of writing this Proposal. Actual parts and quantities will be determined upon completion of Site survey. Any deviation from the list presented shall result in a corresponding adjustment (up or down) in the Proposal price.
4. GE reserves the right to review and re-quote this job if there is a discrepancy between this proposal and the purchase order. If GE receives a specification between the issuance date of this proposal and receipt of the purchase order, GE reserves the right to re-evaluate this proposal.
5. It is assumed that any items (such as cabling, sensors, field devices) that are not being replaced in this Work scope are in a good working order. Replacement of any items determined bad is not part of this Proposal. Site Survey results may necessitate the design and installation of additional cabling and devices and a corresponding adjustment to the pricing and delivery as presented.
6. No field wiring, conduit, or piping of any kind is included in this proposal.
7. All documentation will be in English and per GE standards.
8. The new Mark VIe application may require modification to DCS signals to maintain compatibility. Modification of these DCS signals is the responsibility of the Customer.
9. Changes (ie – additional points) to the existing DCS communication links are not included in the execution of the project. Changes to the existing Modbus communications, if requested, can be performed on a time and material basis by the GE Field Service Engineer at the GE Controls Specialist hourly rates.
10. It is assumed that Seller will be furnished with full drawings and information concerning the state of the existing installation, especially wiring information to the existing terminations within the control panels. If such information is not available Seller will charge for the work involved in obtaining this information.
11. Contact input voltage (CIT) is assumed to be 125 VDC.
12. It is assumed the existing vibration interfaces and configuration will remain as is.
13. This quote is based upon the assumption that existing speed sensing equipment is functional and adequate for this retrofit.
14. 50' of Ethernet cable will be provided with each HMI. This is meant for limited networking needs and is not expected to cover all networking needs. Customer shall be fully responsible for providing necessary networking cables. No other interconnecting fiber optic cabling, Ethernet cabling, or any kind of cabling is included in this proposal except for the internal panel cabling.

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15. Not supplied as part of this offer are any IS barriers or marshaling panels. Those should be supplied by the customer should they be deemed necessary.
16. No networking hardware, hubs, switches and routers, other than those mentioned specifically in this proposal, are provided.
17. Graphic Displays will be created as required from the standards in the GE library for your unit. It is expected that approximately 7 to 10 displays will be required that will support factory test and engineering / maintenance functions. Fixing functionality is part of control system checkout. Typical screens may include the following:
    - Main or Unit Control Display
    - Start Check Display
    - Alarm Display
    - Vibration Display

    Custom screen modifications or development is not included in this proposal.
18. Any items not specifically listed, are not included in this proposal.
19. No cabinet will be provided with the new turbine control system and the old cabinet will be retained.
20. No provisions for a separate integrated FAT or communication testing with DCS or other sub-systems are included in this proposal. Simple communication testing with DCS and other subsystems can be conducted and verified by the GE field engineer carrying out the commissioning onsite. Should the buyer decide to have separate communication testing with other systems at their facility, that will be charged at an additional price.
21. The turbine control shall provide the same functionality as the existing Mark V control system. No work on DCS operator interfaces is part of GE scope. It is the responsibility of the Customer to perform this work if necessary.
22. This proposal does not include any modifications to any OSM's that may exist on site. Please contact the GE M&D center for any modifications that may be required, as the Mark VIe no longer uses Arcnet communications.

5.2 FIELD SERVICE ASSUMPTIONS & CLARIFICATIONS

The following items define the basis for the supplied GE Field Service and Installation tasks. Changes to the scope of supply or division of responsibility will result in changes to the contract price.

1. The installation services bundled price is based on work provided by a GE Controls Specialist for eight (8) consective days, ten (10) hours per day during the outage (exclusive of holidays) to support the migration of the turbine controls. Work performed outside of these hours will be billed as Extra Work at the Overtime rate in effect at the time of performance.
2. The installation services bundled price does not include time for formal site safety training. GE has assumed that saftey and site orientation will be conducted during the site mobilization for a period of time not to exceed 4 hours. If extended, formal site training is required for GE personnel to enter and perform work at the site, the training time will be billed as an extra cost at the current GE Controls Specialist hourly rates.
3. Formal training of the plant operators and maintenance personnel on use and navigation with the HMI and GE ToolboxST is not included in the base proposal. GE strongly suggests that customer personnel unfamiliar with the ControlST and Cimplicity Interface attend a formal GE training class

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to obtain the basic system and tool knowledge.

4. Travel time for a GE Control Specialist to perform one round trip to the plant site has been included in the base price. Additional travel requirements will be billed to the Customer per the GE rate sheet in effect at the time of service.
5. The GE Controls Specialist will perform an IO checkout per GE's standard procedures. A period of 12 hours has been allocated for this activity. The purpose of this checkout is to validate that the Mark V Migration hardware and cabling has been installed properly. Therefore, only a representative sample of signals will be checked. A full panel checkout has not been included in the base offering, but can be provided as an option if so desired.
6. GE has allocated a period of 12 hours to perform the Start-up and Commissioning of the control system which includes the required valve calibrations and unit specific dynamic testing based on GE's standard procedures. Any customer delays associated with permits, equipment failures, additional customer requested tests (or hold points), etc. will be billed as an extra cost at the current GE Controls Specialist hourly rates.
7. Installation of additional Hardware or Materials not listed in the Base Scope of Supply for Mark VIe Control; Mark V Migration Upgrade or customer selected options is not included in the GE scope.
8. Any unit control software modifications for additional I/O, sequencing modifications, advanced features, etc. that are not included in the base scope of supply or customer selected options are not included in the GE scope.
9. Check-out of the communications to customers DCS or other site devices will only include basic assurrance that separate modes are functional. Any complete point-to-point testing can be completed at additional cost. Operation of the control will be tested and commissioned only from the newly installed HMIs (local and/or remote).

5.3 CUSTOMER RESPONSIBILITIES

1. GE has assumed that all field devices, control system hardware, and equipment that will remain in service after the control system migration is in proper working order and will be suitable for connection to the new control system. The Customer shall be responsible for any repair or replacement of field devices, control system hardware, and/or equipment that may be required for proper unit operation.
2. Calibration of field devices is not included in the GE offering. Calibration of devices required due to customer maintenance activity or replacement shall be the responsibility of the Customer.
3. Customer to provide a minimum of one dedicated individual to support the GE Controls Specialist in the I/O checkout, as well as speciality devices, such as function generators, pressure devices, etc required for checkout. Customer personnel provided for this activity must have familiarity with the turbine, location of devices, and methods for adjusting devices to impact change in the control system. Additionally, the Customer shall provide communications equipment/radios to be used by the GE Controls Specialist and Customer personnel during the checkout period.
4. Customer shall be responsible for providing personnel to support steam valve calibrations. Personnel will be responsible for verifying valve movement and assisting in measuring valve crack points for steam admission.
5. Customer shall be responsible for installation and terminations (including testing) of all fiber optic cables that may be required for the network communications between local and remote operator

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stations. This shall include possible changes to fiber optic termination types, SC type connections are required for connection for the GE supplied network switch.

6. Customer shall provide all required installation tools and materials including, but not limited to, fiber optic cable, Ethernet cables, conduit, ladders, tables, work lighting, and consumables.
7. Customer shall provide a desk or workspace for the Controls Specialist to work and a telephone with outside plant access.
8. Customer shall provide access to the latest revised plant drawings necessary for checkout, start-up and commissioning the Mark VIe turbine control system.
9. Customer shall provide qualified operators for duration of start up and commissioning.
10. Upgrade data types and scaling of SCADA or other computer systems that communicate with the control system: When a Mark V gets upgraded to a Mark VIe, many of the integer signals (a.k.a. points, tags, variables) get replaced with floating point signals. This is generally a good thing, but it will have an effect on any external computer system that is reading or writing those variables via Modbus, GSM, or other computer link. The best course of action is to upgrade the system that is reading or writing the data, which is typically easy to do and involves changing data types and getting rid of scaling information that had previously been used to convert the old integers into a more useful format. The conversion is generally easy, but only if the customer realizes that it needs to be done ahead of time, prior to the outage to ensure a smooth start-up and commissioning.
11. Customer shall be responsible for proper storage of control system hardware, from the arrival of equipment on site, until the outage. Staging of material and placing of new controls hardware in the area of the existing Mark V equipment for the outage shall be performed by site personnel prior to the start of the unit outage.
12. Overall project cycle time is dependent upon receipt of current site configuration data. A GE Project Manager will be assigned after receipt of order and will provide instructions for the download and transfer of site data as necessary. Site services to download the data are not included in this offering but can be provided for at an additional cost.
13. Access to Site facilities such as washrooms, toilets, drinking water, etc shall be to be provided by the customer to the GE employess on site during the installation.
14. In accordance with the project schedule, customer will provide the necessary support and engineering resources to review, comment and approve the design and layout of the HMI screen templates, as well as any Hardware, Software designs that are submitted for this purpose. Once approval is received, the design of the HMI screens, and Hardware/Software will be fixed. Any subsequent requested changes by the buyer may require additional engineering time to be allocated to the project, which will be charged as additional cost.
15. Customer shall be responsible for the proper Lock-out-Tag-out of the equipment prior to the start of the installation of the new controls hardware. GE has included a maximum of 4 hours for the Lock-Out-Tag-Out activities to be included in the base project scope for the GE Controls Specialist. Additonal hours required to complete the LOTO will be considered as a delay and be billed at the GE Controls Specialist hourly rates.
16. It is assumed that no hazardous material will be encountered in performing the work scope. Disposal of any hazardous or regulated material will be the responsibility of the Buyer.

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17. As the project must incorporate Buyer specific requirements, Buyer must support all project activities:
    - Support Site kick-off meeting, schedule, Site visits, design reviews, etc.
    - Participate in Site Acceptance Test
    - Respond to Seller Inquiries and Requests for Documentation in a timely manner.
    - Direct all communications through GE's assigned Project Manager.
    - Document, in writing, approvals for all change orders
    - Prepare for & attend project status meetings

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Commercial Section

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6. COMMERCIAL SECTION

6.1 BASE SCOPE PRICING

The base scope price for the scope of work detailed in the proposal, excluding optional items, and with both Unit 1 and Unit 2 control systems being installed at the same time will be as follows:

Item	Qty	Description	Price
1	1	**Unit #1 S/N 940310: Simplex Mark VIe Control**: Migration from Mark V Simplex Control	**$329,650.00**
		2- HMI	
		Installation Services	
		Site Visit	
2	1	**Unit #2 S/N 940311: TMR Mark VIe Control**: Migration from Mark V TMR Control	**$339,098.00**
		2-HMI	
		Installation Services	
		Total Price:	**$668,748.00**

Note: The above price is in CAD Dollars, and does not include taxes.

The base scope price for the scope of work detailed in the proposal, excluding optional items, and with installation of Unit 1 and Unit 2 control systems shipping at the same time, but not being installed at the same time will be as follows:

Item	Qty	Description	Price
3	1	**Unit #1 S/N 940310: Simplex Mark VIe Control**: Migration from Mark V Simplex Control	**$329,650.00**
		2- HMI	
		Installation Services	
		Site Visit	
4	1	**Unit #2 S/N 940311: TMR Mark VIe Control**: Migration from Mark V TMR Control	**$350,000.00**
		2-HMI	
		Installation Services	
		Total Price:	**$679,650.00**

Note: The above price is in CAD Dollars, and does not include taxes.

6.2 OPTIONAL SCOPE PRICING

Item	Qty	Description	Price
1	2	**Mark V Core Charge Credit** (Return legacy Mark V components no longer used to GE)	**($25,000.00)**
2	Lot	**Software Acceptance Test**	**$8,520.00**
3	Lot	**Spare Parts** (Recommended)	**$66,173.00**
4	Lot	**Mark V to Mark VIe migration training**	**$49,018.00**

Note: The above price is in CAD Dollars, and does not include taxes.

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6.3 PROJECT SCHEDULE

The estimated timescale from acknowledgement of PO/contract and receipt of required customer information and documentation to the completion of the work scope or delivery of the goods is **24** weeks and is based on current factory loading and lead times offered by Seller.

Seller will be willing to discuss an alternative schedule to meet Buyer's requirement.

Milestones requiring Buyer input are critical to maintaining the schedule. All buyer inputs need to be complete and fully correct. Likewise, unless otherwise agreed upon in advance, work shall occur in an uninterrupted and sequential fashion.

If Buyer fails to meet milestones or if work is interrupted by or for the convenience of the Buyer, or cannot be performed according to the agreed Project Schedule, Seller reserves the right to charge for additional costs and amend the schedule as a result of Buyer changes. Buyer shall also remain liable for meeting milestone payments as agreed in the project schedule.

6.4 WORK ASSUMPTIONS

The works described herein will be scheduled on dates and at times which are mutually agreeable between the Buyer and Seller. Unless otherwise agreed upon in advance, work shall occur in an uninterrupted and sequential fashion. If the work is interrupted by or for the convenience of the Buyer, or cannot be performed according to the agreed Project Schedule, there will be separate charges for multiple trips and rescheduling of Seller's personnel. Seller reserves the right to charge for additional costs incurred as a result of Buyer intiated changes.

6.5 DELIVERY TERMS

Seller shall deliver Products to Buyer CIP facility, place of manufacture or warehouse (Incoterms 2000). Title to Products shipped from the U.S. shall pass to Buyer immediately after each item departs from the territorial land, seas and overlying airspace of the U.S with risk of loss transferring to Buyer upon title passage.

6.6 TERMS OF PAYMENT

Our proposal is based upon the following payment schedule.

20%	Acceptance of Purchase Order
15%	Submittal of Engineering Design Drawings
45%	Shipment of Hardware
5%	Title Transfer
5%	Services Mobilization
5%	Completion of work (Signature of timesheet)
5%	Submittal of Final Documentation

All payments are net 30 days

6.7 TERMS AND CONDITIONS

This proposal and commercial offer are subject to the below terms.

- Form M&C 104 - CA (Rev04) GE Terms And Conditions for Sale Of Products And Services
- GE Software License Addendum To Terms And Conditions For Sale Of Products And Services

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6.8 PURCHASE ORDER

Buyer's Purchase order shall provide the following deliverables:

- Purchase Order conforming to this proposal.

  Note: Deviations from the proposal in Scope, Price, payment schedule, Terms and Conditions, Shipment Cycle, or Installation Cycle may cause delays or non-acceptance of Purchase Order.

- Site Specific Drawings as detailed in this proposal.

  Note: Submittal of these drawings prior to the Kickoff meeting will allow Seller's engineers to become familiar with the site-specific details and will make the site meetings more efficient.

The execution period of this contract starts from Sellers Order Acknowledgement date.

Upon the Buyer's decision to submit a purchase order, please address the Purchase order to:

GE Energy
1800 Nelson Road
Longmont, CO 80501
Attn: Antonio Santangelo – Eastern Canada Sales Manager

6.9 VALIDITY

This Proposal will remain valid for **90** days from the date indicated in the cover page and may be modified or withdrawn at any time by Seller prior to receipt of Buyer's acceptance.

Prices quoted are based on the Assumptions and Clarifications and the Responsibilities as described in the Proposal Basis and performed according to the Terms and Conditions referenced or provided herein. If there are negotiated terms for this particular customer or project, the negotiated terms shall prevail.

6.10 PRICING LIMITATIONS

Seller reserves the right to review and re-quote this job if there is a discrepancy between this proposal and the purchase order. If Seller receives a specification between the issuance date of this proposal and receipt of the purchase order, Seller reserves the right to re-evaluate this proposal.

Changes to specifications, drawings, services or hardware will be evaluated by Seller for a Change in Scope to the contract. Seller will quote the changes and a customer change order must be received before work is to proceed.

The pricing breakouts outlined in this proposal are for accounting purposes only and are not to be considered as stand-alone prices.

The prices quoted herein exclude tax or other regulatory fees.

Pricing for out-of-scope items will be based according to the rates attached herein.

6.11 GENERAL PRICING CONSIDERATIONS

6.11.1 Out of Scope Works

"Out of scope works" shall be defined as "Any additional work required, requested, or recommended not specifically defined in the scope of work proposed herein". Upon receipt of written request, Seller may provide a firm price quotation or perform the work at the rates provided herein. Additional works will not commence until additional pricing and/or changes to schedule have been agreed. Seller is not responsible for any delays to the schedule due to out of scope items and related delays can be considered for extra charges.

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6.11.2 Travel and Lodging/Living

Travel and Lodging/Living costs (T&L) are included for the base scope of supply and specified duration of the field service. Additional costs for T&L related to Customer delays or additional scope items, will be billed to the Customer per the GE Field Service rate sheet.

6.11.3 Delays

Delays in the performance of work beyond the reasonable control of Seller, or delays caused by acts of the Buyer or prerequisite work by others, shall entitle Seller to an adjustment of schedule and price for completion of its work and expenses resulting there from.

6.11.4 Price Escalation

The base prices stated in this proposal shall be subject to adjustment for components delivered in subsequent years pursuant to the provisions of this clause. Such base prices shall be adjusted annually upward based on SIC and other published index.

6.12 TRANSFER TO SUBSIDIARY OR AFFILIATED COMPANY

Seller may assign or novate its rights and obligations under the Contract, in part or in whole, to any of its affiliates, or may assign any of its account receivables under this Contract to any third party without Buyer's consent, and may subcontract portions of the work, so long as Seller remains responsible for it. Buyer agrees to execute any documents that may be necessary to effect Seller's assignment or novation. The delegation or assignment by Buyer of any or all of its duties or rights under the Contract without Seller's prior written consent shall be void.

6.13 TRADEMARK NOTICE

Product and company names utilized in this document are trademarks or trade names of their respective companies.

*** CIMPLICITY is a registered trademark of GE Fanuc Automation North America, Inc.**

*** Ethernet is a registered trademark of Xerox Corporation.**

*** Mark and ToolboxST are trademarks of the General Electric Company.**

*** Modbus is a registered trademark of Schneider Automation.**

*** HART is a registered trademark of HART Communication Foundation**

*** Proficy is a trademark of GE Fanuc Automation North America, Inc.**

6.14 DEFINED TERMS

The following terms shall have the meanings set forth below as used throughout this Proposal.

"Buyer" means the entity to which Seller's proposal is directed.

"Buyer's Equipment" or "Unit(s)" means Buyer's equipment into which the Parts will be installed and on which the Services will be performed.

"Contract" means the contract between Seller and Buyer resulting from this Proposal.

"Contract Price" or "Proposal Price" means the price to be paid by the Buyer to the Seller under this Proposal or any resulting Contract for the Parts and Services.

"Parts" means the equipment, parts, materials, supplies, components and other goods, which Seller has identified in this Proposal.

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"Primary Services" means such planning, management, Technical Advisory Services, labor, tools and incidental goods necessary to install the Parts identified herein and to move, install, assemble, modify, repair, modernize, start-up and/or maintain the Buyer's Equipment, in connection with any of the foregoing.

"Seller" means, "GE Energy Control Solutions, Inc."

"Services" means all the Primary Services and the Supplementary Services to be performed or provided by Seller under this Proposal.

"Site" means the premises where the Buyer's Equipment is located.

"Supplementary Services" means any of the following, which are identified by Seller in this Proposal:

Engineering Study/Inspection/Test, meaning system design and/or analysis of equipment or systems which can be performed in a repair service shop or at the Site by competent, experienced personnel using special techniques, instruments or devices with the objective of reporting opinions or recommendations related to the current condition and future serviceability of the equipment or system.

Such other services as the parties agree in writing will be performed as Supplementary Services.

"Technical Advisory Services" or "Field Engineering Services" means technical advice and counsel from Technical Advisors or Field Engineers provided by Seller based on Seller's current engineering, manufacturing, installation and operation practices as applicable to the Parts. To the extent specified in this Proposal, such services may also include testing, adjustment, programming and other similar services. Unless otherwise specified in this Proposal, "Technical Advisory Services" / "Field Engineering Services" do not include supervision or management of Buyer's employees, agents, or other contractors.

This proposal and commercial offer are subject to the attached terms.

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Attachments

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7. ATTACHMENTS

7.1 FORM MC104 – CA (REV04) GE TERMS AND CONDITIONS FOR SALE OF PRODUCTS AND SERVICES

Canada_M_C_104_C
A_Rev4_English_Lanç

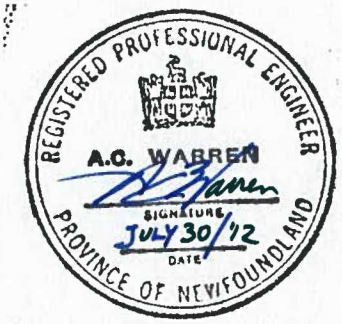
7.2 GE SOFTWARE LICENSE ADDENDUM TO TERMS AND CONDITIONS FOR SALE OF PRODUCTS AND SERVICES

ES-Software-Addend
um-English-Rev3.pdf

7.3 RATES FOR POWER GENERATION SERVICES

02_2012_Outages_C
anada_rev1_Draft[1]

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES



Electrical
Mechanical
Civil
Protection & Control
Transmission & Distribution
Telecontrol
System Planning

Upgrade Gas Turbine Control and Monitoring System

Happy Valley

June 7, 2012

newfoundland labrador hydro
a nalcor energy company

SUMMARY

This report discusses the need to upgrade the Happy Valley gas turbine control and monitoring system to present-day technology. The components of the existing system are obsolete and the manufacturers provide limited support and replacement parts. The existing system provides local and remote control and monitoring of the gas turbine and generator. The main components of the control and monitoring system will be integrated into a single system design where possible and feasible. Hydro's Project Execution Team will manage the project, tender the new control and monitoring system and design the replacement. The system will be installed and commissioned by Hydro Operations under the supervision of the manufacturer's technical representative.

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APPENDIX A A1

1 INTRODUCTION

The Happy Valley gas turbine is a 27 MW generating unit that provides voltage support at the 25 kV level for the 138 kV transmission line L1301 from Churchill Falls and generation for the town of Happy Valley and surrounding areas when the line is out of service. The gas turbine was commissioned in 1992 and has been generally available for service since that time. An electronic control system is used to start, run and stop the gas turbine by local or remote operator commands. The system monitors the operating parameters of the gas turbine to ensure safe and reliable operation.

The control and monitoring system is part of the original design by the gas turbine supplier. It consists of a programmable logic controller, a governor unit, vibration monitoring units, protective relays and an operator control console.

The project is necessary to upgrade the gas turbine controls and vibration monitoring with a new complete control system, consistent with present technology and fully supported by the manufacturer.

2 PROJECT DESCRIPTION

The scope of work is to replace the existing, obsolete control and monitoring system of the Happy Valley gas turbine over a two-year period. The cost of the upgrade is estimated to be $1,190,000. The major devices that will be replaced are the Texas Instruments TI-560 Programmable Logic Controller, the Woodward NetCon 5000 Governor, the Iconics Genesis32 Operator Console software, the IRD Mechanalysis Model 5815 Vibration Monitor and the United Technologies Vibration Monitor. The Woodward TM-55P Electrohydraulic Actuator is to be replaced as it requires a 20-200mA control signal which is not a common industry signal level. The new control and monitoring system is to have a graphical operator interface similar to the existing operator interface. The terminal blocks and assorted materials in the existing control cabinets will also be replaced as required. Field wiring will be retained as much as possible subject to the condition assessed at time of preliminary site investigation. See photos presented under section 3.1 Existing System for depictions of these items. The end result will be an integrated gas turbine control and monitoring system that will be of contemporary technological design having redundant processors.

It is anticipated that the upgrade work will require approximately a seven week outage; two weeks to dismantle the existing system and prepare the cabinets for the new system; two weeks to install the new system and three weeks to commission the new system. It is anticipated that the engineering will commence in 2013 with the purchase of materials and installation period occurring during 2014.

3 JUSTIFICATION

This project is justified on the requirement to replace obsolete infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service to the town of Happy Valley. This project is not justified on the basis of recommendations from any one vendor. Obsolescence and available parts are primary concerns for all equipment platforms discussed in this report. The following points, in decreasing order of criticality, outline the justification for upgrading the control and monitoring components of the gas turbine and are expanded further in this section:

1. The existing system components of all control and monitoring platforms have come to an end of their manufacturing life cycle;
2. The control system does not possess redundant processing capability;
3. The sequencing and governing functionality of the existing system is comprised of different manufacturer product lines;
4. The control logic for the sequencing functions is not in an adequately serviceable version; and
5. The governor system logic is proprietary and not serviceable by Hydro.

Point 3 has been discussed so far. The descriptions that follow of the existing system will elaborate on points 1, 2, 4 and 5.

If one of the obsolete components associated with any platform of the control system were to fail, and there is no spare part to use to return the gas turbine to service, there is a high risk of not being able to supply all the customers connected to the Happy Valley Terminal Station. There are some spare components on hand at site but supply is dwindling as these parts are either no longer manufactured, custom manufactured subject to customer demand or available on an exchange basis only. A third party manufacturer makes components that are compatible with the PLC modules but these have not been tested.

The PLC logic is of more concern than its spare parts. Gas turbine governor and sequencer logic would have to be provided by a supplier that is knowledgeable and experienced in gas turbine installation and commissioning.

3.1 Existing System

The Happy Valley gas turbine is a 27 MW electric generator and power turbine that was commissioned in 1992. The gas turbine unit can be operated in generation mode to provide power to the town of Happy Valley or in synchronous condense mode to provide voltage support for the incoming 138 kV transmission line from Churchill Falls for the Happy Valley System. The control system was provided and installed by Pratt and Whitney in 1992 as part of the gas turbine plant construction. It enables the generator to be operated locally from the generator control panel or remotely from the Energy Control Center. Startup, shutdown and running operation of the gas turbine is an automated process that is monitored and controlled by the control system.

One of the main components of the control system is the Texas Instruments TI-560 Programmable Logic Controller (PLC). The PLC, also referred to as the sequencer, maintains the logical chain of processes that are necessary to keep the gas turbine operating. In addition, it serves as the alarm monitor and interfaces with the governor when the unit is required to produce power. The existing PLC does not have redundant processors, as do the other gas turbine controls at Hardwoods and Stephenville terminal stations. In the event of a processor failure, the gas turbine would trip and production would be lost until the unit was restarted. Redundant processors would maintain operation in the event of failure of one of the processors. Redundancy significantly improves reliability.

Texas Instruments originally manufactured this PLC but the product line was taken over by Siemens. Siemens no longer supports or manufactures this product. Siemens has issued a list of dates indicating the end of support for each component. The last end date was in 2006 for the last few cards that were supported. The list of components and the associated

end of support dates are provided in Appendix A. At present, any components that fail cannot be replaced or repaired by Siemens. A third party company named Control Technologies Incorporated makes modules and programming software that are compatible to the existing PLC but the existing system is still in need of upgrading and PLC logic is still not in a suitable format. The Product Support statement issued by Siemens is included in Appendix A.

The control logic for the sequencing functions is not in an adequately serviceable version. Pratt and Whitney technical staff used a software package called Siemens APT (Advanced Programming Tool) to develop the sequencing logic. This was a text based programming language that then generated, or compiled, the ladder logic for download to the PLC. The ladder logic program was not intended to be edited as it is a compiled product. The original APT source program was not used following commissioning since Hydro staff did not have the programming software. Due to the conception that the ladder logic was the means by which revisions had to be made, Operations and Engineering have been editing the ladder logic since the unit was put in service. The PLC logic is maintained with a software package, TI-SOFT, that has also become obsolete and cannot operate on present industry standard operating systems such as Windows 7. The Protection and Control Technologist have to maintain an older operating system on one of their computers in able to troubleshoot and revise the logic in the PLC. The ladder logic compiled from the original text based language is difficult to follow and troubleshoot. It is anticipated that a new control system will have more serviceable software but still based on the original logic drawings provided by Pratt and Whitney.

Figure 1 shows the PLC processor in the top left of the picture with two racks of input and output cards directly below. Figure 2 shows the third rack of input and output cards with columns of terminal blocks below. The terminal blocks provide the points of isolation for cabling that connect the gas turbine auxiliaries and sensors to the control system.

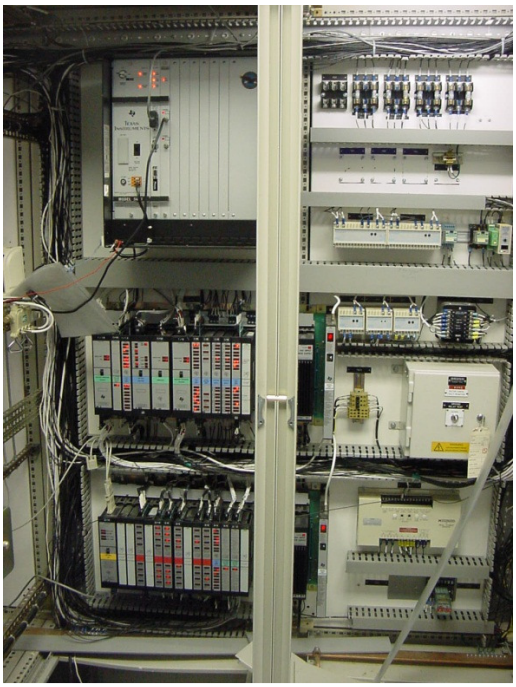

Figure 1: Gas Turbine Sequencer (left cabinet)

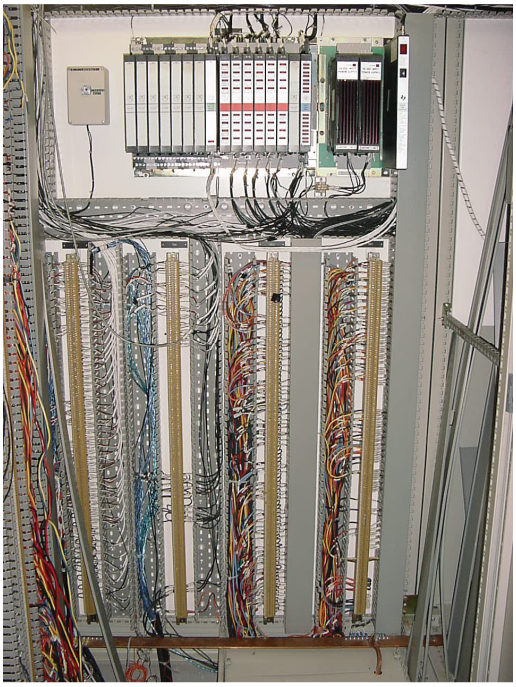

Figure 2: Gas Turbine Sequencer (right cabinet)

The other main device is the Woodward NetCon 5000 governor control unit. This device monitors speed and temperature and adjusts fuel flow to the engine. It works in conjunction with the sequencer (PLC). The governor logic is proprietary to Woodward and

cannot be revised by Hydro although some parameters are available for adjustment. The Woodward NetCon 5000 is shown in Figures 3 and 4.

Figure 3: Gas Turbine Governor (front view)

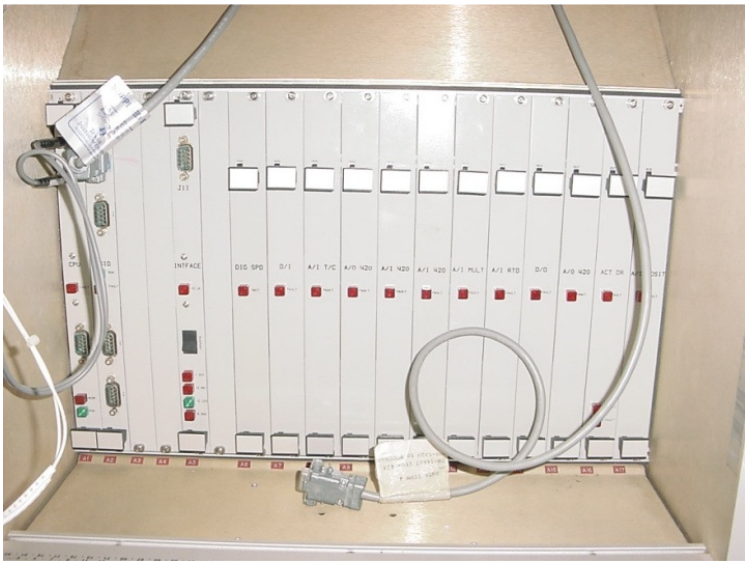

Figure 4: Gas Turbine Governor (inside view)

The NetCon product line is no longer available for new installation and, as of 2015, there will be no spare parts provided by Woodward. Components can be repaired or exchanged only at this time. Of the ten types of input and output modules in the existing unit, there is

only one spare of each of the analog output and discrete output modules. There are no spares for any of the other eight signal modules, the processor or communications module. In the event that one or more of the modules fails with no available replacement on hand, the gas turbine would be out of service until either the module is returned to the manufacturer for repair or exchange or the control system is upgraded. Estimating two days for overnight air freight of the component to the manufacturer, two days minimum to repair or exchange subject to availability and two days for urgent air freight of the component back to Happy Valley, it is anticipated an outage would be at least one week not including the possible delay of a weekend. The Product Support statement issued by Woodward is included in Appendix A.

The vibration monitoring and protection for the alternator is provided by one IRD Mechanalysis 5815 vibration monitoring system and one United Technologies vibration monitoring system. IRD Mechanalysis offices in Columbus, Ohio, USA and Chester, England have since closed. Head Offices and Service are located in India. The vibration monitoring and protection for the engine is provided by a United Technologies vibration monitoring system. This was installed approximately 10 years ago to monitor the engine only; previously the engine vibration monitoring was part of the IRD Mechanalysis unit.

The vibration monitoring and protection equipment is shown in Figure 5.

Figure 5: Gas Turbine Vibration Monitoring and Protection

Vibration sensors, mounted at specific locations on the gas turbine and alternator, provide signals to these units. The vibration levels are monitored and the alarms and trips are sent to the PLC. The IRD Mechanalysis unit is obsolete and no longer manufactured. At the time of this report, the manufacturer of the United Technologies Turbo Power vibration monitor could not be located but it is anticipated that this unit is obsolete as well. There are no spare components at site for either of these units. Both of these units should be replaced with a single platform of modern design that is capable of monitoring the entire gas turbine. If a component fails in one of the vibration monitoring and protection units, the gas turbine would be without adequate protection.

The local operator controls consist of hardwired switches for controlling the gas turbine and a computer system for monitoring the gas turbine operating conditions such as speed, temperature and vibration. The computer system consists of a standard desktop computer with operator interface software called Genesis32 by Iconics. The console is for monitoring and annunciation only; local control of the gas turbine is not done using the computer. It is

anticipated that the new control system will have its own operator interface software and the existing console will be replaced. The existing operator interface computer screen with one of the various graphical screens is shown in Figure 6.

Figure 6: Operator Console

3.2 Operating Experience

The existing control and monitoring system has performed in an acceptable manner over the past 20 years. Although not prone to failures or frequent maintenance, the main devices are obsolete. Most components are either not supported or can only be repaired or exchanged subject to their availability in the manufacturer's stock of refurbished units. The PLC, governor, vibration monitors and operator console are from four different manufacturers. In addition, the logic for the governor and sequencer are not in easily serviceable formats. It would be optimal if the entire system was upgraded and supported by a single manufacturer on the basis of a single point of contact for service and spares as well as assistance in troubleshooting.

3.2.1 Reliability Performance

During the winter months, the current peak loads in Happy Valley are above 60 MW and without the voltage support (Synch Condenser operation) from the gas turbine, only 46 MW of load can be supplied at acceptable voltage levels.

Table 1 below is from Hydro Operating Instruction T-066 with 138kV line L1301 in service.

Table 1: Maximum Customer Load for Equipment Combinations

Happy Valley Terminal Station			
Maximum Permitted Customer Load For Various Equipment Combinations			
L1301	*Sync Condenser*	*Capacitor Banks*	*Max Customer Load*
In Service	In Service	In Service	63MW
In Service	In Service	Not In Service	53MW
In Service	Not In Service	In Service	46MW
In Service	Not In Service	Not In Service	30MW

If the incoming 138 kV transmission line L1301 is out of service, the gas turbine is the only means of generation to serve Happy Valley and surrounding areas. The service reliability of the gas turbine is subject to the availability of spares for critical components.

3.2.2 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements related to this project.

3.2.3 Safety Performance

There are no safety performance requirements related to this project.

3.2.4 Environmental Performance

There are no environmental performance issues related to this project.

3.2.5 Industry Experience

Hardwoods and Stephenville Gas Turbines have each had their control system replaced by one from a single manufacturer. It is the intention to upgrade the controls for the Happy Valley Gas Turbine in the same manner.

3.2.6 Maintenance or Support Arrangements

Pratt and Whitney offer a certain degree of mechanical support for the rotating machinery and provide technical assistance for the existing control system but there is no long term

maintenance agreement in place.

3.2.7 Maintenance History

As indicated in Section 3.2, maintenance is not part of the justification.

3.2.8 Anticipated Useful Life

The anticipated useful life of a digital control system is typically 15 years.

3.3 Development of Alternatives

There is no alternative other than a complete upgrade to the control and monitoring system. Different manufacturing options were considered and the budget proposal is based on the least cost option.

4 CONCLUSION

The control and monitoring system for the Happy Valley gas turbine is in need of upgrade to a modern integrated system. The sequencer, governor and vibration monitoring components are obsolete and fragmented across three manufacturers' platforms. The logic contained is split across two separate devices and is difficult to edit and troubleshoot. The aim of this project is to provide the gas turbine with a technologically up-to-date platform of control and monitoring with logic that is easier to comprehend and maintain and components that are readily acquired and supported by a single point of contact.

4.1 Budget Estimate

The budget estimate for this project is shown in Table 2.

Table 2: Project Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	0.0	10.0	0.0	10.0
Labour	42.0	331.0	0.0	373.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	460.7	0.0	460.7
Other Direct Costs	15.0	58.0	0.0	73.0
Interest and Escalation	4.4	85.6	0.0	90.0
Contingency	0.0	183.3	0.0	183.3
TOTAL	**61.4**	**1,128.6**	**0.0**	**1,190.0**

4.2 Project Schedule

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Project Design Transmittal preparation Site visit and assessment of equipment Project team assignments	January 2013 February 2013	January 2013 February 2013
Design	Prepare Contract for supply of control system Prepare specification for actuator Update applicable drawings	May 2013 July 2013 September 2013	June 2013 July 2013 May 2014
Procurement - 1	Issue Contract	October 2013	October 2013
Procurement - 2	Review and Award Tender	January 2014	January 2013
Procurement - 3	Post Award Site Meeting	January 2014	January 2014
Procurement - 4	Factory Acceptance Test	June 2014	June 2014
Construction - 1	Remove existing control system	July 2014	July 2014
Construction - 2	Install new control system and associated items	July 2014	July 2014
Commissioning	Test controls and monitoring, operate GT Release GT for service	August 2014	August 2014
Closeout	Project Closeout documentation Drafting of As-built drawings	September 2014	October 2014

APPENDIX A

Product Life Cycle Announcements
By Manufacturers

A1 – TI PLC Products Maturity

A2 – Woodward NetCon Support Statement 2002

A3 – Woodward NetCon Support Statement 2005

A4 – IRD Mechanalysis Support Statement

SR= 1-2705614410 maturity
A&D Support USA to: owarren 04/30/2012 12:40 PM

Hello Craig,
There is not an updated statement regarding the TI500 series maturity. Listed below is the statement that was issues when the product line was matured. There is also a link to the website. As for the CTI part numbers, these are manufactured and supported by Control Technologies, Inc. You will need to contact them for information on the CTI devices.

http://support.automation.siemens.com/WW/view/en/4823774

http://support.automation.siemens.com/WW/view/en/4798632

Entry ID:4798632 Date:1996-10-24
The fast moving nature of the electronics industry & the obsoleting of older electronic component parts have added to the need to closely manage these older products families. Manufacturing of these product families will continue with no immediate change to customer availability of these products. However, these products are no longer intended to be actively marketed since a successor product is available.
The SIMATIC Series 500 Product Family has had a long & successful life.The Series 500 Product Family was matured in the late 1980's and is still being manufactured to meet our customers needs. Siemens recognizes the need for this long term commitment for the products it provides for the industrial marketplace. Siemens also recognizes the need to keep customers aware of the status of its older product lines.
The SIMATIC Series 505 Product Family, the next generation to the Series 500, was developed to simplify the automation control task and give our customers a competitive edge with state-of-the-art performance at an affordable price. The transition of our customers from the Series 500 to the Series 505 has been highly successful due to full compatibility of the software & universal I/O connectivity.
The following points will be of interest to our Series 500 customers:

1. Siemens will take new orders for the Series 500 & 6MT products listed on the attachment for a minimum of one year. These orders are subject to standard customer service policies.
2. These Series 500 and 6MT products will continue to be manufactured beyond one year subject to customer demand, availability of raw material from our vendors, and future product management decisions.
3. For this announcement, the list price and ATC discount price will remain as stated on the latest price list. These prices are subject to change due to future market conditions.
4. Product lead-times may vary but all effort will be made to satisfy customer demands.
5. If a Series 500 or 6MT product is to be removed from our manufacturing process and no longer be available for regular purchase, a Manufacturing Discontinuation notice will be sent out and all attempts will be made to offer a minimum of one year for a lifetime-buy opportunity.
6. SIEMENS ENERGY & AUTOMATION, Inc. STANDARD POLICY FOR PHASED-OUT PRODUCT:. Siemens Energy & Automation, Inc. will provide seven year service and support for those SIMATIC products transferred from Texas Instruments,Inc., including upgrade and additions to that product line. The seven year support period for the Series 500 and 6MT product families will be measured starting from the date of this announcement. Manufacturing of these products will continue to meet customer demand but the official date for ending the service and repair of these products will remain at Sept. 30, 2003.

7. THERE ARE NO PLANS TO PHASE OUT THE 505 PRODUCT LINE. SIEMENS ENERGY & AUTOMATION, INC. IS CONTINUING TO ACTIVELY MARKET AND MAKE SUBSTANTIAL R & D INVESTMENTS IN THE 505 PRODUCT LINE. RECENT INTRODUCTIONS OF THE PROFIBUS-DP CPUs (545-1103, 545-1104 , 555-1103, 555-1104, 575-2104), ALONG WITH THE PROFIBUS-DP RBC, ETHERNET TCP/IP & NEW I/O MODULES DEMONSTRATE SIEMENS COMMITMENT TO THE SERIES 505 PRODUCT FAMILY.
   Note: Since release of this document, the 505 series has been matured.

THE FOLLOWING PRODUCTS MAKE UP THE SIMATIC SERIES 500 AND 6MT FAMILIES AFFECTED BY THIS ANNOUNCEMENT:

PRODUCT NUMBER	DESCRIPTION
2492144-8001	CONN KIT, 500-5009
2492144-8008	CONN KIT, 500-5047
2492144-8012	CONN KIT, HI DENSITY 500-5030
2493625-8003	530C BATTERY DOOR
25806-48	25806-48 / 48" CABLE
2587678-8005	BATTERY KIT,530T,560,545-1101
2587679-8006	FUSE,3A
2587679-8007	FUSE,1/5 A
2587679-8009	FUSE, 1/2A, MIN
2587679-8012	3 AMP 125V FUSE
2587679-8013	5A 250V FUSE
2587679-8014	3.15A 125V FUSE
2587679-8015	FUSE 3A 250V 5X20MM SLOW BLOW
2587681-8001	EPROM 2K X 8 500 SER
2587681-8007	EPROMS,2K X 8,5TI
2587681-8012	EPROM,32K X 8,530C
2587681-8015	EPROM, 2732A
2587681-8020	EEPROM 32K X 8525
2587681-8022	USER EEPROM,128KX8 FOR 545 BD
2587693-8006	REPLACE KEY STD
2587871-0059	MANUAL,TIWAY DE
2703770-8001	TIWAY BLOCK TAP
500-2108	500-2108 / I/O CHANNEL CONTROL
500-2109	500-2109 / DIST BASE CONTROLLE
500-2114-A	TURBO RBC,500-2114-A,W/MODEM
500-2151-A	500-2151-A / 110/220VAC PWR SU
500-5001	110V INPUT MODULE,500-5001
500-5002	220V AC IN MODULE, 500-5002
500-5005	24V AC/DC INPUT,500-5005
500-5008	12/24 VDC INPUT MODULE,500-500
500-5009	HS ANALOG IN MODULE,500-5009
500-5011	110V AC OUT MODULE,500-5011
500-5012	220V AC OUT MODULE,500-5012
500-5013	12/24 VDC OUT MODULE,500-5013
500-5016	HS ANALOG OUT MODULE,500-5016
500-5019	WORD OUTPUT MODULE,500-5019
500-5023	HI SPEED PULSE INPUT MODULE,50
500-5030	32PT LVDC INPUT MODULE,500-503
500-5031	32 PT LVDC OUTPUT MODULE,500-5
500-5035	BASIC MODULE,500-5035
500-5037-A	8 CHAN ANALOG IN MODULE,500-50
500-5039	500-5039 / NIM,LL & LL CONFIGU
500-5047-A	8 CHAN ANALOG OUT MODULE,500-5
500-5052	RTD MODULE,500-5052
500-5053	500-5053 / PEER LINK,SINGLE L/
500-5054	500-5054 / PEER LINK, DUAL L/L
500-5055	32 PT 110 VAC INPUT MODULE,500
500-5056	32 PT 110 VAC OUT MODULE,500-5
500-5061	HI CURR RELAY OUT MODULE,500-5
500-5114-A	TURBO RBC,500-5114A,W/485
500-5840	530C ADAPT BASE **(12 WLT)
500-5848	500-5848 / 14 SLOT BASE
500-5892	500-5892 / 6 MODULE BASE
500-6262	SIMATIC S5 PIM MODULE (TIWAY)
500-6920	VAX DRIVER TK50 SNGL USR LICEN
500-8111	500-8111 / MAN P/S USER'S 500-
500-8113	500-8113 / MAN, 500-5030,500-5
500-8114	500-8114 / MAN,USER'S HSPI 500

500-8115	500-8115 / MAN,TW PEERLINK USE
500-8116	500-8116 / MAN, USER'S 500-505
500-8117	500-8117 / MAN USER'S / 500-50
500-8126	500-8126 / MAN, RTD USER'S / 5
500-8140	500-8140 / MANUAL, I/O BASE US
500-8143	500-8143 / 500/505 IOCC/DBC US
500-8144	500-8144/MANUAL, 500-5051 USER
500-8145	500-8145/MANUAL, 500-5047-A US
500-8146	500-8146/MANUAL, 500-5037-A US
500-8148	500-8148/MANUAL, 500 SERIES RE
530-8117	530-8117 / MANUAL, 520C/530C/5
530T-1112	530T-1112 / 530 TURBO 12K
6MT-31	6MT-31 / LOGIC INTERFACE
6MT-32	6MT-32 / LOGIC INTERFACE
6MT-33	6MT-33 / LOGIC INTERFACE
6MT11-AO5L	6MT11-AO5L / INPUT MODULE
6MT12-4OAL	6MT12-4OAL / OUTPUT MODULE
6MT12-4OBL	6MT12-4OBL / OUTPUT MODULE
6MT12-4OEL	6MT12-4OEL / OUTPUT MODULE
6MT13-DO5L	6MT13-DO5L / INPUT MODULE
6MT14-4OCL	6MT14-4OCL / OUTPUT MODULE
6MT14-4ODL	6MT14-4ODL / OUTPUT MODULE
6MT50-2	6MT50-2 / 6MT MOUNTING BASE
TIWAY-8106	TIWAY-8106 / MAN, UNILINK
TIWAY-8108	TIWAY-8108 / MAN,HOST S/W, TI/
TIWAY-8110	TIWAY-8110 / MAN, 500 NIM
TIWAY-8119	TIWAY-8119 / SERIES 500 NIM RE
TIWAY-8121	TIWAY-8121 / TW UNILINK HA USE
VPU200-3605	VPU200-3605 / CABLE,VPU200/520

Best regards,
Alan Archer
Siemens Technical Support
800-333-7421

WOODWARD
Industrial Controls

Woodward Governor Company
1000 East Drake Road
P.O. Box 1519
Fort Collins, CO 80522-1519 USA
Tel: 970-482-5811
Fax: 970-498-3058

September 20, 2002

SUBJECT: Product Support for NetCon (Phase-B) Simplex Controls

The Woodward NetCon control platform was discontinued in July 2001, and is no longer available for sale into new commercial applications. Woodward has produced and supported the NetCon (simplex) product line for many years and continues to sell new NetCon systems into Military applications where we have contractual agreements.

For all like applications the NetCon platform has been replaced by Woodward's MicroNet control platform. The NetCon is unique in the respect that it shares most of its components with the MicroNet, which is in the prime of its production life. Due to this commonality, most of the NetCon modules will be available long after the "NetCon" rationalization dates.

Because of the common modules shared with the MicroNet, the NetCon's discontinuation primarily affects only the chassis and power supplies at this time. There are some older NetCon modules, which have been discontinued due to product obsolescence issues, however, most of these have some type of replacement possibility. Woodward will commit to the following NetCon Phase-B product family support plan:

June 1, 2001 - 2003:
- Unlimited Spare Modules
- Unlimited Repairs
- Replacement Exchange with Service Stock

June 1, 2003 - 2005:
- Limited Spare Modules
- Unlimited Repairs
- Replacement Exchange with Service Stock

June 1, 2005 - 2020:
- Repairs based on parts availability
- Replacement Exchange with Service Stock
- Replacement product utilizing same algorithms and logic where applicable
- Availability of design drawings such that customer can produce the part themselves (with signed "Proprietary Drawing and Assumption of Liability and Release Agreement")

Parts obsolescence from electronic manufacturers can present a challenge to post-life support plans. Woodward strives to hold inventory, or look for alternative parts when components are obsoleted. However, there are times when components can simply not be obtained and where sufficient last-time buys cannot be made. In these cases, Woodward cannot always guarantee that we can maintain the rationalization support plan.

Regards,
Rich Kamphaus
Turbomachinery Controls Product Line Manager
Phone: (970) 498-3388
Fax: (970) 498-3050
E-mail: rkamph@ woodward.com

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August 19, 2005

SUBJECT: Product Support for NetCon Control Systems

As Woodward moves forward with the MicroNet product line, the time has come to rationalize the production of the NetCon chassis, NetCon power supplies, and older VME NetCon modules. The newer generation MicroNet family is fully supported, and an extensive product support plan is scheduled for the NetCon. Affected parts are summarized in Attachment A.

Woodward understands the importance of extended product support for its customers and their critical applications. We will honor this expectation through sales of spares, repairs, and replacement/exchange through service stock as available.

	Through Sept 2010	**Through Sept 2015**	**Through Sept 2025**
Spares	Yes	No	No
Repairs	Yes	Yes	No
Replacement/Exchange*	Yes, as available	Yes, as available	Yes, as available

*Replacement/Exchange utilizes and depends upon availability of Service Stock (reconditioned equipment).

Please note that list price of affected parts will increase 30% effective January 1, 2006.

Electronic component obsolescence from electronic manufacturers can present a challenge to post-life support plans. Woodward strives to hold inventory or look for alternative parts when the components we use are no longer available. However, there are times when components simply cannot be obtained and where sufficient last-time buys cannot be made. In these cases, Woodward cannot guarantee the expected rationalization support plan.

Best Regards,

Bill Becker
Turbomachinery Controls Product Line Manager
Woodward Industrial Controls

WOODWARD
Industrial Controls

August 19, 2005

Attachment A – Parts affected by NetCon Rationalization Plan

The products being rationalized are summarized below:

- NetCon Chassis and Power Supplies (LOCOP products excluded), including NetCon/C and NetCon/P chassis.
- I/O modules that have a functional replacement (e.g., older style "Actuator Driver" modules, older SIO's, PCM).
- Older CPU's (e.g., Motorola 030's, 060's, memory cards, etc.)

Certain products have already been discontinued due to component availability or other reasons. Examples:

- Fiber Optic Remote I/O racks and Fiber Optic Transceiver cards.
- Original Ethernet cards (with BNC or Triax connectors rather than RJ45).
- I/O modules with direct replacements (no system modifications required).

Please Note that Woodward announced and completed the inactivation of the much older NetCon "Phase A" and NetCon FT systems many years ago. Please refer to the appropriate rationalization plan for further details.

Newfoundland and Labrador Hydro A Nalcor- Service, Spares, Obsolescence statement concerning IRD Model 5815
Peter W.Hills
to:
CWarren
05/02/2012 04:05 PM
Cc:
"'C.Narayana'", "Gary Mann IRD USA Partner"
Show Details

5 Attachments

IRD8800 Main Rack Product Data - Aug11.pdf IRD Corp Brochure USA ISO GM Mar12.pdf

Dear Craig

I regret to inform you that around 1998 the IRD5815 was made obsolete and by 2000 Rockwell Automation totally ignored it. There are no spares available apart from scrapped second hand units, if you can find them. Even then this is not a recommended route.

We suffered mightly until in 2005 we became totally separtated from Rockwell. We started to rebuild IRD, first as Mechanalysis (India) Ltd and in 2011 we reverted to our original name as IRD Mechanalysis Ltd and secured the branding trademark as well.

Of course all the above does not solve your problem but what we can offer you is model IRD8800, a 19" Rack API670 compliant monitor that is in fact an ideal replacement for the 5815. At present I am in Kerala India today discussing the replacement of similar model 5915 x 3 units.

Please see attached our Corporate Brochure along with the Product Data Sheet of IRD8800 that will prove to be an economic and practical replacment. Just let me know the type of sensors and we can offer you the complete package to interface with what you have.

Gary Mann is our USA Partner and a former IRD employee there for over 20 years.

Regards
Peter

Peter W. Hills
Managing Director & CEO
IRD Mechanalysis® Limited
The Vibration People®
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+91-22-2285-0480 Fax
Skype: peter.w.hills
www.irdmechanalysis.com

condition management solutions

Please don't print this e-mail unless you really need to

-----Original Message-----
From: CWarren@nlh.nl.ca [mailto:CWarren@nlh.nl.ca]
Sent: Monday, April 30, 2012 8:40 PM
To: service@irdmech.com
Subject: Service, Spares, Obsolescence statement concerning IRD Model 5815

I am looking for a statement of maturity /obsolescence on the IRD 5815
vibration monitoring unit.
Are there any spare parts stocked and can this unit be repaired?
Is there a Canadian or US service facility?

Thank you,

(Embedded image moved to file: pic08795.jpg)

Craig Warren

Supervising Engineer - Controls

Protection, Control & Communications Engineering

Project Execution and Technical Services

Newfoundland and Labrador Hydro - a Nalcor Energy company

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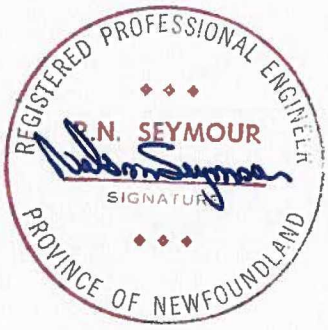
You owe it to yourself, and your family, to make it home safely every day.
What have you done today so that nobody gets hurt?

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

	Electrical
	Mechanical N.S.
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Condition Assessment and Life Extension

Holyrood Thermal Generation Station

June 2012

newfoundland labrador hydro
a nalcor energy company

SUMMARY

This project is the second year of a Level 2 condition assessment study of the Holyrood Thermal Generating Station as described in guidelines by the Electrical Power Research Institute (EPRI). An engineering consulting firm and specialty inspection contractors will assist Hydro engineering staff in completing the work for select systems. The project is a continuance of condition assessment work that began in 2009 when the Board of Commissioners of Public Utilities (Board) approved a project to perform a Level 1 study and most recently in 2012 approved the first year of a three year initiate to perform Level 2 inspection on select systems. The results of this project, as in the case of the results from the first year of the Level 2 assessment, will provide recommendations with cost estimates to perform refurbishments that may be necessary to select systems to ensure the safety and reliability of the plant as it continues to operate to the year 2020.

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1 INTRODUCTION

The Holyrood Thermal Generating Station (Holyrood) plays an essential role in the Island's power system. With three 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. From October to April, at least one unit at Holyrood, and most often two or three units, is required to meet the power demand of the Avalon region. In addition to providing a large amount of energy to the Island system as part of regular annual operations Holyrood also provides backup energy to the Island system in years of low water infeeds into the Island hydro generation reservoirs.

Figure 1: Holyrood Thermal Generating Station

Holyrood was constructed in two stages. In 1969 Stage I was completed bringing on line two generating units, Units 1 and 2, each capable of producing 150 MW. In 1979 Stage II was completed bringing on line one additional generating unit, Unit 3, capable of producing 150 MW. In 1988 and 1989, Units I and 2 were up-rated to 175 MW.

Holyrood is required to enable the Avalon load to be serviced and it must be available to supply full energy output, in case of low inflows into Hydro's reservoirs. Due to the age of

the plant, and experience with unplanned unit outages caused by equipment failure in recent years, Hydro applied to the Board in summer 2009 for approval to begin Phase 1 of a condition assessment and life extension program for the plant. The Board granted approval to Hydro and that work has now been completed with a report finalized in March of 2011. The report, prepared by the engineering consulting firm AMEC, titled *Hoyrood Condition Assessment and Life Extension Study 2010*, was filed with the Board on May 2, 2011.

In summary, the condition assessment and life extension program for Holyrood is based on the following assumptions:

- Holyrood will be required to operate as a generating station at a capacity factor between 30 percent and 50 percent until at least the end of 2016.
- Holyrood will be maintained for standby power mode of operation from 2017 to 2020. To achieve this capability with a high degree of reliability the power generation systems will be maintained and exercised as required.
- Holyrood will primarily be operated as a synchronous condensing station from 2017 into the future.

Phase 1 of the condition assessment and life extension program provided a Level I study as per the EPRI guidelines (see Appendix A, page A33). During the 1970s and 1980s, EPRI developed a structure for performing condition assessment and life extension studies within the utility industry. This structure comprises three levels of complexity and detail that increases progressively as required. Under Phase 1 of the program this process was applied to the total plant generating units and auxiliary systems. While the process is well understood within the utility industry, implementing it for Holyrood has been complicated by the uncertainty surrounding the long term operating mode for the facility.

The scope of Phase 1 was to determine the basic condition of the power plant, assess its remaining useful life, and identify components, systems or facilities which require further

attention. Phase 1 also assists Hydro in selecting the sampling and testing methodologies to be used in performing more detailed investigation where recommended. Within a condition assessment and life extension program, the investigative work is used to determine whether the plant is a candidate for life extension and recommend actions to achieve extended life.

The report prepared by AMEC under Phase 1 was used as a reference for planning this project which is the second year in Phase 2 of the condition assessment and life extension program. The Phase 2 study will enable Hydro to identify equipment and systems that require immediate attention in order to operate Holyrood as a generating facility safely and reliably up to the end of 2016. If the plant is required to continue operating as a base loaded thermal generating station after 2016, more extensive and comprehensive investigative work will be required to assess the cost of extending the operating life of the thermal generating systems compared to other alternatives.

2 PROJECT DESCRIPTION

This project is Phase 2 of a condition assessment and life extension program and is part of an initiative to be completed in 2014. Phase 2 focuses on plant equipment and systems that require an EPRI Level 2 condition assessment study. A report entitled "Holyrood Condition Assessment and Life Extension Study" was completed in March 2011 by engineering consulting firm AMEC under Phase 1 of the condition assessment and life extension program and filed with the Board on May 2, 2011. Equipment and systems that require a Level 2 condition assessment have been summarized in Chapter 12 of the report. Hydro has targeted select items in that report to form the scope of work for Phase 2 and believes these items to be first priority and require action over a three year period. In general, the items pertain to safety and reliability related to the steam systems at the plant, and reliability and life extension related to the synchronous condensing systems. During the third year of the initiative, the operating forecast for the Holyrood plant will be reviewed and it will be determined what additional condition assessment and life extension work should be pursued as Phase 3 of the condition assessment and life extension program.

This project, proposed for completion in 2013, will include the following tasks:

1. Complete detailed investigative analysis for items pertaining to safety and reliability related to steam systems and systems required for synchronous condensing in accordance with EPRI Level 2 guidelines.

2. Prepare recommendations with cost estimates for select items to complete asset refurbishment tasks to maintain reliable operation of the plant in the future based on operating forecast.

In addition to the Level 2 Condition Assessment, the AMEC report recommends a number of work items to be completed through capital expenditure. The Holyrood capital plan recommendations have been summarized in Chapter 13 of the report. Some of these items

were recognized by Hydro prior to receiving the AMEC report, have been submitted to the Board as capital budget proposals for completion, and subsequently been approved. Others will be submitted for approval as part of future year applications to the Board.

Level 2 condition assessment recommendations in the AMEC report are prioritized and assigned a year to be completed. Hydro has reviewed the list of recommendations and has identified high priority focus areas that include select items for the Phase 2 condition assessment. The priority focus areas are as follows:

1. High energy pipe inspection to assess creep, fatigue and flow accelerated corrosion;
2. High energy pipe supports and hanger inspections;
3. Internal generator inspections to determine overhaul and life extension work scope;
4. Power and control cable inspections and testing;
5. Boilers internal inspections and testing (focus on high pressure components);
6. Transformer inspections and testing; and
7. Civil structures related to synchronous condensing inspections.

Focus areas numbered 3 and 6 above are recognized as priority items. However, they will not be undertaken as part of the Phase 2 condition assessment because they are being pursued through other initiatives. Generator internal inspections will be included in the scope of work for separate capital budget proposals submitted to the Board to provide funding for major overhauls of the turbine generators. The major overhaul proposal for Unit 1 turbine generator was submitted as part of Hydro's 2012 Capital Budget Application to the Board and subsequently approved. Major overhaul capital proposals for Units 2 and 3 will follow in 2014 and 2016 respectively. In addition, transformer testing and inspections will not be included as part of this project because it is being performed through another initiative. Although these assets are located at the Holyrood site and are required for Holyrood to provide service to the Island Interconnected System, they are managed by the Transmission and Rural Operations (TRO) group. TRO presently has a condition assessment

program in place for the transformers similar to the program recommended in the AMEC report.

All of the high priority focus areas have been addressed in the AMEC report but have been broken down and identified as many sub-items. For each of the focus areas, Table 1 summarizes the estimated direct cost each year of Phase 2.

Table 1: Focus Areas

High Priority Focus Area ($ x 1,000)	2012	2013	2014	Total
High Energy Pipe Inspection and Testing	200	100	90	390
High Energy Pipe Support and Hangers	100	80	75	255
Electric Cable Inspection and Testing	50	75	45	170
Boilers Inspection and Testing	400	580	550	1,530
Civil Structures	50	75	0	125
Total:	800	910	760	2,470

The expenditures for the 2012 project were approved by Board Order P.U.(5) 2012 as part of Hydro's 2012 capital budget. That work is now in the planning stage with the project targeted for completion by the end of 2012.

The 2013 project will be managed by Hydro personnel. An engineering consulting firm, experienced in thermal power plant operations and condition assessment, will be contracted as required. Inspection and testing work will primarily be contracted out to major equipment service contractors and specialist testing companies. There will be no disruption to generation operations as inspection work requiring outages will take place during regular planned outages.

3 JUSTIFICATION

The life expectancy of a thermal generating station is 30 years, with the plant operating continuously and downtime only occurring to perform routine repairs and maintenance. The 30 year life expectancy can vary depending on the capacity factor (CF) of a plant and how well it has been maintained over the years. However, after a plant has reached or exceeded its life expectancy, life extension work is required to continue reliable and safe operation.

The CF of a power plant is the ratio of the actual generating output capacity of the plant over a given period of time to the full capacity available for the entire time. The maximum CF for a thermal plant such as Holyrood is about 75 percent. To achieve a CF of 75 percent, the plant would operate at full capacity during the year except for scheduled and unscheduled downtime required to perform maintenance work. Historically, Holyrood has experienced CFs from the 25 percent to 60 percent range since the plant went into service, with an average CF of approximately 35 percent.

For the near future, assuming average water infeeds to Hydro's reservoirs, Holyrood is expected to operate at a CF of between 25 percent and 35 percent. In 2014 it is expected to rise to between 40 percent and 50 percent when the new nickel processing facility at Long Harbour is scheduled to commence operation. When the Muskrat Falls generating facility and the Labrador-Island Transmission Link come in service in 2017, Holyrood will utilize its generators to operate as a synchronous condensing facility. A synchronous condenser is a specialized synchronous motor whose purpose is not to produce mechanical power, but to adjust electrical conditions on an interconnected power grid system. Synchronous condensers provide voltage control to the system when power is transmitted over long distances. However, Holyrood will be maintained and staffed to be able to operate as a generating plant for the initial years of operation of the Labrador-Island Link until the reliable operation of that system has been established. Alternatively, if the Lower Churchill

development does not proceed, other sources of generation will be required and Holyrood will be required to continue producing at a higher CF.

When reviewing the ability of a thermal generating station to reliably meet its generating requirements the demand profile of the station should also be considered along with its capacity factor. The demand, or load, placed on Holyrood historically has been high during the winter period often exceeding 80 percent of total plant capacity. This will continue during the coming years up to 2016 but with the duration time operating at high load increasing steadily with a significant increase forecast to take place in 2014. Increased capacity factor and high demand running time accelerates equipment deterioration.

3.1 Existing System

When the condition assessment program began in 2009 it focused at a high level on all systems associated with the Holyrood plant. In 2012 the Board approved a proposal to perform more detailed assessment of select systems. This project is the second year in a continuance of more detailed assessment of other select components. The steam boilers and high pressure steam piping are areas where the work will be concentrated because they are major components, critical to the generation of electricity, and where concern is greatest as it pertains to safety and reliability. The turbine generators are also major components however inspection and refurbishment of these items are being addressed under the regular overhaul schedule in Hydro's capital program.

A boiler and turbine generator operate together and are generally referred to a generation unit. Phase 2 work places most attention on the boilers and pressure piping related to the three generating units at Holyrood. Some attention will be placed on electric cable and civil structures as indicated in Table 1. Many auxiliary systems are needed to operate the generating units such as fuel, compressed air, cooling water, electrical systems and ventilation. Detailed assessments of these are not part of Phase 2.

Age:

Holyrood was built in two stages. Stage I, comprising Units 1 and 2 and site auxiliary facilities, was commissioned in 1970. Stage II, comprising Unit 3 and its auxiliary equipment, was commissioned in 1979. As of December 31, 2011 the operating hours for each unit are as follows:

Unit 1: 175,463 hours

Unit 2: 166,699 hours

Unit 3: 131,030 hours

In 1986, Unit 3 was modified to permit the generator to be decoupled from the turbine for operation as a synchronous condenser. When Unit 3 operates as a synchronous condenser, the wear on the unit is less as compared to the wear when it operates in generation mode. As a result, the operating hours in synchronous condensing mode are not added to the operating hours in generation mode. As of December 31, 2011 the total hours for Unit 3 operating as a synchronous condenser were 43,243 hours.

Operating regime:

Holyrood operates in a seasonal regime. However, it is critical that full plant generating capacity be provided to meet the winter electrical requirements of the Island Interconnected System. Conversely, for a period of time during the summer when customer demand is at its lowest, no generation is required. During the spring and fall seasons the plant operates at less than peak load. In the spring of each year, as the last of the three units is removed from service, Unit 3 is converted to a synchronous condenser and operates in that capacity continuously until a unit is returned to generation mode in the fall. As a result, the generator and some of its auxiliary equipment and systems for Unit 3 operate for significantly more hours each year than the other two units.

Major Work and/or Upgrades

There have been a number of major upgrades to the plant since it was constructed. Please refer to Appendix B.

3.2 Operating Considerations

3.2.1 Outage Statistics

A list of outages for each of the three generating units for the past three years is provided in Appendix D.

3.2.2 Legislative or Regulatory Requirements

There are no specific legislative or regulatory requirements related to completing this project.

3.2.3 Safety Performance

This project is not intended to mitigate any particular safety concerns. However, identification of safety deficiencies in suspect areas is an important objective in addition to reliability deficiencies.

3.2.4 Environmental Performance

Environmental performance is not applicable for the justification of this project.

3.2.5 Industry Experience

As power generating plants age, it is common practice in the industry to perform condition assessment studies to determine what actions need to be taken to extend life. When Hydro applied to the Board to perform Phase 1 of the condition assessment and life extension program, it was familiar with two similar studies that had been performed recently on other generating stations. One study was performed on a three unit plant similar to Holyrood with the exception that the boilers were not included in the scope of work. The other study was completed by another utility on a single-unit plant.

Hydro participates in a thermal generation interest group under the Center for Energy Advancement through Technical Innovation (CEATI) organization with members from most

of the major utilities in Canada and some from the United States. Condition assessment and life extension has been a high profile topic during the past two years with some members carrying out or planning similar initiatives.

3.2.6 Vendor Recommendations

The scope of work for this project will include an investigation and consultation with vendors. In particular, consultations will be made with major equipment suppliers such as Alstom Canada Inc. and Babcock and Wilcox.

3.2.7 Maintenance or Support Arrangements

Service agreements with external contractors are in place for certain systems in operation at Holyrood. A list of those service agreements is provided in Appendix E.

3.2.8 Maintenance History

The five-year maintenance history for Holyrood is provided in Appendix C.

3.2.9 Historical Information

Hydro received approval, under Board Order No. P.U. 28 (2009) to perform the Condition Assessment and Life Extension Study for the Holyrood Thermal Generating Station for $1,895,000. The Phase 1 report was prepared by the engineering consulting firm AMEC, titled Hoyrood Condition Assessment and Life Extension Study 2010 that was filed with the Board on May 2, 2011.

In addition, a Level 2 condition assessment and life extension study was completed on the Holyrood Plant marine terminal under the Phase 1 project in 2010 and Hydro completed a Level 2 condition assessment and life extension study on the Holyrood gas turbine and balance of plant as part of the same project. The study was completed in early 2012.

3.2.10 Anticipated Useful Life

A typical thermal generating station has an estimated service life of 30 years when operated at annual capacity factors in excess of 50 percent. Holyrood Stage 1 has had over 40 years of service and considering that it has operated approximately 4,000 to 5,000 hours per year, it is approaching the end of its useful life (Note: certain components of Unit 3 operate for significantly more hours; see Section 3.1). It is typical for thermal plants to experience more frequent equipment failures when approaching the end of their useful life. Equipment failures have been experienced at Holyrood in recent years (see Appendix D for outage statistics). The increasing number of unexpected equipment failures in recent years and the results of Phase 1 of the condition assessment and life extension program are reasons to continue with Phase 2 of the condition assessment and life extension program. Results of Phase 1 of the program indicate that with proper investment, the useful life of the plant as a reliable facility can be extended. However, a more detailed condition assessment is required to assist in determining what capital expenditures will be needed to achieve this degree of reliability.

3.3 Forecast Customer Growth

Island Interconnected System load is forecast to grow considerably through 2012 to 2017 with increased demand and energy requirements from both industrial and utility customers.

Appendix F contains the latest version of Hydro's Generation Planning Issues report which was prepared in July, 2010.

3.4 Development of Alternatives

There are no alternatives to this project and the status quo is not acceptable. As one of the major generating plants on the Island Interconnected System, it would be imprudent to not continue with Phase 2 of the condition assessment and life extension program to assist in planning for its projected operating future. Failure to do so will result in reduced reliability and increased unplanned outages due to equipment failure. Equipment failures during unplanned outages are significantly more costly to address then identifying and addressing deficiencies as part of a planned program.

4 CONCLUSION

Units 1 and 2 at Holyrood were placed in service 42 years ago and have exceeded the normal life expectancy for such a plant. The facility will be required to meet the growing power generation needs of the Island Interconnected System for the next four or five years. Thereafter, it is expected to operate primarily as a synchronous condensing station but also with the capability to operate as a reliable generating station to 2020. To meet this requirement, it is necessary to continue with Phase 2 of the condition assessment and life extension program to obtain information required to determine the prudent actions that should be taken to ensure that reliable service can continue to be provided.

4.1 Budget Estimate

The budget estimate was prepared based on information provided in the AMEC report and subsequent consultations with the boiler service contractor at Holyrood, Alstom Power. The budget estimate for this project is shown in Table 2.

Table 2: Project Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	20.0	0.0	0.0	20.0
Labour	125.2	0.0	0.0	125.2
Consultant	325.0	0.0	0.0	325.0
Contract Work	435.2	0.0	0.0	435.2
Other Direct Costs	4.0	0.0	0.0	4.0
Interest and Escalation	78.9	0.0	0.0	78.9
Contingency	181.9	0.0	0.0	181.9
TOTAL	**1,170.2**	**0.0**	**0.0**	**1,170.2**

4.2 Project Schedule

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	**Milestone**
Initiation	February 2013
Request For Proposals	March 2013
Inspection Contracts Awarded	April 2013
Site Investigations and Research	October 2013
Report	November 2013
Close Out	December 2013

APPENDIX A

Epri On-Line Boiler Condition Assessment Guideline

EPRI

On-Line Boiler Condition Assessment Guideline (Rev. 1a)

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Glossary

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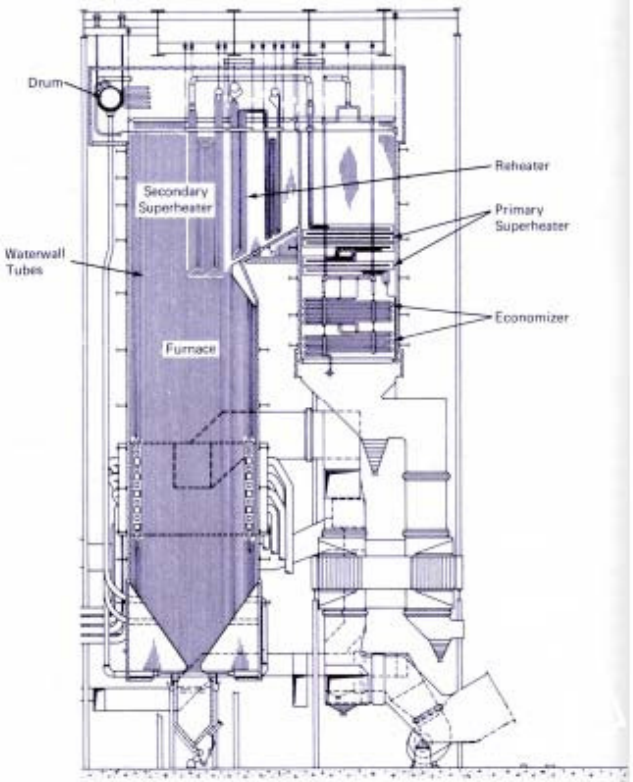
The increasingly competitive environment for power generation demands that utilities pursue all available options to lower power production costs. Typically, this means striking a balance between reducing maintenance costs and ensuring reliability without compromising the top priority—safety. EPRI's On-Line Boiler Condition Assessment Guideline, a reference to the latest information on component damage mechanisms and associated diagnostic techniques, is one tool to help plant personnel achieve this goal.



General arrangement of watertube steam generator. *(Combustion Engineering Inc.)*

Failures in boiler components currently account for the largest percentage of forced outages. In light of this statistic, it is clear that improved operation and maintenance planning are key to reducing unplanned outages. Timely and accurate condition assessment is also key to reducing forced outage rates.

The On-Line Boiler Condition Assessment Guideline features EPRI's three-level structure for performing condition assessments, allowing utilities to optimally match costs with the value of the resulting information. Beginning with logic trees to identify the action sequence, the guideline goes on to tabulate information on damage mechanisms, nondestructive evaluation (NDE) options, analysis and dispositon, and damage prevention opportunities. The general form of these activities is to determine the current state of damage, assess the rate of new damage accumulation, and identify the point when failure risk becomes unacceptable. With this information in hand, utility staff can develop operating and maintenance practices that manage component life. New to this version (Rev. 1a) added details on NDE techniques and analyses to support extension of outage intervals.

More detailed information is available in the referenced EPRI reports upon which this guideline is based. This on-line version of the Boiler Condition Assessment Guideline begins with a glossary with basic descriptions of the major damage mechanisms and NDE techniques. Experienced personnel will want to proceed directly to the report that follows the glossary.

On-Line Boiler Condition Assessment Glossary

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CORROSION

Corrosion damage falls into two general categories: chemical and electrochemical. Direct chemical corrosion is associated with highly corrosive environments, such as those where metal surfaces come into contact with strong acids or alkalis, high temperatures, or both, as in utility boilers. The second category, electrochemical corrosion, involves an oxidation-reduction (redox) reaction, in which one metal, or area of a metal surface, functions as an anode and another as a cathode. Through this process, the metal dissolves in an anodic reaction, producing positively charged metal ions, which are plated out in the cathodic reaction. The presence of dissolved oxygen in water is a major cause of corrosion utility boilers.

The following sections address several specific corrosion-related damage mechanisms that are typical of utility boilers: chemical cleaning damage, corrosion fatigue, and fire-side corrosion.

Chemical cleaning damage

Cause: Acid cleaning, typically with hydrochloric acid, is routinely performed to remove built-up deposits on boiler tube steamside surfaces. Steel corrodes in low pH environments, and for this reason inhibitors are usually added along with the acid to reduce corrosion of the tube metal. If not carefully controlled, however, the cleaning process can lead to extensive tube corrosion. Temperature excursions can cause the inhibitor to break down and become ineffective. Use of inappropriate cleaning agents, excessively high acid concentration or long cleaning times, or failure to completely neutralize, drain, and rinse after cleaning can also result in tube corrosion.

Response: The entire cleaning operation, including temperature, cleaning agent concentration, and the iron and copper content of the cleaning solution during and after the operation, should be carefully monitored. A visual inspection of tube and drum internals should be performed following the cleaning.

Corrosion fatigue

Cause: Corrosion fatigue is caused by the combined action of thermally induced stresses from load cycling and corrosive boiler water conditions. In such an environment, cracks that would normally form over long periods of time at high stress locations, such as tube attachments or restraints, will initiate and propagate at a much faster rate. On the steam-side, cracks that are formed from oxygen or acid cleaning pits, or along cracks in the protective iron oxide coating as a result of cyclic stress, can act as stress concentrators. These cracks may also become anodic and prone to localized corrosion. If these conditions persist, shallow pits or oxide cracks can extend across the tube wall, eventually leading to pin-hole leaks or complete window-type blowout failures.

Response: Corrective actions include redesign of tube attachments to eliminate or reduce differences in thermal expansion between joining components; timely chemical cleaning to remove tube deposits before pitting occurs—while avoiding overly aggressive cleaning; eliminate impurity ingress (e.g., condenser leaks); restore water chemistry stability, with a focus on limiting the dissolved oxygen level to <5 ppbw and maintaining pH within an acceptable range (pH at the economizer inlet of 8.6–9.2 for mixed metallurgy, or 9.0–9.6 for ferrous metallurgy). Restrictions on the amount of cyclic

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operation may also be necessary if corrosion fatigue failures are frequent. Long-term prevention requires locating and replacing tubing that contains cracks, and optimizing boiler shutdown/layup procedures to eliminate the dissolved oxygen or acidic conditions during shutdown that can lead to preferential pitting corrosion at locations with high residual or service stress.

Fireside corrosion

Cause: Corrosion of external superheater or reheater tube surfaces is most often caused by low-melting-point, complex alkali compounds in coal and oil ash. In the case of corrosive coal ash, an alkali-iron-trisulfate layer covering an iron sulfide/iron oxide scale is commonly observed in the deposit. For oil ash corrosion, sodium vanadates or vanadylvanadates are generally found. The leading theory regarding this corrosion mechanism is that the molten alkali compounds flux away the protective oxide surface layer and accelerate oxidation. This corrosion mechanism occurs after the tubing has reached a sufficiently high temperature (either due to high design service temperature or due to buildup of a steamside oxide scale) to melt the corrosive alkali compound. Melting points between approximately 1030°F (550°C) to 1150°F (620°C) have been measured. It is, thus, expected that regions of tubing operating above 1000°F (540°C) are prone to this type of attack. The liquid ash will readily attack both ferritic and austenitic tubing.

Fireside corrosion of superheater and reheater tubing may also involve a sulfidation mechanism when reducing conditions exist. This form of corrosion has been observed on austenitic stainless steel tubing. Discrete iron sulfides have been found in the grain boundaries on the corroded region of the tubes, which also exhibit surface carburization.

Molten salt wastage rates are a strong function of the inherent corrosivity of the fuel. For coals commonly used in the United States, sodium, potassium, sulfur, iron, aluminum, and chlorine have the most influence on the high temperature corrosivity. Vanadium, sodium, and sulfur are the elements most often associated with oil ash corrosion. The position of the tube in a bank, the circumferential position around the tube wall, and the proximity of the tubes to sootblowers also influence corrosion rates.

Response: Corrective actions depend on the severity of the ash corrosion problem. The presence of a liquid ash, which would provide a measure of ash corrosivity, can be confirmed by measuring the melting temperatures of the fireside scale/ash constituents. Long-term solutionzs to fireside corrosion problems include fuel blending or use of additives. Lowering the tube crown temperatures of the hottest tubes through burner tuning or steam flow redistribution, or replacing tubes using more corrosion resistant materials or thicker walls can also be effective. If corrosion is occurring under reducing/carburizing conditions, maintaining sufficient and proper air delivery, secondary, and tertiary air will assure complete combustion and will minimize the carbon monoxide and hydrogen sulfide levels relative to the oxygen concentration. Excessive oxygen concentration must also be avoided, as this will increase the likelihood and rate of liquid ash corrosion.

In the case of oil fuels, lowering flue gas oxygen contents to perhaps 0.25% will produce a drop in liquid ash corrosion rates, especially when the fuel contains high vanadium and sodium levels. The key is that for fuel oils with high vanadium to sodium ratios, low excess air operation is thought to produce lower oxides of vanadium than

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V_2O_5 in the ash deposits. As a result, the formation of low melting point compounds from a combination of V_2O_5 and sodium oxide are less likely. Magnesium or calcium oxide based additives, which raise the melting point of the ash constituents, are also used to control the corrosiveness of oil fuels.

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UNDERDEPOSIT CORROSION

The general category of underdeposit corrosion represents a subset of corrosion damage that includes acid phosphate corrosion, caustic gouging, and hydrogen damage. Each is characterized by localized concentration of a corrosive agent, typically in regions of high heat flux or high deposit buildup such as weld backing rings, protrusions, and crevices.

Acid phosphate corrosion (phosphate hideout and return)

Cause: Phosphate corrosion is caused by a combination of high boiler pressure, high inside surface metal temperature, and high local concentrations of monosodium or disodium phosphate. It has only been observed in boilers in which monosodium and disodium phosphate was added. It has not been observed in boilers that use only trisodium phosphate.

Phosphate corrosion is also associated with phosphate hideout and return, where phosphate concentrations fluctuate with pressure. During boiler shut-down or pressure reduction, the phosphate that hid out in the boiler during pressure increase is returned to the system. The return of phosphate can cause a pH depression in the boiler water, which can lead to depletion of the tube surface protective layer, and ultimately the base metal of boiler tubes.

In high-pressure boilers (above 2600 psig) and at high heat fluxes, sodium phosphate can become concentrated within deposits, leading to rapid corrosion of the underlying metal. This corrosive condition involves a phosphate concentrating mechanism, such as local steam blanketing or boiling within porous deposit, and buildup of a thermal barrier (from local steam blanketing or from the buildup of an internal deposit).

Response: Corrective actions center around improving control of boiler water chemistry by switching to low level or equilibrium phosphate control using only trisodium phosphate; minimizing the ingress of feedwater corrosion products into the boiler; and removal of corrosion product deposits by periodic chemical cleaning. Boiler operating conditions that result in local hot spots, such as excessive overfiring or underfiring, misaligned burners, gas channeling, and inadequate circulation rates, should also be modified. Eliminating welds with backing rings or other internal surface contour irregularities can help reduce internal deposits that can cause a thermal barrier. In severe cases, a switch to all volatile treatment and the addition of condensate polishers may be required, and in cases where inadequate circulation produces local steam blanketing, design modifications may even be necessary.

Caustic gouging

Cause: Caustic gouging is caused by localized concentration of sodium hydroxide (NaOH) to high pH levels, which solubilizes the protective magnetite layer of the tubing steel and leads to rapid dissolution of the underlying tube metal. Susceptible boiler locations include high heat flux regions, horizontal or inclined tubing, and sections that have flow disruptions such as weld backing rings, protrusions, and crevices. In the case of high heat flux areas, feedwater corrosion products deposit and accumulate in these locations and act as concentrators of NaOH through a process known as wick boiling, in which feedwater is drawn to the tube surface underneath the porous deposit where boiling is enhanced, leaving behind any dissolved salts. In inclined or horizontal

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tubes, steam tends to accumulate on the upper surface of the tube, creating a steam blanket in which soluble salts, such as NaOH, can become concentrated. The protective oxide is then attacked by the high pH conditions, and the underlying metal is rapidly corroded, usually in a localized region centered on the crown of the tube where temperatures are highest. The locally thinned tube often corrodes through or succumbs to ductile rupture. Typical reactions of caustic with iron oxide and iron are:

$Fe_3O_4 + 4NaOH \Rightarrow 2NaFeO_2 + Na_2FeO_2 + 2H_2O$

$2NaOH + Fe \Rightarrow Na_2FeO_2 + H_2$

Response: Preventive actions center around improvements in boiler water chemistry, minimizing the ingress of feedwater corrosion products and condenser leakage products, and removing corrosion product deposits through periodic chemical cleaning. In addition, boiler operating conditions that lead to local hot spots, such as excessive overfiring or underfiring, misaligned burners, and gas channeling, should be modified.

Hydrogen damage

Cause: Hydrogen damage results from low pH (acidic) conditions, either in localized areas or in overall boiler water chemistry, that lead to corrosion and subsequent diffusion of hydrogen into the steel tubing. Under low pH conditions, the protective surface oxide of the tubing steel breaks down and exposes the base metal to attack. This corrosion reaction produces hydrogen at the metal surface, which diffuses into the steel and reacts with iron carbide (Fe_3C) to form methane gas. This reaction also produces weakened regions due to local decarburization of the steel. The large methane molecules, which cannot easily diffuse through the metal lattice, become trapped at grain boundaries. As the gas accumulates, the pressure builds, and networks of internal fissures form, which link up over time to cause through-wall fractures.

An overall lowering of the bulk boiler pH may occur in rare circumstances, such as ingress of seawater or accidental acid contamination. Usually, however, low pH conditions only occur locally, such as at high heat flux regions, beneath deposits or in crevices, in slanted or horizontal tubes, or at flow disruptions such as welds. Even slightly abnormal water conditions can result in the formation of local low pH conditions due to concentrating mechanisms, such as wick boiling, steam blanketing, and evaporation. The presence of dissolved salts, such as calcium chloride, sodium chloride, and magnesium chloride, in the bulk water can also cause acid corrosion, especially in deposits or crevices. Salts can decompose to release chloride ions, which can then combine with hydrogen ions to form hydrochloric acid. The acid then disrupts and removes the protective oxide layer, exposing the underlying tube metal to attack. Therefore, hydrogen damage can be particularly severe under conditions of rapid on-load acid chloride corrosion.

Response: Corrective actions include maintaining boiler water chemistry at the proper values; promptly reacting to contaminant ingress and removing the boiler from service if the pH drops below 7; and elimination of hot spots or flow disrupters where excessive deposition can take place. Chemical cleaning can be employed to remove the internal deposits and to stop further generation of hydrogen on the tube surface. It should be considered when the boiler water pH has been below seven for more than one hour due to the ingress of saline condenser cooling water or acidic chemicals into the boiler, or from breakdown of boiler water conditioning elements. If significant wall

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thinning has occurred, the damaged tubing sections must be replaced to prevent repeat failures later in service. The use of low alloy steel tubes will reduce the likelihood of hydrogen damage. Pad weld repairs, which can lead to deposit buildup, should be avoided.

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FIRESIDE EROSION

Fly ash erosion

Cause: Fly ash erosion takes place when flyash particles in flue gas impact boiler tube surfaces at high velocity. The process increases the fireside wastage rate, eventually leading to stress-rupture. Depending on the wastage rate, the tube can fail in one of two modes: a fast wastage rate leads to rapid wall loss and thin-wall failure, while a slower rate of wall loss leads to thick-wall failures due to creep damage from the combined effect of increased temperature and a thinner tube wall. Tube wastage due to fly ash erosion occurs via two mechanisms: fly ash directly impacting the metal surface and removing metal by abrasive wear, or removing the fireside scale during impact, which exposes the base metal and accelerates the oxidation rate. The contribution from these mechanisms changes as the metal temperature increases, with the scale removal mechanism becoming dominant at temperatures above about 800°F (430°C). Fireside erosion is common in units that burn high-ash-content coals and those that contain a high percentage of abrasive ash material, such as quartz (SiO_2).

In the case of abrasive wear, there are three basic modes for metal removal, which are linked to the angle of impingement. At low impingement angles, metal is cut or abraded from the surface. At angles near 45°, metal is deformed with a plowing-type action and particles often imbed into the surface. At angles near perpendicular, the metal is extruded from the impact site and may be removed by a subsequent adjacent particle impact. The maximum erosion generally takes place at impingement angles between 15° and 35°.

Although there is a strong link between erosion rates and particle velocity, the level at which flue gas velocity produces significant flyash erosion (failure in 10,000 to 50,000 hours) is roughly two times greater than average flue gas design velocities. Thus, most erosion damage is due to localized conditions of increased gas flow, such as at narrow, poorly designed passages, blockages, and in the vicinity of sootblowers. Specific locations most prone to this form of damage include:

- Areas that have gaps between the tube bank and the duct walls
- Bends and other locations where the flue gas is made to turn sharply, but the iner tia of the flyash particles causes them to impact the duct walls
- Gas bypass channels where the velocity of the flue gas can be much higher than that of the main flow
- Protrusions or misaligned rows of tubing
- Regions adjacent to tubing where large accumulations of flyash act as a channel that increases velocity

In the early stages of fly ash erosion, damage is marked by smoothly polished areas of the tubing surface. In advanced stages, flat spots and defined edges indicate where the metal has been eroded away.

Response: In general, approaches to reducing flyash erosion focus on either reducing the amount and velocity of ash striking the tube, or increasing the wear resistance of the tube. Changing boiler operation conditions, such as reducing load, lowering excess air levels, balancing air flows, installing distribution and diffusion screens and

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modifying sootblowers are good approaches to reducing ash velocity. Regular soot-blowing should be employed to eliminate ash accumulations that can increase local gas flow rates, but it is important to keep in mind that excessive sootblowing itself can cause erosion. Coal cleaning, or switching to coals with a lower ash content reduces ash loading and thereby erosion rates. The only way to significantly increase erosion resistance is to use coatings, since differences in the erosion resistance of available tubing alloys are too small to provide significant increases in life.

Sootblower erosion

Cause: Sootblower erosion can be caused by excessive blowing, mechanical malfunctions that concentrate the blowing medium, and improper location or operation with excessive moisture in the blowing medium of sootblowers that leads to the formation of wastage flats or gouging of tubing surfaces. In addition, operating a sootblower with condensed water in the media can result in significant erosion. The damage mechanism is often referred to as sootblower enhanced ash erosion because the ash supplies the erosive species and the sootblower action simply increases the approach velocity of the ash impinging the tubing.

Sootblower erosion is associated with locations that receive indirect impingement from wall blowers near the furnace corners; those in the direct path of retractable blowers and in the hotter outlet regions of steam-cooled sections; those that are subjected to a sootblower with a missing or damaged nozzle; and the first tubes in from the wall entrance of retractable blowers.

Response: As always, identifying the exact nature of the problem is the first step. A visual inspection of the sootblower device can identify any malfunction or misalignment, while malfunction of the system can be detected by measuring blowing pressure, testing moisture traps, or checking travel and sequence times. Long-term corrective actions include setting optimized sootblower frequency schedules, and improving maintenance of sootblowers and sootblower system components. Temporary measures, such as shielding, spray coatings, or pad welding can be employed as emergency repairs, but are not recommended as long-term fixes. Visual examination of sootblower operation and calibration of system components during boiler overhaul periods are long-term actions for the prevention of failures by sootblower erosion.

Coal particle erosion

Cause: Coal particle erosion is a damage mechanism that is unique to cyclone boilers. In these boilers, the introduction of combustion air in the burners causes coal particles to be directed tangent to boiler tube surfaces at high velocity. Over time the wear-resistant liners and refractory coatings inside the cyclone burner used to protect the tube surface wear out, allowing erosion of the tube surface. A thin-wall fracture develops when the tube can no longer support the operating stress.

Response: After verifying by examination that the wear-resistant liners and refractory coatings have been degraded, corrective action involves surveillance and replacement of the liners and coatings. Observation of the flow patterns that are established in the burner from the introduction of secondary and tertiary air may reveal where significant erosion will occur. Therefore, adjusting inlet dampers may be necessary to change burner flow patterns to control the rate of liner and coating erosion.

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Supercritical waterwall cracking

Cause: Circumferential waterwall cracking is one of the leading causes of boiler tube failures in supercritical units. It is caused by two complementary processes that enable boiler tube surface temperatures to reach into the creep range: the gradual buildup of deposits on the inside tube surfaces and slagging–deslagging of the fireside surface. The internal deposits are formed from corrosion products entering the boiler from the feedwater and usually appear in a "rippled" formation. In some cases, failure is preceded by increased boiler pressure drop due to flow constraints from internal (ripple) tube deposits.

Waterwall cracking is typically localized, and may be limited to, or more severe in tubes of a specific pass. In addition, cracking is usually limited to a narrow range of elevations in the boiler, usually in a limited span at the burner level that correlates to the maximum heat flux zone. The affected regions are indicated by numerous, closely-spaced cracks. In most, but not all cases, the cracks do not penetrate through the full wall thickness. This type of cracking is often not observed until after a supercritical boiler has been in operation for a number of years. However, once the cracking is detected and repaired, it can return within a matter of months.

Response: Corrective actions focus on cycle chemistry changes, such as oxygenated treatment (OT) and eliminating the oxygen scavenger from all-ferrous feedwater systems. These changes reduce the amount of internal deposits on the waterwalls by lowering the flow of feedwater corrosion products into the boiler, and changing the transported oxide from magnetite (Fe_3O_4), which adheres to the tube surface, to hematite (Fe_2O_3), which does not cause buildup. The combined results reveal that no ripple deposits form, chemical cleaning can be eliminated, and the boiler pressure drop does not increase.

Graphitization

Cause: Graphitization is a diffusion process whereby graphite nodules form as carbon atoms migrate from supersaturated ferrite. Although the microstructure of a typical boiler tube is metastable, it will remain essentially unchanged below about 800˚F (430˚C). If the tube sustains long-term exposure with metal temperatures between 800˚F (430˚C) and 1330˚F (720˚C), the pearlitic microstructure will decompose by spheroidization of the peralitic lamellae, and by graphitization if the steel contains less than about 0.6% chromium. Graphitization occurs preferentially between the two competing mechanisms at temperatures below approximately 1025˚F (550˚C). Graphitization is most damaging when the graphite particles form continuous planes of weakness, which has been observed in the grain refined region of weld heat affected zones.

Response: The extent and cause of the graphitization can be determined by metallographic examination, mechanical tests, chemical composition analysis, and temperature exposure measurements. Steels with more than about 0.6% chromium are immune. Steels containing less than 0.6% chromium (i.e. SA-209-T2) may need to be replaced if used under conditions where long-term exposure promotes graphite formation. In susceptible steels, aluminum contents above 0.025% increase the tendency for graphitization. Weld joints can be stabilized to resist chain-like graphitization by a post-weld heat treatment between 1325˚F (720˚C) and 1350˚F (730˚C) for a minimum of four hours.

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Pitting

Cause: Pitting occurs when small imperfections or cracks develop in a tube's protective oxide layer, exposing the underlying metal to localized corrosion. The corrosion can result from either acidic conditions, or high dissolved oxygen at the tube surface, which cause small anodic regions to form on the tube surface with the adjacent metal acting as the cathode.

Pitting commonly results from two sources, both associated with unit shutdown. The first involves poor shutdown procedures, which produce locations with stagnant oxygenated water. Forced cooling and/or improper draining and venting procedures can result in excess moisture throughout the boiler. Economizer tubes and the bottom of pendant loops of superheaters and reheaters are common locations where stagnant conditions can occur. The second source of pitting occurs primarily in reheater tubes because of deposited Na_2SO_4 compounds. Reheater circuits are particularly susceptible locations because the temperature and pressure conditions increase the solubility of Na_2SO_4 compounds, which acidify during shutdown periods.

Response: Corrective actions focus on protecting tubing during nonoperating periods. Proper draining and venting after shutdown will reduce the amount of moisture that condenses in the tubing as the boiler cools. Nitrogen blankets or caps of the steam-cooled circuits can provide protection during outages of less than four days, while long-term protection involves filling the superheater and reheater tubing with condensate that contains hydrazine and ammonia.

Material flaws

Cause: Material flaws can include laminations, inclusions, seams, or generally inferior properties that can act as crack initiation sites or otherwise make the material inadequate for the intended application. They are generally caused by poor quality control during tube manufacture, either in the steel-making process or the fabrication of the tubes and tube panels. Due to interactions with stress-driven failure mechanisms, material defects are more likely to cause failures in high temperature locations. Therefore, it is also important to maintain proper quality control measures for material storage, labeling, and handling to avoid mistakenly installing inadequate materials in the wrong locations during boiler erection or repairs.

Response: Material flaws can be identified through metallurgical analysis, material properties testing, and review of the procurement records of the tube. A tube containing a material flaw is very likely to fail before the flaw can be found and the tube can be replaced. Since detection of the defective tube is difficult once the tube has been installed, preventive actions are taken to discover defects before installation. Quality control measures are necessary to assure inspection and documentation of the manufacturing, shipping, storage, and installation activities.

Welding flaws

Cause: Welding flaws can include porosity, slag inclusions, excess penetration, lack of fusion, undercut, cracks, and lack of penetration. Such defects can act as stress risers and crack initiation sites or as locations where corrosive contaminants can concentrate and accumulate. Flaws can result from bad welding practices, poor joint preparation and cleaning, improper welding parameters, and lack of or inadequate stress relief.

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Tube blockage from welding debris has also been observed, resulting in a short-term overheating stress-rupture failure. The cause of failures due to welding flaws can be identified by through visual inspection and metallurgical analysis and a review of the welding procedures, the welder's qualifications, the welding inspection records, and the welding material control reports.

Response: Once a defective welded joint has been placed into service, it will usually fail before it can be detected and replaced. Therefore, corrective measures focus on preventive actions (quality assurance procedures) that will minimize the possibility that a defective weld will be produced or that it will go undetected and be approved for use. Strict adherence to well-established quality control measures is necessary to ensure the integrity of welded joints. These measures include qualification of welding procedures, welders, and welding operators; certification of welding inspectors and nondestructive testing examiners; calibration of welding equipment and testing devices; documentation of welding and testing methods, materials, and equipment; and proof tests.

Rubbing/Fretting

Cause: Periodic sliding or impact of tubes against adjacent tubing may cause removal of the protective iron oxide on the fireside surface of the tube which, in turn, accelerates the oxidation rate. In more extreme cases, repeated tube contact will result in complete removal of the oxide followed by adhesive or abrasive wear of the underlying tube material. The end result is accelerated fireside wall thinning. Tube rubbing may be caused by inadequate or nonfunctioning tube supports that allow tubes to impact or slide against adjacent tubes. Tube misalignment can also lead to tube rubbing.

Response: Following a visual examination to identify the extent and cause of damage, corrective actions include realigning misaligned tubing, repairing nonfunctioning tube supports, and modifying supports to eliminate tube to tube contact.

Short-term overheating

Cause: Short-term overheating occurs when a tube is heated well above its design temperature, leading to the formation of cavities or microcracks along grain boundaries that ultimately cause failure. This can happen when local combustion gas temperatures are elevated or when the cooling effect of steam or water flowing through the tube is inadequate. Excessive combustion gas temperature can be produced by overfiring during startup or firing with an irregular fuel burner pattern. Inadequate cooling may result if a tube becomes blocked, the drum level is too low, incomplete boil out of steam-cooled tubing occurs, or conditions lead to local steam blanketing or rapid internal deposit buildup. Short-term overheat failures can occur either below or above the lower critical temperature of the tube alloy.

Response: Choosing the proper corrective action depends upon first identifying the root cause of overheating failure. The first approach is to review plant records and events leading up to the failure in search of an obvious link between tubing failure and operating conditions. The second step is to begin looking for tubing blockages through physical or radiographic examination. If neither of these options ferret out the root cause, then boiler monitoring may be necessary. In this case measuring tubing and/or combustion gas temperatures (using thermocouples, flux gages, infrared cameras, etc.) is called for. If all other options prove fruitless, then a final course of action is a more thorough design/operation/thermal hydraulic review. Once the root cause has

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been determined, fixes include removing blockages, altering startup practices, correcting drum level problems, adjusting burners, or in extreme cases, performing redesigns to improve the thermal-hydraulic response of the affected boiler section.

Long-term overheating/creep

Cause: Tubing failures due to high-temperature creep occur after long-term exposure to temperatures that are within the creep regime, and usually above the oxidation limit of the material. This type of exposure may be a direct result of design conditions, or it may occur when conditions, such as internal deposit buildup or blockages, inadequate coolant circulation, or excess combustion gas temperatures, cause tubing temperatures to rise above the design temperature. Initially, damage occurs by a slight amount of creep deformation. Near the end of life, inter- or transgranular creep voids form.

Tubes that experience above average temperatures will also be likely to have the greatest fireside ash corrosion rates and steamside oxidation rates. Although ash corrosion by sulfur species is not a requirement for long-term overheat failures, ash corrosion will increase the wall loss, and consequently the hoop stress, leading to increased creep damage accumulation rates. As mentioned above, steamside scale buildup can lead to an increase in metal temperature, which leads to accelerated creep damage accumulation rates. Elevated stress levels due to erosion or corrosion can also contribute to higher creep damage rates.

Response: Corrective actions center on determining the remaining life of the tubing based on the actual temperature, stress level, and material properties. Parametric analysis methods, such as the Larson-Miller parameter method, can be used to estimate the effects of various actions. Proper redesign, including material upgrades, may be necessary to provide a more creep-resistant steel in high temperature locations. Steam flow redistribution to lower peak temperatures can also be employed to mitigate degradation and optimize future life and availability.

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NDE TECHNIQUES

EMAT (electromagnetic acoustic transducer)

Electromagnetic acoustic transducers (EMAT) can reduce the acoustic scattering found in piezoelectric transducers that are commonly used in ultrasonic inspections. EMATs exhibit certain advantages over piezoelectric transducers because they do not require a coupling medium between the part and the transducer, and they can be designed to generate and detect focused sound waves unavailable to conventional probes, and can be phased to create different refracted angles or focal distances, rather than using multiple transducers. Because EMATs require no couplant fluid, the surface of a part can be scanned by using synthetic aperture focusing techniques to enhance the detectability of small defects. EMATs can generate and detect shear horizontal waves at an angle to the surface of the part being examined and direct waves to specific locations inside a part without complicated geometrical constructions or loss of energy.

Eddy current testing

Eddy current testing (ECT) can be used to identify material discontinuities, such as changes in thickness, cracks, seams, phase transformation, case depth, cold working, hardness, and heat treatment. When a magnetic field is applied to a metal it establishes an eddy current in the material, which in turn creates an opposing magnetic field. Discontinuities in the metal create changes in the eddy current that can be measured as an apparent change in the impedance of the inducing coil. It is these changes in impedance that are measured and correlated to known defects.

Test coils of various configurations are used to establish a magnetic field in or around the object. Circular coils surround the test specimen, bobbin coils are inserted within it, and probe coils are placed on the surface. Frequencies ranging from 1 Hz to 5 MHz can be used, but frequency will determine the depth of current penetration, with high frequencies revealing only surface defects. Low-frequency testing is sensitive to both surface and deep internal defects. For analysis, ECT uses meters and oscilloscopes that can be adjusted to respond to a specific phase or amplitude, which helps testers narrow the focus of the test.

MT (magnetic particle testing)

Magnetic particle testing (MT) can identify surface or shallow subsurface cracks in ferrous materials. Magnetic particles applied to the surface of a magnetized test object will congregate around inconsistencies in the metal, indicating the location of the problem. The magnetic particles can be applied dry or in a wet suspension of water or kerosene, depending on the nature of the suspected defect and the finish of the component being tested. A wet suspension can more effectively detect fine cracks in smoother surfaces, while a dry powder is recommended when testing for subsurface cracks in rough surfaces. The use of fluorescent particles and an ultraviolet light is popular because that method renders the most striking visual indicator.

Various types of magnetic currents can be used to locate different kinds of anomalies. Alternating, direct, or half-wave direct current are the best options for identifying surface defects. For subsurface defects, half-wave direct current is the most effective. For best results, the current should be applied parallel to the direction of the anticipated

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defect. Although surface defects become apparent, testers should be trained to interpret indications of subsurface defects.

PT (liquid penetrant testing)

Liquid penetrant testing (PT) can reveal surface cracks in nonporous materials. The process uses a penetrant liquid, which is brushed, sprayed, or dripped onto the surface of the metal being tested. After the test specimen has been left for a short time (about 30 minutes to an hour) to allow the liquid to penetrate any cracks that may exist, the surface is thoroughly cleaned and a absorptive coating (developer) is applied to draw the penetrant back out of the cracks. This process reveals the location, shape, and size of any surface defects.

Different types of penetrating liquids are used for testing in visible and ultraviolet light, with best results usually obtained using a fluorescent penetrant and ultraviolet light. The developer consists of a fine powder in a liquid suspension.

Another type of PT, filtered-particle testing, is used for porous objects. In this case a liquid containing suspended particles is typically sprayed on the component. Liquid collects at a crack, making it visible. Some applications use colored or fluorescent sprays to enhance the visibility of cracks.

RT (radiographic testing)

Radiographic testing (RT) uses x-rays, gamma rays, or other high-energy radiation, to reveal features such as cracks, voids, inclusions, and changes in thickness. The radiation is projected at the test object, where it is absorbed at different rates depending on the thickness and density of the material. The result is usually recorded on a radiographic film, although other methods for measuring the level of radiation leaving the object, such as Geiger counters, can also be used. Like photographic films, radiographic films can vary in grain size (speed) and contrast, with slower, small-grain film showing the greatest level of detail. Fast, large-grain films are best suited for revealing large differences in thickness, or other gross features.

Several factors effect the quality and accuracy of the image produced on film. For example, direct radiation forms a clear, sharp image, whereas scattered radiation produces a foggy image. An intensifying screen made of lead can help mitigate scattered radiation for radiography at high voltages. To achieve the clearest picture, the focal point should be small, the ray source should not be too far away, and the film should be placed close to the test object, parallel to the area of interest on the component and perpendicular to the rays emitted by the source.

UT (ultrasonic testing)

Ultrasonic testing is used to identify both surface and subsurface defects as well as measure material thickness. Specific applications include weld inspection, detecting evidence of hydrogen attack, measuring ID oxide scale in boiler tubes, and measuring tubing wall thickness. It can also be used to measure change of stress in a component.

Any material that transmits vibrational energy can be analyzed using ultrasonic testing methods. UT employs a piezoelectric transducer to generate mechanical vibrations, which are transmitted through a coupling liquid into the component being tested.

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Because the velocity of sound through a material is a function of its density and modulus, each material has a characteristic response, and any changes in its properties will cause a change in response. Material flaws or discontinuities can be detected by measuring the presence, position, and amplitude of echoes.

Ultrasonic testing falls into two general categories: pulse-echo systems, which use a

receiving transducer. The optimal frequency range varies depending on material properties. For example, low frequencies (40 kHz to 1.0 MHz) are best suited for materials with low elastic modulus or large grain size, while high frequencies (2.25 to 25 MHz) produce better results with small defects, thin sections, and fine grain materials. Testers can confirm suspected results by comparing received signals (visually or electronically) with reference blocks that have a known similar construction or defect (e.g., holes or cracks).

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REPORT SUMMARY (TR-111559)

The increasingly competitive environment for power generation is requiring that utilities manage their operating plants to achieve least-cost generation. Reducing operating and maintenance costs is one element in that effort. Achieving such cost reduction while still maintaining plant safety and reliability requires a clear picture of the condition of key plant components. This guideline document provides a structure for performing condition assessment activities for major boiler components as a significant part of the overall plant assessment.

Background

Fossil power plant boilers include components subject to damage during both plant operations and maintenance activities. When the damage becomes sufficiently severe, failure of the component will occur with likely consequences for operations and with frequent impact on personnel safety. Failures in boiler components currently account for the largest percentage of plant forced outages. In order to reduce the risks of such failures, utilities perform condition assessment activities that are focused upon determining when the component failure risk is increasing such that remedial actions can be taken to prevent actual failure. The general form of these activities is to determine the current state of damage, assess the rate of new damage accumulation, and identify the point in life when failure is likely to occur. With this information in hand, the utility staff can plan for actions in maintenance and operations that avoid in-service failure.

Objective

To compile structure and information for performing condition assessment actions for fossil-fired boiler components.

Approach

Existing EPRI reports and tools provide a sound technical basis for performing condition assessment activities for boiler components. This current work serves to consolidate and summarize the extensive EPRI database to create a starting point for utility personnel to develop the condition assessment actions required for their fossil power plant boilers. The boiler continues to represent the largest source of forced outages in the industry and is a proper focus for condition assessment. In the context of

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this report and in the bulk of EPRI work on this topic, condition assessment actions are performed on a continuing basis to support maintenance planning, operations, and long-term management of generation assets. This guideline retains the EPRI recommended three-level structure for performing condition assessment. The iterative character of this approach allows utilities to optimally match the cost of condition assessment efforts with the value of having such information. As has also been done in the past, the guidelines start with roadmaps to identify the sequence of actions required to perform condition assessment. Information on damage mechanisms, nondestructive evaluation options, analysis and disposition bases, and damage prevention opportunities is included in tabular form to support the roadmap. More detailed levels of information are, of course, available in the referenced EPRI reports upon which this current guideline is based.

Results

Extensive EPRI and worldwide research has clearly defined the damage mechanisms for major boiler components. The means to perform condition assessment are generally straightforward and only require the organization and execution of appropriate work by the utility. This guideline will assist in that utility activity by consolidating material from multiple sources into a single, streamlined document that can serve as the boiler component condition assessment program plan.

EPRI Perspective

In order to manage the operating and maintenance costs in a cost-effective manner, each utility should have a condition assessment package available for each of its units. The information in such packages will greatly facilitate decision making with regard to maintenance actions, operating parameters, and overall asset value. In past years, utility use of such information was largely devoted to maintenance planning alone. As presented in this guideline, however, special attention should be placed upon those actions that may prevent additional damage from occurring in a particular component. This approach has been successfully demonstrated in past EPRI programs on boiler tube failure (BTF) reduction and is included as a recommended approach in this work.

Interest Categories

Fossil steam plant operation and maintenance (O&M) cost reduction
Fossil assets management

Keywords

Fossil fuel power plants
Condition assessment
NDE

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OVERVIEW AND STRATEGY FOR BOILER CONDITION ASSESSMENT

Introduction

The underlying driver for performing component condition assessment is the need to manage component life to achieve plant operating safety, reliability, and economic objectives. Current power industry changes have not altered these objectives but have, in many instances, provided renewed interest in comprehensively performing condition assessments. This is especially true for economic objectives because competitive forces within the industry place increased importance on trimming operating and maintenance costs to their lowest possible level. For fossil-fired power plants, boiler components command a major portion of maintenance activities and produce a majority of operational outages. Therefore, it is essential that the plant personnel have comprehensive information on the key components of the boiler to manage the operation of the unit effectively and to assess the continuing economic viability of that operation. This boiler condition assessment guideline is intended to aid utilities in preparing and maintaining such information for their fossil units.

This guideline is a compilation of information derived largely from the existing library of EPRI-sponsored work on condition assessment of boiler components. To the extent practical, this material is presented in a streamlined format with the intent to quickly focus efforts on the required activities, and corresponding tools available, to perform boiler component condition assessments. This version (Rev. 1a) of the guideline features added discussion of the procedures and tools needed to extend boiler outage intervals.

Condition Assessment Fundamentals

The objective of this guideline is to assist utility personnel in structuring the critical activities required to perform condition assessment of major fossil boiler components. Condition assessment is the primary requirement for managing the useful life of plant components, and it relies on the following three pieces of information:

- The degree of damage currently in the component
- The rate of damage accumulation
- The degree of damage required to cause failure

EPRI research has provided extensive information in each of these categories, and that material is incorporated within this guideline both directly and via reference. A bibliography is provided at the end of this chapter to identify the key resources used in the preparation of this report.

In the chapters that follow, specific processes are identified for acquiring and evaluating these three pieces of data for key boiler components. Note that attention is given to damage prevention options as a subset of the damage accumulation category. Generally, the most cost-effective life management approach is addressing root causes for component damage and eliminating future damage. Much of EPRI's successful program to reduce boiler tube failures (BTF) is based upon this specific approach and is discussed in Chapter 2, "Boiler Tubing."

A key feature of the condition assessment approach recommended by EPRI has been the use of a multi-level structure in which component evaluations become progressively more detailed. This feature is illustrated in Figure 1-1. Specifically, a three-level structure is provided in which the estimated remaining life (RL) is iteratively compared to the desired life (DL). Note that the DL is typically set by the component maintenance interval (e.g., 1 to 5 years) or by an economics planning window (e.g., 5, 10, 15, or more years). The economics window is, in turn, generally set via an asset management approach applied to all operating units for the utility. This asset management activity is outside the scope of this report.

The iterative approach allows utilities to balance the costs of obtaining additional data against the value of that data in a formalized process. Table 1-1 illustrates the increasing levels of sophistication required in progressing through Level I, II, and III assessments. In the chapters that follow, component-specific activities such as inspections are categorized as Level I, II, or III. Note that a Level III assessment would typically be recommended to obtain the most confident estimate of the RL of a component.

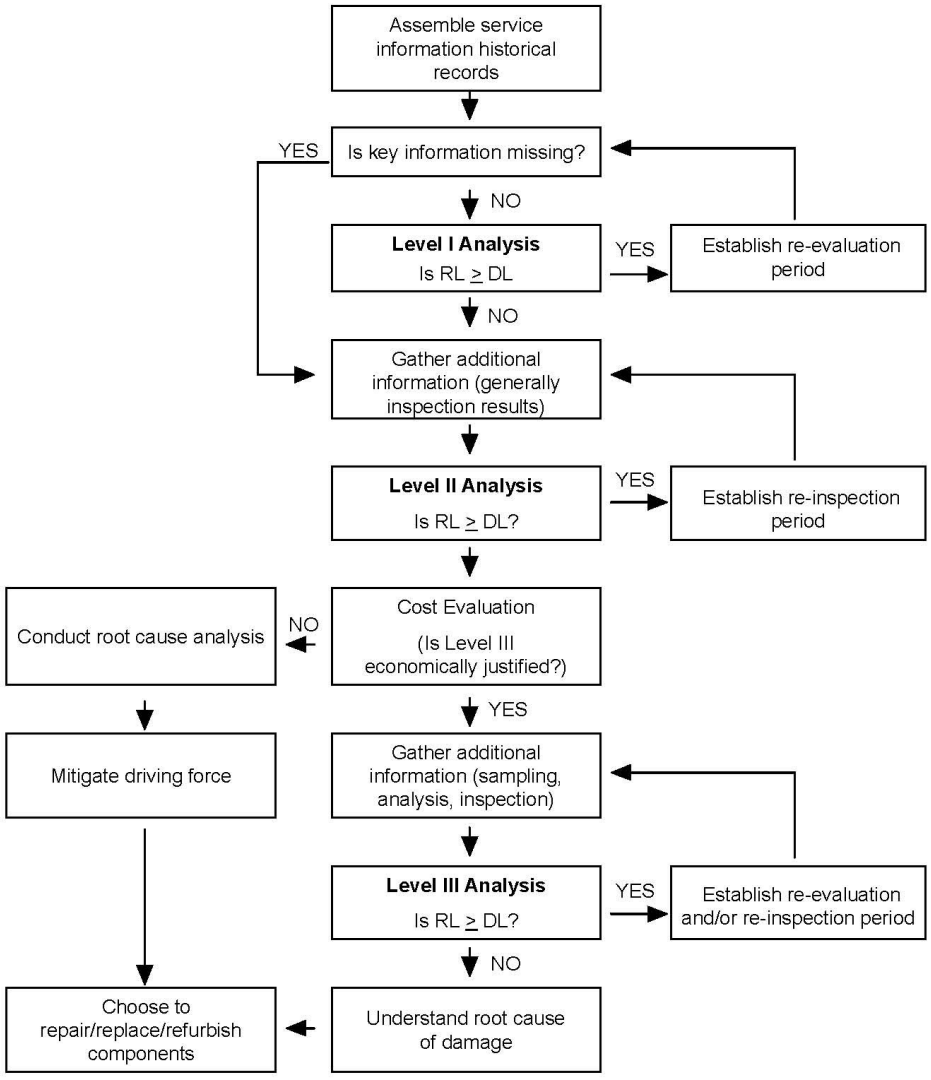

Figure 1-1
Generic Procedures for Mechanical Component Life Assessment

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Table 1-1

Feature	Level I	Level II	Level III
Failure History	Plant records	Plant records	Plant records
Dimensions	Design or nominal	Measured or nominal	Measured
Condition	Records or nominal	Inspection	Detailed inspection
Temperature and pressure	Design or operational	Operational or measured	Measured
Stresses	Design or operational	Simple calculation	Refined analysis
Material properties	Minimum	Minimum	Actual material
Material samples required?	No	No	Yes
More rigorous assessment →			
More accurate operation data required →			
More accurate estimate of equipment RL →			

1-4

Program Plan

To carry out a condition assessment program successfully, utility personnel must have several key elements in place beyond the technical guidance provided in this and other EPRI reports. These elements have been well-established by the successful EPRI BTF reduction program and are summarized as follows:

- Management statement of support
- Cross-functional teaming (including maintenance, operations, and engineering personnel) in performing the program
- Attention to long-term solutions to root cause problems
- Training
- Documentation of results and periodic review

Although these elements are straightforward in concept, it is essential that they be formally included in the condition assessment program plan. These elements ensure the successful execution of the program objectives and effective use of the results to manage component life.

An end result of utility boiler condition assessment efforts should be a document that fully captures the condition assessment results and provides a clear basis for utility decision making. The document should include the following types of information:

- Date the assessment was performed
- Summary of assessment activities, such as inspections, material tests, and results
- Estimate of component RL and summary of basis
- Damage mitigation/prevention actions, if appropriate
- Follow-on inspections or monitoring actions and their timing, if appropriate
- Recommendations for next assessment, including operating changes/upsets that would prompt a re-assessment

All information should be carefully maintained for easy access and future reference. A computer-based database is strongly recommended. EPRI has developed the Boiler Maintenance Workstation (software), which can be used for this function.

Added Considerations for Extending Outage Intervals

Safely extending major boiler inspection and maintenance outages involves a systematic effort to collect component-specific data and operating history data that reduce "material condition" uncertainty and thereby enable removal of the conservatism prudently employed when using "component/material class" (statistical average) information. In addition, new approaches to unit operation and availability have recognized that cracks can be tolerated in certain locations.

As an analogy, this change in approach would be akin to a change in the life insurance industry from policy pricing based on actuarial tables of life expectancy considering only age and whether on smokes to life expectancy estimates based on a comprehensive physical examination and a review of genetic factors. Although the incentive for such a change isn't generally sufficient in the insurance industry, the premium of assured availability at critical times in competitive power markets may warrant added investment in NDE and other techniques to better estimate remaining life and failure probabilities.

In the context of information presented in this guideline, that means more and new types of Level III analyses. Opportunity areas include:

- **Use of EPRI's Boiler Life Evaluation and Simulation System (BLESS) software to analyze cracks and predict the rate of crack growth.** Although techniques for detecting and measuring cracks are well established, methods to confidently predict a component's remaining life after crack initiation are less developed. Recent and ongoing upgrades to EPRI's BLESS software have simplified and improved prediction of crack initiation and growth rates. In many instances, crack initiation may occur early but propagation is so slow that it poses little or no failure risk.

- **Use of acoustic emissions date to distinguish between active (growing) and non-active (stationary) cracks** (e.g., between cracks introduced during fabrication or by other means prior to service vs. cracks induced due to in-service stresses). Often, the current practice is to remove flaws above a certain size detected during inspections without establishing their growth rates. This can lead to the unnecessary removal of stationary flaws posing no failure risk.

- **Use of accelerated creep and fatigue tests on miniature specimens to gauge remaining life.** Traditionally, remaining life estimates have been based on statistical analyses of material properties. Now date from tests of actual component material can help remove the conservatism inherent in "actuarial" type predictions of material properties.

- **Quantifying the ability of weld repairs to provide adequate creep strength to safely extend component life.** Preliminary EPRI findings appear promising.

- **Use of "small punch" tests to gauge a thick-walled component's fracture appearance transition temperature** (FATT, the temperature at which a material's failure mode changes from brittle to ductile). Comparison of the original (as-quenched and tempered) FATT with the FATTs of aged samples provides a measure of susceptibility to embrittlement (reduced toughness at elevated temperatures caused by the precipitation of certain elements at grain boundaries). EPRI and others developed the "small punch test" method in the 1980's using miniature specimens as an alternative to a Charpy V-notch test because it required less material to be removed. Initially applied to turbine rotors, the small punch test has now also been successfully applied to turbine disks, nuclear reactor pressure vessels, and thick-walled boiler components. It is primarily used in situations where a hydrotest will be conduced at a temperature below the current FATT.

- Ongoing investigations are **determining the kinetics of the fine-grain and coarse-grain portions of weld heat-affected zones (HAZ) and their role in Type IV cavity formation and growth.** EPRI suspects that current practices with respect to Type IV cracks (often immediate removal) are overly conservative.

Structure of This Guideline

This guideline is organized by major boiler components, including boiler tubing, high-temperature steam headers, high-energy steam piping, economizer headers, steam and lower drums, and attemperators. Each chapter begins with a roadmap of condition assessment activities for the specific component. These roadmaps have been developed to reflect damage mechanisms and degradation time frames as the key drivers to performing specific condition assessment activities. As a general reference, Table 1-2 provides a summary mapping of boiler components and their major in-service damage mechanisms.

For each component, additional information on nondestructive evaluation (NDE) techniques, life assessment calculations, and damage prevention are presented in tabular form as options linked to the overall roadmap. Level I, II, and III designations are provided as appropriate. Again, the intent of this format is to allow users to quickly identify actions that need to be performed within their condition assessment program. More detailed information is available through the referenced EPRI documents.

Table 1-2
Key Boiler Pressure Components and Damage Mechanisms

Component	Creep	Fatigue	Corrosion	Erosion
Waterwall tubing	X	X	X	X
Superheater (SH)/ reheater (RH) tubing	X	X	X	X
Economizer tubing		X	X	X
Superheater headers	X	X	X	
Reheater headers	X	X	X	
Main steam piping	X	X		
Hot reheat piping	X	X		
Cold reheat piping		X	X	X
Economizer inlet header		X	X	
Drums		X	X	
Downcomers		X	X	
Waterwall headers		X	X	
Attemperator	X	X		

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2

BOILER TUBING

Overview

This section on condition assessment of boiler tubing departs slightly in format from the other sections in this condition assessment guideline. The main reason for this departure is that much of the damage sustained by boiler tubing in service is avoidable. Accordingly, this section particularly emphasizes the processes of establishing the boiler tube damage mechanism and its root cause and of implementing long-term, corrective actions to prevent the root cause. Prior EPRI programs in which this process has been used by utilities have demonstrated significant reductions in tube failures and, correspondingly, increases in achieved boiler tube life.

These same elements of identifying damage mechanism and its root cause and of taking corrective actions are, of course, included for other boiler components. The diversity of damage mechanisms is, however, greatest for the boiler tubing, and the opportunities for damage avoidance are more critical. It is noted that boiler tube failures have been, and continue to be, the largest contributor to fossil plant forced outages.

Programmatic Approach

The EPRI approach to BTF reduction is recommended as the primary basis for performing condition assessment of boiler tubing. This approach is summarized in the roadmap of actions shown in Figure 2-1. As shown, the process begins with identification of the actual tube failure mechanism of concern. EPRI has cataloged 33 separate damage mechanisms, but generally only a few are of concern to the specific boiler tube sections in a particular fossil power plant. Factors such as design and operation, coupled with plant maintenance practices, drive the likelihood of experiencing particular types of tube failures. The EPRI BTF reduction program recognizes this situation and mandates that a cross-functional team with members from maintenance, operations, and engineering jointly undertake the steps in the roadmap.

This programmatic effort must clearly have the sanction of management in order to be carried out effectively. Broad-based training of personnel, including management, is also a cornerstone of success. Consistent with the objectives of this particular guideline, however, the material included in the following sections is intended only to highlight the scope of effort and required actions for condition assessment of boiler tubing components. Inclusion of tables on nondestructive evaluation options offers an opportunity to update periodically a key area in which new technology is continuing to evolve and to provide tools for carrying out the elements of the BTF reduction program in a cost-effective manner. Formal implementation of the EPRI program on BTF reduction is recommended for all utilities as a component of their boiler condition assessment activities.

The process shown in Figure 2-1 is illustrated with the specific case of corrosion fatigue damage in waterwall tubing. Tables 2-1 through 2-8 provide the details for corrosion fatigue corresponding to the actions indicated in the general roadmap approach. Again, the focus for boiler tube failures is root cause identification and implementation of damage prevention actions. The remaining sections in this chapter provide a general breakdown of information by boiler tube sections: waterwalls, superheaters and reheaters, and economizers.

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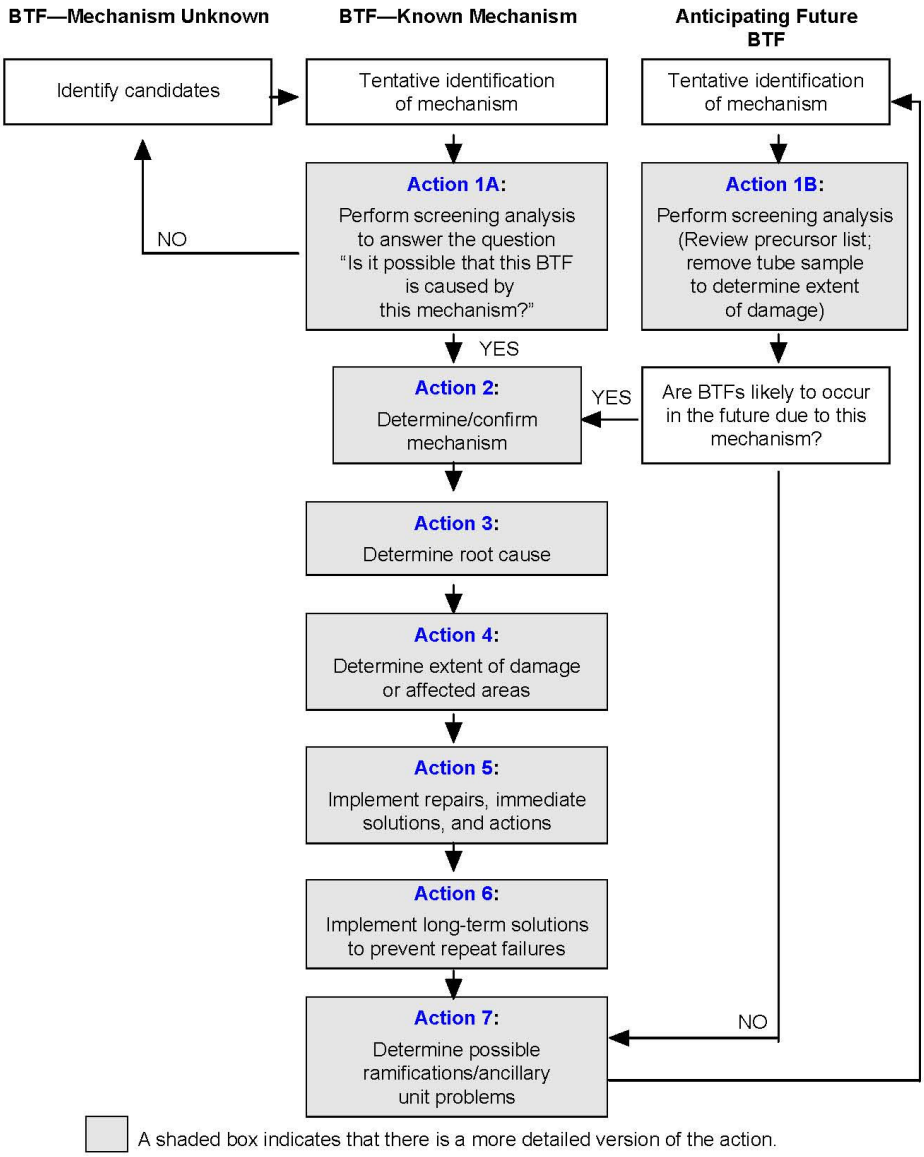

Figure 2-1
Actions for Identifying, Evaluating, and Anticipating BTFs

2-3

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Example Case Actions for Corrosion Fatigue

Actions 1A and 1B

Two paths exist for the BTF team to follow in the investigation of corrosion fatigue. The goal of the actions in these paths is to determine whether further investigation of corrosion fatigue is warranted or if another BTF mechanism should be investigated.

Follow Action 1A if a BTF has occurred and corrosion fatigue is the likely mechanism. Follow Action 1B if a precursor that could lead to future BTF by corrosion fatigue has occurred in the unit.

Table 2-1
Action 1A

Steps for Determining if Corrosion Fatigue is the Likely Mechanism	
1.	Determine whether the failure has occurred in a location that is typical of corrosion fatigue by: ▪ Reviewing typical boiler regions ▪ Reviewing susceptible locations ▪ Determining whether failure locations are near tube attachments or other locations where constraint during transient operations is key
2.	Confirm that the macroscopic appearance of the failure includes features such as the following: ▪ Cracking that has initiated on the inside surface of the tube, typically at multiple locations ▪ Association of the failure with an external attachment ▪ A pinhole leak, a thick-edged crack oriented either axially or circumferentially, or a thick-edged blowout or rupture
3.	Go to Action 2 for further steps to confirm the mechanism if the BTF seems to be consistent with these features of failure.
4.	Go to the screening table for water-touched tubing to find a more likely candidate if the BTF does not seem to have features like the ones listed.

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Table 2-2
Action 1B

Steps to Follow if a Precursor Has Occurred in the Unit	
1.	Determine whether one or more of the following precursors have been found or are likely to have occurred in the unit: ▪ Evidence of cracking found during routine inspections, particularly at susceptible locations ▪ Evidence of corrosion fatigue damage found in similar units ▪ Evidence that one or more risk factor, such as environment ranking, stress ranking, or equivalent operating hours, may lead to a concern ▪ Evaluation of unit cycle chemistry indicates an environmental ranking of E_3 or E_4. Such a warning might be triggered by one or more of the following: ▫ A persistent problem with phosphate hideout and return ▫ One or more tube failures caused by either hydrogen damage or caustic gouging ▫ Cycle chemistry operating ranges for pH, cation conductivity, or dissolved oxygen that are consistently outside the recommended ranges during normal operation or startup ▫ More than one chemical clean by hydrochloric acid ▫ Boiler shutdown and layup procedures that have not included such steps as nitrogen capping, chemical treatment for pH, oxygen control during the layup and on re-start, and dry storage during drained periods ▪ Unit has been subjected to numerous starts or has accumulated a large number of "equivalent operating hours." (This should be considered in conjunction with location stress rank and environmental factors.)
2.	Go to Action 3 to confirm the influence of each if one or more of these precursors has occurred. These precursors can be root cause influences of corrosion fatigue.

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Action 2: Determine/Confirm That the Mechanism Is Corrosion Fatigue

A failure has occurred that the BTF team has tentatively identified as being caused by corrosion fatigue (Action 1A). Action 2 should clearly identify corrosion fatigue as the primary mechanism, or it should point to another cause.

The following actions are executed by removing representative tube samples and conducting a visual examination and a detailed metallographic analysis. One of the primary aims is establish that damage is not outside diameter (OD)-initiated fatigue.

Table 2-3
Action 2

Steps for Determining/Confirming That the Mechanism is Corrosion Fatigue	
1.	Confirm that damage location is consistent with corrosion fatigue. If the answer to the question "Is damage associated with a susceptible location?" is no, review for indications of mechanical failure. The mechanism may still be corrosion fatigue.
2.	Determine the location of damage initiation. If the answer to the question "Is damage initiated from the inside, or waterside, of the tube?" is no, the mechanism is more likely to be mechanically induced fatigue.
3.	Evaluate nature of cracking. If the answer to the question "Is there evidence of multiple initiation sites with wide cracks of a transgranular nature?" is no, check to see if an underdeposit corrosion mechanism such as hydrogen damage, caustic gouging, or acid phosphate corrosion is active.
4.	The following are confirming characteristics of corrosion fatigue: ▪ Cracks that are filled with oxide and are blunt-tipped ▪ Crack profiles that are usually irregular ▪ Signs of discontinuous growth or re-initiation
5.	Go to Action 3.

Action 3: Determine Root Cause of Corrosion Fatigue

A BTF has occurred and the mechanism has been confirmed as corrosion fatigue (Action 2), or a precursor occurred (Action 1B). The goal of Action 3 is for the BTF team to review the potential root causes of corrosion fatigue, identify probable root causes, and take the actions that are needed to confirm which root causes are operative in the unit. This step must be taken so that the proper actions can be taken to prevent future BTF from occurring because of this mechanism.

Execute this action in parallel with Action 4 to determine the extent of the damage.

Table 2-4
Action 3

Major Root Cause Influence	Actions to Confirm
Influence of Excessive Stresses/Strains	
Restraint stresses at attachments	Compare damaged locations to those typical of corrosion fatigue. Inspect susceptible locations before tube failures occur. Selectively sample to identify damage accumulation. Conduct thermocouple and/or strain gauge testing to confirm high-strain locations. Conduct finite element stress analysis to predict high-strain locations.
Subcooling (cooling water stratification) in natural circulation boilers	Review operating records. Thermocouple top and bottom of boiler to monitor ΔT as function of shutdown time. Strain gauge to confirm.

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Major Root Cause Influence	Actions to Confirm
Influence of Environmental Factors	
Poor water chemistry	Review water chemistry logs and practices, with particular emphasis on pH reductions during shutdown and early startup. If review indicates a problem, implement a monitoring program. Calculate environmental parameter from information gathered above for use in the influence diagram. This information will help determine the contribution of environment to the corrosion fatigue problem. Selectively sample tubes from at-risk areas for evidence of pitting or corrosion fatigue damage.
Overly aggressive or improper chemical cleaning	Review chemical cleaning procedures, and correlate chemical cleaning with corrosion fatigue failures. Selectively sample at-risk tubes.
Improper boiler shutdown and/or layup procedures	Review water chemistry logs and practices, with particular emphasis on pH reductions during shutdown and early startup. If review indicates a problem, implement a monitoring program. Calculate environmental parameter from information gathered above for use in the influence diagram. This information will help determine the contribution of environment to the corrosion fatigue problem.
Influence of Historical Unit Operation	
Operating procedures that have produced high stresses	Review operating records to determine operating hours and boiler starts. Plot failure history against unit operating conditions.

Action 4: Determine the Extent of Damage or Affected Areas

The BTF team should follow Action 4 in parallel with Action 3. Evaluation will be based on detecting obvious signs of cracking.

Table 2-5
Action 4

Steps for Determining the Extent of Damage or Affected Areas	
1.	Identify all locations to be examined. Corrosion fatigue is unlikely to have occurred in only one area. (Missed locations are sites where future failures may occur.)
2.	Perform visual examination to detect obvious designs of cracking.
3.	Perform ultrasonic testing (UT)/radiographic testing (RT)/videoprobe survey, as possible, to measure extent of cracking.
4.	Perform tube sampling to confirm results of NDE inspection and to determine the degree of damage.
5.	Use results interactively with Action 3.
6.	Go to Action 5.

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Action 5: Implement Repairs, Immediate Solutions, and Actions

The most important immediate actions for the BTF team are to start the application of the influence diagram method to determine the probable effectiveness of longer-term solutions, to repair or replace damaged tubes, and to implement available short-term changes to operation or chemical cleaning when it is at the root of the existing problem.

Table 2-6
Action 5

Steps for Implementing Repairs, Immediate Solutions, and Actions	
1.	Implement repairs or replacement of affected tubes as identified from the NDE survey (Action 4). Develop a plan to reduce affected tubing on the basis of the root causes and probable choice of long-term solution.
2.	Apply the influence diagram. (Using the influence diagram approach will help pinpoint which root cause must be addressed to prevent repeat failures caused by corrosion fatigue. This is primarily a long-term action.) An immediate action that can be implemented during any repair or replacement activity is ensuring that the necessary plant information is gathered.
3.	Implement the appropriate guidelines, controls, and monitoring if the root cause is poor cycle chemistry.
4.	Institute modified procedures to correct overly aggressive chemical cleaning.
5.	Modify procedures if improper unit shutdown or layup procedures underlie the problem.
6.	Go to Action 6.

Action 6: Implement Long-Term Actions to Prevent Repeat Failures

The correction of the underlying problems and the prevention of repeat failures are priorities for the BTF team. The proper choice of long-term actions will be based on clear identification of the underlying root causes and guided by the influence diagram. The most effective long-term solution has been lowering the applied stresses by modifying attachment designs. However, improper modifications have intensified the problem.

Table 2-7
Action 6

Major Root Cause Influences	Long-Term Actions
Influence of Excessive Stresses	
Restraint stresses at attachments	The most effective measures have been modification of attachments to lower stresses.
Subcooling (cooling water stratification) in natural circulation boilers	Install off-line boiler circulation pumps to reduce level of subcooling.
Influence of Environmental Factors	
Poor water chemistry	Clean up overall cycle, and confront specific chemistry problems such as condenser leaks, impurity ingress, lack of appropriate procedures, and lack of appropriate monitoring devices. Apply appropriate guideline procedures for specific chemistry, monitoring, and instrumentation.
Overly aggressive or improper chemical cleaning	Optimize chemical cleaning procedures and frequency.
Improper boiler shutdown and/or layup procedures	Optimize shutdown and layup procedures.
Influence of Historical Unit Operation	
Operating procedures that have produced high stresses	Reduction of stresses or improvement in environmental parameter are possible actions.

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Action 7: Determine Possible Ramifications/Ancillary Problems

The final step for the BTF team is to review the possible ramifications to other cycle components implied by the presence of corrosion fatigue or its precursors.

Table 2-8
Action 7

Corrosion Fatigue Aspect	Alert for Other Cycle Components	Actions
Problems with boiler water or feedwater chemistry control	Potential for boiler tube damage by other mechanisms, such as acid phosphate corrosion, if underlying problem is phosphate hideout or hydrogen damage, such as via condenser leakage Potential for carryover in steam to reheater	Implement stricter cycle chemistry control program and instrumentation. Stay alert to potential problems throughout cycle.
Excessive or overly aggressive chemical cleaning	Potential for boiler tube damage by other mechanisms	Apply guidelines for chemical cleaning.
Inadequate or improper shutdown procedures	Potential for boiler tube damage by other mechanisms, such as pitting	Modify shutdown procedures.

Waterwall Tubing

Damage Mechanisms

Due to the large number of potential damage mechanisms for boiler tubing, it is essential that a correct identification be made of specific mechanisms producing tube failures in the waterwall. Once the correct identification is made, the recommended procedure is to determine the root cause of the mechanism and to then take corrective action to eliminate the root cause. Table 2-9 summarizes the damage mechanisms that should be considered for waterwall tubing. Additional detail is available in EPRI's BTF reduction technical reports (see the bibliography at the end of Chapter 1).

Table 2-9
Damage Mechanisms for Waterwall Tubing

Typical Fracture Surface Appearance	Other Likely Macroscopic and Metallographic Features	Typical Locations	Possible Mechanism
Thick-Edged Fracture Surface			
Thick-edged (Pinhole leak also possible)	Multiple, transgranular cracks that initiate on the inside of the tube	Near attachments, particularly where high-restraint stresses can develop	Corrosion fatigue
Thick-edged Leak or window blowout	Internal damage, such as gouging or wall thinning Tube deposits	High heat flux areas Hot side of tube Horizontal or inclined tubing Pad welds Locations with local flow disruptions, such as upstream of weld Backing ring or other discontinuities	Hydrogen damage

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Typical Fracture Surface Appearance	Other Likely Macroscopic and Metallographic Features	Typical Locations	Possible Mechanism
Thick-edged	Multiple, parallel cracks on outside tube surface or on membrane Sharp, V-shaped oxide-coated cracks Wall thinning from external surface when found with fireside corrosion	Maximum heat flux locations Fireside or waterside tubing, or membranes between tubes	Supercritical waterwall cracking
Thick-edged	Outside surface-initiated Intergranular crack growth with evidence of grain boundary creep cavitation and creep voids	Predominant in tube bends, particularly at intrados on outside surface, and at other locations that are subject to high residual, forming, or service stresses	Low-temperature creep cracking
Thick-edged	Transgranular cracking that is OD-initiated and associated with tubing	Near attachments, particularly solid or jammed sliding attachments At bends in tubing	Fatigue
Thin-Edged Fracture Surface			
Thin-edged Longitudinal "Cod- or fish-mouth"	Polishing of outside surface of tube Localized damage Wastage flats	Near side and rear walls	Fly ash erosion
Thin-edged Leak or split	Internal damage, such as gouging and wall thinning Tube deposits	Same as for hydrogen damage	Acid phosphate corrosion
Thin-edged Leak or split	Internal damage, such as gouging and wall thinning Tube deposits	Same as for hydrogen damage	Caustic gouging

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Typical Fracture Surface Appearance	Other Likely Macroscopic and Metallographic Features	Typical Locations	Possible Mechanism
Thin-edged Long "fish-mouth"	External wastage Probably affects a number of tubes Maximum wastage at crown facing flame (maybe flame impingement) Damage extending in 120° arc around tube Hard deposits on outside surface of tube	Areas with locally substoichiometric environment Side and rear walls near burners Highest heat flux areas	Fireside corrosion (coal-fired units)
Thin-edged "Fish-mouth"	Wastage flats on tube external surface at 45° around tube from sootblower direction with little or no ash	Circular pattern around wall blowers	Sootblower erosion
Usually thin-edged	Often shows signs of tube bulging or "fish-mouth" appearance Real keys will be transformation products in microstructure May also be thick-edged under certain circumstances	Highest heat flux locations above locations such as the site of a tube or orifice blockage or in horizontal tubing where a downcomer steam "slug" can occur	Short-term overheating
Thin-edged	External wastage with little or no ash Location should be key	Tubes near replaceable wear liners in cyclone burners Throat or quarl region of burners	Coal particle erosion
Thin-edged	External erosion or mechanical impact damage features	Sloping wall tubes and/or ash hopper near bottom	Falling slag damage
Pinhole Damage			
Pinhole	Internal tube surface damage	Locations at which boiler water can stagnate during unit shutdown	Chemical cleaning damage Pitting

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Typical Fracture Surface Appearance	Other Likely Macroscopic and Metallographic Features	Typical Locations	Possible Mechanism
Various Other Damage Types			
Depends on underlying cause	Usually obvious from type of damage and correspondence to past maintenance activity		Main-tenance damage
Depends on defect			Materials flaws
Usually thick-edged	Care required to separate weld defects from other problems located at welds		Welding flaws

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NDE Options

Many options are available for performing inspections of boiler tubes for existing damage. Table 2-10 supports the inspection activity under the tubing condition assessment roadmap (Figure 2-1). It summarizes currently available options as a function of the condition assessment level—I, II, or III—being considered. As expected, the Level III options represent the most rigorous inspections. If the goal of the condition assessment program and subsequent operation plan is to obtain the maximum available tubing life, then the recommended condition assessment analysis would default to Level III options. For shorter-term assessments, the recommendation is to start with the lower-cost Level I options and only move to Level II and III options as required.

Table 2-10
NDE Options for Waterwall Tubing

Component/Location	NDE Detection Technique Levels I and II	NDE Characterization Technique Level III
Tubing	Visual Ultrasonic testing (UT) Electromagnetic acoustic transducer (EMAT) Low frequency eddy current (LFEC) Radiographic testing (RT)	UT EMAT LFEC
Membranes	Visual Magnetic particle testing (MT)/ penetrant testing (PT)	
Welds	Visual MT/PT RT	

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Analysis and Disposition

As in the case of NDE options, the activities to be performed in support of the roadmap step on analysis and disposition are organized according to the three-level condition assessment approach. Table 2-11 summarizes the currently available options for waterwall tubing. Note that results from performing this roadmap step for a particular level—I, II, or III—will frequently lead to a decision to perform the next highest level because it is within this step that the issue of remaining life is fully addressed. All results of analyses and the final disposition decision must be documented as part of the boiler condition assessment program.

After the run, repair, or replace decision has been reached, a time interval for performing the next condition assessment activity should be established. Typically, intervals are set to support planning efforts for major maintenance outages. However, the interval should not exceed the RL estimate produced by the analysis. Provision should also be made to initiate a tubing condition assessment activity whenever there is a significant change in operating conditions (e.g., addition of NO_x controls).

Table 2-11
Analysis and Disposition for Waterwall Tubing

Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
Tubing inside surface	Minor wall loss which does not result in wall thickness <70% of design minimum Minor corrosion-fatigue cracking, less than 30% through wall Damage growth not to exceed limits before next planned inspection	Corrosion pitting mechanisms can reduce wall thickness below that required to meet pressure stress and can result in failure. Wall loss to <70% of design minimum is typically used to set action for replacement. Localized pitting can be evaluated in detail to determine actual minimum wall limits according to the American Society of Mechanical Engineers (ASME International) code. As necessary, replace tubing to restore wall integrity. Pad-welding to restore wall thickness should be used only on an emergency basis and only as a temporary repair until tube replacement can be performed.

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Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
		Actions should be taken to eliminate the root cause of the damage (corrosion pitting or corrosion fatigue).
Tubing fireside	Minor wall loss which does not result in wall thickness <70% of design minimum Damage growth not to exceed limits before next planned inspection	Wall loss can occur via corrosion and erosion mechanisms. Minor wall loss can be trended over time by performing periodic wall thickness measurements. Wall loss to <70% of design minimum is typically used to set action for replacement. As necessary, replace tubing to restore wall integrity. Pad-welding to restore wall thickness should be used only on an emergency basis and only as a temporary repair until tube replacement can be performed. Actions should be taken to eliminate the root cause of the damage.

Preventive Actions

As noted in the introduction to condition assessment for boiler tubing, the most effective approach to obtaining optimum life is to eliminate the root cause for the damage mechanism producing failures in waterwall tubing. Table 2-12 summarizes the usual root causes, or precursors, for various damage mechanisms. In general, these precursors can be addressed in normal operations and maintenance activities without major impact on plant performance or major capital investment. Therefore, this approach represents a recommended shortcut to the usual three-level process of performing condition assessment on waterwall tubing. Along with these precursors, corrective actions are identified and should be considered as part of the overall condition assessment activity.

Table 2-12
Preventive Actions for Waterwall Tubing

Category	Precursor / *Corrective Actions*	Mechanisms of Concern
	Inspection/Appearance	
Waterwall tubing (waterside)	Excessive waterside deposits (>>30 mg/cm^2) for high-pressure boilers / *Perform chemical clean and optimize cycle chemistry per EPRI guidelines*	Hydrogen damage Acid phosphate corrosion Caustic gouging Short-term overheating
	Excessive waterside deposits, such as ripple Fe_3O_4 in once-through (O/T) and supercritical units / *Perform chemical clean and optimize cycle chemistry per EPRI guidelines*	Supercritical waterwall cracking
	Boiler water samples that appear black (high suspended solids) / *Correct cycle chemistry procedures*	Acid phosphate corrosion
	Corrosion/erosion in feedwater system / *Maintain cycle chemistry limits per EPRI guidelines* Fouling in boiler feed pump or orifices / *Perform chemical clean and optimize cycle chemistry per EPRI guidelines*	Supercritical waterwall cracking of supercritical or O/T units Hydrogen damage, acid phosphate corrosion, or caustic gouging of subcritical or non-O/T units
	Pressure drop across circulation pumps (orifices are plugging) / *Perform chemical clean and optimize cycle chemistry per EPRI guidelines*	Short-term overheating in waterwall tubing

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Category	Precursor / *Corrective Actions*	Mechanisms of Concern
Waterwall tubing (fireside)	Flame impingement caused by burner change or misalignment, leading to excessive tube deposits */ Correct burner alignment and balancing*	Hydrogen damage Acid phosphate corrosion Caustic gouging Fireside corrosion
	Fresh rust found on tubes after unit washing External flat spot Burnishing or polishing */ Correct or repair tube shields. Correct or repair sootblowers and monitor frequency of use.*	Fly ash erosion Sootblower erosion in waterwalls Coal particle erosion
	Failed tubes, or any upstream tube leaks, as a warning to scout for the potential short-term overheating */ Check for flow blockages*	Short-term overheating in waterwall tubing
	Cycle Chemistry	
All units	Problem with high levels of feedwater corrosion products Operating ranges for pH, cation conductivity, or dissolved oxygen consistently outside recommended ranges, including persistent reducing conditions or excessive use of oxygen scavengers */ Optimize and control cycle chemistry per EPRI guidelines. Repair or install appropriate cycle chemistry instrumentation.*	Corrosion fatigue Hydrogen damage Acid phosphate corrosion Caustic gouging Waterwall fireside corrosion Supercritical waterwall cracking Short-term overheating in waterwall tubing
	Major acid contamination event (pH<8) when unit is at full load */ Perform boiler chemical clean* Condenser leak, breakdown of makeup, or condensate polisher regeneration chemical */ Repair equipment and perform boiler chemical clean*	Hydrogen damage
Units on phosphate treatments	Evidence of a persistent problem with phosphate hideout, particularly where mono-sodium and/or an excess of di-sodium phosphate has been added to the boiler */ Optimize phosphate treatment per EPRI guidelines*	Acid phosphate corrosion

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Boiler Tubing

Category	Precursor / *Corrective Actions*	Mechanisms of Concern
	Persistent phosphate hideout with phosphate return causing a pH depression */ Optimize phosphate treatment with shift to Equilibrium Phosphate*	Corrosion fatigue
	Caustic level in excess of the amount needed for optimal control (>>2ppm) */ Optimize treatment per EPRI guidelines*	Caustic gouging
Units on all-volatile treatment (AVT)	Caustic used in excess of the amount necessary for optimal control of contaminant ingress (to counteract pH depressions on startup) */ Optimize treatment per EPRI guidelines*	Caustic gouging
	pH depression during shutdown and early startup (pH around 7-8) Hideout/return of sulfate */ Optimize treatment per EPRI guidelines*	Corrosion fatigue
Units on caustic treatments	Caustic used in excess of the amount necessary for optimal control (>>2ppm) */ Optimize treatment per EPRI guidelines*	Caustic gouging
Maintenance-Related		
Chemical cleaning	Evidence of shortcoming in chemical cleaning process, such as inappropriate cleaning agent, excessively strong concentration, or long cleaning time Too high a temperature Failure to neutralize, breakdown of inhibitor, or inadequate rinse */ Revise and improve chemical cleaning process. Replace damaged tubing.*	Chemical cleaning damage in waterwalls Short-term overheating
	Evidence that level of Fe in cleaning solution continued to increase instead of leveling out when cleaning process was ended */ Revise and improve chemical cleaning process. Replace damaged tubing.*	Chemical cleaning damage in waterwalls
	Need for excessive cleaning in supercritical units (interval <2 years) */ Optimize cycle chemistry per EPRI guidelines, especially switch to Oxygenate Treatment*	Supercritical waterwall cracking

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Category	Precursor / *Corrective Actions*	Mechanisms of Concern
Repairs	Use of backing rings, pad welds, canoe pieces, or weld overlay that penetrates to inside surface as a source of flow disruption and excessive deposits in water-touched tubes */ Revise repair procedures to eliminate these damage sources*	Hydrogen damage Acid phosphate corrosion Caustic gouging
	Cu in waterside deposits in water-touched tubes */ Revise repair procedures*	Hydrogen damage Welding defects
Operation Related		
Combustion conditions	Heat flux change caused by change to higher British thermal unit (Btu)-value coal, dual firing with gas, or changeover to oil- or gas-firing leading to excessive tube deposits in waterwalls New burners causing impingement */ Adjust combustion parameters*	Hydrogen damage Acid phosphate corrosion Caustic gouging Fireside corrosion
	Implementing low excess air strategies for NO_x control and the potential for waterwall fireside corrosion */ Adjust burners and/or provide corrosion resistance by improved material (>20% chromium) on fireside surface*	Waterwall fireside corrosion
Fuel choices and changes	Change to a fuel that contains either more ash or elements which are more erosive, such as quartz */ Adjust flow dampers and monitor damage rate to allow timely replacement of liners and shields*	Fly ash erosion
	Change to a more corrosively-aggressive coal, particularly one high in chlorine, Na, K, or S contents */ Install tubing with better corrosion resistance (duplex tubes, weld overlay with high chromium alloys)*	Waterwall fireside corrosion
	Use of Mg-based additives for oil-fired units, leading to coating of waterwalls, reflecting heat into convection passes */ Reduce or eliminate additive. Perform periodic wall cleaning*	Long-term overheating (creep)

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Boiler Tubing

Category	Precursor / *Corrective Actions*	Mechanisms of Concern
Cycling	Conversion of the unit to cycling operation, or an increase in the number of cycles */ Reduce severity of ramps up and down*	Corrosion fatigue Fatigue in water-touched tubing
Shutdown or layup	Evidence of a shortcoming during unit shutdown/layup, such as uncertainty about water and/or air quality during period Insufficient nitrogen blanketing Insufficient N_2H_4 Evidence of air inleakage */ Improve layup procedures to eliminate moisture in components*	Pitting in water-touched or steam-touched tubes Maybe corrosion fatigue
	Indication that stagnant, oxygenated water may have rested in tubes during shutdown or layup, particularly in economizer and RH */ Improve layup procedures to eliminate moisture*	Pitting in water-touched or steam-touched tubes
Other	Operation above the maximum continuous design rating with excess air flow settings and unbalanced fans or air heaters, leading to non-uniform gas flows */ Adjust fans and maintain operation within design basis*	Fly ash erosion
	Low drum level */ Improve instrumentation and control to maintain drum water level*	Short-term overheating
Specific Equipment		
Condensers	Major condenser leaks or minor leaks that have occurred over a long period of time */ Inspect and repair condenser. Verify alarms functional for high conductivity*	Hydrogen damage
Water treatment plant/condensate polisher	Upset in water treatment plant or condensate polisher regeneration chemicals leading to low pH condition in boiler (pH<8) */ Inspect and repair equipment. Verify alarms functional for high conductivity*	Hydrogen damage
	Upset in water treatment plant or condensate polisher regeneration chemicals leading to high pH condition */ Inspect and repair equipment. Verify alarms functional for high conductivity*	Caustic gouging

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Category	Precursor / ***Corrective Actions***	Mechanisms of Concern
Sootblowers	Poor sootblower maintenance */ Review and improve maintenance procedures*	Sootblower erosion in waterwalls
Supports/attach-ment (redesign)	Redesign of waterwall tube attachments to increase flexibility without analysis to determine whether solution is actually beneficial */ Perform detailed evaluations to validate proper redesign and perform follow-on monitoring to confirm effectiveness*	Corrosion fatigue

Superheater/Reheater (SH/RH) Tubing

Damage Mechanisms

Due to the large number of potential damage mechanisms for boiler tubing, it is essential that a correct identification be made of specific mechanisms producing tube failures in the superheat and reheat sections. Once the correct identification is made, the recommended procedure is to determine the root cause of the mechanism and to then take corrective action to eliminate the root cause. Table 2-13 summarizes the damage mechanisms that should be considered for SH/RH tubing. Additional detail is available in EPRI's BTF reduction technical reports (see the bibliography at the end of Chapter 1).

Table 2-13
Damage Mechanisms for SH/RH Tubing

Typical Fracture Surface Appearance	Other Likely Macroscopic and Metallographic Features	Typical Locations	Possible Mechanism
Thick-Edged Fracture Surface			
Thick-edged	Outside-surface initiated Intergranular crack growth with evidence of grain boundary creep cavitation and creep voids	Predominant in lower temperature regions in tube bends, particularly at intrados on outside surface and in other locations subject to high residual, forming, or service stresses	Low-temperature creep cracking
Thick-edged	Internal thick scales, which may be accompanied by external wastage at the 10 o'clock and 2 o'clock positions Generally longitudinal orientation Damage on heated side of tube	High temperature locations near material transitions, in or just beyond cavities, in the final leg of tubing just prior to the outlet header, and where there is a variation in gas-touched length	Long-term overheating (creep)
Thick-edged Leak	Usually fusion line cracking on low alloy side of weld Circumferential orientation	At dissimilar metal welds	Dissimilar metal weld failure

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Typical Fracture Surface Appearance	Other Likely Macroscopic and Metallographic Features	Typical Locations	Possible Mechanism
Thick-edged May manifest as a pinhole	Cracking is transgranular or intergranular, usually with significant branching Initiation can be at inside diameter (ID), which is most common, or on OD Circumferential or longitudinal orientation	Bends and straight tubing with low spots High-stress locations are particularly susceptible at bends, welds, tube attachments, supports, or spacers	Stress Corrosion Cracking
Thick-edged	Transgranular cracking OD-initiated and associated with tubing (particularly at tube bends or attachments) or headers (particularly at the ends)	Tubing-related failures associated with attachments or bends in tubing Header-related (generally at ends of header)	Fatigue
Thick-edged Leak	Most commonly in HAZ of C or C-Mo steel tubes Key is microstructure appearance of graphite particles or nodules	Adjacent to weld fusion line at heat-affected zone most common	Graph-itization
Thin-Edged Fracture Surface			
Thin-edged (unless creep-assisted)	External polishing of tube surface Localized damage	Most prominent in backpass regions and bends near walls	Fly ash erosion
Thin-edged	External damage Wastage at 10 o'clock and 2 o'clock (flue gas at 12 o'clock) Longitudinal cracking Perhaps "alligator hide" appearance Real key to identification will be the presence of low-melting point ash in external deposits	Highest temperature tubes are leading tubes, tubes that are out of alignment, tubes around radiant cavities, and near tube transitions	Fireside corrosion (coal-fired units and oil-fired units)

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Typical Fracture Surface Appearance	Other Likely Macroscopic and Metallographic Features	Typical Locations	Possible Mechanism
Thin-edged	Often shows signs of tube bulging or "fish-mouth" appearance Longitudinal orientation	Most commonly near bottom bends in vertical loops of SH/RH, in outlet legs, and near material transitions	Short-term overheating
Thin-edged Pinhole or "thin" longitudinal blowout	External wastage flats at 45° around tube from sootblower direction Little or no ash	First tubes in from wall entrance of retractable blowers Tubes in direct path of retractable blowers	Sootblower erosion
Thin-edged	External damage Obvious metal-to-metal contact on tube surface		Rubbing/ fretting
Pinhole Damage			
Pitting	Internal tube surface damage	Tubes where condensate can form and remain during shutdown Bottoms of pendant loops on either SH or RH Low points in sagging horizontal tubes	Chemical cleaning damage Pitting
Various Other Damage Types			
Depends on underlying cause	Usually obvious from type of damage and correspondence to past maintenance activity		Main-tenance damage
Depends on defect			Material flaws
Usually thick-edged or pinholes	Care required to separate weld defects from another problem located at a weld		Welding flaws

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NDE Options

Many options are available for performing inspections of boiler tubes for existing damage. Table 2-14 supports the inspection activity under the tubing condition assessment roadmap (Figure 2-1). It summarizes currently available options as a function of the condition assessment level—I, II, or III—being considered. As expected, the Level III options represent the most rigorous inspections. If the goal of the condition assessment program and subsequent operating plan is to obtain the maximum available tubing life, then the recommended condition assessment analysis would default to Level III options. For shorter-term assessments, the recommendation is to start with the lower-cost Level I options and only move to Level II and III options as required.

Table 2-14
NDE Options for SH/RH Tubing

Component/Location	NDE Detection Technique Levels I and II	NDE Characterization Technique Level III
Tubing	UT (cracking, thickness / inside diameter pitting detection) EMAT (cracking, thickness / inside diameter pitting detection) LFEC (thickness / inside diameter pitting detection) RT (cracking / inside diameter pitting detection)	UT (metal and steam-side oxide thickness, crack sizing)
Welds/dissimilar metal welds	PT (surface cracking)	UT (crack sizing)
Attachments and spacers	Visual (surface cracking) PT (surface cracking)	

Analysis and Disposition

As in the case of NDE options, the activities to be performed in support of the roadmap step on analysis and disposition are organized according to the three-level condition assessment approach. Table 2-15 summarizes the currently available options for superheater/reheater tubing. Note that results from performing this roadmap step for a particular level—I, II, or III—will frequently lead to a decision to perform the next highest level because it is within this step that the issue of RL is fully addressed. All results of analyses and the final disposition decision must be documented as part of the boiler condition assessment program.

After the run, repair, or replace decision has been reached, a time interval for performing the next condition assessment activity should be established. Typically, intervals are set to support planning efforts for major maintenance outages. However, the interval should not exceed the RL estimate produced by the analysis. Provision should also be made to initiate a SH/RH tubing condition assessment activity whenever there is a significant change in upper furnace operating conditions.

Table 2-15
Analysis and Disposition for SH/RH Tubing

Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
Tubing inside surface	Wall loss of less than 30% due to pitting corrosion Damage growth not to exceed limits before next planned inspection	Corrosion pitting mechanisms can reduce wall thickness below that required to meet pressure stress and can result in failure. Wall loss to <70% of design minimum is typically used to set action for replacement. Localized pitting can be evaluated in detail to determine actual minimum wall limits according to ASME code. As necessary, replace tubing to restore integrity. Actions should be taken to eliminate the root cause of the damage (corrosion pitting or corrosion fatigue).

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Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
Tubing outside surface	Wall loss of less than 30% due to erosion and corrosion Wall loss associated with creep damage should be evaluated separately Damage growth not to exceed limits before next planned inspection	Erosion and corrosion mechanisms can reduce wall thickness below that required to meet pressure stress and can result in failure. Wall loss to <70% of design minimum is typically used to set action for replacement. Localized pitting can be evaluated in detail to determine actual minimum wall limits according to ASME code. Creep life evaluations can be performed by using steamside oxide thickness measurements combined with tube wall thickness and operating parameters. Calculated results should be benchmarked to metallurgical results from removal of tube samples. As necessary, replace tubing to restore integrity. Actions should be taken to eliminate the root cause of the damage.
Tubing dissimilar metal welds	Not established	Level III analysis using weld metal composition, unit operating history, and tube metal temperatures may be performed to estimate RL.

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Preventive Actions

As noted in the introduction to condition assessment for boiler tubing, the most effective approach to obtaining optimum life is to eliminate the root cause for the damage mechanism producing failures in SH/RH tubing. Table 2-16 summarizes the usual root causes, or precursors, for various damage mechanisms. In general, these precursors can be addressed in normal operations and maintenance activities without major impact on plant performance or major capital investment. Therefore, this approach represents a recommended shortcut to the usual three-level process of performing condition assessment on SH/RH tubing. Along with these precursors, corrective actions are identified and should be considered as part of the overall condition assessment activity.

Table 2-16
Preventive Actions for SH/RH Tubing

Category	Precursor / *Corrective Actions*	Mechanisms of Concern
	Inspection/Appearance	
Water-touched tubes (fireside)	Excessive furnace slagging that could lead to overheating in convective passes (or fuel change) / *Optimize sootblowing*	Short-term overheating in SH/RH tubing
Steam-touched tubes (steamside)	Excessive steamside oxide, which is detected by UT measure of oxide thickness or analysis of removed tube samples and is evidence of excessive exfoliation like solid particle erosion in turbine / *Chemical cleaning of tubes, steam flow redistribution to reduce peak temperatures*	Long-term overheating (creep) SH/RH fireside corrosion Dissimilar metal weld failures Short-term overheating
	Steamside deposits in RH tubing, particularly of sodium sulfate or high Na or SO_4 levels in steam / *Improve cycle chemistry controls and instrumentation*	Pitting and failure in steam-touched tubes
Steam-touched tubes (fireside)	Excessive flue gas temperature Displaced fireball Delayed combustion Periodic overfiring or uneven firing of burners / *Adjust combustion parameters: burners, fans, dampers, etc.*	Long-term overheating (creep) SH/RH fireside corrosion
	High levels of excess oxygen / *Adjust combustion parameters: burners, fans, dampers, etc.*	SH/RH fireside corrosion for oil-fired units

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Category	Precursor / *Corrective Actions*	Mechanisms of Concern
	Blockage or laning of boiler gas passages observed during boiler inspection / *Optimize gas flow using cold air velocity testing and distribution and diffusion screens. Maintain correct sootblower performance. Upgrade tube material for improved corrosion resistance.*	Fly ash erosion Long-term overheating (creep) SH/RH fireside corrosion for coal- and oil-units
	Excessive temperatures measured by thermocouples in vestibule or header area / *Optimize gas flow using cold air velocity testing and distribution and diffusion screens. Maintain correct sootblower performance. Upgrade dissimilar metal welds. Correct steam flow distribution to reduce peak temperatures.*	Fly ash erosion Long-term overheating (creep) Dissimilar metal weld failures
	Evidence of "alligator hide" appearance on external tube surface observed during boiler inspection and associated with wall loss or thinning / *Optimize gas flow using cold air velocity testing and distribution and diffusion screens. Maintain correct sootblower performance. Upgrade tube material for improved corrosion resistance.*	Long-term overheating (creep) SH/RH fireside corrosion
	Fresh rust found on tubes after unit washing External flat spots Burnishing or polishing / *Optimize gas flow using cold air velocity testing and distribution and diffusion screens. Maintain correct sootblower performance. Upgrade tube material for improved corrosion resistance.*	Fly ash erosion Sootblower erosion in SH/RH
	Significant hardness or ovality, particularly associated with tube bends, found during routine inspection / *Assess extent of damage and replace damaged tubing*	Low-temperature creep cracking

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Boiler Tubing

Category	Precursor / *Corrective Actions*	Mechanisms of Concern
	Distortion or misaligned tube rows found during routine inspection */ Correct tube alignment and assess temperature distributions. Repair or correct support attachments.*	Fly ash erosion SH/RH fireside corrosion Dissimilar metal weld failures Fatigue of SH/RH tubing Rubbing/fretting
	Failed tube supports and lugs Location of dissimilar metal welds close to fixed supports */ Correct tube support design to eliminate excessive stresses*	Fatigue of SH/RH tubing Dissimilar metal weld failures
Cycle Chemistry		
All units	Carryover of volatile chemicals from boiler, such as NaOH for units on caustic treatment or excess of Na, SO_4, and/or chloride / Improve cycle chemistry instrumentation and control per EPRI guidelines Steam limits exceeded */ Improve plant instrumentation and controls*	Stress corrosion cracking Pitting in SH/RH tubes
Maintenance Related		
Chemical cleaning	Evidence of shortcoming in chemical cleaning process, such as inappropriate cleaning agent, excessively strong concentration, or long cleaning time Too high a temperature Failure to neutralize, breakdown of inhibitor, or inadequate rinse */ Revise and improve chemical cleaning process. Replace damaged tubing.*	Chemical cleaning damage in SH/RH Short-term overheating
	Shortcoming in SH/RH cleaning process, such as inadequate rinse or improper flow verification */ Revise and improve chemical cleaning process. Replace damaged tubing.*	Short-term overheating in SH/RH tubing
	Evidence that level of Fe in cleaning solution continued to increase instead of leveling out when cleaning process was ended */ Revise and improve chemical cleaning process. Replace damaged tubing.*	Chemical cleaning damage in waterwalls or SH/RH

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Category	Precursor / *Corrective Actions*	Mechanisms of Concern
	Contamination in SH/RH (particularly by chlorides) during chemical cleaning of SH/RH (breakdown of inhibitors or improper flushing of solvents) or waterwalls (caused by poor backfill procedures that failed to protect SH circuits) */ Revise and improve chemical cleaning process. Replace damaged tubing.*	Stress corrosion cracking
Repairs	Application of shielding, baffles, or palliative coatings to mitigate fly ash erosion without the use of a cold-air velocity test */ Optimize gas flow using cold air velocity testing and distribution and diffusion screens. Maintain correct sootblower performance.*	Fly ash erosion
Operation Related		
Startup procedures	Rapid unit startups that cause the reheater to reach temperature before full flow starts (no furnace exit gas temperature control) */ Improve startup procedures and controls*	SH/RH fireside corrosion
Combustion conditions	Operation with high levels of excess oxygen in oil-fired units (>1%) */ Correct or improve air-to-fuel controls*	SH/RH fireside corrosion in oil-fired units
Fuel choices and changes	Change to a fuel that contains either more ash or elements which are more erosive, such as quartz */ Adjust flow dampers and monitor damage rate to allow timely replacement of liners and shields*	Fly ash erosion
	Change to a more corrosively-aggressive coal, particularly one high in chlorine, Na, K, or S contents */ Install tubing with better corrosion resistance (duplex tubes, weld overlay with high chromium alloys)*	SH/RH fireside corrosion
	Use of Mg-based additives for oil-fired units, leading to coating of waterwalls, reflecting heat into convection passes */ Reduce or eliminate additive. Perform periodic wall cleaning*	Long-term overheating (creep) SH/RH fireside corrosion in oil-fired units
Cycling	Conversion of the unit to cycling operation or an increase in the number of cycles */ Reduce and control severity of ramp rates up and down in power*	Fatigue in SH/RH tubing Dissimilar metal weld failures

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Boiler Tubing

Category	Precursor / *Corrective Actions*	Mechanisms of Concern
Shutdown or layup	Evidence of a shortcoming during unit shutdown/layup, such as uncertainty about water and/or air quality during period Insufficient nitrogen blanketing Insufficient N_2H_4 Evidence of air inleakage */ Improve layup procedures to eliminate moisture in components*	Pitting in SH/RH tubes
	Indication that stagnant, oxygenated water may have rested in tubes during shutdown or layup, particularly in RH */ Improve layup procedures to eliminate moisture in components*	Pitting in SH/RH tubes
	Evidence that condensate is forming in SH/RH bends during unit shutdown, exacerbated if steam purity is not good (as determined by elevated levels of SO_4) */ Reduce or avoid forced cooling*	Short-term overheating in SH/RH tubes Pitting in SH/RH tubes
Other	Operation above the maximum continuous design rating with excess air flow settings and unbalanced fans or air heaters, leading to non-uniform gas flows */ Adjust fans and maintain operation within design basis. Optimize gas flow using cold air velocity testing.*	Fly ash erosion
	Low drum level */ Improve instrumentation and control to maintain drum water level*	Short-term overheating
Specific Equipment		
Condensers	Condenser leak, leading to condenser cooling water constituents in attemperator spray water */ Inspect and repair condenser. Verify alarms functional for high conductivity*	Stress corrosion cracking
Drum	Carryover test indicates high mechanical carryover */ Improve level control instrumentation and procedures* Operating with high drum level Allowing excessive carryover into steam */ Improve level control instrumentation and procedures*	Stress corrosion cracking Pitting in SH/RH tubing Pitting in SH/RH tubing

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Category	Precursor / *Corrective Actions*	Mechanisms of Concern
Sootblowers	Poor sootblower maintenance */ Review and improve maintenance procedures*	SH/RH sootblower erosion
High temperature headers	Excessive relative movement of header/tube during unit transients Restricted movement Header is not allowed to expand freely (maybe ash-related) Unit change to cycling */ Inspect and correct support structures. Reduce startup and shutdown temperature ramp rates*	Fatigue in SH/RH tubing
Turbine	A problem with solid particle erosion (SPE) in the turbine */ Chemical cleaning of tubes, steam flow redistribution to reduce peak temperatures*	Short-term overheating in SH/RH tubing Long-term overheating (creep)
SH/RH circuit (redesign)	Redesign of the SH/RH circuit may change the absorption patterns through other SH/RH sections and increase tube temperatures */ Inspect for damage, assess impact, correct design*	Long-term overheating (creep) SH/RH fireside corrosion Dissimilar metal weld failures
Supports/attach-ments (redesign)	Addition of supports without consideration of their impact on the stresses of dissimilar metal welds */ Inspect for damage, assess impact, correct support structures*	Dissimilar weld failures

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Economizer Tubing

Damage Mechanisms

Due to the large number of potential damage mechanisms for boiler tubing, it is essential that a correct identification be made of specific mechanisms producing tube failures in the economizer. Once the correct identification is made, the recommended procedure is to determine the root cause of the mechanism and to then take corrective action to eliminate the root cause. Table 2-17 summarizes the damage mechanisms that should be considered for economizer tubing. Additional detail is available in EPRI's BTF reduction technical reports (see the bibliography at the end of Chapter 1).

Table 2-17
Damage Mechanisms for Economizer Tubing

Typical Fracture Surface Appearance	Other Likely Macroscopic and Metallographic Features	Typical Locations	Possible Mechanism
Thick-Edged Fracture Surface			
Thick-edged (Pinhole leak also possible)	Multiple, transgranular cracks that initiate on the inside of the tube	Near attachments, particularly where high-restraint stresses can develop	Corrosion fatigue
Thick-edged Leak or crack	First sign is pinhole leak at toe of stub weld Multiple, longitudinal cracks Bore hole cracking	Economizer inlet header stub tubes nearest the feedwater inlet	Thermal fatigue
Thick-edged	Transgranular cracking that is OD-initiated and associated with tubing	Near attachments, particularly solid or jammed sliding attachments At bends in tubing	Fatigue

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Typical Fracture Surface Appearance	Other Likely Macroscopic and Metallographic Features	Typical Locations	Possible Mechanism
Thin-Edged Fracture Surface			
Thin-edged Longitudinal "Cod- or fish-mouth"	Polishing of outside surface of tube Localized damage Wastage flats	Near economizer banks Near plugged or fouled passages At places where baffles have previously been installed	Fly ash erosion
Thin-edged rupture	Erosion and wall thinning from inside "Orange peel" appearance	Economizer inlet header stub tubes nearest to point of feedwater inlet	Erosion Corrosion
Thin-edged	External (thinned or missing external oxide) Generally in economizer	Low-temperature areas of economizer	Acid dewpoint corrosion
Pinhole Damage			
Pinhole	Internal tube surface damage	Locations at which boiler water can stagnate during unit shutdown	Chemical cleaning damage Pitting
Various Other Damage Types			
Depends on underlying cause	Usually obvious from type of damage and correspondence to past maintenance activity		Main-tenance damage
Depends on defect			Materials flaws
Usually thick-edged	Care required to separate weld defects from other problems located at welds		Welding flaws

NDE Options

Many options are available for performing inspections of boiler tubes for existing damage. Table 2-18 supports the inspection activity under the tubing condition assessment roadmap (Figure 2-1). It summarizes currently available options as a function of the condition assessment level—I, II, or III—being considered. As expected, the Level III options represent the most rigorous inspections. If the goal of the condition assessment program and subsequent operating plan is to obtain the maximum available tubing life, then the recommended condition assessment analysis would default to Level III options. For shorter-term assessments, the recommendation is to start with the lower-cost Level I options and only move to Level II and III options as required.

Table 2-18
NDE Options for Economizer Tubing

Component/Location	NDE Detection Technique Levels I and II	NDE Characterization Techniques Level III
Tubing	Visual Ultrasonic testing (UT) Radiographic testing (RT)	
Welds	Penetrant testing (PT)	
Attachments and spacers	Visual PT	

Analysis and Disposition

As in the case of NDE options, the activities to be performed in support of the roadmap step on analysis and disposition are organized according to the three-level condition assessment approach. Table 2-19 summarizes the currently available options for economizer tubing. Note that results from performing this roadmap step for a particular level—I, II, or III—will frequently lead to a decision to perform the next highest level because it is within this step that the issue of RL is fully addressed. All results of analyses and the final disposition decision must be documented as part of the boiler condition assessment program.

After the run, repair, or replace decision has been reached, a time interval for performing the next condition assessment activity should be established. Typically, intervals are set to support planning efforts for major maintenance outages. However, the interval should not exceed the RL estimate produced by the analysis. Provision should also be made to initiate an economizer tubing condition assessment activity whenever there is a significant change in boiler operating conditions.

Table 2-19
Analysis and Disposition for Economizer Tubing

Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
Tubing inside surface	Minor wall loss which does not result in wall thickness <70% of design minimum Minor corrosion-fatigue cracking, less than 30% through wall Damage growth not to exceed limits before next planned inspection	Corrosion mechanisms can reduce wall thickness below that required to meet pressure stress and can result in failure. Wall loss to <70% of design minimum is typically used to set action for replacement. Localized corrosion pitting can be evaluated in detail to determine actual minimum wall limits according to ASME code. As necessary, replace tubing to restore wall integrity. Actions should be taken to eliminate the root cause of the damage (corrosion pitting or corrosion fatigue).

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Boiler Tubing

Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
Tubing outside surface	Minor wall loss which does not result in wall thickness <70% of design minimum Damage growth not to exceed limits before next planned inspection	Wall loss can occur via erosion mechanisms. Minor wall loss can be trended over time by performing periodic wall thickness measurements. Wall loss to <70% of design minimum is typically used to set action for replacement As necessary, replace tubing to restore wall integrity. Pad-welding to restore wall thickness should be used only on an emergency basis and only as a temporary repair until tube replacement can be performed. Actions should be taken to eliminate the root cause of the damage.

Preventive Actions

As noted in the introduction to condition assessment for boiler tubing, the most effective approach to obtaining optimum life is to eliminate the root cause for the damage mechanism producing failures in economizer tubing. Table 2-20 summarizes the usual root causes, or precursors, for various damage mechanisms. In general, these precursors can be addressed in normal operations and maintenance activities without major impact on plant performance or major capital investment. Therefore, this approach represents a recommended shortcut to the usual three-level process of performing condition assessment on economizer tubing. Along with these precursors, corrective actions are identified and should be considered as part of the overall condition assessment activity.

Table 2-20
Preventive Actions for Economizer Tubing

Category	Precursor / *Corrective Action*	Mechanisms of Concern
	Inspection/Appearance	
Water-touched tubes (waterside)	Corrosion/erosion in feedwater system Fouling in boiler feed pump or orifices / *Optimize and control cycle chemistry per EPRI guidelines*	Corrosion/erosion of economizer inlet header stub tubing
Water-touched tubes (fireside)	Fresh rust found on tubes after unit washing External flat spot Burnishing or polishing / *Correct or repair tube shields. Correct or repair sootblowers and monitor frequency of use.*	Fly ash erosion
	Cycle Chemistry	
All units	Problem with high levels of feedwater corrosion products Operating ranges for pH, cation conductivity, or dissolved oxygen consistently outside recommended ranges, including persistent reducing conditions or excessive use of oxygen scavengers / *Optimize and control cycle chemistry per EPRI guidelines*	Erosion/corrosion in economizer inlet header stub tubing

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Boiler Tubing

Category	Precursor / *Corrective Action*	Mechanisms of Concern
Units on phosphate treatments	Persistent phosphate hideout with phosphate return causing a pH depression / *Optimize phosphate treatment per EPRI guidelines*	Corrosion fatigue
Units on AVT	pH depression during shutdown and early startup (pH around 7-8) Hideout/return of sulfate / *Optimize treatment per EPRI guidelines*	Corrosion fatigue
Maintenance Related		
Repairs	Application of shielding, baffles, or palliative coatings to mitigate fly ash erosion without the use of a cold-air velocity test / *Optimize gas flow using cold air velocity testing and distribution and diffusion screens.*	Fly ash erosion
Operation Related		
Startup procedures	Feedwater introduced intermittently into economizer inlet at high flow rates during startups and particularly during off-line top-ups / *Correct or improve startup procedures and controls*	Economizer inlet header thermal fatigue
Fuel choices and changes	Change to a fuel that contains either more ash or elements which are more erosive, such as quartz / *Optimize gas flow using cold air velocity testing and distribution and diffusion screens.*	Fly ash erosion
	Change to a more corrosively-aggressive coal, particularly one high in chlorine, Na, K, or S contents / *Increase temperatures or lower acid dewpoint via operating changes*	Acid dewpoint corrosion
Cycling	Conversion of the unit to cycling operation, or an increase in the number of cycles / *Reduce severity of ramp rates up and down*	Corrosion fatigue Economizer inlet header thermal fatigue Fatigue in economizer tubing

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Category	Precursor / *Corrective Action*	Mechanisms of Concern
Shutdown or layup	Evidence of a shortcoming during unit shutdown/layup, such as uncertainty about water and/or air quality during period Insufficient nitrogen blanketing Insufficient N_2H_4 Evidence of air inleakage / *Improve layup procedures to eliminate moisture in components*	Pitting in economizer tubing Maybe corrosion fatigue
	Indication that stagnant, oxygenated water may have rested in tubes during shutdown or layup, particularly in economizer and RH / *Improve layup procedures to eliminate moisture in components*	Pitting in water-touched or steam-touched tubes
Other	Operation above the maximum continuous design rating with excess air flow settings and unbalanced fans or air heaters, leading to non-uniform gas flows / *Optimize gas flow using cold air velocity testing and distribution and diffusion screens.*	Fly ash erosion
Specific Equipment		
Low-temperature headers	Header has large number of operating hours and has experienced large thermal gradients Spacing of ligament holes is small (< 1.5 in or 3.5 cm) Header thickness is well above code minimum / *Reduce severity of thermal transients during startup and shutdown. Increase ligament spacing when header replaced* Header-to-stub tube joints made with partial penetration welds / *Replace welds with improved designs and correct tube supports to reduce stresses*	Economizer inlet header thermal fatigue

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3

HIGH-TEMPERATURE STEAM HEADERS

Roadmap Introduction

The roadmaps shown in Figures 3-1, 3-2, 3-3, and 3-4 are the starting points for setting up and performing condition assessments for headers. Following the steps in these roadmaps will organize the information required to assess current header condition and estimated remaining life. Activities within the roadmaps are further supported by summary tables that list the typical options available to complete the activity. For example, component-specific nondestructive evaluation options are identified in a separate table to support the inspections activity in the roadmap. It is important to note that the three-level condition assessment approach reviewed in Chapter 1, "Overview and Strategy for Boiler Condition Assessment," is applied to the roadmaps by either formal inclusion or implied inclusion as iterations on the analysis and disposition activity.

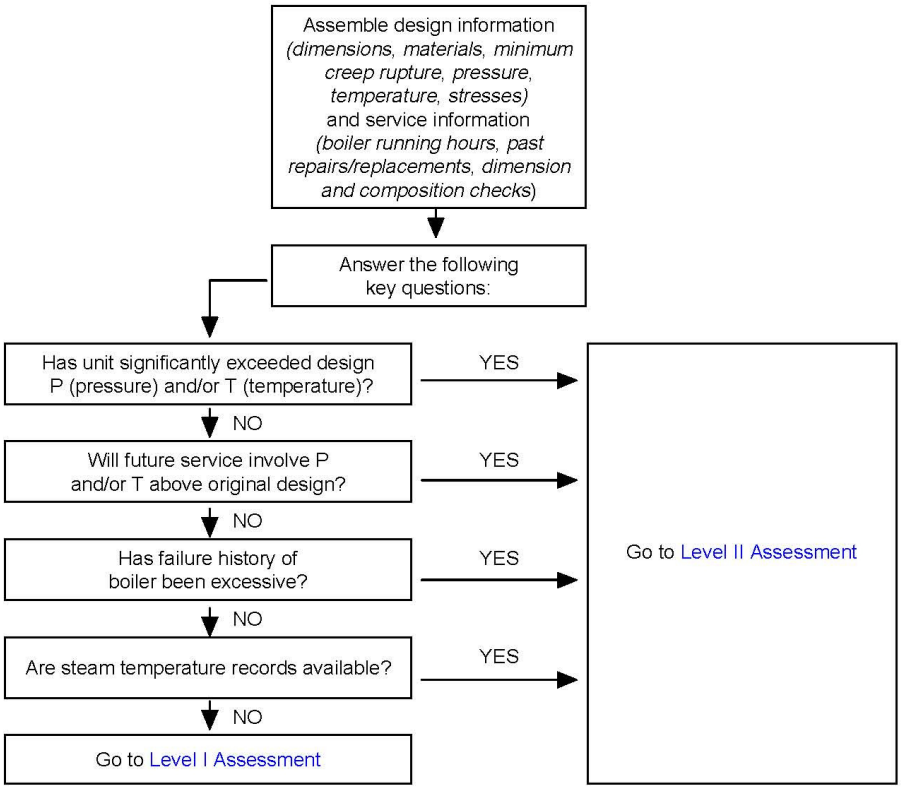

Figure 3-1
General Roadmap for High-Temperature Steam Headers

3-2

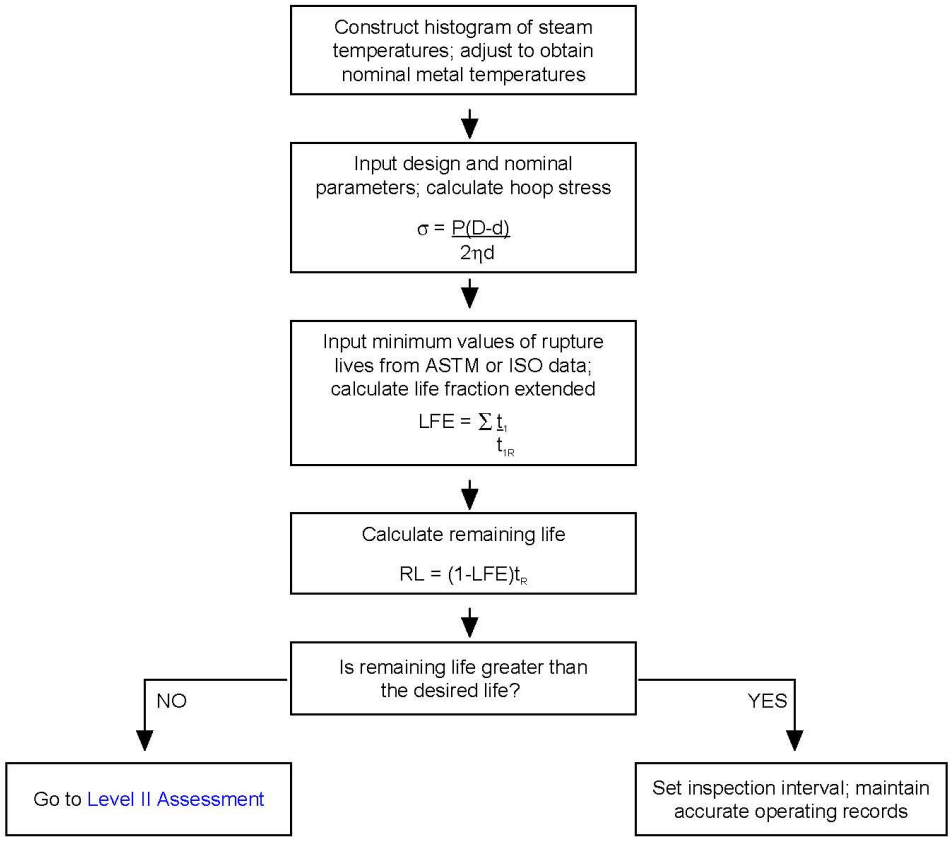

Figure 3-2
Level I Assessment: High-Temperature Headers

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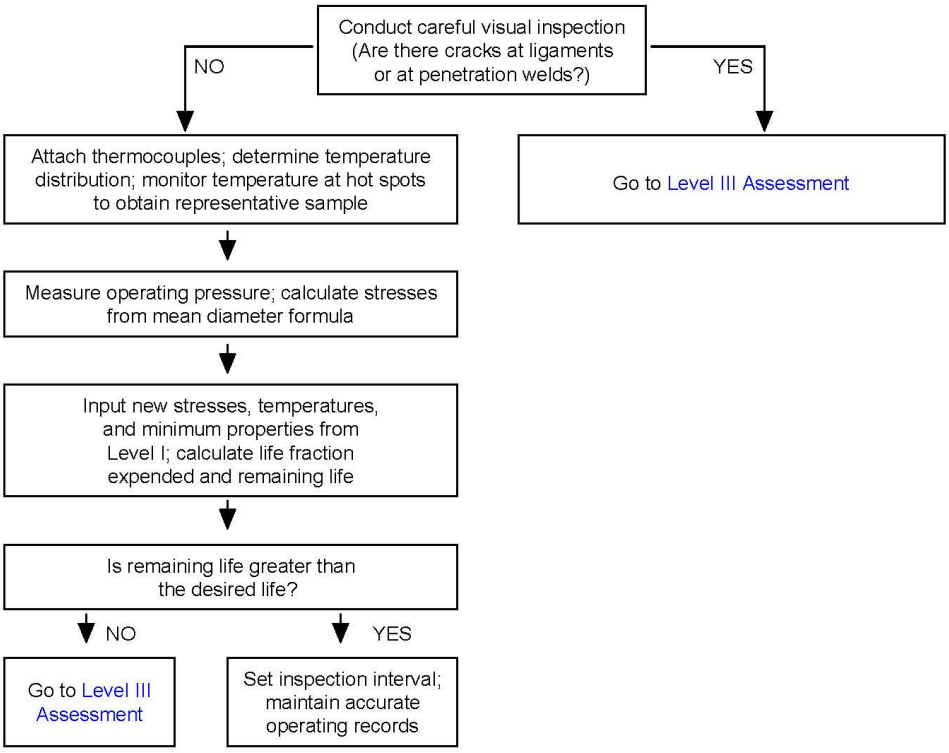

Figure 3-3
Level II Assessment: High-Temperature Headers

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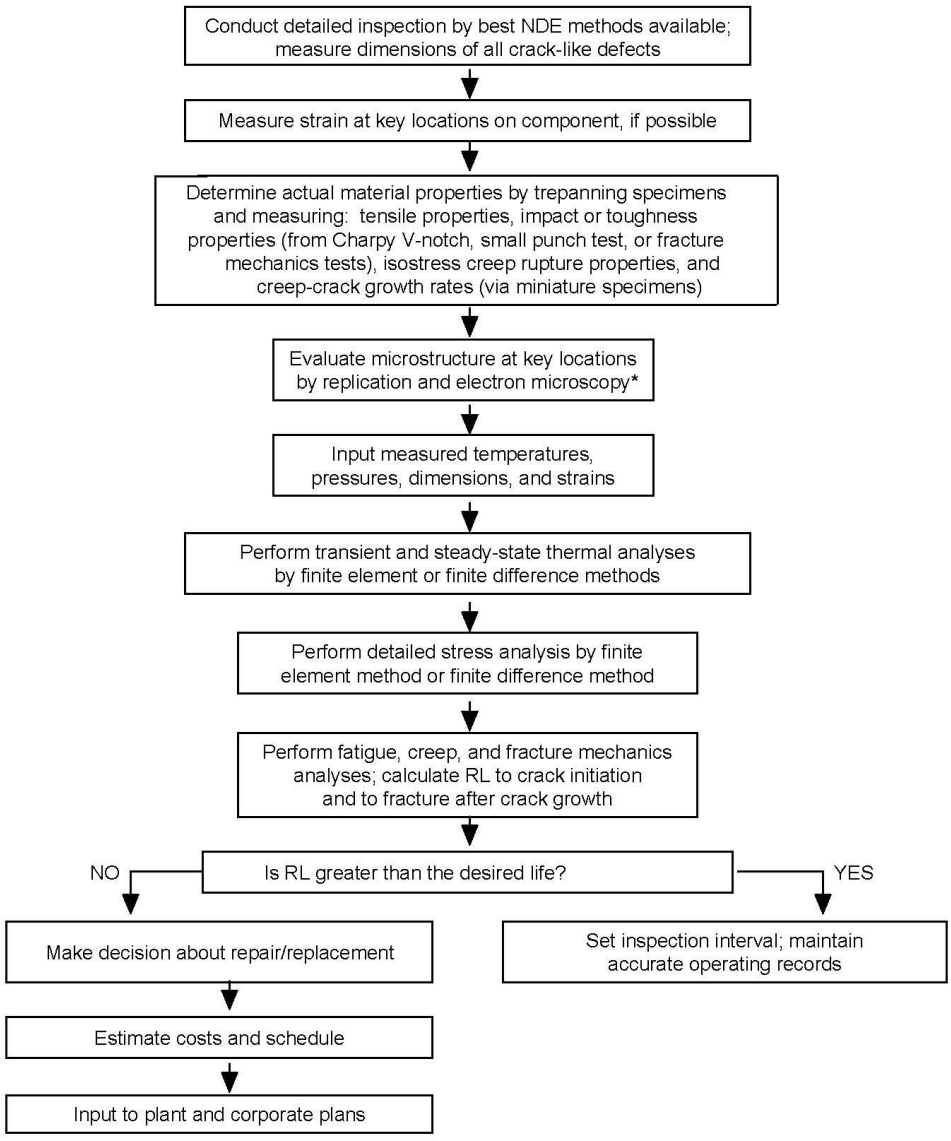

Figure 3-4
Level III Assessment: High-Temperature Headers

*determine creep cavity density and size; classify for BLESS analysis (i.e., oriented, linked, etc.)

Damage Mechanisms

Fundamental to condition assessment is an understanding of the life-limiting damage that can occur in the high-temperature headers. Table 3-1 highlights the major damage mechanisms that should be considered when assessing header condition. This summary table does not provide detailed background on the specific damage mechanisms; the links lead to basic descriptions. Considerable supporting material is available with a greater level of detail; see the EPRI technical reports listed in the bibliography in Chapter 1. In the "NDE Options" and "Analysis and Disposition" sections of this chapter, an application breakdown is provided for mapping the appropriate tools to the damage mechanism of interest.

Table 3-1
Damage Mechanisms for High-Temperature Steam Headers

Component/Location	Damage Mechanism
Body spool pieces	Creep swelling Temper embrittlement Thermal softening
Tee body	External creep cracking Internal thermal fatigue cracking
Ligament regions	Thermal fatigue cracking in bore holes and at corners
Girth welds	External creep damage Internal thermal fatigue cracking at counterbores
Seam welds	Creep cracking
Saddle welds	Creep cracking
Stub tubes	Creep swelling Thermal softening Wall wastage from oxide exfoliation Internal thermal fatigue cracking
Stub tube welds	External creep cracking Weld root creep cracking

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Component/Location	Damage Mechanism
Drain line penetrations	Internal thermal fatigue cracking Internal thermal shock cracking External creep-fatigue cracking
Radiographic testing (RT) plug and thermowell welds	Creep cracking With bimetallic welds, creep cracking
Supports	Creep cracking Thermal softening

NDE Options

Many options are available for performing inspections for existing damage. Table 3-2 supports the inspection activity under the header condition assessment roadmaps. It summarizes currently available options as a function of the condition assessment level—I, II, or III—being considered. As expected, the Level III options represent the most rigorous inspections. If the goal of the condition assessment program and subsequent operating plan is to obtain the maximum available life for steam headers, then the recommended condition assessment analysis would default to Level III options. For shorter-term assessments, the recommendation is to start with the lower-cost Level I options and move to Level II and III options only as required.

Table 3-2
NDE Options for High-Temperature Steam Headers

Component/Location	NDE Detection Technique Level I and Level II	NDE Characterization Technique Level III
Body spool piece	Dimensional Replication Hardness testing	Replication Chemical analysis
Tee body	Video-probe Conventional ultrasonic testing (UT) Focused UT Time-of-flight diffraction UT Radiographic testing (RT)	Focused ultrasonic testing (UT) Time-of-flight diffraction UT
Ligament regions	Dimensional Video-probe Penetrant testing (PT) Conventional UT Focused UT Time-of-flight diffraction UT Eddy current testing	Focused UT Time-of-flight diffraction UT Acoustic emission

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Component/Location	NDE Detection Technique Level I and Level II	NDE Characterization Technique Level III
Girth weld	PT Magnetic particle testing (MT) Conventional UT Time-of-flight diffraction UT RT Replication Hardness testing Chemical analysis	Focused UT Time-of-flight diffraction UT Acoustic emission Replication Chemical analysis Alternating current (AC) potential drop
Seam welds	PT MT Conventional UT Time-of-flight diffraction UT RT Replication Hardness testing Chemical analysis	Focused UT Time-of-flight diffraction UT Acoustic emission Replication Chemical analysis AC potential drop
Saddle welds	PT MT Conventional UT Time-of-flight diffraction UT RT Replication Hardness testing Chemical analysis	Focused UT Time-of-flight diffraction UT Acoustic emission Replication Chemical analysis AC potential drop

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Component/Location	NDE Detection Technique Level I and Level II	NDE Characterization Technique Level III
Stub tubes	Visual inspection Dimensional measurements UT thickness measurements UT oxide measurements Replication	Dimensional measurements UT thickness measurements UT oxide measurements Replication
Stub tube welds	PT MT Conventional UT Focused UT RT Replication Hardness testing Chemical analysis	Conventional UT Focused UT RT Replication Chemical analysis
Drain line penetrations	Video-probe Conventional UT Focused UT RT	Focused UT RT
RT plug and thermowell welds	PT MT RT Replication Chemical analysis	RT Replication Chemical analysis

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Component/Location	NDE Detection Technique Level I and Level II	NDE Characterization Technique Level III
Supports	Visual inspection PT MT Replication Chemical analysis	Replication +++--

Analysis and Disposition

As in the case of NDE options, the activities to be performed in support of the roadmap step on analysis and disposition are organized according to the three-level condition assessment approach. Table 3-3 summarizes the currently available options for high temperature steam headers. Note that the results gained from performing this roadmap step for a particular level—I, II, or III—will frequently lead to a decision to perform the next highest level because it is within this step that the issue of RL is fully addressed. All results of analyses and the final disposition decision must be documented as part of the boiler condition assessment program.

After the run, repair, or replace decision has been reached, a time interval for performing the next condition assessment activity should be established. Typically, intervals are set to support planning efforts for major maintenance outages. However, the interval should not exceed the RL estimate produced by the analysis. Provision should also be made to initiate a component condition assessment activity whenever there is a significant change in operating conditions.

Table 3-3
Analysis and Disposition for High Temperature Steam Headers

Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
Header ligament cracking	Shallow (<15% through wall), non-growing cracks may be left in place. Deeper flaws may be allowed if supported by Level III analysis.	Perform creep fatigue crack growth analysis to assure crack growth will not exceed failure criteria before next inspection. Use the Boiler Life Evaluation and Simulation System (BLESS) code or equivalent for crack growth analysis. If necessary, weld repair to restore ligament integrity.
Header body seam welds	Dependent upon location and characteristics of damage within the area of the weld Presence of flaws detected by NDE actions requires Level III analysis of flaw growth.	Perform creep-fatigue crack growth analysis to assure crack growth will not exceed failure criteria before next inspection. Use the BLESS code or equivalent for crack growth analysis. If necessary, weld repair to restore weld integrity.

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Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
Header body girth welds	Dependent upon location and characteristics of damage within the area of the weld Presence of flaws detected by NDE actions requires Level III analysis of flaw growth.	Perform creep-fatigue crack growth analysis to assure crack growth will not exceed failure criteria before next inspection. Use the BLESS code or equivalent for crack growth analysis. If necessary, weld repair to restore weld integrity.
Tube attachment welds	None established	Perform cycling crack growth analysis to assure weld integrity until next planned inspection. If necessary, grind out cracks and weld repair to restore weld integrity.

Preventive Actions

In most cases, a cost-effective approach for maximizing component life is to reduce or eliminate the root-cause mechanisms that produce component damage. EPRI has long recommended this strategy in areas such as boiler tube failures. Table 3-4 summarizes options that may be implemented to prevent or reduce continued damage accumulation. The effectiveness of any of these options, however, depends on the specific design and operating conditions of the component.

Table 3-4
Preventive Actions for High-Temperature Steam Headers

Damage Mechanism	Preventive Actions
Thermal fatigue cracking of ligaments	Avoid fast thermal transients during startups, shutdowns, and load changes. Establish safe operating envelope. Equalize temperature distributions of superheater and reheater tubing into outlet headers to reduce localized thermal mismatch.
Creep fatigue of header body weldments	Maintain temperatures at or below design basis. Correct/repair header supports to minimize bending stress on girth welds. Correct end-to-end temperature distribution to minimize thermally induced bending stresses.
Creep fatigue cracking of tube attachment welds	Correct/repair tube supports to minimize bending stresses at header attachments. Correct tube temperature distributions to maintain design limits.

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4

HIGH-ENERGY STEAM PIPING

Roadmap Introduction

The roadmap shown in Figure 4-1 is the starting point for setting up and performing condition assessments for high-energy piping. Following the steps in the roadmap will help organize the information required to assess the current condition and estimated remaining life of the component. Activities within the roadmap are further supported by summary tables that list the typical options available to complete the activity. For example, component-specific nondestructive evaluation options are identified in a separate table to support the inspection activity in the roadmap. It is important to note that the three-level condition assessment approach reviewed in Chapter 1, "Overview and Strategy for Boiler Condition Assessment," is applied to the roadmaps by either formal inclusion or implied inclusion as iterations on the analysis and disposition activity.

Due to specific issues regarding the integrity of seam-welded, high energy piping, it is strongly recommended that the EPRI "Guidelines for the Evaluation of Seam-Welded High-Energy Piping," as cited in the bibliography at the end of Chapter 1, be directly consulted for performing condition assessment on such piping sections. The material in this chapter provides a summary overview that covers both seamed and seamless piping, as well as cold reheat piping and high-energy valves.

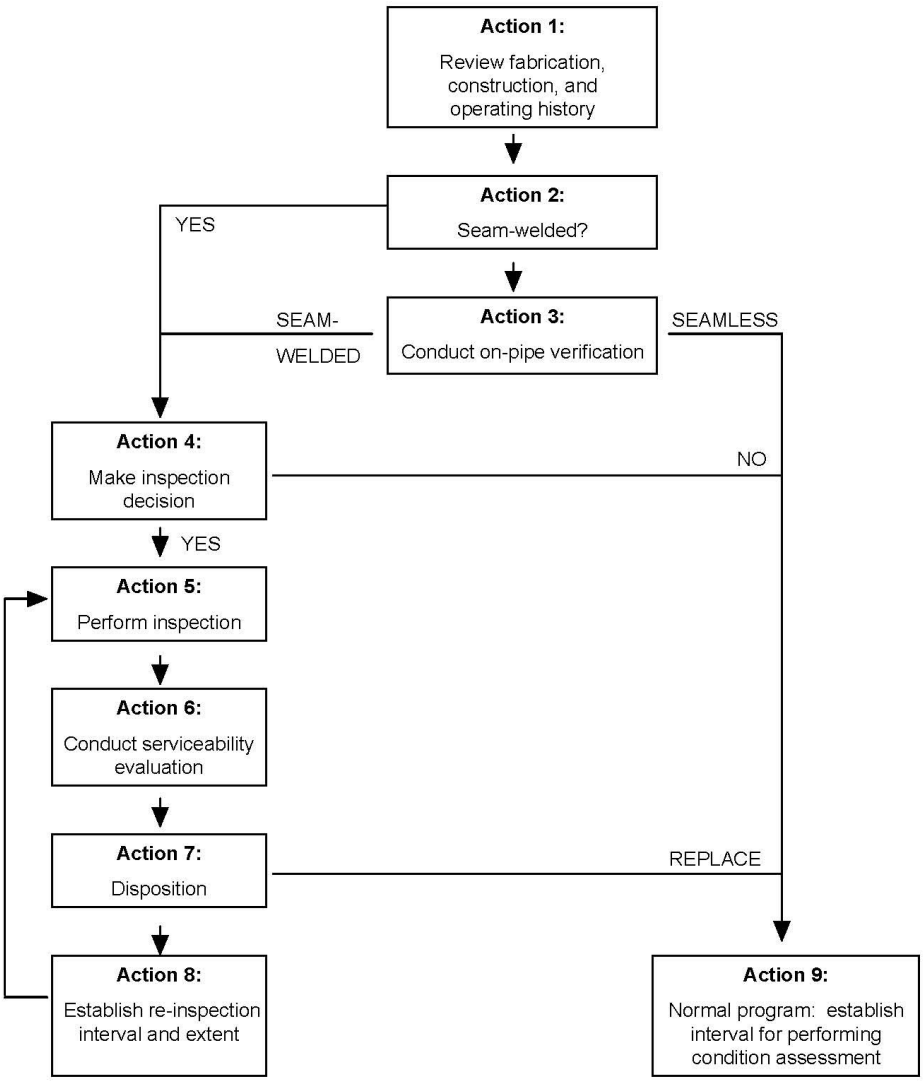

Figure 4-1
General Roadmap for High-Energy Steam Piping

4-2

Damage Mechanisms

Fundamental to condition assessment is an understanding of the life-limiting damage that can occur in high-energy piping. Table 4-1 highlights the major damage mechanisms that should be considered when assessing piping condition. This summary table does not provide background on the specific damage mechanisms; the links lead to basic descriptions. Considerable supporting material is available with a greater level of detail; see the EPRI technical reports listed in the bibliography in Chapter 1. In the "NDE Options" and "Analysis and Disposition" sections an application breakdown is provided for mapping the appropriate tools to the damage mechanism of interest.

Table 4-1
Damage Mechanisms for Hot Reheat Piping, Main Steam Piping, and High-Energy Valves

Component/Location	Damage Mechanism
Spool pieces	Creep swelling Temper embrittlement Thermal softening
Wye and tee body	External creep cracking External thermal fatigue cracking Internal thermal fatigue cracking
Girth welds	External creep damage Internal thermal fatigue cracking at counterbores
Seam welds	Creep cracking
Saddle welds	Creep cracking
Radiographic testing (RT) plug and thermowell welds	Creep cracking With bimetallic welds, creep cracking
Drain line and pressure tap penetrations	Internal thermal fatigue cracking Internal thermal shock cracking
Supports	Creep cracking Overload Thermal Softening

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NDE Options

Many options are available for performing inspections for existing damage in piping. Table 4-2 supports the inspection activity under the high-energy piping condition assessment roadmap (Figure 4-1). It summarizes those currently available options as a function of the condition assessment level—I, II, or III—being considered. As expected, the Level III options represent the most rigorous inspections. If the goal of the condition assessment program plan and subsequent piping is to obtain the maximum available life of the piping, then the recommended condition assessment analysis would default to Level III options. For shorter-term assessments, the recommendation is to start with the lower-cost Level I options and move to Level II and III options only as required.

Table 4-2
NDE Options for Hot Reheat Piping, Main Steam Piping, and High-Energy Valves

Component/Location	NDE Detection Technique Levels I and II	NDE Characterization Technique Level III
Spool pieces	Dimensional Replication Hardness testing	Replication Chemical analysis
Tee and wye body	Video-probe Magnetic particle testing (MT) Replication Conventional ultrasonic testing (UT) Focused UT Time-of-flight diffraction UT Radiographic testing (RT)	Focused UT Time-of-flight diffraction UT

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Component/Location	NDE Detection Technique Levels I and II	NDE Characterization Technique Level III
Girth welds	Liquid penetrant testing (PT) MT Conventional UT Time-of-flight diffraction UT RT Replication Hardness testing Chemical analysis	Focused UT Time-of-flight diffraction UT Acoustic emission Replication Chemical analysis Alternating current (AC) potential drop
Seam welds	PT MT Convention UT Time-of-flight diffraction UT RT Replication Hardness testing Chemical analysis	Focused UT Time-of-flight diffraction UT Acoustic emission Replication Chemical analysis AC potential drop
Saddle welds	PT MT Conventional UT Time-of-flight diffraction UT RT Replication Hardness testing Chemical analysis	Focused UT Time-of-flight diffraction UT Acoustic emission Replication Chemical analysis AC potential drop

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High-Energy Steam Piping

Component/Location	NDE Detection Technique Levels I and II	NDE Characterization Technique Level III
RT plug and thermowell welds	PT MT Conventional UT Focused UT RT Replication Hardness testing Chemical analysis	Conventional UT Focused UT RT Replication Chemical analysis
Pressure tap and drain line penetrations	Video-probe Conventional UT Focused UT RT	Focused UT RT
Supports	Visual inspection PT MT Replication Chemical analysis	Replication Chemical analysis
NOTE: In addition to the NDE techniques listed above, infrared thermography (IRT) is often used to determine if the valve is passing steam during operation. Acoustic emission (AE) leak detection is also useful for finding leaks in valves.		

4-6

Analysis and Disposition

As in the case of NDE options, the activities to be performed in support of the roadmap step on analysis and disposition are organized according to the three-level condition assessment approach. Table 4-3 summarizes the currently available options for hot reheat piping, main steam piping, and high energy valves. Note that results from performing this roadmap step for a particular level—I, II, or III—will frequently lead to a decision to perform the next highest level because it is within this step that the issue of remaining life is fully addressed. All results of analyses and the final disposition decision must be documented as part of the boiler condition assessment program.

After the run, repair, or replace decision has been reached, a time interval for performing the next condition assessment activity should be established. Typically, intervals are set to support planning efforts for major maintenance outages. However, the interval should not exceed the RL estimate produced by the analysis. Provision should also be made to initiate a component condition assessment activity whenever there is a significant change in operating conditions.

Table 4-3
Analysis and Disposition for Hot Reheat Piping, Main Steam Piping, and High-Energy Valves

Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
Longitudinal seam welds on hot reheat piping	Dependent upon location and characteristics of damage within the area of the weld Presence of flaws detected by NDE actions requires Level III analysis of flaw growth.	Perform creep-fatigue crack growth analysis to ensure crack growth will not exceed failure criteria before next inspection. Use the Boiler Life Evaluation and Simulation System (BLESS) code or equivalent for crack growth analysis. If necessary, weld repair to restore weld integrity or replace with seamless pipe section.

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Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
Girth welds (all piping and valves)	Dependent upon location and characteristics of damage within the area of the weld Presence of flaws detected by NDE actions requires Level III analysis of flaw growth.	Perform creep-fatigue crack growth analysis to assure crack growth will not exceed failure criteria before next inspection. Use BLESS code or equivalent for crack growth analysis. If necessary, weld repair to restore weld integrity.
Longitudinal seam welds on main steam piping	Current methodologies do not support crack growth analysis.	Immediate repair of the weldment is recommended if Type IV creep damage is detected in the welds.

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Preventive Actions

In most cases, a cost-effective approach for maximizing component life is to reduce or eliminate the root-cause mechanisms that produce component damage. EPRI has long recommended this strategy in areas such as boiler tube failures. Table 4-4 summarizes options that may be implemented to prevent or reduce continued damage accumulation. The effectiveness of any of these option, however, depends on the specific design and operating conditions of the component.

Table 4-4
Preventive Actions for Hot Reheat Piping, Main Steam Piping, and High-Energy Valves

Damage Mechanism	Preventive Actions
Creep fatigue of seam welds (both hot reheat and main steam piping)	Maintain temperatures at or below design basis. Correct/repair piping supports to minimize axial stress on welds. Reducing temperature below design basis will reduce the rate of creep damage but will also impact thermal performance of the unit and reduce net electric generation. Minimize cycling duty to reduce fatigue contribution to total damage.
Creep fatigue of girth welds (both hot reheat and main steam piping)	Maintain temperatures at or below design basis. Correct/repair piping supports to minimizing bending stress on girth welds. Minimize cycling duty to reduce fatigue contribution to total damage.
Creep fatigue of high-energy valves	Maintain temperatures at or below design basis. Minimize cycling duty to reduce fatigue contribution to total damage.

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Cold Reheat Piping

Roadmap Introduction

The roadmap shown in Figure 4-2 is the starting point for setting up and performing condition assessments of cold reheat piping. Following the steps in the roadmap will organize the information required to assess the current piping condition and estimated remaining life. Activities within the roadmap are further supported by summary tables that list the typical options available to complete the activity. For example, component-specific NDE options are identified in a separate table to support the inspections activity in the roadmap. It is important to note that the three-level condition assessment approach reviewed in Chapter 1, "Overview and Strategy for Boiler Condition Assessment," is applied to the roadmaps by either formal inclusion or implied inclusion as iterations on the analysis and disposition activity.

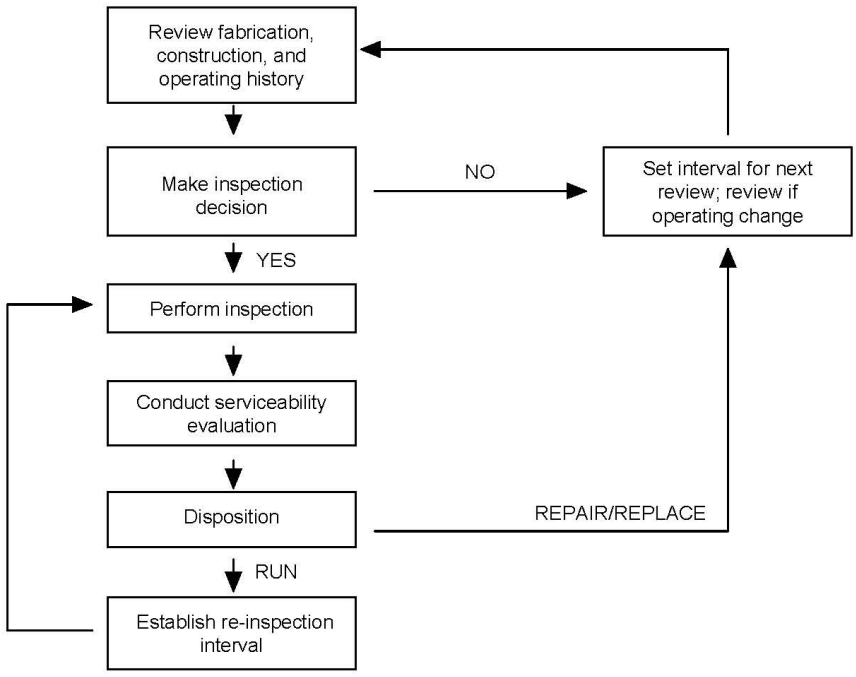

Figure 4-2
General Roadmap for Cold Reheat Piping

Damage Mechanisms

Fundamental to condition assessment is an understanding of the life-limiting damage that can occur in cold reheat piping. Table 4-5 highlights the major damage mechanisms that should be considered when assessing piping condition. This summary table does not provide background on the specific damage mechanisms; the links lead to basic descriptions. Considerable supporting material is available with a greater level of detail; see the EPRI technical reports listed in the bibliography in Chapter 1. In the "NDE Options" and "Analysis and Disposition" sections for cold reheat piping, an application breakdown is provided for mapping the appropriate tools to the damage mechanism of interest.

Table 4-5
Damage Mechanisms for Cold Reheat Piping

Component/Location	Damage Mechanism
Spool pieces	Erosion Corrosion Tensile overload/deformation Thermal shock/fatigue Foreign object damage
Girth welds	External cracking Internal thermal fatigue cracking at counterbores
Supports	Overload

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NDE Options

Many options are available for performing inspections for existing damage in piping. Table 4-6 supports the inspection activity under the cold reheat piping condition assessment roadmap (Figure 4-2). It summarizes those currently available options as a function of the condition assessment level—I, II, or III—being considered. As expected, the Level III options represent the most rigorous inspections. If the goal of the condition assessment program and subsequent operating plan is to obtain the maximum available life of the piping, then the recommended condition assessment analysis would default to Level III options. For shorter-term assessments, the recommendation is to start with the lower-cost Level I options and move to Level II and III options only as required.

Table 4-6
NDE Options for Cold Reheat Piping

Component/Location	NDE Detection Technique Levels I and II	NDE Characterization Technique Level III
Spool piece	Dimensional Video-probe Magnetic particle testing Conventional UT Focused UT Time-of-flight diffraction Radiography	Chemical analysis Focused UT Time-of-flight diffraction UT
Girth welds	Penetrant testing Magnetic particle testing Conventional UT Time-of-flight diffraction UT Radiography Chemical analysis	Focused UT Time-of-flight diffraction UT Acoustic emission Chemical analysis AC potential drop

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High-Energy Steam Piping

Component/Location	NDE Detection Technique Levels I and II	NDE Characterization Technique Level III
RT plug and thermowell welds	Penetrant testing Magnetic particle testing Conventional UT Focused UT Radiography Chemical analysis	Conventional UT Focused UT Radiography Chemical analysis
Pressure tap and drain line penetrations	Video-probe Conventional UT Focused UT Radiography	Focused UT Radiography
Supports	Visual inspection Penetrant testing Magnetic particle testing Chemical analysis	Chemical analysis

Analysis and Disposition

As in the case of NDE options, the activities to be performed in support of the roadmap step on analysis and disposition are organized according to the three-level condition assessment approach. Table 4-7 summarizes the currently available options for cold reheat piping. Note that results from performing this roadmap step for a particular level—I, II, or III—will frequently lead to a decision to perform the next highest level because it is within this step that the issue of remaining life is fully addressed. All results of analyses and the final disposition decision must be documented as part of the boiler condition assessment program.

After the run, repair, or replace decision has been reached, a time interval for performing the next condition assessment activity should be established. Typically, intervals are set to support planning efforts for major maintenance outages. However, the interval should not exceed the RL estimate produced by the analysis. Provision should also be made to initiate a component condition assessment activity whenever there is a significant change in operating conditions.

Table 4-7
Analysis and Disposition for Cold Reheat Piping

Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
Internal surface corrosion and fatigue cracking	Must maintain minimum wall thickness per the American Society for Mechanical Engineers (ASME Inernational) code	Perform cycling crack growth analysis to ensure minimum wall not exceeded before next inspection. Use BLESS code or equivalent for crack growth analysis. If necessary, weld repair to restore wall thickness
Girth weld fatigue cracking	Use crack growth analysis to avoid failure before next inspection. Typically 0.030-0.050 inch (0.075-0.125 cm).	Perform cycling crack growth analysis to ensure weld integrity until next planned inspection. Use BLESS code or equivalent for crack growth analysis. If necessary, grind out cracks and weld repair to restore weld integrity.

Preventive Actions

In most cases, a cost-effective approach for maximizing component life is to reduce or eliminate the root-cause mechanisms that produce component damage. EPRI has long recommended this strategy in areas such as boiler tube failures. Table 4-8 summarizes options that may be implemented to prevent or reduce continued damage accumulation. The effectiveness of any of these options, however, depends on the specific design and operating conditions of the component.

Table 4-8
Preventive Actions for Cold Reheat Piping

Damage Mechanism	Preventive Actions
Corrosion	Maintain dry conditions in lines during shutdown/layup periods.
Thermal fatigue cracking	Avoid fast thermal transients during startup, shutdown, and load changes.

EPRI Licensed Material

5

ECONOMIZER HEADERS

Roadmap Introduction

The roadmap shown in Figure 5-1 is the starting point for setting up and performing condition assessment's for economizer headers. Following the steps in the roadmap will help organize the information required to assess the current condition and estimated remaining life of the component. Activities within the roadmap are further supported by summary tables that list the typical options available to complete the activity. For example, component-specific nondestructive evaluation options are identified in a separate table to support the inspection activity in the roadmap. It is important to note that the three-level condition assessment approach reviewed in Chapter 1, "Overview and Strategy for Boiler Condition Assessment," is applied to the roadmaps by either formal inclusion or implied inclusion as iterations on the analysis and dispositon activity.

EPRI Licensed Material

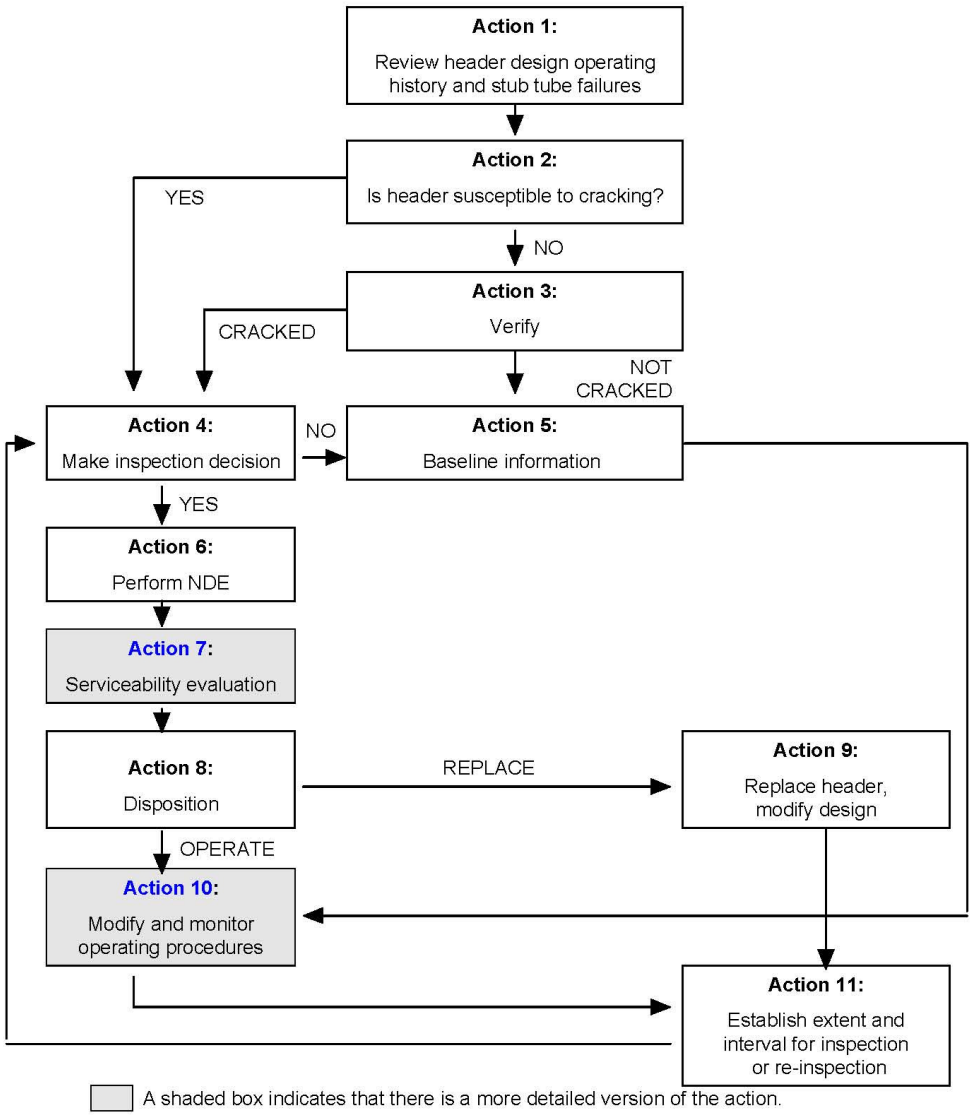

Figure 5-1
General Road map for Economizer Inlet Headers

5-2

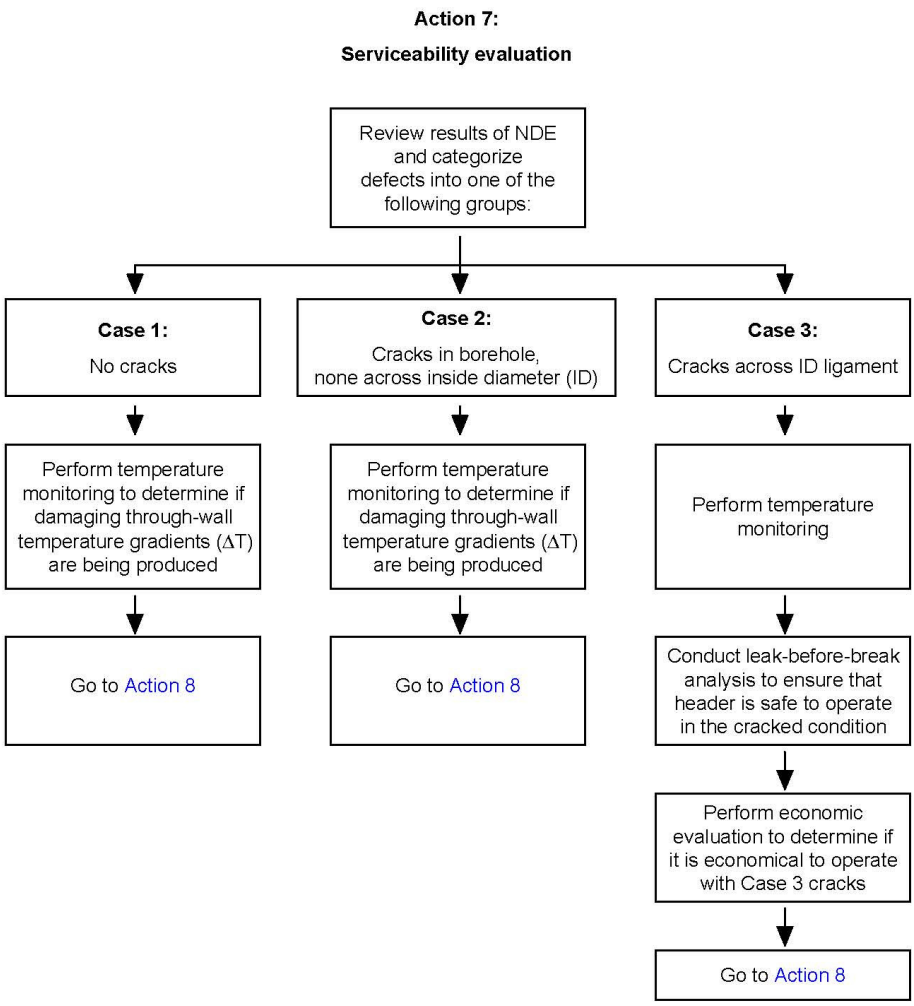

Figure 5-2
Details of Action 7

EPRI Licensed Material

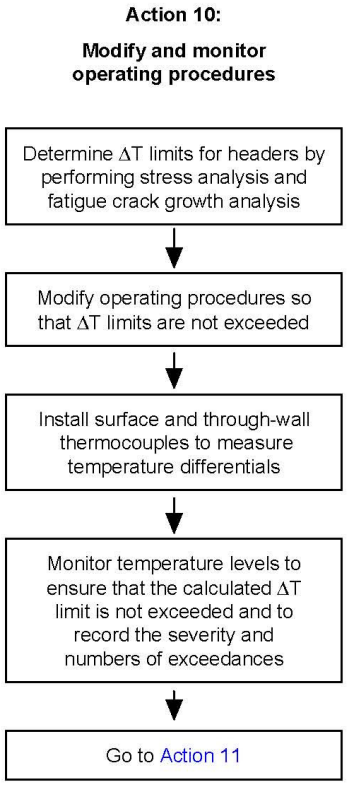

Figure 5-3
Details of Action 10

EPRI Licensed Material

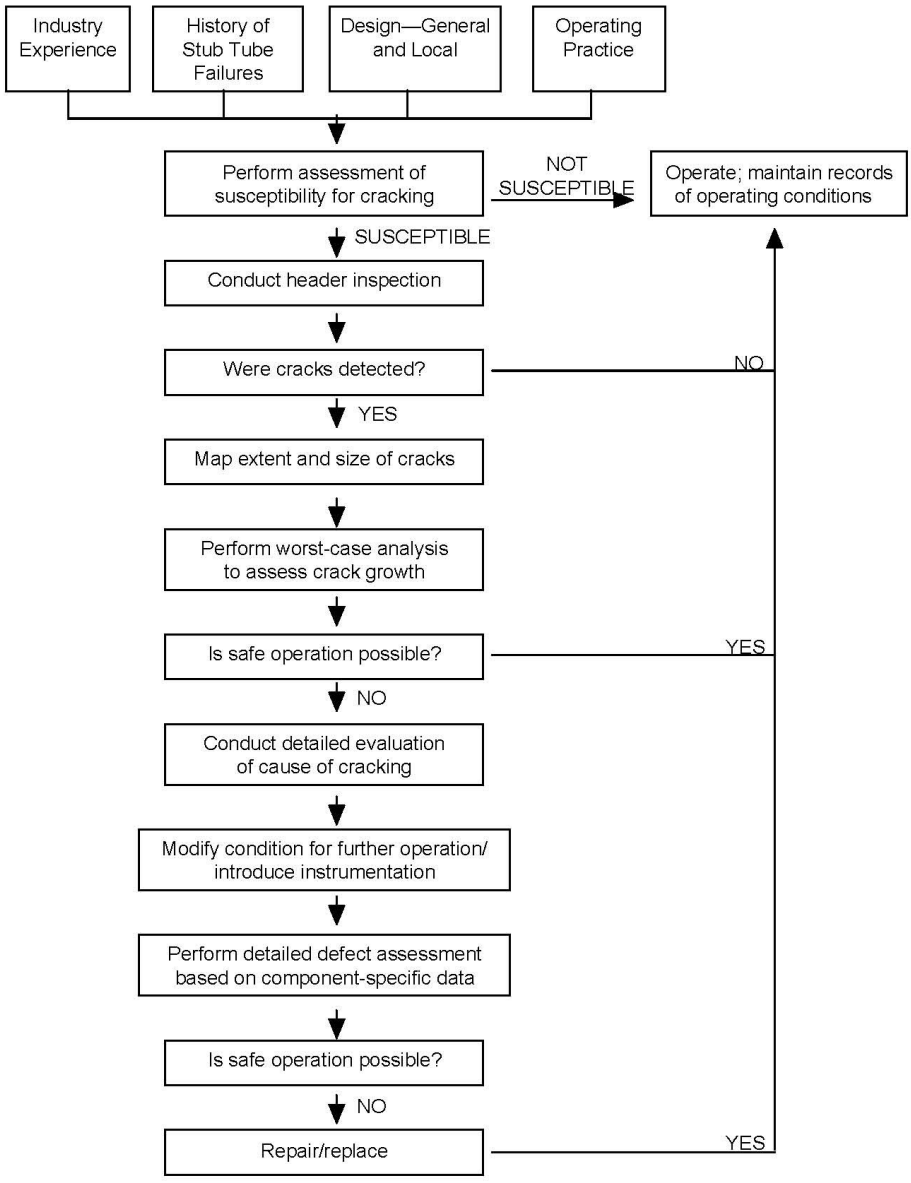

Figure 5-4
Three-Level Methodology for Analysis of Economizer Inlet Headers

EPRI Licensed Material

Damage Mechanisms

Fundamental to condition assessment is an understanding of the life-limiting damage that can occur in economizer headers. Table 5-1 highlights the major damage mechanisms that should be considered when assessing component condition. This summary table does not provide background on the specific damage mechanisms; the link leads to a basic description. Considerable supporting material is available with a greater level of detail; see the EPRI technical reports listed in the bibliography in Chapter 1. In the "NDE Options" and "Analysis and Disposition" sections of this chapter, an application breakdown is provided for mapping the appropriate tools to the damage mechanism of interest.

Table 5-1
Damage Mechanisms for Economizer Headers

Component/Location	Damage Mechanism
Header ID surface Tube and piping attachments	Corrosion Units that have been acid-cleaned many times may experience corrosion-related problems with welded connections and inlet line attachments.
Header ligaments	Thermal fatigue Units that cycle frequently (especially if force-cooled to deal with boiler tube leaks) are subjected to high local stresses around economizer tube penetrations. These stresses, in combination with corrosion, initiate fatigue damage. The thermal/corrosion effects of fatigue have been severe enough to cause cracking in drums.
NOTE: Creep damage in header drums is not a factor because temperatures are too low.	

EPRI Licensed Material

NDE Options

Many options are available for performing inspections for existing damage. Table 5-2 supports the inspection activity under the component condition assessment roadmap (Fiugre 5-1). It summarizes currently available options as a function of the condition assessment level—I, II, or III—being considered. As expected, the Level III options represent the most rigorous inspections. If the goal of the condition assessment program and subsequent operating plan is to obtain the maximum available life of the component, then the recommended condition assessment analysis would default to Level III options. For shorter-term assessments, the recommendation is to start with the lower-cost Level I options and only move to Level II and III options as required.

Table 5-2
NDE Options for Economizer Headers

Component/Location	NDE Detection Technique Levels I and II	NDE Characterization Technique Level III
Internal surfaces, especially bore hole ligaments	Visual Magnetic particle testing (MT)/ penetrant testing (PT)	Ultrasonic testing (UT)
Tube attachment welds	Visual MT/PT	UT Alternating current (AC) potential drop

EPRI Licensed Material

Analysis and Disposition

As in the case of NDE options, the activities to be performed in support of the roadmap step on analysis and disposition are organized according to the three-level condition assessment approach. Table 5-3 summarizes the currently available options for economizer headers. Note that results from performing this roadmap step for a particular level—I, II, or III—will frequently lead to a decision to perform the next highest level as it is within this step that the issue of RL is fully addressed. All results of analyses and the final disposition decision must be documented as part of the boiler condition assessment program.

After the run, repair, or replace decision has been reached, a time interval for performing the next condition assessment activity should be established. Typically, intervals are set to support planning efforts for major maintenance outages. However, the interval should not exceed the RL estimate produced by the analysis. Provision should also be made to initiate a component condition assessment activity whenever there is a significant change in operating conditions.

Table 5-3
Analysis and Disposition for Economizer Headers

Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
Internal surface corrosion and fatigue cracking	Must maintain minimum wall thickness per the American Society of Mechanical Engineers (ASME International) code.	Perform cycling crack growth analysis to assure minimum wall not exceeded before next inspection. If necessary, weld repair to restore wall thickness or plan header replacement.
Tube attachment welds		Grind out cracks and repair weld.

EPRI Licensed Material

Preventive Actions

In most cases, a cost-effective approach for maximizing component life is to reduce or eliminate the root-cause mechanisms that produce component damage. EPRI has long recommended this strategy in areas such as boiler tube failures. Table 5-4 summarizes options that may be implemented to prevent or reduce continued damage accumulation. The effectiveness of any of these options, however, depends on the specific design and operating conditions of the component.

Table 5-4
Preventive Actions for Economizer Headers

Damage Mechanism	Preventive Actions
Corrosion	Monitor effluents from chemical cleaning to assure all residual acids removed.
Thermal fatigue cracking	Avoid fast thermal transients during startup, shutdown, and load changes to reduce ligament damage. Correct/repair tubing supports to reduce bending stresses at weld attachments.

EPRI Licensed Material

6

STEAM AND LOWER DRUMS

Roadmap Introduction

The roadmap shown in Figure 6-1 is the starting point for setting up and performing component condition assessment's for drums. Following the steps in the roadmap will help organize the information required to assess the current condition and estimated remaining life of the component. Activities within the roadmap are further supported by summary tables that list the typical options available to complete the activity. For example, component-specific nondestructive evaluation options are identified in a separate table to support the inspection activity in the roadmap. It is important to note that the three-level condition assessment approach reviewed in Chapter 1, "Overview and Strategy for Boiler Condition Assessment," is applied to the roadmaps by either formal inclusion or implied inclusion as iterations on the analysis and disposition activity.

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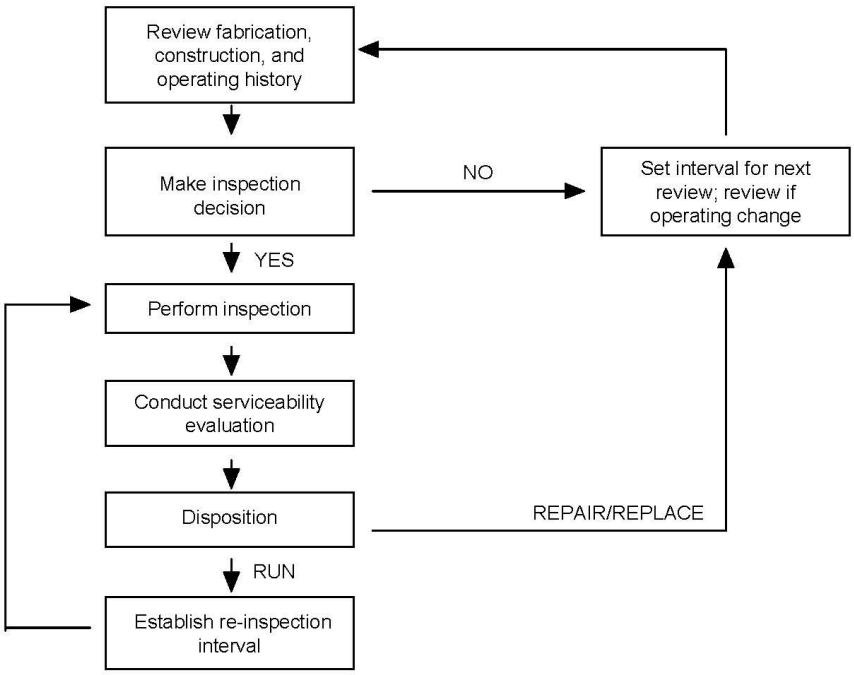

Figure 6-1
General Roadmap for Steam and Lower Drums

6-2

Damage Mechanisms

Fundamental to condition assessment is an understanding of the life-limiting damage that can occur in drums. Table 6-1 highlights the major damage mechanisms that should be considered when assessing component condition. This summary table does not provide background on the specific damage mechanisms; the link leads to a basic description. Considerable supporting material is available with a greater level of detail; see the EPRI technical reports listed in the bibliography in Chapter 1. In the "NDE Options" and "Analysis and Disposition" sections in this chapter, an application breakdown is provided for mapping the appropriate tools to the damage mechanism of interest.

Table 6-1
Damage Mechanisms for Steam and Lower Drums

Component/Location	Damage Mechanism
Internal surfaces	Corrosion Thermal fatigue cracking
Internal structures and attachments	Corrosion Thermal fatigue cracking
Tube attachments, including downcomers	Corrosion Thermal fatigue cracking

EPRI Licensed Material

NDE Options

Many options are available for performing inspections for existing damage. Table 6-2 supports the inspection activity under the component condition assessment roadmap (Figure 6-1). It summarizes currently available options as a function of the condition assessment level—I, II, or III—being considered. As expected, the Level III options represent the most rigorous inspections. If the goal of the condition assessment program and subsequent operating plan is to obtain the maximum available life of the component, then the recommended condition assessment analysis would default to Level III options. For shorter-term assessments, the recommendation is to start with the lower-cost Level I options and move to Level II and III options only as required.

Table 6-2
NDE Options for Steam and Lower Drums

Component/Location	NDE Detection Technique Levels I and II	NDE Characterization Technique Level III
Internal surfaces	Visual Magnetic particle testing (MT)/ penetrant testing (PT)	Ultrasonic testing (UT) Alternating current (AC) potential drop
Internal structures and attachments	Visual MT/PT	Repair/replace decision made from Level I and II results
Tube attachments, including downcomers	Visual MT/PT	UT AC potential drop

Analysis and Disposition

As in the case of NDE options, the activities to be performed in support of the roadmap step on analysis and disposition are organized according to the three-level condition assessment approach. Table 6-3 summarizes the currently available options for steam and lower drums. Note that results from performing this roadmap step for a particular level—I, II, or III—will frequently lead to a decision to perform the next highest level because it is within this step that the issue of RL is fully addressed. All results of analyses and the final disposition decision must be documented as part of the boiler condition assessment program.

After the run, repair, or replace decision has been reached, a time interval for performing the next condition assessment activity should be established. Typically, intervals are set to support planning efforts for major maintenance outages. However, the interval should not exceed the RL estimate produced by the analysis. Provision should also be made to initiate a component condition assessment activity whenever there is a significant change in operating conditions.

Table 6-3
Analysis and Disposition for Steam and Lower Drums

Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
Internal surface corrosion and fatigue cracking	Must maintain minimum wall thickness per the American Society of Mechanical Engineering (ASME International) code	Perform cycling crack growth analysis to ensure minimum wall not exceeded before next inspection. If necessary, weld repair to restore wall thickness.
Internal structures and attachments	None established	Repair/replace decision made per unit experience and consultation with insurer's authorized inspector.
Tube attachments, including downcomers	None established	Perform cycling crack growth analysis to assure weld integrity until next planned inspection. If necessary, grind out cracks and weld repair to restore weld integrity.

EPRI Licensed Material

Preventive Actions

In most cases, a cost-effective approach for maximizing component life is to reduce or eliminate the root-cause mechanisms that produce component damage. EPRI has long recommended this strategy in areas such as boiler tube failures. Table 6-4 summarizes options that may be implemented to prevent or reduce continued damage accumulation. The effectiveness of any of these options, however, depends on the specific design and operating conditions of the component.

Table 6-4
Preventive Actions for Steam and Lower Drums

Damage Mechanism	Preventive Actions
Corrosion	Maintain boiler water chemistry parameters per EPRI guidelines. Perform thorough system flush after boiler chemical cleaning. Monitor effluent.
Thermal fatigue cracking	Avoid fast thermal transients, especially forced cooling of the boiler.

EPRI Licensed Material

7

ATTEMPERATORS

Roadmap Introduction

The roadmap shown in Figure 7-1 is the starting point for setting up and performing condition assessment's for attemperators. Following the steps in the roadmap will help organize the information required to assess the current condition and estimated remaining life of the component. Activities within the roadmap are further supported by summary tables that list the typical options available to complete the activity. For example, component-specific nondestructive evaluation options are identified in a separate table to support the inspections activity in the roadmap. It is important to note that the three-level condition assessment approach reviewed in Chapter 1, "Overview and Strategy for Boiler Condition Assessment," is applied to the roadmaps by either formal inclusion or implied inclusion as iterations on the analysis and disposition activity.

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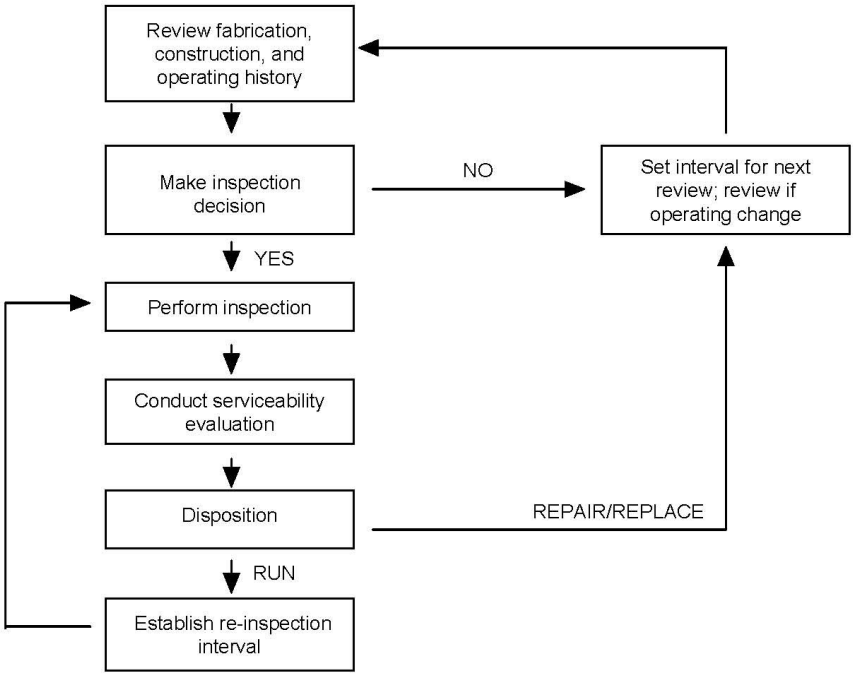

Figure 7-1
General Roadmap for Attemperators

EPRI Licensed Material

Damage Mechanisms

Fundamental to condition assessment is an understanding of the life-limiting damage that can occur in attemperators. Table 7-1 highlights the major damage mechanisms that should be considered when assessing component condition. This summary table does not provide background on the specific damage mechanisms; the link leads to a basic description. Considerable supporting material is available with a greater level of detail; see the EPRI technical reports listed in the bibliography in Chapter 1. In the "NDE Options" and "Analysis and Disposition" sections of this chapter, an application breakdown is provided for mapping the appropriate tools to the damage mechanism of interest.

Table 7-1
Damage Mechanisms for Attemperators

Component/Location	Damage Mechanism
Thermal shields	Thermal fatigue cracking High cycle fatigue due to vibrations
Spray nozzles	Thermal fatigue cracking
Attachment welds to steam piping	Creep Thermal fatigue cracking

EPRI Licensed Material

NDE Options

Many options are available for performing inspections for existing damage. Table 7-2 supports the inspection activity under the component condition assessment roadmap (Figure 7-1). It summarizes currently available options as a function of the condition assessment level—I, II, or III—being considered. As expected, the Level III options represent the most rigorous inspections. If the goal of the condition assessment program and subsequent operating plan is to obtain the maximum available life of the component, then the recommended condition assessment analysis would default to Level III options. For shorter-term assessments, the recommendation is to start with the lower-cost Level I options and only move to Level II and III options as required.

Table 7-2
NDE Options for Attemperators

Component/Location	NDE Detection Technique Levels I and II	NDE Characterization Technique Level III
Thermal shields	Visual Magnetic particle testing (MT)/ penetrant testing (PT)	Repair/replace decision from Level I and II results
Spray nozzles	Visual PT	Repair/replace decision from Level I and II results
Attachment welds to steam piping	MT/PT	Ultrasonic testing (UT) Replication

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Analysis and Disposition

As in the case of NDE options, the activities to be performed in support of the roadmap step on analysis and disposition are organized according to the three-level condition assessment approach. Table 7-3 summarizes the currently available options for attemperators. Note that results from performing this roadmap step for a particular level—I, II, or III—will frequently lead to a decision to perform the next highest level because it is within this step that the issue of RL is fully addressed. All results of analyses and the final disposition decision must be documented as part of the boiler condition assessment program.

After the run, repair, or replace decision has been reached, a time interval for performing the next condition assessment activity should be established. Typically, intervals are set to support planning efforts for major maintenance outages. However, the interval should not exceed the RL estimate produced by the analysis. Provision should also be made to initiate a component condition assessment activity whenever there is a significant change in operating conditions.

Table 7-3
Analysis and Disposition for Attemperators

Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
Thermal shields	None. Fatigue cracks progress rapidly in this component.	Grind out surface cracking. Replace if damage is severe.
Spray nozzles	None. Fatigue cracks progress rapidly in this component.	Grind out surface cracking. Replace if damage is severe.
Attachment welds to steam piping	Maintain minimum wall per the American Society for Mechanical Engineering (ASME International) code.	Perform crack growth analysis using fracture mechanisms code. If necessary, perform weld repair to maintain integrity until next planned inspection.

EPRI Licensed Material

Preventive Actions

In most cases, a cost-effective approach for maximizing component life is to reduce or eliminate the root-cause mechanisms that produce component damage. EPRI has long recommended this strategy in areas such as boiler tube failures. Table 7-4 summarizes options that may be implemented to prevent or reduce continued damage accumulation. The effectiveness of any of these option, however, depends on the specific design and operating conditions of the component.

Table 7-4
Preventive Actions for Attemperators

Damage Mechanism	Preventive Actions
Thermal fatigue cracking	Increase temperature of inlet water/steam. Replace with higher-strength materials.
High-cycle fatigue	Maintain thermal shield/liner geometry to avoid steam flow vibrations. Replace with new design using higher-strength materials and stiffer structure.
Creep	Evaluate and adjust piping supports to eliminate bending stresses on the weldment.

APPENDIX B

Major Upgrades List

Newfoundland and Labrador Hydro
Holyrood Thermal Generating Station
Major Upgrades List

	Major Upgrade	Year
1)	Uprate Generation Units 1 and 2 (150 MW to 175 MW)	1989
2)	Major Turbine/Generator Disassembly, Overhaul and Repair (each Generation Unit)	every 9 yrs
3)	Turbine/Generator Valves Disassembly, Inspection and Repair (each Generation Unit)	every 3 yrs
4)	Boilers Internal Cleaning, Inspection and Minor Repairs	annually
5)	Construct New Water Treatment Plant	1992
6)	Construct New Wastewater Treatment Plant	1994
7)	Replace Unit 1 Boiler Stack Liner	2000
8)	Replace Unit 2 Boiler Stack Liner	2001
9)	Upgrade Unit 1 and 2 Exciter	2002
10)	Upgrade Unit 1 and 2 Governor Controls	2003
11)	Replace Uninterrupted Power System	2000
12)	Replace Boilers Breeching	1990
13)	Upgrade Units 1, 2, and 3 Controls System	2002-2003
14)	Install Warm Air Make-up System	1992
15)	Construct New Security Building	2004
16)	Plant Asbestos Removal Program (3 year project)	2003-2006
17)	Replace Boiler No. 2 Superheater	2007
18)	Replace Boiler No. 1 Superheater	2008
19)	Replace Roof and Upgrade Siding	1990-2000
20)	Replace Boiler No. 2 Partial Water Wall	2006
21)	Install Boiler Soot Blower	1995
22)	Upgrade Boiler Air Pre-heater Steam Heat Exchanger	1990
23)	Install Continuous Emissions Monitoring System (shared)	2003
24)	Construct five Ambient Air Monitoring Stations	1993
25)	Replace Heating, Ventilation & Air Conditioning Units	2002-2005
26)	Install Cooper Ion Injection System	2007
27)	Replace Unit 2 Boiler Stop Valve	2008
28)	Refurbish Fuel Oil Storage Facility Phase 1 of 4	2009

29)	Replace Steam Seal Regulator Unit #3	2009
30)	Replace Unit #2 Air Pre-Heater Cold End	2009
31)	Condition Assessment Phase 1	2010
32)	Refurbish Fuel Oil Storage Facility Phase 2 of 4	2010
33)	Replace Burner Management Control System Units #1 and #2	2010
34)	Replace Boiler Blow Down Tanks	2011
35)	Install Powerhouse Ventilation Weather Hoods	2011
36)	Upgrade PLC – Water Treatment Plant	2011

Notes: 1) Major items are identified but list is not complete.
2) Years noted are approximate.

APPENDIX C

Five Year Maintenance Expenditures

Thermal Generation

Actual Expenditures

Sum of Actuals	**Fiscal Year**				
Work Plan	**2007**	**2008**	**2009**	**2010**	**2111**
Corrective	$ 5,815,665	$ 6,335,586	$ 5,238,567	$ 3,995,514	$ 3,142.758
Non Maintenance	$10,404,864	$11,260,723	$10,701,868	$11,204,689	$11,433,584
Operating Projects	$ 337,546	$ 498,145	$ 595,677	$ 480,193	$ 316,901
Preventive	$ 6,421,115	$ 4,349,042	$ 4,645,410	$ 5,094,003	$ 7,183,871
Grand Total	$22,979,190	$22,443,496	$21,181,721	$20,774,399	$22,077,114

APPENDIX D

Annual Outage Summary

ANNUAL SUMMARY 2009 ANNUAL AVAILABILITY UNIT 1

YEAR 2009 0	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	*Total Outage CEA*	REASONS FOR OUTAGES/DERATINGS
Jan 1-16	90.91		368	150	33.45	33.45	*WFD fan vibration brought forward*
Jan 16-Feb 25	94.55		972.92	156	53.07	53.07	*WFD fan duct vibration to 156 mw @ 0800 hrs*
Feb 25-26	0.00	21.31			0.00	21.31	*FO (3) H2 cooler vent line broken*
Feb 26-Mar 26	94.55		666.5	156	36.35	36.35	*OFD WFD fan duct vibration to 156 mw @ 1814 hrs*
Mar 26-30	94.55		99.3	156	5.42	5.42	*ABNO - FD @ 1244 hrs (ECC requirement)*
Mar 30-April 4	0.00	116.9			0.00	116.90	*FO State 21 (exciter problem)*
4-Apr	94.55		9.92	156	0.54	0.54	*O - FD @ 1254 hrs (ECC requirement)*
April 4-7	94.55		56.18	156	3.06	3.06	*ABNO-FD @ 2249 hrs (ECC requirement/Stack testing issues)*
April 7-8	0.00	23.58			0.00	23.58	*FO State 21 (4) @ 0700 hrs (economizer vent line leak)*
April 8-23	94.55		373.7033	156	20.38	20.38	*OFD WFD fan duct vibration to 156 mw @ 0635 hrs*
April 23-27	94.55		81.37	156	4.44	4.44	*ABNO-FD @ 2017 hrs (ECC requirement)*
April 27-May 5	94.55		205.033	156	11.18	11.18	*O - FD @ 0539 hrs (ECC requirement)*
May 5-July 24	0.00	1925.32			0.00	1925.32	*Planned Outage @ 1841 hrs May 5*
July 25-Aug 29	0.00	855.25			0.00	855.25	*FEPO @ July 25 @ 0000 hrs (Nozzle Block failure)*
4-Oct	100.00	0.85			0.00	0.85	*FO State 21 high drum leve3l*
4-Oct	100.00	0.44			0.00	0.44	*FO Perform O/S trip*
Oct 4-7	60.61		81.05	100	31.93	31.93	*OSD EVT safety valves pending*
Oct 11-15	0.00	104.9			0.00	104.90	*FO @ 1436 hrs (steam leak and No. 1 bearing wire causing vibration spikes)*
Oct 21-23	0.00	34.17			0.00	34.17	*FO @1647 hrs # 2 Bearing smoking due to oil leak from around the RTD local area*
Oct 30-31	42.42		17.67	70	10.17	10.17	*OFD @ 2120 hrs (superheat spray block valve broken)*
3-Nov	48.48		9.5	80	4.89	4.89	*OFD @ 1130-2100 hrs BFPE Motor IB bearing in alarm*
4-Nov	51.52		29.04	85	14.08	14.08	*OFD @ 1532 hrs EBFP motor alignment*
6-Nov	42.42		10.000	70	5.76	5.76	*Nov 6 OFD @ 0300 hrs-1700 hrs (attemperation spray block valve broken)*
11-Nov	42.42		5.75	70	3.31	3.31	*Nov 11 OFD West spray gland valve broken*
4-Dec	100.00	6.58			0.00	6.58	*FO (1) trip (condeser backwash)*
Dec 20-23	0.00	60.28			0.00	60.28	*MO State 24 Fan bearing IB west) BFPE Check valve cover)*
		3150				**3388**	

ANNUAL SUMMARY 2009 ANNUAL AVAILABILITY UNIT TWO

YEAR 2009	PERCENT	OUTAGE DURATION	DERATED		ADJ HOURS	*Total Outage*	REASONS FOR OUTAGES/DERATINGS
0	LOAD	HOURS	HRS	MW		*CEA*	***External conditions in red***
Jan 17-Mar 31	100.00				0.00	**0.00**	*No. 5 hp heater failure (all heaters out of service) Selected components*
31-Mar	100.00	0.6			0.00	**0.60**	*FO State 21 (1) Unit 1 86 lockout operated in error by TK*
July 16-Sept 4	0.00	1208.33			0.00	**1208.33**	*PO State 25 @ 1540 hrs Annual outage*
Sept 4-Oct 18	0.00	1074.08			0.00	**1074.08**	*PO State 25 @ 0000 hrs (No. 5 hp heater installation)*
Oct 27-29	60.61		61.75	100	24.33	**24.33**	*OSD @ 0215 hrs EVT safety valves*
6-Nov	100.00	1.6			0.00	**1.60**	*FO (1) @ 1941 hrs (Main feedwater control valve linkage was loose)*
Nov 6-7	24.24		26.05	40	19.73	**19.73**	*OFD to 40 mw @ 2117 hrs (load restricted due to problem not solved)*
Nov 18-Dec 4	81.82		383.5	135	69.73	**69.73**	*OFD to 135 mw (A/H motor drives in alarm high amps seals rubbing at 135)*
Dec 4-15	72.73		247.5	120	67.50	**67.50**	*OFD to 120 mw (A/H motor drives in alarm high amps seals rubbing at 135)*
Dec 15-Jan 2	80.00		441.1	132	88.21	**88.21**	*OFD to 132 mw (A/H motor drives in alarm high amps seals rubbing at 135)*
		2285				**2554**	

Annual Summary **2009** **ANNUAL AVAILABILITY, UNIT 3**

YEAR 2009	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	*Total Outage CEA*	REASONS FOR OUTAGES/DERATINGS
Jan 21-22	66.67		25.00	100	8.33	**8.33**	*OFD to 100 mw Burner yoke broken*
Feb 9-10	100.00	7.3833			0.00	**7.38**	*FO State 21 (1) Unit trip DCS configuring by FOXBORO*
April 8-June 29	0.00	1969.70			0.00	**1969.70**	*Planned Outage State 25 @ 1420 hrs (convert to Sync Condenser mode) ABNO June 29 @ 1603 hrs*
April 12-16	0.00	100.00			0.00	**100.00**	*Convert to SC mode*
April 21-23	0.00	52.18			0.00	**52.18**	*Realignment of coupling*
April 23-24	100.00				0.00	**0.00**	*Preparing for start up*
April 24-25	100.00				0.00	**0.00**	*Sync to system high vibration*
April 25-27	0.00	60.0500			0.00	**60.05**	*Off at 0347 hrs April 25 (Preparing permit for investigation)*
April 27-28	0.00	29.900			0.00	**29.90**	*Permit time Sync condenser issued at 1550 hrs April 27 terminated at 2142 hrs april 28*
May 3-4	0.00	34.7			0.00	**34.70**	*Permit time Sync condenser issued at 1053 hrs May 3 terminated at May 4 @ 2130 hrs*
July 21-Aug 2	0.00	292.0			0.00	**292.00**	*"MO" SC re-alignment high vibration*
Sept 9-Oct 29	0.00	1204.9			0.00	**1204.92**	*Planned Outage (Steam seal regulator)*
Nov 1-5	0.00	99.9			0.00	**99.90**	*FO SC off due to B3T3 damage in wind conditions on Nov1 @ 0811 hrs*
Nov 9-24	0.00	348.9			0.00	**348.90**	*PO on Nov 9 @ 2023 hrs Conversion to Gen mode Permit time Nov 9-24*
Nov 22-24	0.00	35.450			0.00	**35.45**	*FO (4) Boiler tube leak on Nov 22 @ 2150 hrs WW West 7 th floor while on SC permit*
Nov 24-26	0.00	51.2			0.00	**51.22**	*FO (4) Boiler tube leak ww West 7 th floor vestibule starting when SC permit terminated @ 0917 hrs on the 24 th*
Nov 26-Dec 3	0.00	177.5			0.00	**177.50**	*FO (4) Boiler tube leak ww West 7 th floor vestibule @ 1230 Nov 26 SPT passed SSR commissioning*
		4464				**4472**	

ANNUAL SUMMARY 2010 **ANNUAL AVAILABILITY UNIT 1**

YEAR 2010	PERCENT	OUTAGE DURATION	DERATED		ADJ HOURS	*Total Outage*	REASONS FOR OUTAGES/DERATINGS
0	LOAD	HOURS	HRS	MW		*CEA*	***External Conditions in red***
Jan 14-15	41.21		21.83	68	12.83	12.83	*OFD @ 1700 hrs Attem block valve gland blew out*
Jan 15-17	72.73		48.42	120	13.21	13.21	*OFD to 120 mw robbed relay from WCW pump for U2 fd fan*
23-Apr	100.00	8.46			0.00	8.46	*MO State 24 @ 0702 hrs (auto sync testing)*
May 31-June 4	0.00	94.87			0.00	94.87	*MO State 24 @ 1048 hrs (pre outage air heater wash)*
June 12-25	0.00	304.63			0.00	304.63	*MO State 21 @ 1926 hrs (Fire in Switch yard)*
June 28-July 15	0.00	434.0			0.00	434.00	*PO State 25 @ 1121 hrs (zone 30 permit) (FW System)*
July 15-Sept 9	0.00	1350.2			0.00	1350.15	*PO State 25 @ 1321 hrs (zone 20 permit) (Boiler)*
Sept 15-17	0.00	65.0			0.00	65.02	*FO State 21 @ 0100 hrs (leak in Boiler)*
20-Sep	100.00	9.41			0.00	9.41	*FO State 21 (4) (noise in East Fd fan) False alarm*
Sept 26-28	0.00	53.55			0.00	53.55	*FO State 21 (4) Turning gear chain off sprocket sprocket loose on shaft)*
Oct 5-6	0.00	40			0.00	40.00	*OFD State 12 to 110 mw @ 0000 hrs (burner scanners)*
Oct 6-8	48.48		88	80	45.33	45.33	*OFD State 12 to 80 mw @ 1600 hrs (burner scanners) (SWOP issue)*
		2360				**2431**	

ANNUAL SUMMARY 2010 ANNUAL AVAILABILITY UNIT TWO

YEAR 2010	PERCENT	OUTAGE DURATION	DERATED		ADJ HOURS	*Total Outage*	REASONS FOR OUTAGES/DERATINGS
0	LOAD	HOURS	HRS	MW		*CEA*	***External conditions in red***
Jan 2-7	0.00	118.88			0.00	118.88	*MO @ 1804 Jan 2 (A/H Circ Seals East)(CW Pump East leak)HP drains*
jan 7-15	87.88		194.35	145	23.56	23.56	*OFD @ 1657 hrs A/H seals rubbing causing drive motor amps to come in alarm*
15-Jan	100.00	4.7			0.00	4.70	*FO replace protection relay in East FD fan robbed from Unit 1 cw pump E*
Jan 15-22	87.88		355.73	145	43.12	43.12	*OFD @ 1908 hrs A/H seals still rubbing at 145 mw*
Jan 22-Feb 9	93.94		403.49	155	24.45	24.45	*OFD @ 1723 hrs A/H seals still rubbing at 155 mw*
Feb 9-10	93.94		32.38	155	1.96	1.96	*ABNO-FD A/H seals rubbing*
Feb 16-19	0.00	74.91			0.00	74.91	*MO @ 1435 hrs Feb 16, economizer inlet valve repair*
march 30-April 2	0.00	72.8			0.00	72.80	*MO @ 1437 hrs (economizer inlet valve leak)*
21-Apr	100.00	4.45			0.00	4.45	*MO @ 1243 hrs (auto sync testing)*
22-Apr	100.00	6.250			0.00	6.25	*FO @ 0956 hrs (switching to SS (human error)*
10-Jun	0.00	24.12			0.00	24.12	*A/H Wash @ 0943 hrs*
Aug 29-Sept 29	0.00	738.54			0.00	738.54	*PO (Zone 20 boiler @ 1430 hrs)*
Sept 29-Oct 7	0.00	195.05			0.00	195.05	*PO (Zone 10 T/G @ 0902 hrs)*
Oct 7-13	0.00	146.58			0.00	146.58	*Fireside Permit @ 1205 Oct 7*
22-Oct	100.00	0.45			0.00	0.45	*Run down trip*
Oct 22-27	0.00	99.65			0.00	99.65	*FO @ 1052 Oct 22 (No. 2 Bearing leaking oil causing smoking conditions)*
Nov 3-4	0.00	26.25			0.00	26.25	*FO @ 1330 hrs (Boiler Stop valve warm up valve gland leak)*
	100.00				0.00	0.00	
		1513				**1606**	

Annual Summary **ANNUAL AVAILABILITY, UNIT 3**

YEAR 2010	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	*Total Outage CEA*	REASONS FOR OUTAGES/DERATINGS *External Conditions in red*
27-Jan	100.00	1.1			0.00	**1.12**	*MO @ 1412 hrs test west RH intercept valve*
2-Mar	100.00	1.0200			0.00	**1.02**	*MO @ 1422 hrs test west RH intercept valve*
March 23-24	0.00	21.99			0.00	**21.99**	*FO northesat disconnect arcing (external conditions)*
April 8-17	0.00	222.42			0.00	**222.42**	*Convert to SC mode (Permit Time)*
May 4-June 28	0.00	1322.30			0.00	**1322.30**	*Planned Outage State 25 @ 0811 hrs (Steam Generator)*
June 28-July 2	0.00	93.5			0.00	**93.50**	*Sync Condenser off line for (Turbine valve maintenance) @ 1029 hrs June 28*
July 2-Sept 1	0.00	1475.2			0.00	**1475.22**	*Zone 10 T/G Permit issued @ 0802 hrs July 2*
Sept 1-2	0.00	20.5500			0.00	**20.55**	*FEPO State 23 @ 1913 hrs Sept 1 (crack in CW line)*
Sept 8-12	0.00	97.920			0.00	**97.92**	*FO State 21 (3) @ 0955 hrs (arcing on B phase disconnect (B3T3)*
Nov 17-23	0.00	150.9			0.00	**150.85**	*PO State 25 @ 0843 hrs (Convert to Gen mode) Permit time*
29-Nov	100.00	0.8			0.00	**0.75**	*FO @ 1320 hrs (burner issues)*
29-Nov	100.00	1.5			0.00	**1.51**	*FO @ 1705 hrs (burner issues)*
Nov 29-30	23.33		28.7	35.0	22.00	**22.00**	*OFD @ 1836 hrs (burner issues)*
Nov 30-Dec 1	46.67		18.5	70.0	9.89	**9.89**	*OFD @ 2318 hrs to 70 mw (burner issues)*
Dec 1-2	54.00		18.3	81.0	8.44	**8.44**	*OFD @ 1750 hrs to 81 mw (burner issues)*
Dec 2-3	57.33		24.3	86.0	10.36	**10.36**	*OFD @ 1730 hrs to 86 mw (burner issues)*
Dec 3-7	60.67		97.2	91.0	38.23	**38.23**	*OFD @ 1746 hrs to 91 mw (burner issues)*
Dec 7-30	92.00		546.0	138.0	43.68	**43.68**	*OFD @ 1858 hrs to 138 mw (burner issues)*
Dec 30-31	0.00	17.470			0.00		*FO @ 1257 hrs Fuel Oil Pump West trip)*
31-Dec	92.00		17.6	138.0	1.41		*OFD @ 0625 hrs to 138 mw (burner issues)*
		3427				**3542**	

	ANNUAL	SUMMARY	2011		ANNUAL AVAILABILITY UNIT 1		
YEAR	PERCENT	OUTAGE	DERATED		ADJ	***Total***	REASONS FOR OUTAGES/DERATINGS
2011		DURATION			HOURS	***Outage***	
0	LOAD	HOURS	HRS	MW		***CEA***	*External Conditions in red*
Feb 4-5	0.00	16.34			0.00	16.34	*(FO) Attemperator spray line leak 2 nd floor*
April 1-2	100.00	1.08			0.00	1.08	*"MO" Replace / adjust brushes*
10-May	100.00	2			0.00	2.00	*"MO" Inspect/replace brushes*
12-May	100.00	1			0.00	1.00	*"FO" HP Heater induction check*
June 11-14	0.00	74.54			0.00	74.54	*"FO" Boiler tube leak on start up*
25-Jun	100.00	6.7			0.00	6.70	*"MO" Pre- outage Air heater wash*
Aug 8-Oct 22	0.00	1808.4			0.00	1808.35	*"PO" WTP PLC and clarifier upgrade & annual outage*
Oct 29-Nov 1	0.00	82.0			0.00	82.00	*"FO" FDFE motor fail will not start*
Nov 1-3	0.00	43.05			0.00	43.05	*"FO" BFUEL PE seal leak*
3-Nov	100.00	9			0.00	9.00	*"FO" SE H2 Cooler water leak*
Nov 3-10	84.85		160.95	140	24.39	24.39	*"OSD" EVT Safety valves*
	100.00				0.00	0.00	
		2027				**2068**	

	ANNUAL	SUMMARY	2011		ANNUAL AVAILABILITY		UNIT TWO
YEAR	PERCENT	OUTAGE	DERATED		ADJ	***Total***	REASONS FOR OUTAGES/DERATINGS
2011		DURATION			HOURS	***Outage***	
0	LOAD	HOURS	HRS	MW		***CEA***	*External conditions in red*
Feb 10-23	93.94		315.31	155	19.11		*OFD to 155 mw @ 0941 hrs (East A/H seals rubbing)*
7-Mar	100.00	7.69			0.00		*DA Check valve from HP drains abroad Unit back working normal*
18-Mar	100.00	6.17			0.00		*MO CW line N. Patch CBD tank*
3-Apr	100.00	1.43			0.00		*MO @ 0102 hrs - 0228 hrs (Check brushes)*
June 20-30	48.48		239.12	80	123.18		*ABNO-SD @ 1421 hrs BFP West O/H*
June 30-Sept 13	0.00	1804.62			0.00		*PO State 25 @ June 30 @ 1328 hrs (Boiler Zone 20)*
July 12-Sept 10	0.00	1441.78			0.00		*PO State 25 (Boiler Zone 10 @ 1605 hrs July 12-Sept 10 @ 1752 hrs)*
July 15-Sept 9	0.00	1349.52			0.00		*PO State 25 (Boiler Zone 30 @ 1345 hrs July 15-Sept 9 @ 1916 hrs)*
Sept 22-27	0.00	106.5			0.00		*FO State 21 (4) Boiler tube failure) (Pressure Test successful @ 1130 hrs sept 26*
							Water side permit continued until 2000 hrs on Sept 27
Oct 4-13	72.73		218.8	120	59.68		*OSD (EVT Safety valves)*
Oct 5-6	100.00	7.460			0.00		*MO State 24 Test E & P O/S trips POST 3958 rpm EOST 3710 rpm*
Oct 27-Nov 4	84.85		202.00	140	30.61		*OFD State 12 @ 1800 hrs (3D Burner not commissioned in BMS)*
Nov 14-21	100.00		176.57				*No. 4 & 5 heaters u/s @ 0506 hrs (No. 5 vent valve) (Selected Components)*
Nov 21-25	100.00		120				*No. 6 out @ 1340 hrs with 4 & 5 due to level control) (Selected Components)*
	0.00	4725.17					
		4725.17			**232.58**		

Annual Summary **ANNUAL AVAILABILITY, UNIT 3**

YEAR 2011	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	***Total Outage CEA***	REASONS FOR OUTAGES/DERATINGS *External Conditions in red*
Dec 31-Jan 14	92.00		344.13	138	27.53	**27.53**	*OFD @ 0625 hrs Dec 31 to 138 mw (burner issues)*
14-Jan	100.00	1.9700			0.00	**1.97**	*FO (4) rotation check on uncoupled west fuel pump motor*
Jan 14-27	92.00		290.78	138	23.26	**23.26**	*OFD @ 1631 hrs Jan 14 to 138 mw (burner issues)*
jan 27-30	92.00		67.29	138	5.38	**5.38**	*ABNO FD @ 1918 hrs January 27 (burner Issues)*
jan 30-Feb 3	92.00		465.8	138	37.26	***58.15***	*OFD @ 1435 hrs Jan 30 to 138 mw (burner issues)*
Feb 3-11	93.33		183.8	140	12.25	**12.25**	*OFD @ 1715 hrs Jan 30 to 140 mw (burner issues)*
March 23-April 16	0.00	579.9			0.00	**579.90**	*FO @ 1606 hrs (Exciter Brush Failure)/SC changeover*
April 26-June 24	0.00	1424.0			0.00	**1424.00**	*Planned Outage @ 0800 hrs (Zone 20 Permit)*
April 28-29	100.00	10.640			0.00	**10.64**	*Planned Outage(AOP Failure)*
2-Jun	100.00	4.4			0.00	**4.35**	*Planned Outage (Off to check brushes for 4.35 hrs)*
May 3-July 19	0.00	1849.5			0.00	**1849.48**	*Planned Outage @ 1316 hrs (Zone 30 Permit) HP & LP Feedwater systems*
Aug 8-15		184.0			0.00	**184.00**	*Planned Outage @ 0800 hrs (WTP PLC & Clarifier upgrade) TPO*
Aug 15-	0.00	1008.0			0.00	**1008.00**	*Planned outage @ 0849 hrs (Zone 20 permit blowdown tank installation)*
22-Aug	0.00	16.8			0.00	**16.83**	*Planned outage at 0602-2252 (new MCC tie in)*
Aug 22-	0.00	840.0			0.00	**840.00**	*Planned Outage @ 2252 (Zone 20 still blowdown tank installation)*
27-Sep	100.00	5.15			0.00	**5.15**	*MO to repalce brushes (none in warehouse)*
29-Sep	100.00	4.70			0.00	**4.70**	*MO Replace Brushes*
6-Oct	100.00	2.8			0.00	**2.79**	*MO State 24 (1325-1612 hrs) Replace Brushes*
Nov 14-30	0.00	390.9			0.00	**390.88**	*PO (Convert to Gen mode & Front Standard maint)*
	0.00	**6322.690**			**0.00**	**6332.97**	

APPENDIX E

Service Contracts

Holyrood Thermal Generating Station
Service Contracts

	Service Contract	**Company**
1)	Boiler Maintenance	Babcock and Wilcox
2)	Turbine / Generator Maintenance	Alstom
3)	Non- Destructive Testing	Team Industrial Services
4)	Motor Repairs	*To be tendered*
5)	Inverter Service	*To be tendered*
6)	Vacuum Truck and Pressure Washing	Pardy's Waste Management
7)	Safety Valve Repairs	New Valve Services
8)	Elevator Service	Thyssen Krupp
9)	Heating, Ventilation and Air Conditioning Service	Johnson Controls
10)	Distributed Control System Service	Invensys Systems Canada
11)	Cranes Maintenance Service	Atlantic Cranes
12)	Tanker and Boom Service	Shirickden
13)	Controlled Waste Landfill Maintenance	Hubert Murphy Ltd
14)	Fire System Service	Simplex Grinnell
15)	Stack Testing	Air Testing Services
16)	Laboratory Equipment Service	HACH
17)	Lube Oil Analysis	Wear Check
18)	Asbestos and Heavy Metals Abatement	Parker Kaefer
19)	Air Sampling and Testing	Enviroteck
20)	Waste Water Consulting and Unit Inspection	GE Betz
21)	Lab Analysis and Waste Water Treatment	Jacques Whitford Ltd
22)	Performance Monitoring	General Physics Ltd
23)	Insulation Services	Parker Kaefer
24)	Pump Maintenance Services	Pennecon Energy Technical Services

APPENDIX F

Generation Planning Issues 2010 July Update

GENERATION PLANNING ISSUES
2010 JULY UPDATE

System Planning Department
July 2010

Executive Summary

This report provides an overview of the Island Interconnected System (System) generation capability, the proposed timing of the next requirement for additional generation supply, the resources available to meet that requirement, and identifies any issues that need to be considered to ensure that a decision on the preferred source can be made through an orderly and cost-effective process.

The Province's 2007 Energy Plan outlines specific measures to address environmental concerns related to the Holyrood Thermal Generating Station (HTGS). The long-term plan proposed in the Energy Plan is to replace the energy provided by the HTGS with electricity from the Lower Churchill development through a High Voltage Direct Current (HVdc) transmission link from Labrador to the island. In the event the Lower Churchill Project does not proceed, scrubbers and precipitators are to be installed at the HTGS. This requires Newfoundland and Labrador Hydro (Hydro) to maintain two preliminary generation expansion plans; one for the HVdc link and one for the Isolated Island scenario. Under both scenarios based on an examination of the System's existing plus committed capability, in light of the 2010 Planning Load Forecast (PLF) and the generation planning criteria, capacity (Loss of Load Hours (LOLH)) deficits start in 2015. There are no energy deficits in either case until post-2019.

In order to protect the in-service date for the Island Pond hydroelectric development alternative, which has been identified as the preferred next source of generation from Hydro's portfolio, under an Isolated Island scenario, the addition of a Request for Proposal (RFP) process necessitates a decision to proceed in late 2010 to meet an in-service date of fall 2015. This is due to the need to complete the RFP evaluation and subsequent Newfoundland and Labrador Board of Commissioners of Public Utilities (Board) review and have a final decision by spring 2012.

It should be noted that while Hydro is closely monitoring potential emissions reductions regulations, the analysis presented does not model potential costs or credits under an environmental mitigation strategy such as a cap-and-trade system.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- HVdc Transmission Link – Hydro must be prepared for events that may delay the proposed Lower Churchill Project or if the project is not sanctioned;
- HTGS End-of-Life – Hydro must determine what is required to ensure the HTGS can be operated reliably under both a HVdc link future and an Isolated Island future. For the latter case, other future generation sources should be considered;
- Government Emissions Reductions Initiatives – Hydro must remain vigilant in considering the impact that Government emissions reductions initiatives could have on production costing and future generation planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling for all new generation sources due to increased environmental assessments in the form of Environmental Impact Studies;
- Fuel displacement – Hydro must continue to pursue and develop projects and incorporate energy conservation activities that are technically and economically feasible to displace fuel at the HTGS;
- Industrial expansion and contraction – Hydro must continue to assess, as updated information is provided, the impacts of industrial activity both positive and negative on the System's capacity and firm energy balance;
- Resource Inventory – Hydro must ensure that it maintains a current inventory of resource options with sufficient study as to provide confidence in overall project concept, costs and schedules.
- Demand reduction initiatives through demand management programs and rate design considerations

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Appendix A A1

1.0 Introduction

This report provides an overview of the Island Interconnected System (System) generation capability, the timing of the next requirement for additional generation supply, the resources available to meet that requirement, and identifies any issues that need to be considered to ensure that a decision on the preferred source can be made through an orderly process.

In September 2007, the Provincial Government released its Energy Plan. The Energy Plan directed Hydro to evaluate two options to deal with environmental concerns at the Holyrood Thermal Generating Station (HTGS). Option A was to replace HTGS produced electricity with electricity from the Lower Churchill River development via a High Voltage Direct Current (HVdc) transmission link to the Island. Option B was to install scrubbers and electrostatic precipitators to control emissions at the HTGS and maximize the use of wind, small hydro and energy efficiency programs to reduce the reliance on HTGS produced electricity. These two options require significantly different strategies to effectively implement and require the development of two separate, preliminary, generation expansion plans to manage the near-term until a decision is made on which option will be pursued for future development.

This report addresses the timing of the next requirement, in light of the most recent load forecast, for additional generation supply under both options and the resources available to meet that requirement. The report also identifies any issues that need to be addressed to ensure that a decision on the preferred source can be made through an orderly and cost-effective process.

2.0 Load Forecast

This review utilizes the 2010 Planning Load Forecast (PLF) as prepared by the Market Analysis section of Hydro's System Planning Department during the winter of 2009/2010. Long-term load forecasts for the Province are derived using Hydro's own electricity demand models and are driven by corresponding Provincial economic forecasts that are regularly prepared for Hydro by the Department of Finance, Government of Newfoundland and Labrador. Some key assumptions respecting existing and incremental economic activity impacting electricity demand and supply futures are:

- Single Island newsprint operation at Corner Brook and single Island oil refining operation at Come by Chance;
- Vale Inco NL nickel processing facility at Long Harbour with initial connection in late 2011 and commercial production occurring across the 2013[1] to 2014 period;
- Teck Resources Limited mining operations at Duck Pond continuing through 2013[2]; and
- Development of the Hebron oil field.

Growth rate summaries of the salient high-level economic indicators for the province as forecast by the provincial Department of Finance are presented in Table 2-1.

[1] Amended 2002 Development Agreement, Vale Inco and the Government of Newfoundland and Labrador
[2] Teck Cominco 2007 Annual Report.

Table 2-1

Provincial Economic Indicators – 2010 PLF			
	2009-2014	2009-2019	2009-2029
Adjusted Real GDP at Market Prices* (% Per Year)	1.5%	1.0%	0.9%
Real Disposable Income (% Per Year)	1.5%	1.0%	0.9%
Average Housing Starts (Number Per Year)	2575	2400	2135
End of Period Population ('000s)	515	510	507
*Adjusted GDP excludes income that will be earned by the non-resident owners of Provincial resource developments to better reflect growth in economic activity that generates income for local residents.			

Hydro is responsible for the generation planning for the System and that includes the power and energy supplied by Hydro's customer-owned-generation resources in addition to Hydro's bulk and retail electricity supply, including power purchases. The projected electricity growth rates for the System are presented in Table 2-2.

An important source of load growth for the utility sector on the Island continues to be the unwavering preference for electric water heating systems along with a majority preference for electric space heating across residential and commercial customers. For Hydro's existing industrial customers, single newsprint mill and oil refinery operations are maintained with the Teck Resources mine expected to operate through 2013. The Vale Inco NL nickel processing facility is scheduled to be provided a transmission connection in late 2011 with commercial production expected in the 2013 to 2014 time frame.

Table 2-2

Electricity Load Growth Summary – 2010 PLF			
	2009-2014	2009-2019	2009-2029
Utility[1]	1.8%	1.2%	1.2%
Industrial[2]	7.1%	3.8%	1.9%
Total	2.7%	1.7%	1.3%

1. Utility load is the summation of Newfoundland Power and Hydro Rural.
2. AbitibiBowater ceased production of newsprint at its Grand Falls mill in February 2009. Industrial load post 2009 is the summation of Corner Brook Pulp and Paper, North Atlantic Refining, Teck Resources and Vale Inco NL

Table 2-3 provides a summary of the 2010 PLF electric power and energy requirements for the System for the period 2010 to 2019. Similar long-term load projections are prepared for the Labrador Interconnected System and for Hydro's Isolated Diesel Systems to derive a Provincial electricity load forecast. Appendix A contains the longer term PLF that was used to complete the generation expansion analysis.

Table 2-3

Electricity Load Summary – 2010 Island PLF						
	Utility[1]		Industrial[1]		Total System[2]	
	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)
2010	1,342	6,115	190	1,278	1,519	7,585
2011	1,360	6,244	195	1,271	1,538	7,709
2012	1,385	6,292	228	1,362	1,571	7,849
2013	1,400	6,410	276	1,604	1,601	8,211
2014	1,423	6,496	269	1,789	1,666	8,485
2015	1,440	6,551	269	1,853	1,683	8,606
2016	1,452	6,567	269	1,853	1,695	8,623
2017	1,461	6,601	269	1,853	1,704	8,663
2018	1,471	6,670	269	1,853	1,714	8,732
2019	1,486	6,739	269	1,853	1,729	8,803

Note: 1. Utility and Industrial demands are non-coincident peak demands.
2. Total System is the total Island Interconnected System and includes losses. Demands are coincident peak demands.

3.0 System Capability

Hydro is the primary supplier of system capability to the Island Interconnected System, accounting for 78 percent of its net capacity and 78 percent of its firm energy. Capability is also supplied by customer generation from Newfoundland Power Inc., and Corner Brook Pulp and Paper Limited (Kruger Inc.) Hydro also has contracts with two Non-Utility Generators (NUGs) for the supply of power and energy as well as contracts with two wind power projects that became operational in late 2008 and early 2009. Hydro also receives energy from the expropriated assets at Star Lake and on the Exploits River.

Hydroelectric generation accounts for 64 percent of the System's existing net capacity and firm energy capability. The remaining net capacity comes from wind farms and thermal resources. The thermal resources are made up of conventional steam, combustion turbine and diesel generation plants. Of the existing thermal capacity, approximately 71 percent is located at the HTGS and is fired using 0.7 percent sulphur No. 6 fuel oil. The remaining capacity is located at sites throughout the Island. A complete breakdown of the System's existing capability is provided in Table 3-1.

Table 3-1

Island Interconnected System Capability – As of June 2010			
* - non-dispatchable (see Section 9.1)	Net Capacity [MW]	Energy [GWh]	
		Firm	Average
Newfoundland & Labrador Hydro			
Bay d'Espoir	592.0	2,272	2,629
Upper Salmon	84.0	492	561
Hinds Lake	75.0	290	343
Cat Arm	127.0	678	710
Granite Canal	40.0	191	223
Paradise River	8.0	33	37
Snook's, Venam's & Roddickton Mini Hydros	1.3	5	7
Total Hydraulic	927.3	3,961	4,510
Holyrood	465.5	2,996	2,996
Combustion Turbine	110.0	-	-
Hawke's Bay & St. Anthony Diesel	14.7	-	-
Total Thermal	590.2	2,996	2,996
Total NL Hydro	**1,517.5**	**6,957**	**7,506**
Newfoundland Power Inc.			
Hydraulic*	96.6	324	428
Combustion Turbine	36.5	-	-
Diesel	7.0	-	-
Total	140.1	324	428
Corner Brook Pulp and Paper Ltd.			
Hydraulic*	121.4	793	879
Star Lake and Exploits Generation			
Hydraulic*	105.8	634	761
Non-Utility Generators			
Corner Brook Cogen*	15.0	65	65
Rattle Brook*	4.0	13	16
St. Lawrence Wind*	27.0	92	104
Fermeuse Wind*	27.0	75	84
Total	73.0	245	269
Total Island Interconnected System	**1,957.8**	**8,953**	**9,843**

4.0 Planning Criteria

Hydro has established criteria related to the appropriate reliability, at the generation level, for the System that sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the System to ensure an adequate supply for firm demand; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities the following have been adopted:

Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more that 2.8 hours per year[3].

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability[4].

5.0 Identification of Need

Table 5-1 presents an examination of the HVdc link and Isolated Island load forecasts compared to the planning criteria. It does not incorporate Hydro's preliminary expansion plan to show uncommitted generation additions. In 2006, firm system capability was updated to reflect a 115 GWh increase in Hydro's hydroelectric-plant capability. This change was the result of a hydrology adjustment and the use of an integrated system model which determines a more

[3] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.
[4] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (HTGS) is based on energy capability adjusted for maintenance and forced outages.

realistic firm system capability. Previously, firm system capability was calculated using the summation of individual firm values provided by the design consultants of each facility.

Table 5-1 illustrates when supply capacity and firm capability will be outpaced by forecasted electricity demand under the two different expansion scenarios being considered. The table shows that under both the HVdc link and Isolated Island scenarios, capacity (LOLH) deficits (LOLH exceeding 2.8 hours per year) start in 2015 but that there are no energy deficits in either case until post-2019. Since the closure of the pulp and paper mills in Stephenville and Grand Falls, capacity deficits now precede energy deficits indicating that the system is now capacity, rather than energy, constrained.

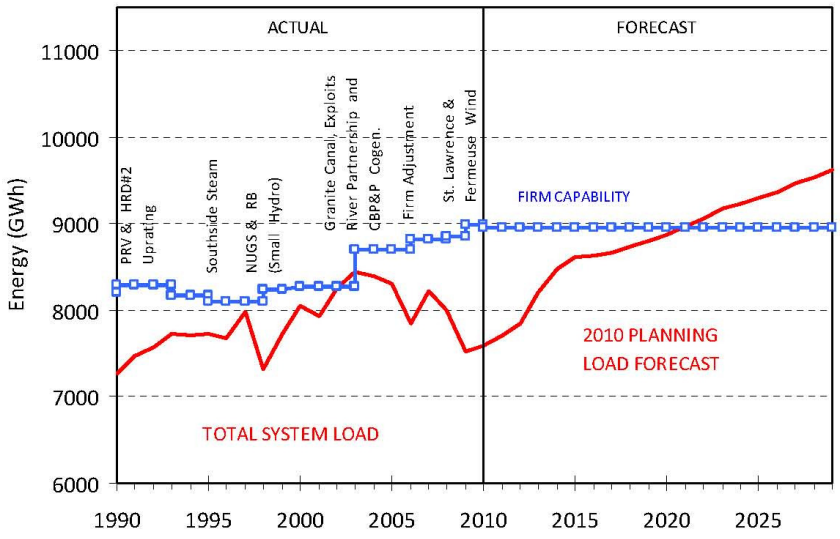
It should be noted that the capacity deficits trigger the need for the next generation source by 2015 under the current planning criteria. Under the expansion scenario ultimately pursued, this need may be met by different sources as explained in the Preliminary Generation Expansion Analysis section (Section 7).

Table 5-1 – Load Forecast Compared to Planning Criteria

Year	Island Load Forecast		Existing System		LOLH (hr/year) (limit: 2.8)		Energy Balance (GWh)	
	Maximum Demand (MW)	Firm Energy (GWh)	Installed Net Capacity (MW)	Firm Capability (GWh)	HVdc Link	Isolated Island	HVdc Link	Isolated Island
2010	1,519	7,585	1,958	8,953	0.15	0.15	1,368	1,368
2011	1,538	7,709	1,958	8,953	0.22	0.22	1,244	1,244
2012	1,571	7,849	1,958	8,953	0.41	0.41	1,104	1,104
2013	1,601	8,211	1,958	8,953	0.84	0.84	742	742
2014	1,666	8,485	1,958	8,953	2.52	2.52	468	468
2015	1,683	8,606	1,958	8,953	3.41	3.41	347	347
2016	1,695	8,623	1,958	8,953	3.91	3.91	330	330
2017	1,704	8,663	1,958	8,953	4.55	4.55	290	290
2018	1,714	8,732	1,958	8,953	5.38	5.38	221	221
2019	1,729	8,803	1,958	8,953	6.70	6.70	150	150

Figure 5-1 presents a graphical representation of historical and forecasted load and system capability for the HVdc link and Isolated Island scenarios. It is a visual representation of the energy balance shown in Table 5-1.

Figure 5-1
Island Interconnected System Capability vs. Load Forecast



6.0 Near-Term Resource Options

This section presents a summary of identified near-term generation expansion options. It represents Hydro's current portfolio of alternatives that may be considered to fulfill future generation expansion requirements. Included is a brief project description as well as discussion surrounding project schedules; the basis for capital cost estimates; issues of bringing an alternative into service; and other issues related to generation expansion analysis.

6.1 Island Pond

Island Pond is a proposed 36 MW hydroelectric project located on the North Salmon River, within the watershed of the existing Bay d'Espoir development. The project would utilize approximately 25 metres of net head between the existing Meelpaeg Reservoir and Crooked Lake to produce an annual firm and average energy capability of 172 GWh and 186 GWh, respectively.

The development would include the construction of a three kilometre diversion canal between Meelpaeg Reservoir and Island Pond, which would raise the water level in Island Pond to that of the Meelpaeg Reservoir. Also, approximately 3.4 kilometres of channel improvements would be constructed in the area. At the south end of Island Pond, a 750 metre long forebay would pass water to the 23 metre high earth dam, and then onto the intake and powerhouse finally discharging it into Crooked Lake via a 550 metre long tailrace. The electricity would be produced by one 36 MW Kaplan turbine and generator assembly.

The facility would be connected to TL263, a nearby 230 kV transmission line connecting the Granite Canal Generating Station with the Upper Salmon Generating Station.

Schedule and Cost Estimate Basis

To ensure that Hydro is in a position to properly evaluate Island Pond, an outside consultant was commissioned to prepare a final-feasibility level study and estimate. The final report, *Studies for Island Pond Hydroelectric Project*, was presented to Hydro in December 2006. The report prepared a construction ready update report including an updated capital cost estimate and construction schedule. In the absence of any further work beyond what was identified, the overall schedule is estimated to be approximately 42 months from the project release date to the in-service date.

6.2 Portland Creek

Portland Creek is a proposed 23 MW hydroelectric project located on Main Port Brook, near Daniel's Harbour, on the Northern Peninsula. The project would utilize approximately 395 metres of net head between the head pond and outlet of Main Port Brook to produce an annual firm and average energy capability of 99 GWh and 142 GWh, respectively.

The project would require: a 320 metre long diversion canal; three concrete dams; a 2,900 metre penstock; a 27 kilometre 66 kV transmission line from the project site to Peter's Barren Terminal Station; and the construction of access roads. The electricity would be produced by two 11.5 MW Pelton turbine and generator assemblies.

Schedule and Cost Estimate Basis

The current schedule and capital cost estimate for Portland Creek is based on a January 2007 feasibility study, *Feasibility Study for: Portland Creek Hydroelectric Project*, prepared for Hydro by outside consultants. The proposed construction schedule indicates a construction period of 32 months from the project release date to the in-service date. The main activities that dictate the schedule are the construction of access roads and the procurement of the turbine and generator units.

6.3 Round Pond

Round Pond is a proposed 18 MW hydroelectric project located within the watershed of the existing Bay d'Espoir development. The project would utilize the available net head between the existing Godaleich Pond and Long Pond Reservoir to produce an annual firm and average energy capability of 108 GWh and 139 GWh, respectively.

Schedule and Cost Estimate Basis

The current schedule and capital cost estimate for Round Pond is based on the 1988 feasibility study, *Round Pond Hydroelectric Development*, prepared for Hydro by outside consultants, and the associated 1989 Summary Report based on the same. In the absence of any further work beyond what was identified in this study, the overall program for the Round Pond development is estimated to be completed in 33 months, including detailed engineering design. The period for site works includes two winter seasons during which construction activities can be expected to be curtailed. Work on transmission line, telecontrol and terminal equipment would be incorporated in this schedule.

6.4 Wind Generation Projects

The Island of Newfoundland has a world-class wind resource with many sites exhibiting excellent potential for wind-power development. Despite this, there are a number of operational constraints that limit the amount of additional non-dispatchable generation that can be accepted into the System. In January 2007, Hydro signed its first power purchase agreement (PPA) for 27 MW of wind power located at St. Lawrence and in December 2007 it signed a second PPA for another 27 MW of wind power located at Fermeuse. Both of these projects are currently generating power into the Island grid. Pending further review and eventual operating experience and with the loss of the load associated with the shutdown of the Grand Falls Pulp and Paper Mill in late 2008, it was decided to postpone a RFP for a third wind farm, as the potential for spill, due to the additional non-dispatchable generation, makes the project economically unattractive (see Section 9.1 Intermittent and Non-Dispatchable Resources).

Any future wind farm would potentially consist of a number of interconnected wind turbines, each ranging in size from 1.8 to 3.0 MW (or larger, as the technology becomes

available), tied to a single delivery point on the System's transmission network. For example, a nominal 25 MW wind farm could consist of eight turbines and, depending on the location's wind resource, produce an estimated annual firm and average energy capability of approximately 70 and 110 GWh, respectively.

Hydro would not develop wind-based projects strictly to address capacity deficits due to the inability to selectively dispatch turbines during periods of high demand. However, these projects do carry some inherent capacity value based on their positive influence on the LOLH calculation and could possibly defer the need for other new generation sources.

Schedule and Cost Estimate Basis

Wind projects typically require at least six to eight months of site-specific environmental monitoring to adequately define the resource. Project development, environmental review and feasibility studies for attractive sites are typically initiated concurrent with the resource study and are finalized shortly after completing the resource assessment. The final design and construction for a wind farm could be completed over an additional 12 to 18 months. The overall project schedule is approximately 30 months from the project release date to the in-service date. Additional time may be required, depending on market conditions, to secure turbine delivery.

6.5 Combined Cycle Plant

The combined cycle facility, also known as a combined-cycle combustion turbine (CCCT) facility, consists of a combustion turbine fired on light oil (in the absence of natural gas), a heat recovery steam generator, and a steam turbine generator.

Two alternative sites are being considered and estimates have been prepared based on two different power ratings at each site. One alternative calls for a proposed combined-cycle plant to be located at the existing HTGS to take advantage of the operational and capital cost savings associated with sharing existing facilities. The other alternative is to develop a greenfield site at a location that has yet to be determined. The greenfield alternative may be preferred due to environmental constraints that may be placed on any new developments at Holyrood and reduce the risk of loss of multiple generation sources in the event of major events.

In either alternative, the power ratings being considered are either a 125 MW or a 170 MW (net) CCCT facility. The annual firm energy capability is estimated at 986 GWh for the 125 MW option and 1,340 GWh for the 170 MW option.

Schedule and Cost Estimate Basis

It is expected that a combined-cycle plant would require an Environmental Preview Report (EPR) with the guidelines for its preparation similar to the 1997 review of the proposed Holyrood Combined Cycle Plant. The overall project schedule is estimated to be at least 36 months from the project release date to the in-service date.

The capital cost estimate for each power rating of the Holyrood Combined Cycle Plant is based on the *Combined Cycle Plant Study Update, Supplementary Report* which was completed in 2001, with a review by Hydro's Mechanical Engineering Department in 2009 and updated to 2010.

6.6 Holyrood Thermal Generating Station Unit IV

HTGS Unit IV is a 142.5 MW (net) conventional steam unit fired on heavy oil and is based on similar technology as the three existing HTGS units. The unit would be located at

the HTGS adjacent to the existing units. The annual firm energy capability is estimated at 936 GWh.

Schedule and Cost Estimate Basis

It is expected that the HTGS Unit IV project would require, at a minimum, an EPR with the guidelines for its preparation similar to that of a 1997 review of the proposed project. The overall project schedule is estimated to be approximately 51 months from the project release date to the in-service date.

Sensitivity analysis has demonstrated that the capital cost of the proposed HTGS Unit IV project would have to drop considerably compared with the combined-cycle option given that environmental mitigation requirements, which would be required for this facility, will increase the cost of such a facility. As well, GHG emission rates for conventional steam units exceed those for combined-cycle plants, further adding to the cost. It is highly unlikely that this option would be competitive with a combined-cycle option. Therefore, Hydro will continue to include the proposed HTGS Unit IV project in its portfolio of alternatives but the cost estimate should be updated, in detail, when the appropriate sensitivity analysis identifies the project as a potential near-term addition.

6.7 Combustion Turbine Units

These nominal 50 MW (net), simple-cycle combustion turbines (CT) would be located either adjacent to similar existing units at Hydro's Hardwoods and Stephenville Terminal Stations, at the Holyrood site or at greenfield locations. They are fired on light oil and due to their modest efficiency relative to a CCCT plant, they are primarily deployed for peaking and voltage support functions but, if required, can be utilized provide an annual firm energy capability of 394 GWh each.

Schedule and Cost Estimate Basis

It is anticipated an EPR would be required for each proposed CT project. The overall project schedule is estimated to be at least 36 months from the project release date to the in-service date.

The capital cost estimate for these units was reviewed in 2009, by Hydro's Mechanical Engineering Department and updated in 2010. Approximately 90 percent of the direct cost is for the gas turbine package and due to recent fluctuations in demand for gas turbines; prices remain volatile. Hydro should continue to monitor turbine prices to determine when a further in-depth review of the capital cost estimates becomes necessary.

6.8 High Voltage Direct Current (HVdc) Link

As part of the potential development of the lower Churchill River (Lower Churchill Project), a HVdc link would be constructed to the Island to replace power and energy required from the HTGS and to help meet the future energy requirements of the Island. The schedule and capital cost estimate for this project is currently under development.

7.0 Preliminary Generation Expansion Analysis

To provide an indication of the timing and scale of future resource additions required over the load forecast horizon, Hydro uses *Ventyx Strategist*® software to analyse and plan the generation requirements of the System for a given load forecast. *Strategist*® is an integrated, strategic planning computer model that performs, amongst other functions, generation system reliability analysis, projection of costs simulation and generation expansion planning analysis.

The expansion scenarios presented are considered preliminary and they have not been submitted for approval by the Board. In the Province's Energy Plan, Hydro has been directed to pursue one of two options for dealing with environmental concerns related to the HTGS. The first option is based on replacing the HTGS with energy from the Lower Churchill River development via a HVdc link to the Island. The second option is based on an isolated System and is similar to present day operations but the HTGS environmental concerns of sulphur dioxide (SO_2) and particulate emissions will be addressed via the addition of scrubbers and electrostatic precipitators. The scrubbers and electrostatic precipitators will not address greenhouse gas issues. These two options have been named for the purposes of this report as the HVdc link scenario and the Isolated Island scenario.

These expansion plan scenarios represent Hydro's preferred path, utilizing resources from the identified portfolio.

The generation expansion analysis uses an 8.00 percent discount rate with all costs modeled in current (as spent) Canadian dollars, and the results discounted to the base year of 2010.

Based on the study assumptions outlined previously, the least-cost[5] generation expansion plan, under the two scenarios, is shown below in Table 7-1 and graphically in Figures 7-1 and 7-2.

[5] For Hydro, the term "least-cost" refers to the lowest Cumulative Present Worth (CPW) of all capital and operating costs associated with a particular incremental supply source (or portfolio of resources) over its useful economic life, versus competing alternatives or portfolios. CPW concerns itself only with the expenditure side of the financial equation. The lower the CPW, the lower the revenue requirement for the utility and hence, the lower the electricity rates will be. By contrast, the term Net Present Value (NPV) typically refers to a present value taking into account both the expenditure and revenue side of the financial equation, where capital and operating expenditures are negative and revenue is positive. The alternative with the higher NPV has the greater return for the investor.

7.1 High-Voltage Direct Current Link Scenario

Under the HVdc link scenario, a 50 MW CT would be planned for 2014. Dependant on environmental assessment approvals, the current schedule could see Lower Churchill Project commissioning and operations in the 2015-2016 timeframe and this would provide Hydro's system capability requirements well beyond the horizon of this expansion analysis. As well, the existing 50 MW CTs at Hardwoods and Stephenville would be retired in 2022 and 2024, respectively.

7.2 Isolated Island Scenario

Under the Isolated Island scenario, the third wind project would be planned for 2014, in the same time frame the additional load from the Vale Inco NL facility is forecast to come on to the grid, enabling the grid to absorb more non-dispatchable generation. Wind is considered due to the benefits of fuel displacement and emissions reductions at the HTGS. The final decision on whether or not to proceed with a wind project will require further analysis to determine the optimal timing, and size of a potential project.

The next supply options in the least-cost generation expansion scenario are the indigenous hydroelectric plants of Island Pond in 2015, Portland Creek in 2018, and Round Pond in 2020 followed by a 170 MW CCCT plant in 2022 and 50 MW CTs in 2024 and 2027. The CCCT plant is indicative of the most economic thermal plant for supplying base load, which the Island would require in the long-term for firm capability as an isolated system.

For the Isolated Island scenario, further additions of thermal-electric plants can be expected post 2029. Many of Hydro's assets are nearing their expected end-of-life and it is important to point out that under both expansion plans, the 54 MW combustion turbines located at Hardwoods and Stephenville are scheduled to retire during the study period.

While the expansion plans are indicative of the scale of future requirements, any final decision on resource additions will be made at an appropriate time in the future following a full review and allowing time for proper implementation. These, and other issues, are discussed further in the following section.

Table 7-1

2010 Generation Expansion Plans (Preliminary)		
Year	HVdc Link Scenario Hydro's Alternatives (Capacity/Firm Capability)	Isolated Island Scenario Hydro's Alternatives (Capacity/Firm Capability)
2010		
2011		
2012		
2013		
2014	CT (50 MW/394.2 GWh)	Wind Farm (25 MW/77 GWh)
2015		Island Pond (36MW/172 GWh)
2016	HVdc link (800 MW)	
2017		
2018		Portland Creek (23 MW/99 GWh)
2019		
2020		Round Pond (18 MW/108 GWh)
2021		
2022	Hardwoods CT retired	CCCT (170 MW/1,340 GWh) Hardwoods CT retired
2023		
2024	Stephenville CT Retired	CT (50 MW/394.2 GWh) Stephenville CT Retired
2025		
2026		
2027		CT (50 MW/394.2 GWh)
2028		
2029		
Note: The HVdc link expansion plan satisfies Hydro's generation planning criteria well beyond the 2029 planning horizon. However, the Isolated Island expansion plan will require further additions as HTGS units are retired beginning in 2033 (estimated).		

Figure 7-1
Preliminary HVDC Link Expansion Plan vs. Load Forecast

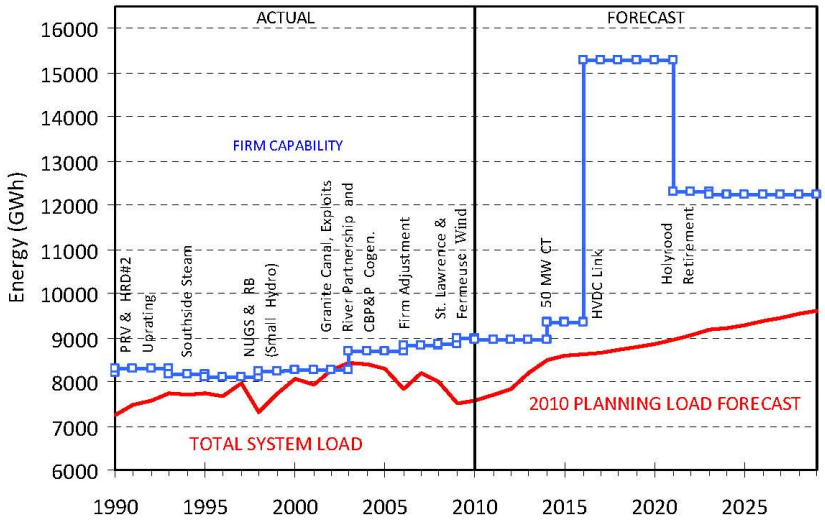
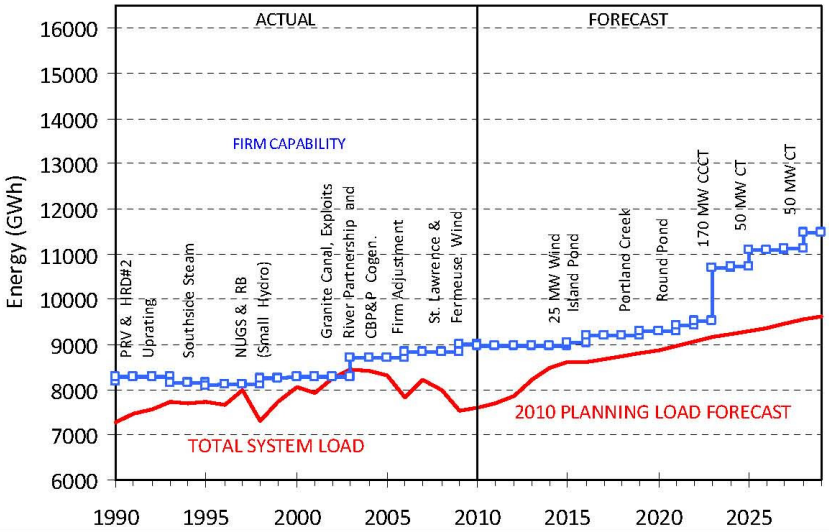


Figure 7-2
Preliminary Isolated Island Expansion Plan vs. Load Forecast



8.0 Timing of Next Decision

8.1 Request for Proposals

In addition to those resources included in Hydro's own portfolio of near term alternatives, any number of alternatives may be brought forward under a RFP. As with the 1997 RFP, alternatives submitted under a general RFP can range from various forms of conventional technologies to alternate technologies such as wind power.

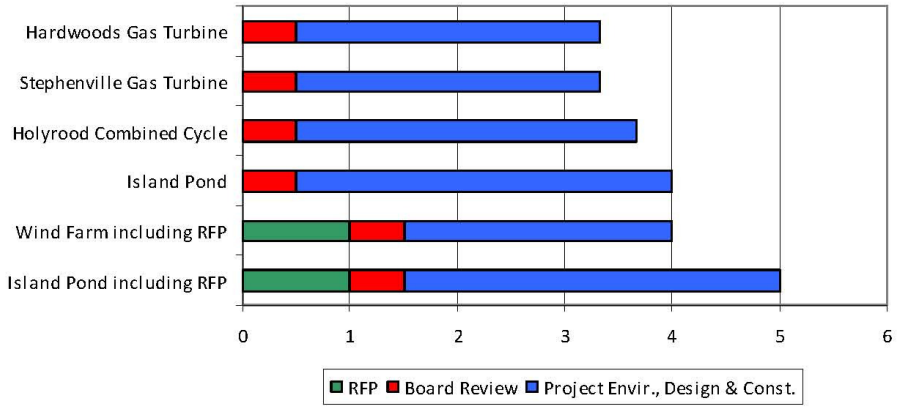
In addition to the time required to bring a project through the normal environmental and construction schedules, additional lead time is required to implement an RFP process. Based on Hydro's 1997 experience, the minimum amount of time required to issue and evaluate proposals through an RFP process is approximately seven months. This was accomplished only through having a high priority placed on the process by the Leadership Team, the commitment of key personnel from various departments and the assistance of consultants. Due to the urgency to have a final report on generation expansion alternatives ready by mid-June 1997, the RFP, issued in mid-January, gave proponents only approximately three months to submit proposals. Many proponents expressed concern about the short time allotted to prepare proposals and it was evident that if more time had been provided, there may have been more submissions. Ideally, the RFP process requires approximately 15 months to complete, as was the case for Hydro's first RFP for small hydro non-utility generators in 1992. An RFP process with a 12 month schedule from issue through to completion of the project evaluations is a reasonable compromise between the accelerated schedule of the 1997 RFP and the much longer 1992 RFP schedule.

8.2 Newfoundland and Labrador Board of Commissioners of Public Utilities

Prior to 1996, Hydro was not required to seek approval from the Board for its capital program. However, with the 1996 amendments to the Hydro Corporation Act, Hydro, in the absence of a Government of Newfoundland and Labrador exemption, must seek Board approval before committing to acquire a new generation project. Given that this process has yet to be tried, approval is estimated to take as long as six months depending on the level of interest shown and the number of interveners requesting standing at the hearings. Based on the level of interest shown at recent Board hearings and as expressed in the 1997 RFP, it is expected that there would be significant interest in a hearing for a new generation source.

Assuming an additional 25 MW wind project is brought in-service by 2014, for fuel displacement at Holyrood, additional generation will be required by the fall of 2015. Based on the requirement for additional generation by the fall of 2015 under an Isolated Island scenario, the following bar chart illustrates the lead times, including that required for a Board review, for each of the near term alternatives to achieve in-service by that time.

Figure 8-1 - Project Lead Times



The addition of an RFP process necessitates a decision to proceed in late 2010 to meet an in-service date of fall 2015. This is due to the need to complete the RFP evaluation and subsequent Board review and have a final decision by spring 2012 to protect the in-service date for the Island Pond alternative, which has been identified as the preferred next source of generation from Hydro's portfolio.

9.0 Other Issues

9.1 Intermittent and Non-Dispatchable Resources

Based on the Island's existing plus committed generating capacity, approximately 397 MW, or 20 percent of net capacity can be characterized as non-dispatchable generation (see Table 3-1). While energy production from these resources is predictable over the long term, the generation may not be available when needed. The concern with this type of generation comes on two fronts; first in the availability of the generation to meet higher loads; and second on occasions of light load when the non-dispatchable capacity can no longer be absorbed into the system without adverse technical and economic impacts.

From a generation planning point of view, when assessing the adequacy of system resources to meet peak demands, the characteristics of non-dispatchable generation are incorporated into the unit models. Therefore, on a go-forward basis, new non-dispatchable resources are appropriately evaluated in generation capacity planning analyses.

However, long-term generation planning may not necessarily capture the short-term operational constraints of intermittent and non-dispatchable resources, particularly those related to the ability of the system to absorb the capacity under light load periods. As more and more intermittent and non-dispatchable capacity is added to the system, there comes a point at which the ability to maintain stability and acceptable voltages throughout the system

may be compromised. As well, there is an increased risk of spilling during high inflow periods as hydraulic production is reduced to accept non-dispatchable production.

In advance of any future RFP that would likely feature non-dispatchable resources such as small hydro and wind energy, it is necessary to determine what limitations on non-dispatchable resources are appropriate. While this has been studied a number of times, changes in available generation and load, such as the Grand Falls paper mill ceasing operations, necessitates a revisting of the analysis. In this light it is recommended that System Planning, in cooperation with Generation Operations, continue to conduct studies to identify the amount of non-dispatchable capacity that may be added without adversely affecting the operation of the system. Changes in these areas may affect proposals in an RFP process in the context of the type of proposal and price.

9.2 Environmental Considerations

Known environmental costs, such as environmental mitigation and monitoring measures that may be identified under the Environmental Assessment Act, and the current Provincial Government 25,000 tonnes per year limitation on SO_2 emissions from the HTGS, have traditionally been included in generation planning studies. In 2007, the Provincial Energy Plan communicated that Hydro would deal with environmental emissions concerns at the HTGS either by pursuing the development of the lower Churchill River and a HVdc link to the Island, or install capital intensive environmental mitigation technologies in the form of scrubbers and electrostatic precipitators to control emissions at the HTGS.

In 2006, Hydro began burning one percent sulphur No. 6 fuel oil for the HTGS. While there can be additional purchase costs for one percent sulphur over two percent sulphur fuel oil, this improvement in fuel grade has reduced SO_2 and other emissions by about 50 percent. In 2009, Hydro further switched to 0.7 percent sulphur fuel, which may reduce SO_2 and other emissions by a further 30 percent.

There remains considerable potential for other Government-led environmental initiatives (such as the Clean Air Act, cap-and-trade systems, carbon taxes, etc.) that can impact utility decision-making. While it is impossible to predict the exact nature of future emissions controls or other environmental programs, and their resulting costs, it is necessary to be aware of the issue.

The most prominent environmental issue currently under consideration is greenhouse gases and their impact on global warming. Carbon dioxide (CO_2) is the primary greenhouse gas of concern and Hydro's Holyrood Plant emits an average of approximately 866,000 tonnes per year[6] of CO_2. In the absence of a transmission link from Labrador to the Island, the long-term incremental energy supply for the Island is very likely to be thermal-based and thus this issue could have a significant impact on production costing and future generation planning decisions. It is pertinent to note that the addition of scrubbers and precipitators to the Holyrood Plant will not reduce CO_2 emissions.

For example, under a cap-and-trade system, the amount of effluent, such as CO_2, Hydro could be permitted to emit could potentially be capped by a regulator at a certain level. To exceed this level, credits could perhaps be purchased from a market-based system at a price set by the market. Conversely, surplus credits for effluent not emitted under the cap level might be traded on the market to generate revenue. This type of system could have significant impacts on Hydro's production costing and the cost of electricity, especially under the Isolated Island scenario.

Other emissions that may come under further regulation include nitrogen oxides (NO_x) and particulate.

Hydro maintains a base of knowledge to be able to provide a qualitative level of analysis on the potential consequences of environmental initiatives such as this on resource decisions. As well, Hydro is closely monitoring national and international activity in this area.

[6] Based on the 5-year average of 866,158 tonnes per year of CO_2 from 2005 through 2009.

9.3 Holyrood Thermal Generating Station End-of-Life

Units 1 and 2 of the HTGS were commissioned in 1971 and Unit 3 was commissioned in 1979. Under an Isolated Island future, the energy these units will be required to produce will be approaching their firm capability. Under a HVdc link future, these units will be required, as a minimum, to function as synchronous condensers to provide System voltage support as well as to provide a backup supply for some period after the HVdc link comes in-service. Due to the age of these assets, significant capital investments may be required to ensure that they are capable of operating reliably until their anticipated end of life. Typically, as thermal plants age they are derated to account for their decreasing reliability caused by increasing failure rates of aging components. Under an Isolated Island scenario, Hydro cannot derate these units without adding additional generation sources. Hydro must determine what is required for the HTGS to function until its anticipated end of life under both expansion scenarios and to facilitate this, the Board has approved a Condition Assessment of the facility, which is currently being carried out.

9.4 Energy Conservation

The takeCHARGE residential rebate programs for insulation, thermostats and ENERGY STAR® windows have had increasing uptake since their launch and are now in the market for a full year. Work is now underway to explore expanded technologies for additional rebate programs. The Commercial Lighting program was launched in 2009 and discussions continue with the Province and other key players in the commercial lighting market to ensure participation in the program and identification of opportunities for inclusion of high efficiency lighting in their purchase specifications. The Industrial Energy Efficiency program will be launched in 2010. In

addition to the rebate programs, work continues on outreach and awareness efforts with customers, retailers and builders to ensure participation in the programs.
As well in 2009 Hydro partnered with the Provincial Department of Natural Resources to deliver a community based energy efficiency program in two Coastal Labrador communities. This project was a pilot to explore the impact of community based interventions on energy efficiency. It was very successful, providing efficiency tools, local job opportunities and promotions and awareness to increase the knowledge base and assist residents in taking immediate action on efficiency.

10.0 Conclusion

Based on an examination of the System's existing plus committed capability, in light of the 2010 PLF and the generation planning criteria, the Island system can expect capacity deficits starting in 2015 under both the HVdc link and Isolated Island scenarios but no energy deficits until post-2019.

Due to the direction given to Hydro under the Provincial Government's Energy Plan, two generation expansion plans are to be maintained until a sanction decision on the Lower Churchill Project can be reached. These two expansion plans differ based on the inclusion of a HVdc link as an available alternative to meet the System's energy requirements. The decision for sanctioning for the Lower Churchill Project is scheduled for 2010 and at that time, the expansion scenario that Hydro will ultimately pursue will be known. Until that time, it would be desirable to avoid committing to one generation expansion plan over another; however, Hydro must be prepared to react to protect the reliability of energy supply for the Provincial market. If a revised forecast indicates that a decision is required prior to the Lower Churchill Project sanctioning, a detailed study on how best to proceed will have to be prepared to ensure that the most appropriate decision can be undertaken in an orderly process.

In order to meet the deficits noted in 2015, Hydro has identified two possible sources. The preferred source depends whether or not the Lower Churchill Project and the HVdc link are sanctioned. Assuming that the Project and link are sanctioned, a 50 MW CT will be required in 2014, and then the HVdc link will meet the capacity and energy requirements of the Island for many years to come. However, if the Project and link are not sanctioned, Hydro will likely require the construction of the 36 MW Island Pond hydroelectric plant to meet its capacity requirements, as well as a third wind farm. It is likely that the remaining hydroelectric facilities of Portland Creek and Round Pond would also be constructed for their capacity and energy benefits along with their economic and environmental benefits associated with the displacement of fuel required to produce energy at the HTGS. In order to protect the in-service date for the Island Pond alternative, which has been identified as the preferred next source of generation from Hydro's portfolio, the addition of a RFP process for other supplies necessitates a decision to proceed in late 2010 to meet an in-service date of fall 2015. This is due to the need to complete the RFP evaluation and subsequent Board review and have a final decision by spring 2012.

The impact of energy conservation measures resulting from the *Five-Year Energy Conservation Plan* will need to be evaluated to determine what, if any impact, it has on the decision for the next source. At this time, it is expected that the principal benefits will be the economic and environmental benefits of the reduced reliance on HTGS produced electricity and that the timing for the next decision will be unaffected.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- HVdc Transmission Link – Hydro must be prepared for events that may delay the proposed Lower Churchill Project or if the project is not sanctioned;
- HTGS End-of-Life – Hydro must determine what is required to ensure the HTGS can be operated reliably under both a HVdc link future and an Isolated Island future. For the latter case, other future generation sources should be considered;

- Government Emissions Reductions Initiatives – Hydro must remain vigilant in considering the impact that Government emissions reductions initiatives could have on production costing and future generation planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling for all new generation sources due to increased environmental assessments in the form of Environmental Impact Studies;
- Fuel displacement – Hydro must continue to pursue and develop projects and incorporate energy conservation activities that are technically and economically feasible to displace fuel at the HTGS;
- Industrial expansion and contraction – Hydro must continue to assess, as updated information is provided, the impacts of industrial activity both positive and negative on the System's capacity and firm energy balance;
- Resource Inventory – Hydro must ensure that it maintains a current inventory of resource options with sufficient study as to provide confidence in overall project concept, costs and schedules.

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Appendix A

Table A-1
2010 Island Planning Load Forecast

Year	Maximum Demand [MW]	Firm Energy [GWh]
2010	1,519	7,585
2011	1,538	7,709
2012	1,571	7,849
2013	1,601	8,211
2014	1,666	8,485
2015	1,683	8,606
2016	1,695	8,623
2017	1,704	8,663
2018	1,714	8,732
2019	1,729	8,803
2020	1,744	8,869
2021	1,757	8,965
2022	1,776	9,062
2023	1,794	9,169
2024	1,813	9,232
2025	1,827	9,290
2026	1,840	9,372
2027	1,856	9,461
2028	1,872	9,543
2029	1,888	9,623