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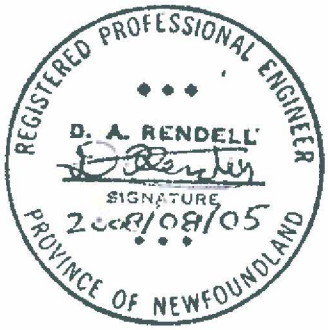
HYDRO

THE POWER OF COMMITMENT

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Holyrood Thermal Generating Station Refurbishment of the Fuel Oil Storage Facility

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

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NEWFOUNDLAND AND LABRADOR HYDRO

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1 INTRODUCTION

The purpose of this project is to refurbish the components of the Oil Storage Facility for No. 6 fuel at the Holyrood Thermal Generating Station (HTGS) to a more reliable state (see Appendix A for photos of the Fuel Oil Storage Facility).

A study completed by SGE Acres entitled *"Evaluation of Fuel Oil Storage Tanks, Associated Pipelines and Dyked Drainage System, Holyrood Thermal Generating Station"*, dated March 2006 (attached as Appendix B) summarized many deficiencies requiring corrective action. The findings of the report formed the basis for this budget proposal and the deficiencies are as follows:

- Ineffective storm water drainage system;
- Pipeline support structures are subject to frost heaving;
- Oxidation of steel fuel oil storage tanks;
- Inadequate communications system; and
- Inadequate illumination of the tank farm.

The primary causes of the deficiencies are the retention of storm water within the oil storage facility and the age of the system components. The current drainage system is inadequate because it has partially failed, resulting in the inability to discharge unwanted storm water from within the earth dyke that surrounds the fuel oil storage tanks.

The level of storm water occasionally reaches the level of electrical equipment such as heat tracing and junction boxes, particularly during spring run off. This poses a risk of electrical failure and potential for electrical shock. The loss of heat tracing could impair tanker off-loading especially during winter months which is the peak operating season. This creates a risk of reduced plant output and potential plant outages.

As a result of the water being retained, many of the facility's components have undergone significant deterioration and immediate attention is required to provide a useful life comparable to that of the rest of the HTGS.

The components that require attention are:

- the four fuel oil storage tanks;
- the earth dyke and tank farm floor area;
- the fuel oil pipeline and associated support foundations; and
- the electrical system comprising lighting, communication system, and closed circuit television (CCTV).

The work on the above components is also required to ensure that the Fuel Oil Storage Facility meets all required provincial legislation and regulations as discussed in Section 4.4. Should the Lower Churchill Project proceed, the earliest that the facility will not be required is 2015.

2 PROJECT DESCRIPTION

This project involves the reinstatement, repair, and upgrade of existing components within the Fuel Oil Storage Facility at the HTGS for the purpose of extending its useful life, ensuring system reliability, and increasing the level of safety within the facility. The scope of the work is to improve the earthworks and storm water drainage system and repair the fuel oil pipe supports.

2.1 Earthworks and Storm Water Drainage System

Drainage enhancements are required within the tank farm to improve the capacity and efficiency of the drainage of storm water from within the boundaries of the dyked perimeter. Collection of water within the tank farm reduces the capacity to hold No. 6 fuel in the event of a fuel spill, magnifies the effect of freeze-thaw conditions on the pipeline support foundations, and accelerates the corrosion of the tank's metal components. Table 1 below provides the direct costs associated with this component of the project. For a more detailed description of these items see pages 2-23 to 2-25 of the SGE Acres Study in Appendix B. Costing of these items is located in Appendix B of the SGE Acres report.

Table 1
Earth Works and Storm Water Drainage Systems Costs

	Costs ($000)
1. Site Grading	
Vegetation removal	17
Dyke floor in open areas	99
Dyke floor around pipe racks	103
Roads and parking	122
Steps and berms	11
Total Site Grading	352

	Costs ($000)
2. Drainage	
Discharge piping for tanks	427
Discharge piping for support bases	157
Interceptor ditch	57
Piping for dyke 2	8
Oil separator and by-pass	201
Steam trap drain connections	41
Total Drainage	891
3. Surveys and Investigations	
Topographic	7
Video inspection of piping	21
Flushing of piping	2
Excavation and examination	5
Total Surveys and Investigations	35
4. Restoration	
Main berm	50
Hydrant valve markers	5
Total Restoration	55
TOTAL	**1,333**

The sub-components shown in Table 1 are explained in more detail in Section 2.7 of the SGE Acres report.

2.2 Fuel Oil Pipeline and Associated Support Structures

Deteriorated pipeline support structures need to be repaired. Improvements will be made to the concrete foundations and the heavily oxidized structural steel pipe support structures. In addition, connections to the fuel oil pipeline will be replaced. Table 2 below provides the direct costs associated with this component of the project. For a more detailed description of these items see pages 3-1 to 3-4 of the SGE Acres Study in Appendix B.

Table 2
Pipeline Support Structure Costs

Description	Costs ($000)
1. Pipe Supports	
Anchor blocks	84
Supports	323
Isolation valve and piping	195
Third party inspection	17
Sand blasting and painting	78
TOTAL	697

The costs in the above tables are based on SGE Acres Study, section 6.1 and have been calculated to 2008 dollars. The escalation is due to increased labour and material costs and finance costs. The total cost shown in Tables 1 and 2 is the estimate for contract work provided in Table 4, Section 5.1.

3 EXISTING SYSTEM

3.1 Existing System

There are four main fuel oil storage tanks and associated pipelines and a dyked drainage system at the Holyrood Thermal Generating Station. The earth dykes surrounding the tanks have a drainage system to discharge water outside the dyke. Hydro's concern is that discharge rates from the dykes are low requiring operator attendance up to eight hours a day while draining the dykes. Site drainage throughout the dyke is generally over flat ground with moderate slopes in a westerly direction but there are locations in traffic and work areas where water is trapped and ponded. Water tends to build up in the following areas:

- southwest corner of the dyke;
- south end at the toe of the embankment;
- southeast of Tank 2 and Tank 3; and
- northeast and northwest of Tank 4.

The perforated drainage piping is buried at approximately 600 mm below ground and observations indicate that it is partially blocked. This observation is made by looking into the discharge end of the pipe. This piping was designed to drain water to a shallow sump. From there, a single 300 mm diameter pipe discharges water to a concrete chamber and then a 500 mm diameter pipe discharges water into a ditch outside the site fence.

Ineffective drainage has created three major concerns:

1. A reduced capacity of the dyke to hold any spilled fuel oil because of the volume of retained water that cannot be discharged from the system.
2. The saturated soils within the tank farm freeze, causing the pipe support foundations to be subject to significant frost heave which creates undue stresses on the pipelines, therefore, increasing the risk of a fuel oil spill.

3. The four fuel storage tanks require repairs to correct oxidized metal components primarily on the exterior of each tank because of water in the dykes.

3.2 Age of Equipment or System

The first phase of the HTGS was completed in 1969, including the construction of fuel storage tanks 1 and 2, all the associated supply and delivery pipelines and the earth dyke. The second phase of the HTGS was completed in 1977, including the construction of fuel storage tanks 3 and 4.

3.3 Major Work or Upgrades

There have been no major upgrades on the fuel storage facilities since construction.

3.4 Anticipated Useful life

The anticipated useful life of the fuel storage facility is 35 years. The existing facilities are at the end of their useful lives. The recommended maintenance and repairs to the drainage system and pipe supports is expected to extend the useful life of the storage facility by 20 years, or at least until the fuel storage facility is no longer required if the Lower Churchill project receives sanction.

3.5 Maintenance History

Table 3 presents a summary of maintenance costs associated with the fuel storage facility. All maintenance has been corrective in nature.

Table 3
Fuel Storage Facility Maintenance History

Year	Total Maintenance ($000)	Description of Work
2002	36.5	Pipe Supports
1992	37.0	Dyke Modifications
1989	5.8	Land Improvements

3.6 Outage Statistics

The HTGS incurred an internal valve failure on Tank 2 in 2007 necessitating the tank to be taken out of service, thereby reducing the winter storage capacity and increasing the risk of short supply during customer peak load demand periods. The risk involves the inability of a supply tanker to dock because of ice conditions occurring during peak load periods. A project to upgrade Tank 2 has been approved by Board Order P.U. 30 (2007) for $500,000. Also, in 2007, a similar valve failure and an internal tank heater problem put Tank 4 at risk of being removed from service. Although the tank did not have to be removed from service, the internal valve problems limited tank isolation capability and increased environmental risk during the operating months.

3.7 Industry Experience

Industry experience with above ground fuel oil storage tanks indicates that typically, the floors and ceilings of the tanks are affected the most by oxidation. Trapped water within the tank and the air void above the fuel oil subject the tank floor and ceiling to oxidation. Generally, the walls of the steel storage tanks do not oxidize from the inside because they are continuously coated with oil. The main protection against oxidation for the exterior surfaces has been epoxy coating systems.

In relation to dykes, Hydro relies upon the experience of the consultant, SGE Acres.

3.8 Maintenance or Support Arrangements

General maintenance for the fuel oil storage facility has been performed by Hydro personnel. Major maintenance such as epoxy coating and steel work has been performed by outside contractors specializing in professional paint work and steel fabrication.

3.9 Vendor Recommendations

There are no relevant vendor recommendations with respect to the improvements to the fuel oil storage facility.

3.10 Availability of Replacement Parts

The availability of replacement parts is not applicable to this project because a complete refurbishment is required and not just replacing of parts.

3.11 Safety Performance

Because of the deficiencies in the drainage system, any storm water trapped within the fuel storage area impairs access to valves and other critical equipment. Pooled storm water within the dyke causes soft ground conditions which pose difficulty for vehicle and pedestrian traffic. Depending on the amount of the pooled water, the extent of routine operating duties particularly during busy times such as tanker off-loading, tank gauging and daily checks is limited. The potential for electrical shock exists when water reaches the level of electrical equipment.

3.12 Environmental Performance

With the current drainage system, dewatering the storm water from the tank farm is a difficult process because of an inadequate and partially plugged drainage pipe network and poor surface drainage within the tank farm floor. Any storm water trapped within the tank farm reduces the capacity of the dyke to hold fuel oil in the event of a spill, and saturates the soil, causing the pipeline support structures to heave from the freeze thaw process.

The deterioration of the tank floors and settling of tank floor support rings is a result of corrosion, accelerated by the collection of storm water, thus increasing the risk of environmental spills and leakage of No. 6 fuel from the storage tank. Environmental operating permits are based on the ability of the dyke to retain the volume of heavy oil. This requirement is not met if the facility is unable to effectively drain standing water from the dyke system, refer to SGE Acres Study, page 2-8.

3.13 Operating Regime

The HTGS is seasonally operated; however, the fuel storage facility is in continuous operation since fuel is always present.

4 JUSTIFICATION

This project is justified on the requirement to replace failing and deteriorated fuel oil storage infrastructure in order for the HTGS to provide safe, environmentally responsible, least-cost, reliable electrical service. Storm water trapped within the fuel storage area has created three major issues, and the system has deteriorated to a point where there is a significant risk for oil leakage and inoperability. Corrective action must be taken.

This project will directly address issues 1 and 2 and will have benefits for issue 3 in that further oxidization will be abated through the removal of water from the dyke.

4.1 Net Present Value

A Net Present Value calculation was not performed in this instance as there are no viable alternatives.

4.2 Levelized Cost of Energy

This project does not involve analyzing a new energy generation source or enhancing the existing HTGS.

4.3 Cost Benefit Analysis

A cost benefit analysis is not applicable for this project because the there are no quantifiable benefits.

4.4 Legislative or Regulatory Requirements

The Gasoline and Associated Products Regulations (GAP) specify the minimum requirement for the holding capacity of the secondary containment dyke, and the requirement to dispense of any collected storm water. Clause 27.8 of the regulations states:

> Above ground storage tanks shall be surrounded by a dyke which shall be designed and constructed as follows:
> "Where a dyked area contains more than one storage tank, the dyked area shall retain not less than 110 percent of the capacity of the largest tank or 100 percent of the capacity of the largest tank plus 10 percent of the aggregate capacity of all the other tanks, whichever is greater."

Currently, the capacity of the tank farm dyke is adequate; however, retained water reduces the available capacity for fuel to levels below the GAP Regulations; refer to SGE Acres Study, page 2-8. Drainage enhancements for the elimination of storm water accumulations inside the dyke will be incorporated in the required civil works.

4.5 Historical Information

The fuel oil storage tanks and associated components are inspected and repaired in accordance with API standard 653 which is the repair standard for tanks specified under API 650. Inspections are made after fuel has been transferred to another tank. During these inspections preventative and corrective maintenance is performed to remedy the deficiencies such has patching holes found in the steel roof and steel floor.

4.6 Forecast Customer Growth

There are no anticipated customer growth implications that can be attributed to this project.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits that can be expected from this project.

4.8 Losses during Construction

There are no losses during construction as this project will not require the HTGS to be out of service.

4.9 Status Quo

The status quo is not an acceptable option. The existing system has deteriorated components that require repairs to extend its useful life and to ensure compliance with regulatory requirements established by GAP and API.

4.10 Alternatives

The existing system is repairable and this is the only viable alternative. Although full replacement of the whole facility is possible, it is obvious that the cost of replacement is much greater than refurbishment and, thus, not a viable alternative.

5 CONCLUSION

Storm water trapped within the fuel storage area has caused the system to deteriorate to a point where action must be taken to correct the drainage issues and return the components of the system to a reliable condition.

This project will:

1. Restore full capacity of the dyke to hold any spilled fuel oil by rectifying the system so that water will be adequately discharged from the dyke.
2. Allow drainage so that the soils within the tank farm will not become saturated and freeze causing undue stresses on the pipelines.

5.1 Budget Estimate

The estimate cost of the Refurbishment of the Fuel Oil Storage Facility is shown in Table 4.

Table 4
Budget Estimate

Project Cost:($ x1,000)	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	0.0	0.0	0.0	0.0
Labour	48.0	0.0	0.0	48.0
Consultant	215.0	0.0	0.0	215.0
Contract Work	2,030.0	0.0	0.0	2,030.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln	344.4	0.0	0.0	344.4
Contingency	229.3	0.0	0.0	229.3
TOTAL	**2,866.7**	**0.0**	**0.0**	**2,866.7**

5.2 Project Schedule

Table 5 provides the planned project schedule.

Table 5
Project Schedule

Activity	Milestone
Design	March 2009
Tender	April 2009
Award Tender	May 2009
Contract	November 2009
Closeout Project	December 2009

APPENDIX A

Photos of the Fuel Oil Storage Facility

Photo 1: West Side of Fuel Oil Storage Facility, Looking North.

Photo 2: Storm Water Retained Around Tank 1, NW Corner of Tank Farm.

Photo 3: Intermediate Earth Dyke Between Tanks, and Fuel Oil Pipeline.

Photo 4: Typical Pipeline Foundation Showing Evidence of Frost Heave.

Photo 5: Typical Pipeline Steel Support Structure, Heavy Oxidation.

APPENDIX B

March 2006 Study - "Evaluation of Fuel Oil Storage Tanks, Associated Pipelines and Dyked Drainage System, Holyrood Thermal Generating Station"

Prepared for

Newfoundland and Labrador Hydro

Hydro Place, Columbus Drive, St. John's, NL A1B 4K7

Evaluation of Fuel Oil Storage Tanks, Associated Pipelines and Dyked Drainage System

Holyrood Thermal Generating Station

FINAL REPORT

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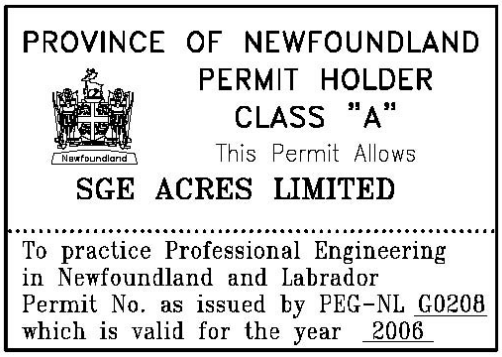

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P16806-C-B1-002 Rev. B – Grading and Drainage Improvements
P16806-E-B1-001 Rev. A - Existing Site – Illumination Plan

HTGS Refurbishment of the Fuel Oil Storage Facility

Appendix B

Introduction

1 Introduction

This report has been prepared by SGE Acres for the Engineering Services Division of Newfoundland and Labrador Hydro as an Evaluation of Four Main Fuel Oil Storage Tanks and Associated Pipelines and Dyked Drainage System at the Holyrood Thermal Generating Station. The objective of this assessment is to determine the extent of upgrades required for the tanks, pipelines and drainage, as well as the power and lighting system, to extend the useful life of the facility by at least 20 years.

The scope of the work included a review and assessment of the condition of the four main Bunker C storage tanks and associated piping and supports, dyke drainage system, electrical power and lighting systems along with a determination of the upgrades required to meet existing and pending regulations, and a preparation of a plan and cost estimates for a phased program of remedial works over a four-year period commencing in 2008.

Tanks 1 & 2 were constructed in 1968 while Tanks 3 & 4 were added in 1979. In 2003, an inspection was done on Tank 3, repairs were made to the floor, and the exterior was epoxy coated. A similar exercise was carried out on Tank 4 in 2004, and Tank 1 in 2005.

In 2005, permanent yard lighting improvements were being implemented at the site.

The earth dykes surrounding the tanks were constructed in 1968 and included a minimal drainage system with controlled discharge to the ocean. Draining the dyked area requires significant time which interferes with access to the tanks, and water in the area likely reduces the life of the pipelines and tank bottoms. Modifications to the drainage system and dyke have been made since originally constructed; however, these have not been sufficiently effective to satisfy operational requirements. Concerns also exist with regard to movement of fuel line piping due to heaving of pipe supports throughout the dyke. Attempts have been made to address this problem, however, concerns remain that the pipelines are still at risk.

This report presents the results of the evaluation as follows: Section 2 covers site drainage and civil works; Section 3 addresses piping and pipe supports; Section 4 deals with the tanks; Section 5 describes the electrical systems. Section 6 provides cost estimates for remedial work and presents a proposed implementation plan for the four year period from 2008 to 2011.

Civil Works

2 Civil Works

This section of the report summarizes the findings of our field investigations, contains a sampling of comments contained in recent reports prepared by Hydro operations personnel, includes an engineering assessment of drainage conditions, and presents a series of observation and options for remedial work.

An Existing Conditions Plan, Drawing No. C-B1-001 has been prepared to present information collected and observations made at the site, and a Grading and Drainage Improvements Plan, Drawing No. C-B1-002, have been prepared to illustrate options for remedial works. Site photographs are included where appropriate to illustrate existing conditions. Cost estimates are also presented along with a phasing plan for implementation.

Operational and Safety Issues
The following are extracts from reports prepared by Hydro personnel related to drainage issues and essentially summarize the problem being experienced at the site.

> *"The present Tank Farm Drainage system is inadequate (e.g. grading, drainage, drainage materials, etc). Tank Farm Water Drainage is an important issue for the following reasons:*
>
> *.1 It affects the integrity of the Oil Storage Tank metal bottoms.*
> *.2 Oil piping support shifting (due to freezing of the accumulated water/melting of ice).*
> *.3 It reduces the Tank Farm Dyke holding capacity, in the event of a large Oil Spill, if adequate drainage isn't available.*
> *.4 Ice presents a Safety Hazard to Plant personnel who perform regular inspections, maintenance work, Tank gauging, Tanker Off-loading, etc.*
> *.5 A considerable amount of unplanned work has already been performed with more planned for the future as a result of inadequate drainage including tank bottom rusting and patching, planned replacement of Tank bottom, piping support have been insulated with drainage stone/rock, Correcting of faults on the Electrically Traced Oil line from the Marine Facility.*
> *.6 A considerable amount of time is spent draining the Tank Farm and inevitably involves overtime."*

Concern has been expressed by Hydro that discharge rates from the dyke are low resulting in excessive operator attendance while draining the dykes. Up to 8 hours in a single day have been reported as well as up to 4.5 hours on consecutive days in December and January. February is said to require more than this. For the most part this report confirms the above findings.

Various improvements and suggestions have been proposed by Hydro operations personnel and have been documented in internal reports and correspondence. During the preparation of this report several other improvements were suggested by Hydro; these included the installation of an Oil-Water Separator that would allow water to drain from the dyke on a continuous basis, and sub-drainage piping installation over the entire floor of the dyke. These have been reviewed and taken into account in preparing this assessment of the tank farm and related costs for upgrading.

Permits
Existing permits, approvals from regulatory authorities and registration documents have not been reviewed as part of this study. We assume that the Department of Environment and Conservation, as well as the Government Service Center have issued all required permits and that these are up to date.

2.1 Existing Surface Grading and Drainage

Tank floor elevations are at approximately 16.0 m. Elevations of the dyke floor vary over the site: 14.6 m at pipe inlets, between 14.95 m and 15.54 m in swales, from 16.0 m to 16.7 m at intermediate berms, to as high 16.0 m to 17.3 m along the edges of traffic areas.

General site drainage throughout the dyke is over ground at flat to moderate slopes in a westerly direction, but there are a lot of low spots in traffic and work areas where water is trapped.

The tanks are separated by intermediate berms; surface drainage within each dyke being independent of the others – except that all drainage eventually is directed to Dyke 2 for release by operators.

Water tends to build up at several locations which were noted during the surveys. These include:

- The southeast corner of the dyke – this is a low spot with trapped water and organic materials.
- South end at the toe of the embankment.
- Northeast and northwest of Tank No. 4.
- Southeast of Tank No 3.
- Southeast of Tank No 2.

Observations

- Dyke 1 – Consider minor grading work on the west side.
- Dyke 2 – Consider minor grading work on the west side.
- Dyke 3 – West side needs re-sloping or trench to existing swale.
- Dyke 4 – West side needs re-sloping or trench to existing swale.
- Dyke 4 – East side/south side – consider removing grubbing and organics, placing rockfill and Class B, and matching existing grades, french drain from here to main drainage ditch at the west side of Tank No. 4.

The southeast corner of the dyke – this is a low spot with trapped water and organic materials.

Swales and Ditches

Slopes on existing ditches and swales are very flat as described below:

- 0.2% to 0.4% in ditches immediately adjacent to the tanks but some local high points exist. Note that these ditches do not extend all the way to the main drain on the west side.
- 0.4% in swale west of Tank 1 and Tank 2.
- Minus 0.3% in the swale west of Tank 3 – this ditch is actually back-graded
- 0.15% in the swale west of Tank 4.
- 0.3% in the swale south of Tank 4 – this ditch is actually back-graded, but could be reverse graded at 0.40%

High points exist in ditches which are causing trapped water to build up in several areas as follows:

- South west corner at dyke perimeter – 47 cm deepening needed.
- North of Tank 4 at tank perimeter - 20 cm deepening needed.
- South of Tank 3 at tank perimeter - 15 cm deepening needed.
- South of Tank 2 at tank perimeter - 10 cm deepening needed.
- North of Tank 1 at tank perimeter – 10 cm deepening needed.

Observations

- 100 mm PVC pipe south of Tank 4 appears to be not working.
- Consider removal of 250 mm diameter pipe culvert south of Tank 4.
- Clean out and deepen existing swales and ditches adjacent to tanks and extend to main drainage ditch along the west side of the dyke. Backfill lower part of ditch with washed stone.
- Clean out and deepen existing swales and ditches along south end and on the west side of dyke.
- Re-grade new ditch on east side of road and connect to existing ditch on south side of Tank 4.

North of Tank #1 - the tank perimeter swale should be deepened.

Sub-drainage Piping and Inlets

Drawings indicate that underground perforated drainage piping and filter material exist west of Tank 1 and Tank 2 - this apparently drains to a shallow sump and inlet screen. Piping is believed to be buried approximately 600 mm below grade. The screen inlet elevation is 14.615 m.

West of Tank 3 an open ended 200/250 mm (to be confirmed) diameter pipe collects water from dyke 3 at invert approximately 14.8 m; this apparently also drains to the sump/inlet near Tank 2 at elevation 14.651 m. Whether this pipe is perforated sub-drainage piping is not clear - to be confirmed.

Piping for individual dyke isolation is not exposed and appears to be partially blocked.

No piping exists from individual tank perimeter ditches to the main drain on the west side.

The usefulness of the 200 mm piping and valve across the berm between Tank 3 and Tank 4 is questionable.

Observations:

- Intermediate berm piping – consider inspection, removal and replacement of pipe and valves (3) if needed.
- 200/300 mm diameter pipe west of Tank 3 to the inlet sump – consider inspection / camera test / flushing (connection to inlet to be confirmed).
- 200/300 mm diameter sub-drainage from inlet to north side of Tank1 – needs inspection.
- Install drainage piping or french drain from end of existing tank perimeter ditches to the main drain on the west side.

The inlet screen between Tank #2 and Tank #3 and the underground piping. The inlet and the pipes need to be replaced.

Discharge Piping

A single 200/300 mm diameter cast iron pipe serves as the discharge from the tank farm. Fed from the sump/inlet, it is controlled by a manually operated valve, which is normally closed. This pipe leaves the inlet sump at elevation 14.39m and empties into a concrete valve chamber at elevation 13.51m where it drains to a 500 mm diameter CMP. This pipe connects downstream to buried culverts which discharge into an open ditch outside the site fence. As-built details should be confirmed by inspections. Good flow was observed at the culvert outlet while operations personnel had the valve opened.

Observations

- 200/300 mm diameter pipe from inlet to valve chamber (16.8 m at 5% slope) – consider inspection.
- 500 diameter pipe from valve chamber to 900 diameter outfall (150 m at 2% slope) – consider inspection.

Discharge location of the 2-900 mm CMP.

2.2 Dyke

The main dyke is formed by a continuous gravel berm, approximately 2.3 meters high, constructed of impervious till, on the east, north, and west sides while on the south side an excavated embankment serves as the dyke wall. Design elevation of the top of the berm is approximately 17.8 m. Surveys indicate that parts of the berm are below this by as much as 20 cm.

A check of the available containment capacity of the existing dyke has been carried out using the topo information obtained during the survey. Using the lowest actual elevation of the existing berm that is 17.45 m, our estimate of gross containment available is 61.8 million liters. Subtracting the displacement for tanks, pipelines and pipe supports etc reduces the actual containment volume to 40.2 million liters. Based on the design elevation for the berm, that is 17.7 m, the potential net available storage is 47.2 million liters. The containment volume required by GAP is 44.8 million liters.

Intermediate berms divide the tank farm into four dykes, one for each tank, however, the top elevations of these berms, 16.1m to 16.7m, are lower than the main berm. These berms appear to be constructed of granular fill, instead of impervious till.

Observations

- Surveys indicate that parts of the main berm are below the design elevation by as much as 20 cm.
- The purpose of the intermediate berms is not clear. They appear to serve as a precautionary measure to prevent spilled product from moving to other areas of the dyke floor. Removal should be considered.

Main berm west side – new lighting cable being installed.

Dyke Liner

The till soil layer on which the dyke is constructed serves as a liner. Suitability of the till was documented in 1997 in a report prepared by Jacques Whitford. The depth of till and type of underlying soils, bedrock or granular soils, are not known. For the purposes of this assessment we are assuming that 600 mm of impervious soil exists and that this forms an adequate liner to meet GAP requirements.

Containment elevation of the till liner is approximately 17.7 m. In areas where the main berm is eroded the till liner is also impacted.

Observations

- Liner adequacy needs to be confirmed, that is, for thickness and permeability.
- Penetrations into the till liner may exist, e.g., pipe support bases.

Vegetation

A fair amount of vegetation consisting of grass, shrubs and alders, exists inside the dyke. It varies form being fairly dense to spotty.

Observations

- All vegetation should be removed as required by the Fire Code. (Reference Section 4.1.5.5).

Vegetation at the southeast corner and south end of the dyke.

Walkways

Approximately 15 wooden/metal walkways exist inside the dyke.

Observations

- Generally, best practice would suggest that wood products be avoided and efforts should be made to replace this with non-combustible materials over

time. However this is not a Fire Code requirement. (Reference Section 4.1.5.5).

Typical installation of wooden / steel walkways.

2.3 Roads and Parking

Vehicle access is provided into the dyke from the east side where the main access road crosses the berm. Access within the dyke by vehicle is not available on the west side due to the above ground piping, otherwise all other sides of the tanks can be accessed fairly readily. The condition of the gravel floor is fair to good.

Vehicle access is provided over the intermediate berms to access Tank 2, Tank 3, and Tank 4.

A gravel road exists between the west side of the dyke and the site fence. This road is in fair condition. It provides direct vehicle access to the drainage valve chamber and fire

hydrants in this area. It also serves for parking for inspection and maintenance crews accessing the pipelines from the west side.

Observations

- East side of Tank 4 – Consider raising the road as much as 300 mm and moving it eastward to about 5 meters away from tank. This would provide a drier road bed and a better working pad in this area.
- Gravel surfaces require some maintenance, re-surfacing, re-shaping and grading to fix problems that have developed due to snow clearing, erosion and traffic.

Vehicle access - provided into the dyke from the east side where the main access road crosses the dyke.

2.4 Pipe Supports

Rock ballasting was recently installed around many of the existing in-ground concrete pipe supports to add weight to minimize movement of the supports during freeze-thaw conditions. An evaluation of this effort has been carried out by Hydro but was not further assessed as part of this study.

Observations

- Wet soil conditions near the surface suggest that sub-drainage around pipe supports could contribute to the movement problem.

Pipe support bases - rock ballasting around many of the existing in-ground concrete pipe supports

2.5 Fire Protection

A 150/200 mm asbestos cement water supply main loops the entire tank farm. There are several hydrants on the west and east sides of the berm which can be accessed via the gravel road or along the top of the berm. Water pressure is reported to be over 690 kPa (100 psi).

Observations:

- System appears to be adequate, although not assessed as part of this study; no concerns were raised by operations personnel.
- The location of isolation valves are not clearly marked and are difficult to find when snow covers the ground.
- It should be noted that AC pipe is no longer acceptable for new installations.

Fire protection – water main around the perimeter with several fire hydrants.

2.6 Hydrology and Hydraulics

2.6.1 Hydrology

A preliminary assessment of the site hydrology has been carried out using a limited amount of information; the results and discussion of the findings are presented below and illustrated in the attached tables.

The total area contributing flow into the dyke is approximately 3.3 hectares, including 0.35 hectares from the south end. Dykes 1 and 2 are approximately the same size, Dyke 3 is about 13% larger, while Dyke 4 is about 50% larger than Dykes 1 and 2. Considering the amount of infrastructure in the dykes and the topography, the total ground area likely to be inundated with runoff for typical storm conditions is approximately 0.84 hectares. This will determine the depth of water that will accumulate on the dyke floor.

Considering various storm frequency events and total 24 hour rainfall, it is estimated that the average depth of water that will collect in the dyke would range from 180 mm in Dyke 3 to 620 mm in Dyke 1 for the 2 year and the 100 year rainfall respectively, assuming no water is released until the storm is over and no water remained in the dyke from previous rainfalls. Given existing dyke floor elevations, this would mean, for example, that water could reach within 80 mm of the floor of Tank 1 during a 5 year storm and likewise be within 100 mm of Tank 4 during a 100 year storm.

These conditions could have serious implications. For winter conditions with frozen ground and snow and ice in the dykes, the situation could become worse.

The following table presents a preliminary estimation of rainfall volumes and water ponding depths for various storm frequencies.

Table No. 1
Estimates of Ponding Volumes and Depths

				24 hour Rainfall (mm)			
				62.8	76.4	85.4	113.6
Runoff Areas				24 hr Rainfall Volumes			
Basin	Total Area	Upstream Drainage	Total for Rainfall Contribution	2 yr	5 yr	10 yr	100 yr
	(m^2)	(m^2)	(m^2)	(m^3)	(m^3)	(m^3)	(m^3)
Tank 1	6,450	0	6,450	405	493	551	733
Tank 2	6,415	0	6,415	403	490	548	729
Tank 3	7,280	0	7,280	457	556	622	827
Tank 4	9,400	3,500	12,900	810	986	1,102	1,465
Totals	**29,545**	**3,500**	**33,045**	**2,075**	**2,525**	**2,822**	**3,754**

Ground Storage Area Available							Estimate of Ponding Depth			
Basin	Main Storage Area	Rock Protection	Concrete Pipe Support	Int Berm	Tank + Enclosure	Total Storage Area Available	2 yr	5yr	10yr	100 yr
	(m^2)	(m^2)	(m^2)	(m^2)	(m^2)	(m^2)	(m)	(m)	(m)	(m)
Tank 1	3,820	195	13.85	35	2,400	1,176	0.34	0.42	0.47	0.62
Tank 2	4,450	225	12.72	71	2,400	1,741	0.23	0.28	0.31	0.42
Tank 3	5,300	250	14.72	88	2,400	2,547	0.18	0.22	0.24	0.32
Tank 4	5,700	315	10.75	53	2,400	2,921	0.28	0.34	0.38	0.50
Totals	19,270	985	52.04	247	9,600	8,386	-	-	-	-

From reports and photos reviewed during this study, it appears that the highest water levels occur in Dyke 1, which generally agrees with the above findings. Maximum depth of water probably occurs in Dyke 2, at the inlet; a rough estimate would be 0.9 m for the 2 year storm and 1.1m for the 100 year storm.

2.6.2 Hydraulics

To assess hydraulic performance of the drainage system, it is necessary to look at both ditches and piping and evaluate these based on an acceptable level of expected performance in terms of time required to drain the dykes and the tolerance level for accumulated water in the dykes.

Reports and observations indicate that Dykes 1 and 2 drain first upon opening of the drain valve and that these dykes can be drained to a reasonably dry condition for working in these dykes; performance of this part of the system appears to be satisfactory. Information obtained from Hydro indicates that a new sub-drainage piping and rock fill were placed along the west side of Tanks 1 and 2 and this appears to be working well. The existing 200/300 mm discharge pipe appears to be working well.

However, Dykes 3 and 4 are very slow to drain; this suggests that the connection from these to the inlet in Dyke 2 is not performing well. An open-ended pipe exists in the swale in Dyke No. 3, but it appears that this is not functioning adequately. As well, the intermediate berm piping from Dyke 4 to Dyke 3 and from Dyke 3 to Dyke 2, appears to be blocked.

Scenarios for Drainage Improvements

Three scenarios for drainage improvements are presented: one for existing conditions and two for modifications. For each of these the existing shut-off valve in the valve chamber will continue to be manually operated to drain any water from the dyke as is the case at the present time.

The accuracy of the results presented for these scenarios must be viewed as preliminary as the amount of information provided by NL Hydro or collected during the study was not sufficient to carry out a precise determination of results. For the purposes of this study they are adequate and indicate that drain times can be improved considerably if improvements are made to the drainage system.

Table 2 shows the total rainfall collected in the dyke for a range of storm frequencies along with theoretical discharge rates and time needed for draining the dykes for these return periods.

For Scenario No. 1, using the existing discharge pipe size as 200 mm and a slope of 5% we have estimated the discharge capacity from Dyke 2 to be approximately 68 liters per second (899 gpm). Assuming unobstructed flow to the discharge pipe, the time to drain the dykes to a dry condition would range from about 8 hours to 16 hours for the 2 year and 10 year storm respectively. This does not appear to be the case in practice, suggesting that that there are

problems with the existing drainage system. Simply up-sizing the existing pipe will not likely result in significant improvement since sub-drainage throughout is a problem.

In Scenario No. 2, for example, if the existing 200 mm pipe were replaced with a 375 mm pipe, and new sub drainage was installed throughout the dyke, at a lower elevation than now exists, the theoretical discharge time would be between 4 to 6 hours for the 2 to 10 year storms.

For Scenario No. 3, if the existing 200 mm pipe were kept in service to handle Dykes 1 and 2, and was twinned with a 300 mm diameter from Dykes 3 and 4, and new sub- drainage was installed throughout the dyke, at a lower elevation than now exists, the theoretical discharge time would be between 3 to 7 hours for the 2 to 10 year storms.

Figure 1 graphically displays the results of the above analysis of the three scenarios that is presented in Table 2.

We reviewed the possible installation of an underground Oil-Water Separator in combination with the improvements proposed in the above scenarios. In this case the Oil-Water Separator would be installed downstream of the existing shut-off valve; the unit would operate in the running mode at all times with water being released from the dyke on a continuous basis. Flow would be restricted to match the unit's rated capacity. In the event that operating conditions require a faster release of water, the unit would be shut down and a bypass pipe would be activated to drain the dyke as per the scenarios presented above. Sizing of the unit would be such that the dyke would be dry within 12-24 hours, as this is deemed satisfactory for normal operations. A preliminary estimate of the capacity of the unit would be in the order of 1,800 to 3,600 liters per minute and approximate tank dimensions would be in the order of 3 meter diameter by 10 meters long, to be confirmed once a final decision is made on required drain down time.

The Provincial GAP regulations, Section 27 (8) (d) requires "a method for the elimination of water accumulations inside the dyke shall be incorporated in the dyke design and construction". Hydro needs to obtain approval from the Department of Environment for the installation of an oil/water separator.

Table 2
Dyke Drain-down Analysis (for 100% dry conditions)

SCENARIO No. 1: Existing Conditions - 200mm * diameter iron pipe @ 5.0%
* Pipe size, condition and and slope to be confirmed

Existing Discharge Piping Capacity
- 200 mm dia @ 5% = 68 l/s = 899 gpm - theoretically can drain dyke in approx 8 to 16 hours

Storm Frequency	Storage Volume Liters	Discharge Rate Required for Selected Drain-down Times - hours					
		16	12	8	6	4	2
2 yr	2,075,000	36 l/s	48 l/s	72 l/s	96 l/s	144 l/s	288 l/s
		476 gpm	635 gpm	952 gpm	1,270 gpm	1,904 gpm	3,809 gpm
5 yr	2,525,000	44 l/s	58 l/s	88 l/s	117 l/s	175 l/s	351 l/s
		579 gpm	772 gpm	1,159 gpm	1,545 gpm	2,317 gpm	4,635 gpm
10 yr	2,822,000	49 l/s	65 l/s	98 l/s	131 l/s	196 l/s	392 l/s
		647 gpm	863 gpm	1,295 gpm	1,727 gpm	2,590 gpm	5,180 gpm
100 yr	3,754,000	65 l/s	87 l/s	130 l/s	174 l/s	261 l/s	521 l/s
		861 gpm	1,148 gpm	1,723 gpm	2,297 gpm	3,445 gpm	6,891 gpm

Existing discharge piping theoretical capacity is 8 - 16 Hours

SCENARIO NO. 2: With Modifications Use single 375 mm diameter pipe at 0.5%

New 375 mm piping discharge capacity = 161 l/s = 2,128 gpm
- theoretically can drain dyke in approx 4 to 6 hours

Storm Frequency	Storage Volume Liters	Discharge Rate and Draining Times - hours 16	12	8	6	4	2
2 yr	2,075,000	36 l/s	48 l/s	72 l/s	96 l/s	144 l/s	288 l/s
		476 gpm	635 gpm	952 gpm	1,270 gpm	1,904 gpm	3,809 gpm
5 yr	2,525,000	44 l/s	58 l/s	88 l/s	117 l/s	175 l/s	351 l/s
		579 gpm	772 gpm	1,159 gpm	1,545 gpm	2,317 gpm	4,635 gpm
10 yr	2,822,000	49 l/s	65 l/s	98 l/s	131 l/s	196 l/s	392 l/s
		647 gpm	863 gpm	1,295 gpm	1,727 gpm	2,590 gpm	5,180 gpm
100 yr	3,754,000	65 l/s	87 l/s	130 l/s	174 l/s	261 l/s	521 l/s
		861 gpm	1,148 gpm	1,723 gpm	2,297 gpm	3,445 gpm	6,891 gpm

Modified piping 4 - 6 Hours

SCENARIO NO.3: With Modifications - use existing pipe plus a single 300 mm diameter pipe at 0.5%
*** Pipe size and slope to be confirmed**

Combined piping discharge capacity = 157 l/s = 2,075 gpm
- theoretically can drain dyke in approx 3 to 7 hours

Storm Frequency	Storage Volume Liters	Discharge Rate and Draining Times - hours 16	12	8	6	4	2
2 yr	2,075,000	36 l/s	48 l/s	72 l/s	96 l/s	144 l/s	288 l/s
		476 gpm	635 gpm	952 gpm	1,270 gpm	1,904 gpm	3,809 gpm
5 yr	2,525,000	44 l/s	58 l/s	88 l/s	117 l/s	175 l/s	351 l/s
		579 gpm	772 gpm	1,159 gpm	1,545 gpm	2,317 gpm	4,635 gpm
10 yr	2,822,000	49 l/s	65 l/s	98 l/s	131 l/s	196 l/s	392 l/s
		647 gpm	863 gpm	1,295 gpm	1,727 gpm	2,590 gpm	5,180 gpm
100 yr	3,754,000	65 l/s	87 l/s	130 l/s	174 l/s	261 l/s	521 l/s
		861 gpm	1,148 gpm	1,723 gpm	2,297 gpm	3,445 gpm	6,891 gpm

Modified piping 3 - 7 hours

(Note: actual time would be different for Dykes 1and 2, compared to Dykes 3 and 4. D1 and D2 drain to existing piping while D3 and D4 drain to new piping . D1 and D2 could drain in 1.5 to 4.5 hours; D3 and D4 could drain in 5.4 hours. Would need to up-size piping from D3 and D4 to 375 mm to drain in 3 hours.)

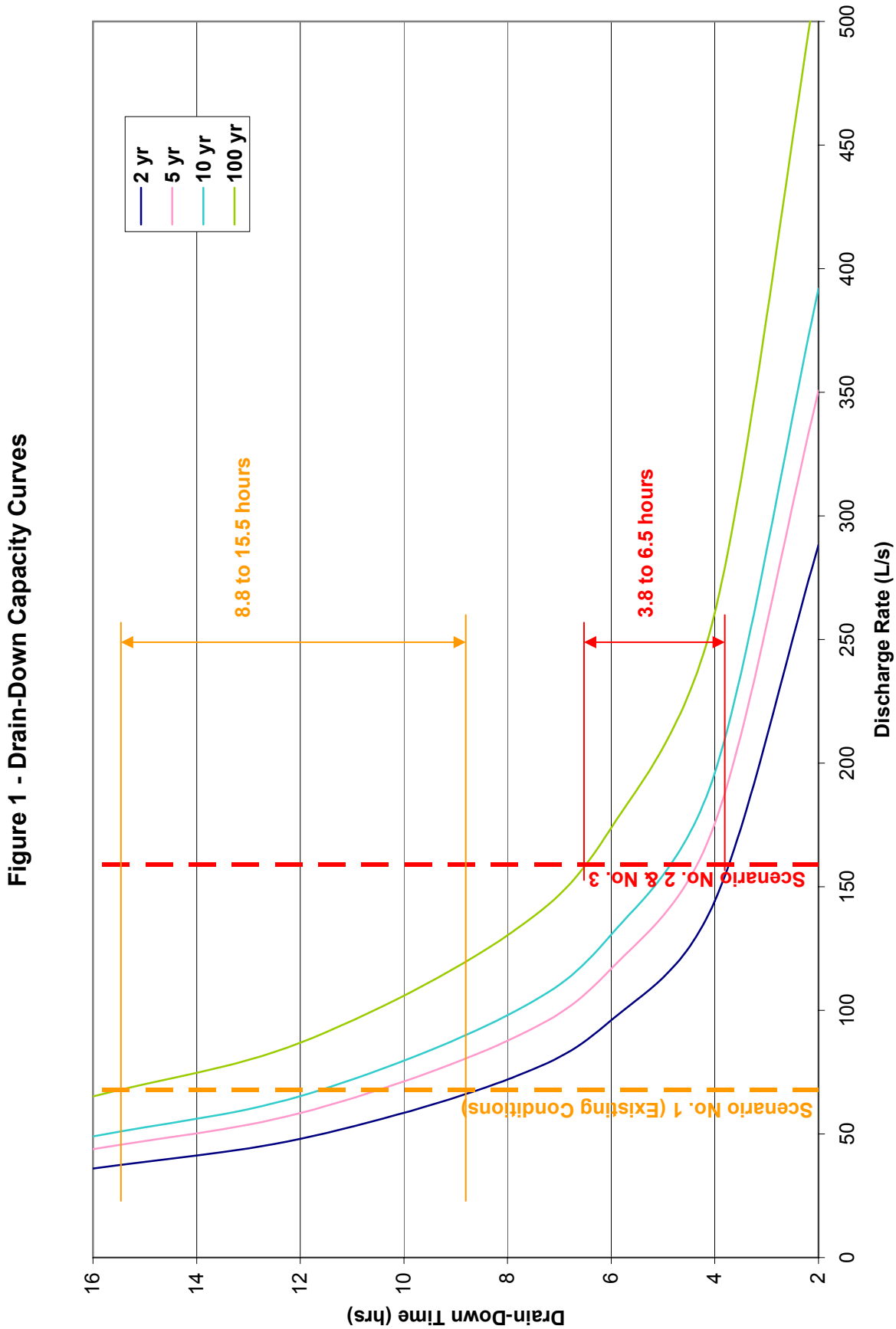
Figure 1 - Drain-Down Capacity Curves
Drain-Down Time (hrs)
Discharge Rate (L/s)
2 yr
5 yr
10 yr
100 yr
8.8 to 15.5 hours
3.8 to 6.5 hours
Scenario No. 2 & No. 3
Scenario No. 1 (Existing Conditions)
16
14
12
10
8
6
4
2
0
50
100
150
200
250
300
350
400
450
500

2.7 Options for Improvements and Phasing

2.7.1 Construction Items

The following provides a description of options for dyke improvements and the benefit to be achieved by each. Also indicated is a proposed phasing plan for items of work based on priority groupings of P1, P2 or P3. At this point these are presented without considering the logistics or practicality of packaging these into meaningful work contracts to achieve economies of scale or to bundle similar work activities together:

Site and Road Grading

Priority 1

1. Remove vegetation – *to meet code requirements and to improve access around the dyke*

Priority 2

1. Reshape and re-grade dyke floor in open areas – *to allow for better access and improved surface drainage*

2. Reshape, re-grade road and parking area, including excavation of unsuitable road materials and raising the road level on the east side of Tank 4 - *to allow for better access to the block house and other work areas, and improved surface drainage*

Priority 3

1. reshape and re-grade dyke floor around pipe racks - *to allow for improved surface drainage*

2. Remove existing intermediate berms between the tanks – *these no longer serve any meaningful purpose; to allow for easier access within the dyke*

Drainage

Priority 1

1. construct sub-drainage system along the south and west sides of dyke along with piping from dykes 3 and 4 to the existing valve chamber - *to improve capture of surface water, provide for quicker release to the discharge piping, and to lower the water table over the dyke floor*

2. construct sub-drainage system along west side of dyke adjacent to the concrete fuel pipe support bases; install a similar system in an east-west direction across the dyke, and install drainage piping to an outfall at the shoreline embankment – *to lower water table around bases, reduce movement of bases and fuel piping due to freeze- thaw action, and lower the water table throughout the dyke*

3. replace tank swales with a sub-drainage system (buried perforated pipe and filter material) and connect directly to the new sub-drainage piping on the west side of dyke - *improved surface drainage*

4. install catch basins or inlet drains at selected locations on the dyke floor - *to capture surface water and direct it quickly to the sub-drainage piping system*

Priority 2

1. construct an east-west sub-drainage system between tanks - *to improve capture of surface water, quicker release, and lower water table*

2. construct interceptor ditch along south embankment – *to reduce surface drainage into dyke*

Priority 3

1. replace existing piping from dyke 2 to the valve chamber - *to improve capture of surface water, provide for quicker release*

to the discharge piping, and to lower the water table over the dyke floor

Surveys

Priority 1

1. topographic survey – obtain additional site spot elevations, location survey for underground piping and above ground pipelines and pipe supports – *to obtain additional site specific information, to further assess options, and for use in detailed design*

2. carry out camera surveys and inspection of underground piping *– to obtain additional information on piping conditions and to further assess options*

3. excavate to expose and examine drainage piping - *to obtain additional information on piping conditions*

4. flush drainage lines – *to obtain additional information on piping conditions*

Maintenance Items

Priority 1

1. clean out and deepen existing swales around tanks *– to improve site operations (this should be done on an on-going basis until these are replaced)*

2. Locate hydrant valves and install location markers to improve accessibility.

Priority 2

1. restore top of main berm to containment elevation - *to remain compliant with permit*

Piping and Pipe Supports

3 Piping and Pipe Supports

3.1 Piping

This section of the report summarizes the findings of our field investigations of the existing fuel and steam line pipes and supports within the dyke and presents a series of observations, photographs of typical conditions, and options for remedial work along with cost estimates. The line to the dock and lines to the plant were not in the scope of work of this study.

There is an on going program of insulation removal and inspection. Several areas of pipe wall thinning and pinhole leaks have been discovered and repaired. The steam tracing on the tank discharge lines are also being inspected and replaced as required. Branch line isolation valves have been installed on all the fill lines to the tanks except Tank 1. A cost for the supply and installation of this valve is included in the cost estimate for the refurbishment of this tank.

3.2 Pipe Supports

A visual inspection of the pipe supports for the Bunker C and steam lines was performed to identify any pertinent issues and to develop a cost estimate for remedial action. The pipelines are insulated and the inspection was of the exposed portions of the pipe supports only. It is understood that NLH will separately perform a stress analysis of the pipelines using survey data.

Observations
NLH is aware that the pipe supports are heaving and settling due to frost action. An annual elevation survey is performed to monitor the movement. Considerable evidence of pipe support movement was observed. Pipe saddles are not in contact with the support structure and extension plates are welded onto pipe saddles to bridge the gap between saddle and structure. (Photo 1)

Approximately 30% of the pipe supports are not carrying vertical loads or are carrying vertical loads unequally.

A less frequent issue is lateral or longitudinal movement of the pipe resulting in shifting of the saddle relative to the support structure. (Photos 2 and 3)

Generally, corrosion of pipe supports is not a problem except for the supply branch lines to Tanks 3 and 4. (Photo 4)

Severe deterioration of several concrete anchor blocks was observed. It is unknown if the anchor blocks failed due to excessive forces from the pipe attempting to move or if concrete failed due to freeze/thaw cycles and then the pipe was free to move. (Photo 5)

In total, 35 to 40 pipe supports require remedial work and 4 to5 anchor blocks require replacement.

Photographs

Photo 1: Main line expansion loop at Tank 4. Extension plates welded to saddle and spacer plate on beam.

Photo 2: Expansion Loop near Tank 4. Evidence that saddle moved laterally.

Photo 3: Main Trunk Line near Tank 3. Pipe saddle moved longitudinally and previously repaired.

Photo 4: Branch Line to Tank 3. Severe corrosion of saddle and support.

Photo 5: Anchor Block between Tanks 1 and 2. Anchor block completely failed.

Tanks

4 Tanks

There are four 200,000 bbl aboveground fuel storage tanks containing bunker C. The tanks are 180 ft in diameter and 48 feet high and were constructed by McNamara Industries Limited. Tanks 1 and 2 were built in 1969 and Tanks 3 and 4 were built in 1977 during the expansion of the thermal generating station.

The 18 inch supply line from the ship unloading area to the tanks is electrically heat traced. The tank suction heaters and the generating station supply lines are steam traced.

The tanks have undergone both internal and external inspections in accordance with API 653. The main concerns discovered relate to the corrosion of the floor and roof plate. Water ponding inside the dyke due poor drainage has caused underside corrosion to the floor plate of Tanks 3 and 4. Tanks 1 and 2 although older, have floor plate which is in relatively good condition. The roof plate of Tank 1 is heavily corroded on the underside. All tank inspections are subject to the requirements given in the API Standard 653 and in particular the inspection frequency is dictated by the requirements of Section 4 – Inspection.

None of the tanks have floors that are cathodically protected from underside corrosion. Based on the proven service life of the tanks, product stored and proposed drainage improvements of the dyke new cathodic protection of the tanks is not recommended.

4.1 Tank No. 1

The inspection of this tank was completed in December 2005. AITEC completed a magnetic flux leakage test of the floor and found very few areas where the plate was under the minimum thickness.

4.1.1 Inspection Findings and Immediate Repairs

1. The areas of the floor which have a thickness less than 0.10 inches (API 653 – Table 4-1) were repaired by installing 12 patch plates in accordance with the approved detail. The corrosion rate calculated by AITEC is 0.029 inches per year which they estimate gives the tank bottom a 10 year life. The corrosion rate will be confirmed during the next scheduled inspection.

2. Areas of the floor where rocks deformed the plate were removed and repaired in accordance with the approved procedure.
3. Shell to floor interior fillet weld and shell pitting corrosion are to be repaired in accordance with the approved procedure.
4. Two small roof plate cut outs were patched in accordance with the approved procedure. These plates were sent for chemical analysis to confirm the material specification. Large areas of roof plate were found to be below the minimum required thickness of 0.09 inches. No further repairs were performed as the roof needs replacing in the next 5 years. As a safety measure temporary handrail and a platform were installed in the gauging area to prevent access to the remainder of the tank roof.
5. An interior inspection of the roof rafters indicates that many of them are not straight but have a pronounced sweep. This is not visible from the ground but is clearly visible from scaffolding. A design check was performed on the rafters to determine their stress level. It was determined the rafters meet the API code requirements for live load and dead load stress levels. We do have a concern for the amount of deflection. The worst case is the intermediate rafter which has a span/deflection ratio of 116. Normally this would be limited to 180. This is not a cause for concern regarding structural integrity but does contribute to the water ponding problem.
6. Unused 1 1/2 inch nozzles were removed and the shell repaired in accordance with the approved procedure.

4.1.2 Life Extension Recommendations

1. The tank dyke drainage needs to be maintained the same or better to ensure there is no acceleration of the underside corrosion. The next floor scan inspection is recommended in 2011. This will also assist in establishing the corrosion rate.
2. The interior coating system on the floor plate and lower section of shell plate needs to be maintained to prevent interior corrosion. Although the there does not appear to be a problem with the existing coating system, as a preventative measure, we are recommending the removal of the existing floor coating system and recoating of the floor and lower 1 meter of the tank shell.
3. The roof plate needs to be replaced in 5 years due the unusual underside corrosion. Many areas of the plate do not meet the required minimum

thickness thus requiring patching or replacement. Due the size if the area affected we recommended replacement.

4. Roof rafters need to be checked to determine cause of sweep. Replacement is not warranted unless members have permanent deformations or have thinned from corrosion. A further inspection should be carried out during roof plate replacement.

4.2 Tank No. 2

The inspection of this tank was completed in October 1998 by fga Canspec. A magnetic flux leakage test of the floor found very few areas where the plate was under the minimum thickness.

4.2.1 Inspection Findings and Immediate Repairs

1. One underside corrosion pit required repair. In a memo from Alberta Marche dated November 25, 1998 it stated this repair was completed. No predicted life of the floor was listed in the report.
2. A crack in the suction heater tube required repair and as stated in the same memo it was repaired.
3. Three holes in the roof plate required repair and as stated in the same memo these holes were repaired.
4. It was recommended that a stress analysis be completed of the annular floor area or repair the floor to API 653 – 1995 requirements. As far as we know the only work completed was sand blasting and recoating of 12 inches of the shell and floor in the area around the shell to floor joint.
5. It was recommended that the vegetation growing in the crack between the floor plate and the concrete ring beam be removed. There is no indication in the memo or in any other report that this was completed.
6. Corrosion on the spiral stair was noted. There is no indication in the memo or in any other reports that these repairs were completed.

4.2.2 Life Extension Recommendations

1. The tank dyke drainage needs to be maintained the same or better to ensure there is no acceleration of the underside corrosion. It is recommended that a

floor scan be performed during the next proposed inspection in 2008. This will assist in establishing a corrosion rate for the floor.

2. The interior coating system on the floor plate and lower section of shell plate needs to be maintained to prevent interior corrosion. Although the there does not appear to be a problem with the existing coating system, as a preventative measure, we are recommending the removal of the existing floor coating system and recoating of the floor and lower 1 meter of the tank shell.
3. We recommend the roof plate be inspected for underside corrosion using interior scaffolding, similar to Tank 1, to determine if the roof plate needs to be replaced. Also the roof rafters need to be inspected to determine if they are deflected in a similar manner to those in Tank 1. If possible a movable scaffold system should be used so that a more thorough examination can be made. The water ponding problem on the roof is a result of the plate deflection and flexibility of the rafters. Replacement cost for the roof and rafters and the cost for a new exterior coating system have been included in the estimate.

4.3 Tank No. 3

The inspection of this tank was completed in November 2003 by AITEC. A magnetic flux leakage test of the floor was completed and 66 plates were found to have pitting corrosion causing areas of these plates to be under the minimum required thickness.

4.3.1 Inspection findings and Immediate Repairs

1. A total of 195 repair patches were installed over the corroded areas.
2. A corrosion rate of 0.005 inches per year was estimated based on the findings. The estimated life of the floor is 5-6 years.
3. A magnetic particle inspection of the floor to shell weld was made in an area where there was pronounced edge settlement and no weld defects were found.
4. The bottom settlement and rigid tilt surveys were completed but not analyzed.
5. Holes in the roof plate were found and these areas repaired.
6. The roof vents did not have bird screens.

7. Samples of the soil under the floor were taken by removal of small areas of floor plate.

4.3.2 Life Extension Recommendations

1. The tank dyke drainage in this area is poor and is contributing to the pitting corrosion of the floor plate. Dyke drainage improvements are required to reduce the corrosion rate.
2. The inspection in 2003 required the installation of numerous patch plates. The installation of these plates extended the life of the floor but in doing so prevents future conventional magnetic flux leakage scanning. We recommend the replacement of the floor and coating of the floor and 1m of the lower shell in 2010.
3. The roof plate needs to be continuously monitored for corrosion. The water ponding is a result of the plate deflection and flexibility of the rafters. Maintenance of the coating system is required to prevent pitting corrosion. During the floor replacement an underside inspection of the roof plate and rafters is recommended.
4. A bottom settlement analysis is not recommended as the floor plate is recommended to be replaced including rebedding of the sand foundation.

4.4 Tank No. 4

The inspection of this tank was completed in August 2004 by AITEC. A magnetic flux leakage test of the floor was completed and 90 plates were found to have pitting corrosion causing areas of these plates to be under the minimum required thickness.

4.4.1 Inspection findings and Immediate Repairs

1. A total of 730 repair patches were installed over the corroded areas.
2. A corrosion rate of 0.005 inches per year was estimated based on the findings. The estimated life of the floor is 5-6 years.
3. In a few areas surface laminations of the exterior of the shell plate were discovered and repaired by grinding smooth.
4. The bottom settlement and rigid tilt surveys were completed but not analyzed.
5. Samples of the soil under the floor were taken by removal of small areas of floor plate.

4.4.2 Life Extension Recommendations

1. The tank dyke drainage in this area is poor and is contributing to the pitting corrosion of the floor plate. Dyke drainage improvements are required to reduce the corrosion rate.
2. The inspection in 2004 required the installation of numerous patch plates. The installation of these plates extended the life of the floor but in doing so prevents future conventional magnetic flux leakage scanning. We recommend the replacement of the floor and coating of the floor and 1m of the lower shell in 2009.
3. The roof plate needs to be continuously monitored for corrosion. The water ponding is a result of the plate deflection and flexibility of the rafters. Maintenance of the coating system is required to prevent pitting corrosion. During the floor replacement an underside inspection of the roof plate and rafters is recommended.
4. A bottom settlement analysis is not recommended as the floor plate is recommended to be replaced including rebedding of the sand foundation.

4.5 Tank Vent Exhaust Odour Control

NLH has identified that they wish to control the emission of hydrogen sulphide from the Bunker C storage tanks which is causing an undesirable odour in neighbouring communities. The fuel normally used in the boilers has 2 percent sulfur. Although hydrogen sulphide gas is continuously released from the fuel, it is normally only emitted from the tanks when they are being filled. Otherwise, the tanks are not venting or drawing in air. The maximum fill rate of the tanks is 15,000 bbls/h [1400 cfm].

A common technology to deal with odours is activated carbon. To absorb hydrogen sulphide, the carbon can be impregnated with potassium hydroxide. The tank vent is piped to ground level where it is connected to a canister of impregnated carbon. From there the cleaned gas emission can be vented to atmosphere. The canister is normally mounted at ground level due to the weight of the product and the need to replenish the carbon every three to four years.

A challenge with installing a filter on the tank vent is that it will create a back pressure in the tank during filling. Normally the filling rate is much greater than the drawdown rate and hence vacuum is not considered. An activated carbon filter canister is normally sized to produce a back pressure of ½" Hg [0.25 psi]. For normal tank design, API 650 requires that the weight of the tank roof exceed the uplift force on the roof due to internal pressure. That is not the case for the Holyrood storage tanks if subjected to an internal pressure of ½" Hg. However, the weight of the roof, structure and shell combined does exceed the uplift force. To include these additional components, the design of roof-to-shell junction must meet certain requirements. Further engineering analysis of the tanks must be performed to determine if they can withstand the internal pressure or must be reinforced.

NLH has purchased a 1 percent sulfur fuel and will evaluate the odour emissions during tank filling. At this time, cost for implementation of odour control equipment has not been included in the estimate.

Photo 1 - Tank No. 4 - Floor Plate – Underside of Bottom Plate Exposed (Left Hand Side) - Soil Exposed for Testing (Right Hand Side)

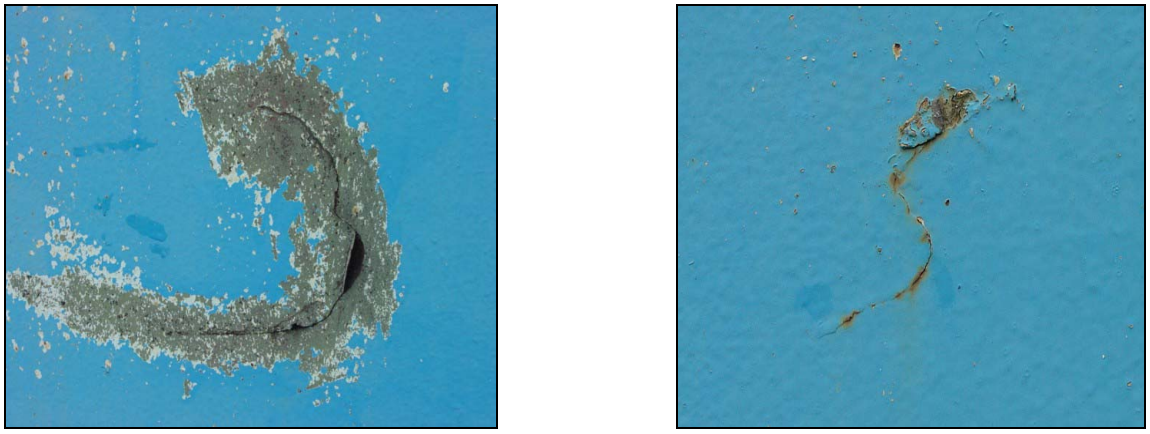

Photo 2 - Tank No. 4 - Surface Laminations

Photo 3 – Tank No. 1 – Interior Roof Scaling and Rafter Sweep

Photo 4 - Tank No. 4 - Floor Plate - Repair Patch Plates and Inspection of Lap Joint

Photo 5 - Tank No. 1 – Interior View of Insert Plate and Floor Repair Patch

Photo 6 - Tank No. 1 – Roof Plates Showing Location of Thickness Measurements

Electrical Systems

5 Electrical Systems

5.1 Background

This section of the report summarizes the findings of field investigations of the existing electrical installations and provides related cost estimates for improvements. In addition, it covers the existing lighting system at the tank farm, feasibility of adding CCTV coverage, and additional audio paging at the tank farm. Newton Engineering Limited was sub-contracted to SGE Acres to provide this input to the report. Drawing No. E-B1-001 presents information regarding site lighting levels.

5.2 Area Classification (Electrical)

According to the NFPA code the area immediately surrounding the electrical installations in the tank farm is not classified as hazardous. This is based on the determination that Number 6 Fuel Oil is a Class IIIA liquid which is not heated beyond its flash point of 65°C.

Note that lighting fixtures installed within and on the heater enclosures are rated for Class 1, Division 2 locations, however, this is the only electrical equipment presently installed which is rated for installation in a hazardous location, with the exception of the existing paging equipment.

5.3 Electrical Issues

The following are a number of issues which require remedial work, some for compliance with the Canadian Electrical Code.

1) A number of conduits and boxes are presently not secured to the walls within the Block Houses for Tanks 3 and 4.

2) In some cases, RGS conduit has rotted through, exposing the insulated conductors within. In many other instances, RGS conduit has rusted severely.

3) A length of flexible steel conduit used to connect a thermocouple within enclosure 2 is damaged, exposing the instrumentation cable.

4) An exterior lighting fixture is missing at the enclosure for Tank 1.

5) An Lb conduit fitting on the exterior of enclosure 2 is broken, exposing the insulated power conductors within.

6) One of the new flood lighting fixtures is mounted upside down.

7) An instrumentation conduit fitting located along the main distribution lines near tank 2 is broken, exposing the instrumentation cable.

8) Obsolete lighting equipment including fixtures, conduit, wire, enclosure, ground rods and disconnect switch located on the east side of the tank farm should be removed.

9) The majority of branch circuits and feeders associated with the lighting power panel near Tank 1 are run loose within the outer enclosure to the panelboard. These conductors must be installed in conduit.

10) Bonding terminations in the panel enclosure near Tank 1 are poor. Branch circuit bonding connections are to be made within the panel at ground lugs.

11) PVC conduit recently installed for level monitoring run along the base of tanks is subject to damage. Protection should be provided.

12) Additional support is required for flexible conduits to thermocouples and for recent PVC conduit installations.

13) 30A circuit breakers supplying lighting and receptacles in enclosures for tanks 3 and 4 exceeds the 20A maximum.

14) Transformer ground wire spliced to smaller conductor within panel enclosure. Conductor size and electrode to be further investigated for code compliance.

15) Teck 90 cable run along the surface of the east berm and connecting to the panel near Tank 1 is not secured and is subject to damage. This cable should be buried to a minimal depth of 600 mm for code compliance and secured to the panel support structure.

16) The majority of conduit supports are adequate for the conduit size however, additional supports are required at a number of conduit installations along the pipe rack.

5.4 Communications at Tank Farm

Currently there are two stations for paging and communicating at the tank farm; one located near Tank 1 on the berm and the other located on the exterior of Tank 3 heater enclosure. These consist of a loud speaker and handset. This equipment is part of a party page system located throughout the facility whereby a page can be initiated or responded to at either station. An amplifier at each station powers the loud speaker for that location. Both existing tank farm stations are reported to be operational.

The existing layout is reportedly not serving the south end of the tank farm where there is significant activity during off loading operations. We would propose to extend the existing communications system with an additional handset and loud speaker station (weatherproof rated) located along the berm in the southwest corner of the site. System specific communications cabling would be extended from the Tank 3 heater enclosure, running underground to the new station location.

An estimate of the construction cost is not included in this study.

5.5 CCTV System

Presently, a CCTV system is in use with eight camera locations around and within the facility and a head end unit installed at the Guard House. The cameras are color and are pan-zoom-tilt type. A digital video recorder (DVR) is located in the Guard House.

A CCTV installation at the tank farm would necessitate either the installation of increased lighting to enable viewing after dark, or infrared projectors which would illuminate subjects after dark. Current lighting levels are not sufficient for nighttime viewing and the positioning of fixtures would create restricted views.

We would propose the installation of a system consisting of the following components, based on the supposition that lighting levels would be increased, also providing poles on which to mount the cameras.

1. Five (5) day/night, pan-tilt-zoom, color cameras in weatherproof, corrosion resistant enclosures (4X and IP66) mounted on perimeter poles at locations indicated on the attached CCTV Layout Plan.

2. Direct buried underground armored cables for video from and power to cameras, terminating in the Guard House. The video media intended is multimode fiber optic cable.

3. A 16 channel, 500GB with burner, DVR to incorporate the existing and new cameras.

4. New 19" monitor to replace the existing.

An estimate of the construction cost is not included in this study.

5.6 Exterior Site Lighting

There are a number of recently installed flood lighting fixtures located along the west and east sides of the tank farm, located at the top of the berm. The fixtures are Keene BTY series, 400W, metal halide fixtures mounted atop relatively short steel poles, resulting in the fixtures being located approximately 3 meters above the top of the berm. We understand that the low mounting height was intended to eliminate the requirement for a boom truck when servicing the fixtures. The fixtures appear to have no photo control, as all were on during our daytime site inspection. The low mounting height of these fixtures creates a significant glare issue when looking in the direction of the fixtures. In addition, the illumination levels attained at grade are very low. See the attached Existing Site Illumination Plan for calculated illumination levels based upon the existing fixture utilization as well as levels actually recorded on site during our nighttime site visit. Note that the IES recommended maintained light level for exterior fuel storage tank areas for electric generating stations is 10 lux while the majority of the tank farm area has essentially no illumination, or zero lux (calculated and measured). Note also that the contribution from the incandescent fixtures mounted on the exterior of the heater enclosures is not reflected in the calculated values indicated. The contribution of these fixtures is negligible, however, to other than the immediate area at the heater enclosures. (*Note that IES standards are guidelines only, not code requirements. An owner's decision will determine the lighting level to be provided; however, for this facility the existing lighting levels should be increased for safety and liability reasons)*

To properly light this tank farm, fixtures should be mounted atop high poles (7.5 m recommended) to achieve maximum light spread and minimal glare. The number of fixtures required would increase from the existing installation; however, utilizing larger wattage (1,000 W) fixtures would minimize the number of fixtures and poles required. Such an installation would necessitate the use of boom trucks to service the fixtures, however. Discussions held with the owner have resulted in a decision to leave the existing lighting poles/fixtures on the west side as is. The additional lighting considered, therefore, at this time is for a number of poles located on the east side of the farm, each with a number of flood lights mounted. The power required to operate these fixtures is a concern and may require an additional power supply to the tank farm from the plant or from a separate service as the power required would be approximately 10 kva. Distribution wiring between poles could be accomplished using Teck 90 copper cables buried to a depth in accordance with code and sized to overcome the resulting voltage drop. Fixtures could be controlled with individual photocells or from a photocell/contactor combination for reduced maintenance at elevation.

Additional lighting will be required to illuminate the new oil/water separator. This can be provided from a 250 W HID flood fixture mounted atop a pole located at the separator. Power can be provided to supply the additional light from the existing west side lighting circuit.

The estimated construction cost of the lighting fixtures, poles and underground wiring is $30,000 plus HST. The additional power supply and distribution equipment is not included in this estimate.

5.7 Block House Lighting

The lighting within the heater enclosures attached to the side of each tank is provided from two incandescent lighting fixtures controlled from a standard non-rated toggle switch. The fixtures themselves are rated for class 1 locations, however, this rating is not required for this installation. Illumination levels are very low, measured as under 10 lux at most locations. The recommended light level for this type of building is between 50 and 100 lux.

We recommend replacing the existing lighting fixtures with industrial grade, two lamp, fluorescent strip fixtures which would yield lighting levels between 150 and 200 lux with

good uniformity. The fixtures should be complete with wire guards to prevent inadvertent damage to the exposed lamps.

5.8 Thermocouple Wiring Replacement

The existing conduit system for the thermocouple wiring to the Heater Enclosures is broken in a number of locations and requires repair. To accomplish this, it is recommended to also replace the thermocouple extension wire as the existing cable may become damaged if attempting to remove and reinstall it. While the existing conduit supports are generally adequate with respect to spacing (maximum of 3 m spacing for 41 mm RGS conduit) additional supports will be required in some instances. It is proposed to provide a multiple single pair non-armored thermocouple extension cables between each of the Heater Enclosures, allowing for one spare cable in each run; this as opposed to a multiple pair cable providing an overabundance of spare pairs.

5.9 Oil/Water Separator Monitoring Controls

The monitoring system at the proposed oil/water separator will require 120V ac power. This can be provided from the existing tank farm panel board with wiring run directly to the separator. Utilizing the recent power installation to the west side lighting fixtures is not practical, as this circuit may someday be controlled to de-energize the circuit during daylight hours. The proposed location of the separator requires this branch circuit to be buried in its entirety, utilizing a Tech 90 cable.

Cost Estimates and Implementation Plan

6 Cost Estimates and Implementation Plan

6.1 Cost Estimates

This section provides construction cost estimates for the various options presented along with priority allocations. It must be noted that the estimates are preliminary in nature and are based on incomplete site information. These can be considered to be reliable to an overall accuracy of ±25%, although some specific items could change more than this once these are looked at in more detail. All costs presented here are considered preliminary, but the contingency is considered appropriate for budgetary purposes. These will need to be reviewed prior to confirming which work items are to be implemented. This can be done at the pre-design stage.

Engineering and contingency allowance is included, but HST is not included. Inflation has not been factored into the cost estimates specifically but is adequately covered in the contingency amount. Owner's costs are not included.

With regard to dyke drainage, it is noted that as an option to gravity drainage from the dyke, a pumped system was considered. Pumping capacity would be in the order of 190 liters per second (2,500 gpm) consisting of a dual submersible pump system and wet well. However, capital costs for this would likely be in the order of an additional $50,000, and would introduce another maintenance responsibility, making this option unattractive.

With regard to pipe supports and based on recent work at petroleum storage facilities in Newfoundland, estimated costs of $5,000 per pipe support and $10,000 per anchor block have been applied. Additional work can be expected if the repairs are not performed now but done 3-5 years in the future. This cost estimate includes remedial work to only those pipe supports that are deteriorated or not carrying load. It does not include addressing the heaving/settling issue of other pipe supports. The cost for the installation of a new isolation valve on Tank 1 has been included in the estimate. With regard to site lighting, additional power supply and distribution equipment is estimated at $63,000 (not including transformers, pole structures and HV equipment/materials). For CCTV, providing IR projectors instead of the additional lighting would cost approximately $15,000. These cost estimates are not included in Table 6.1.

Table 6.1 provides a detailed list of remedial work items proposed for upgrading of the existing tank farm and dyke.

Table 6.1
HOLYROOD GENERATING STATION TANK FARM
Cost Estimates for Upgrading

Item	Description	Base Cost	Engineering	Contingency	Eng + Cont	Total
1	**Civil**					
1.1	**Site Grading**					
0.1	Remove Vegetation	$10,000	20%	20%	$4,000	$14,000
0.2	Dyke Floor in Open Areas	$61,000	15%	20%	$21,350	$82,350
0.3	Dyke Floor around Racks	$64,000	15%	20%	$22,400	$86,400
0.4	Roads and Parking	$75,500	15%	20%	$26,425	$101,925
0.5	Remove Intermediate Berms and Modify Steps	$6,500	20%	20%	$2,600	$9,100
	Sub-total Grading	$217,000			$76,775	**$293,775**
1.2	**Drainage**					
0.1	Sub-drainage and discharge piping for Tanks	$264,000	15%	20%	$92,400	$356,400
0.2	Sub-drainage and discharge piping for pipe support bases	$97,000	15%	20%	$33,950	$130,950
0.3	Interceptor Ditch	$35,000	15%	20%	$12,250	$47,250
0.4	Piping from Dyke 2	$5,000	20%	20%	$2,000	$7,000
0.5	Oil Water Separator and Bypass	$120,000	20%	20%	$48,000	$168,000
0.6	Steam Trap Drain Connections	$25,000	15%	20%	$8,750	$33,750
	Sub-total Drainage	$546,000			$197,350	**$743,350**
1.3	**Surveys and Investigations**					
0.1	Topographic	$4,500	20%	10%	$1,350	$5,850
0.2	Video Inspection of Piping	$13,500	20%	10%	$4,050	$17,550
0.3	Flushing of Piping	$1,500	20%	10%	$450	$1,950
0.4	Excavate and examine existing piping	$3,000	20%	20%	$1,200	$4,200
	Sub-total Surveys	$22,500			$7,050	**$29,550**
1.4	**Maintenance**					
0.1	Restore Main Berm	$30,000	20%	20%	$12,000	$42,000
0.2	Hydrant valve markers	$3,000	20%	20%	$1,200	$4,200
	Sub-total maintenance	$33,000			$13,200	$46,200
	Sub-total Civil Works	$818,500			$294,375	**$1,112,875**
2	**Pipe Supports**					
2.1	Anchor Blocks	$50,000	20%	20%	$20,000	$70,000
2.2	Supports	$200,000	15%	20%	$70,000	$270,000
2.3	Isolation Valve and Piping	$125,000	10%	20%	$37,500	$162,500
2.4	Third Party Inspection	$10,000	20%	20%	$4,000	$14,000
2.5	Sand Blasting & Painting	$50,000	10%	20%	$15,000	$65,000
	Sub-total Pipe Supports	$435,000			$146,500	$581,500

Item	Description	Base Cost	Engineering	Contingency	Eng + Cont	Total
3	**Tanks**					
3.1	**Tank 1**					
0.1	Replace Roof Plate	$620,000	2%	20%	$136,400	$756,400
0.2	Roof Coating	$100,000	5%	20%	$25,000	$125,000
0.3	Roof Rafters	$160,000	5%	20%	$40,000	$200,000
0.4	Tank Cleaning	$250,000	2%	10%	$30,000	$280,000
0.5	Center Vent Fall Protection	$5,000	20%	20%	$2,000	$7,000
0.6	Floor Coating	$165,000	2%	20%	$36,300	$201,300
0.7	Roof Platform	$10,000	20%	20%	$4,000	$14,000
0.8	Third Party Inspection	$10,000	20%	20%	$4,000	$14,000
	Sub-total Tank 1	$1,320,000			$277,700	**$1,597,700**
3.2	**Tank 2**					
0.1	Replace Roof Plate	$620,000	5%	20%	$155,000	$775,000
0.2	Roof & Shell Coating	$165,000	10%	20%	$49,500	$214,500
0.3	Roof Rafters	$160,000	20%	20%	$64,000	$224,000
0.4	Floor Scan	$25,000	10%	20%	$7,500	$32,500
0.5	Tank Cleaning	$500,000	2%	10%	$60,000	$560,000
0.6	Center Vent Fall Protection	$5,000	20%	20%	$2,000	$7,000
0.7	Floor Coating	$165,000	10%	20%	$49,500	$214,500
0.8	Roof Platform	$10,000	20%	20%	$4,000	$14,000
0.9	Third Party Inspection	$10,000	20%	20%	$4,000	$14,000
	Sub-total Tank 2	$1,660,000			$395,500	**$2,055,500**
3.3	**Tank 3**					
0.1	Floor Coating	$165,000	2%	20%	$36,300	$201,300
0.2	Replace Floor Plate	$750,000	2%	20%	$165,000	$915,000
0.3	Rebedding Soil Under Floor	$20,000	5%	20%	$5,000	$25,000
0.4	Tank Cleaning	$250,000	2%	10%	$30,000	$280,000
0.5	Roof Platform	$10,000	20%	20%	$4,000	$14,000
0.6	Third Party Inspection	$20,000	20%	20%	$8,000	$28,000
	Sub-total Tank 3	$1,215,000			$248,300	**$1,463,300**
3.4	**Tank 4**					
0.1	Floor Coating	$165,000	2%	20%	$36,300	$201,300
0.2	Replace Floor Plate	$750,000	4%	20%	$180,000	$930,000
0.3	Tank Cleaning	$250,000	2%	10%	$30,000	$280,000
0.4	Roof Platform	$10,000	20%	20%	$4,000	$14,000
0.5	Third Party Inspection	$20,000	20%	20%	$8,000	$28,000
	Sub-total Tank 4	$1,195,000			$258,300	**$1,453,300**
	Sub-total Tanks	$5,390,000			$1,179,800	**$6,569,800**
4	**Electrical**					
0.1	General	$12,500	20%	20%	$5,000	$17,500
0.2	Lighting	$32,500	20%	20%	$13,000	$45,500
0.3	Thermocouple Wiring	$30,000	20%	20%	$12,000	$42,000
0.4	O/W Separator Controls	$4,000	20%	20%	$1,600	$5,600
	Sub-total Electrical	$79,000			$31,600	$110,600
	TOTALS	**$6,722,500**	**$459,775**	**$1,192,500**	**$1,652,275**	**$8,374,775**
	Notes:					
1	Design costs are incurred to maintain schedule for contract packages. The total Consulting Fee is 6.8%					
2	Inflation and Owner's costs are not included in above					

6.2 Implementation Plan

This section provides an outline of proposed implementation phasing for the remedial works identified. Work should be scheduled to avoid conflicts between civil and tank works that will occur if both are proceeding in the same location at the same time.

In terms of priorities for the tanks it is expected that the schedule will involve one tank per year, starting in 2008, as follows: Tank 2, Tank 4, Tank 3, and finally Tank 1. Tank 1 roof replacement and possible rafter replacement are needed no later than 2011; Tank 2 floor scan should be completed by 2008; Tank 3 floor replacement will be needed by 2010; Tank 4 floor replacement will be needed by 2009.

Table 6.2 presents a proposed capital implementation plan for the four year period 2008 to 2011 based on priorities identified in the report. Engineering design for the first year's capital program (2008) is shown as being carried out in 2007. Engineering design for work in subsequent years is shown as being completed in the year prior to construction.

Table 6.2
HOLYROOD GENERATING STATION TANK FARM
Capital Works Implementation Plan

Item	Description	Total	Priority	Implementation Year				
				2007	2008	2009	2010	2011
1	**Civil**							
1.1	**Site Grading**							
0.1	Remove Vegetation	$14,000	High		$14,000			
0.2	Dyke Floor in Open Areas	$82,350	Medium		$4,575	$77,775		
0.3	Dyke Floor around Racks	$86,400	Medium			$4,800	$81,600	
0.4	Roads and Parking	$101,925	Medium		$2,831	$48,131	$2,831	$48,131
0.5	Remove Intermediate Berms and Modify Steps	$9,100	High		$9,100			
	Sub-total Grading	**$293,775**		**$0**	**$30,506**	**$130,706**	**$84,431**	**$48,131**
1.2	**Drainage**							
0.1	Sub-drainage and discharge piping for Tanks	$356,400	High	$9,900	$173,250	$173,250		
0.2	Sub-drainage and discharge piping for pipe support bases	$130,950	High	$3,638	$63,656	$63,656		
0.3	Interceptor Ditch	$47,250	High		$2,625	$44,625		
0.4	Piping from Dyke 2	$7,000	Low				$500	$6,500
0.5	Oil Water Separator and Bypass	$168,000	High		$168,000			
0.6	Steam Trap Drain Connections	$33,750	High		$33,750			
	Sub-total Drainage	**$743,350**		**$13,538**	**$441,281**	**$281,531**	**$500**	**$6,500**
1.3	**Surveys and Investigations**							
0.1	Topographic	$5,850	High	$5,850				
0.2	Video Inspection of Piping	$17,550	High	$17,550				
0.3	Flushing of Piping	$1,950	High	$1,950				
0.4	Excavate and examine existing piping	$4,200	High	$4,200				
	Sub-total Surveys	**$29,550**		**$29,550**	**$0**	**$0**	**$0**	**$0**
1.4	**Maintenance**							
0.2	Restore Main Berm	$42,000	High		$42,000			
0.3	Hydrant Valve Markers	$4,200	High		$4,200			
	Sub-total maintenance	**$46,200**		**$0**	**$46,200**	**$0**	**$0**	**0**
	Sub-total Civil Works	**$ 1,112,875**		**$43,088**	**$517,988**	**$412,238**	**$84,931**	**$54,631**
2	**Pipe Supports**							
2.1	Anchor Blocks	$70,000	Medium			$5,000	$65,000	
2.2	Supports	$270,000	Medium			$15,000	$255,000	
2.3	Isolation Valve and Piping	$162,500	Medium				$6,250	$156,250
2.4	Third Party Inspection	$14,000	Medium				$0	$14,000
2.5	Sand Blasting & Painting	$65,000	Medium			$2,500	$62,500	
	Sub-total Pipe Supports	**$581,500**		**$0**	**$0**	**$22,500**	**$388,750**	**$170,250**

Item	Description	Total	Priority	Implementation Year				
				2007	2008	2009	2010	2011
3	**Tanks**							
3.1	**Tank 1**							
0.1	Replace Roof Plate	$756,400	Low				$6,200	$750,200
0.2	Roof Coating	$125,000	Low				$2,500	$122,500
0.3	Roof Rafters	$200,000	Low				$4,000	$196,000
0.4	Tank Cleaning	$280,000	Low				$2,500	$277,500
0.5	Center Vent Fall Protection	$7,000	Low				$500	$6,500
0.6	Floor Coating	$201,300	Low				$1,650	$199,650
0.7	Roof Platform	$14,000	Low				$1,000	$13,000
0.8	Third Party Inspection	$14,000	Low				$0	$14,000
	Sub-total Tank 1	**$1,597,700**		**$0**	**$0**	**$0**	**$18,350**	**$1,579,350**
3.2	**Tank 2**							
0.1	Replace Roof Plate	$775,000	High		$775,000			
0.2	Roof & Shell Coating	$214,500	High		$214,500			
0.3	Roof Rafters	$224,000	High		$224,000			
0.4	Floor Scan	$32,500	High		$32,500			
0.5	Tank Cleaning	$560,000	High		$560,000			
0.6	Center Vent Fall Protection	$7,000	High		$7,000			
0.7	Floor Coating	$214,500	High		$214,500			
0.8	Roof Platform	$14,000	High		$14,000			
0.9	Third Party Inspection	$14,000	High		$14,000			
	Sub-total Tank 2	**$2,055,500**		**$0**	**$2,055,500**	**$0**	**$0**	**$0**
3.3	**Tank 3**							
0.1	Floor Coating	$201,300	Medium			$1,650	$199,650	
0.2	Replace Floor Plate	$915,000	Medium			$7,500	$907,500	
0.3	Rebedding Soil Under Floor	$25,000	Medium			$500	$24,500	
0.4	Tank Cleaning	$280,000	Medium			$2,500	$277,500	
0.5	Roof Platform	$14,000	Medium			$1,000	$13,000	
0.6	Third Party Inspection	$28,000	Medium			$0	$28,000	
	Sub-total Tank 3	**$1,463,300**		**$0**	**$0**	**$13,150**	**$1,450,150**	**$0**
3.4	**Tank 4**							
0.1	Floor Coating	$201,300	High		$1,650	$199,650		
0.2	Replace Floor Plate	$930,000	High		$15,000	$915,000		
0.3	Tank Cleaning	$280,000	High		$2,500	$277,500		
0.4	Roof Platform	$14,000	High		$1,000	$13,000		
0.5	Third Party Inspection	$28,000	High		$0	$28,000		
	Sub-total Tank 4	**$1,453,300**		**$0**	**$20,150**	**$1,433,150**	**$0**	**$0**
	Sub-total tanks	**$ 6,569,800**		**$0**	**$2,075,650**	**$1,446,300**	**$1,468,500**	**$1,579,350**
4	**Electrical**							
0.1	General	$17,500	High		$17,500			
0.2	Lighting	$45,500	Medium		$3,250	$42,250		
0.3	Thermocouple Wiring	$42,000	Medium		$3,000	$39,000		
0.4	O/W Separator Controls	$5,600	Medium		$400	$5,200		
	Sub-total Electrical	**$ 110,600**		**$0**	**$24,150**	**$86,450**	**$0**	**$0**
	TOTALS	**$8,374,775**		**$43,088**	**$2,617,788**	**$1,967,488**	**$1,942,181**	**$1,804,231**
	Fees for Consulting Services (included above)			$43,088	$217,556	$101,069	$74,381	$23,681

Drawings

DATE	NO.	REVISIONS	CH.	APP.	APP.
NOV.01.2005	A	ISSUED FOR REVIEW			
DEC.02.2005	B	ISSUED FOR REVIEW			

DRAWING No. P0XXXXXX-00-001 REV. A
SHEET OF

PRELIMINARY
DO NOT USE
FOR CONSTRUCTION

PROVINCE OF NEWFOUNDLAND
CLASS "A"
This Permit Allows
PERMIT HOLDER
SGE ACRES LIMITED
To perform Professional Engineering
in Newfoundland and Labrador
Permit No. as issued by PEG-NL C0154
which is valid for the year 2005

SUSAN LEE
DATE
JOHN LEONARD
PROFESSIONAL ENGINEER
REGISTERED PROFESSIONAL ENGINEER
NEWFOUNDLAND & LABRADOR

SGE Acres

NEWFOUNDLAND HYDRO
HOLYROOD THERMAL GENERATING STATION
FUEL STORAGE AREA STUDY

FUEL STORAGE AREA STUDY
HOLYROOD THERMAL
GENERATING STATION
– EXISTING CONDITIONS
PLAN

DESIGN	SGE ACRES LIMITED
REVISED	G. SAUNDERS
DRAWING	J.LEONARD
REVISED	D0'D
CHECKED	M.SWEENEY
TECHNICAL PROJECT ENGINEER	J.LEONARD
PROJECT ENGINEER	J.LEONARD
PROJECT MANAGER	G. SAUNDERS

SCALE AS SHOWN
SGE ACRES PROJECT NO. P16806.01
DRAWING NO. P16806-C-B1-001
SHEET 1 OF 2
REVISION B

EXISTING CONDITIONS – PLAN
SCALE 1:500

TYPICAL SECTION A–A
SCALE 1:200

SCALE 1:500

PLOT SCALE 1=1

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Mar 24, 2006 - 3:03pm

NEWFOUNDLAND HYDRO

HOLYROOD THERMAL GENERATING STATION

FUEL STORAGE AREA STUDY

FUEL STORAGE AREA STUDY HOLYROOD THERMAL GENERATING STATION – GRADING & DRAINAGE IMPROVEMENTS

SGE ACRES LIMITED

DESIGN	SGE ACRES LIMITED
REVIEWED	J.LEONARD
CHECKED	G. SAUNDERS
DRAWING	M.SWEENEY
CHECKED	D.O'D
REVIEWED	J.LEONARD
DEPARTMENTAL PROJECT ENGINEER	
PROJECT ENGINEER	J.LEONARD
PROJECT MANAGER	G. SAUNDERS

SCALE: AS SHOWN — DRAWING No. P16806-C-B1-002 — REVISION B

SIZE: ARCH D — PROJECT No. P16806.01 — SHEET 2 OF 2

No.	DATE	REVISIONS	CH.	APP.	APP.
A	DEC.02.2005	ISSUED FOR REVIEW			
B	Mar.01.2006	ISSUED FOR REVIEW			

PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
CLASS "A"
This Permit Allows
SGE ACRES LIMITED
To practice Professional Engineering
in Newfoundland and Labrador
Permit No. as issued by PEC-NL C0156
which is valid for the year 2006

PRELIMINARY
DO NOT USE
FOR CONSTRUCTION

PROFESSIONAL ENGINEERS & GEOSCIENTISTS NEWFOUNDLAND & LABRADOR
PERMIT TO PRACTICE
SGE ACRES LIMITED
SIGNATURE
DATE
JOHN LEONARD
SEAL
SIGNATURE

GRADING AND DRAINAGE IMPROVEMENTS – PLAN

SCALE 1:500

0 10 20 30 40 50m

SECTION B–B

SCALE 1:200 H
1:100 V

DETAIL 1

SCALE 1:50

DETAIL 2

SCALE 1:50

TYPICAL SECTION A–A

SCALE 1:200

DRAWING No. PXXXXXXX-00-001 REV. A
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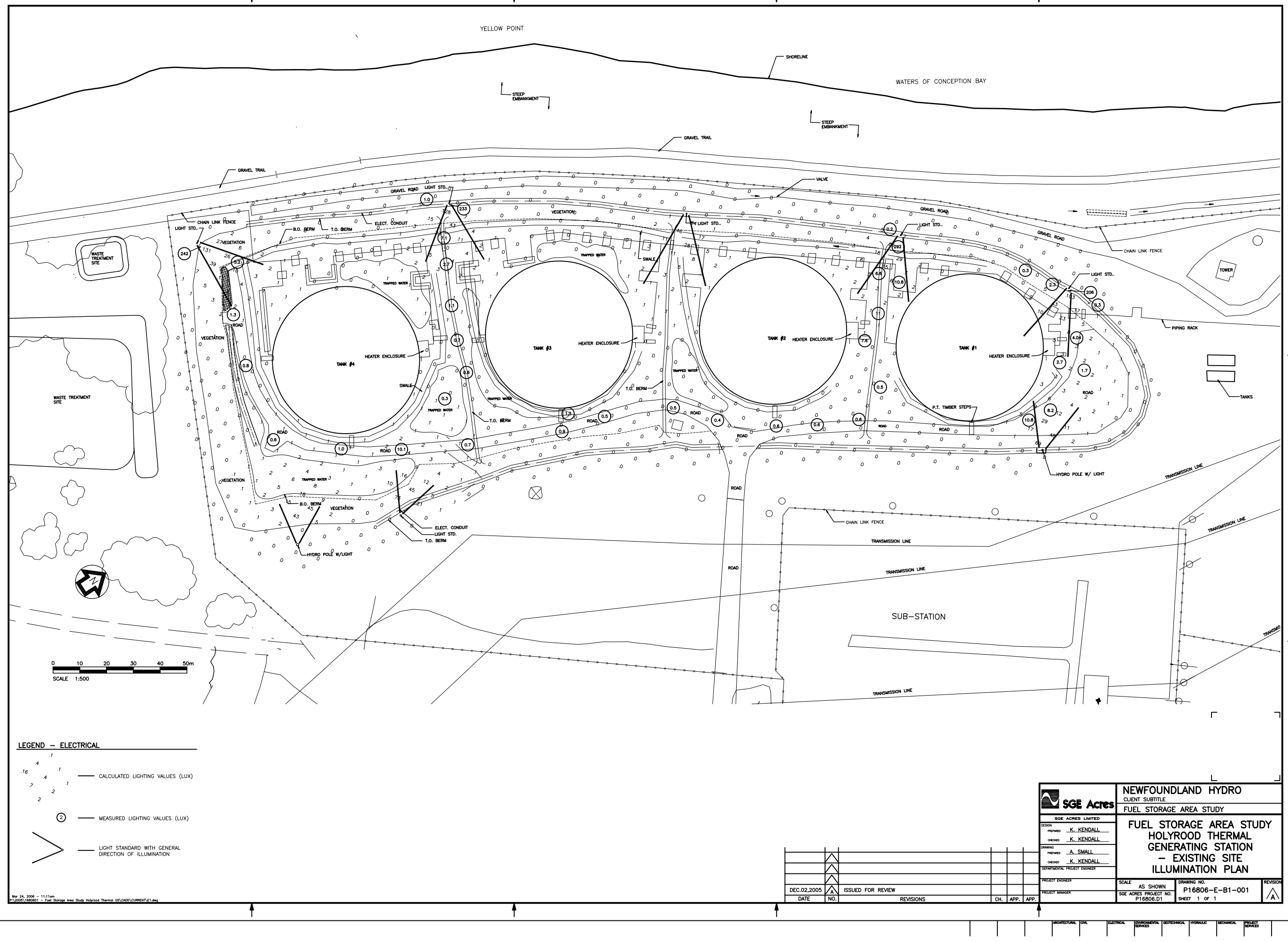

LEGEND – ELECTRICAL

- CALCULATED LIGHTING VALUES (LUX)
- (2) MEASURED LIGHTING VALUES (LUX)
- LIGHT STANDARD WITH GENERAL DIRECTION OF ILLUMINATION

DRAWING No. P16806-E-B1-001 REV. A
SHEET 1 OF 1

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PLOT SCALE 1=1

DATE	NO.	REVISIONS	CH.	APP.	APP.
DEC.02,2005	A	ISSUED FOR REVIEW			

SGE Acres
SGE ACRES LIMITED
DESIGN PREPARED K. KENDALL
DESIGN CHECKED K. KENDALL
DRAWING PREPARED A. SMALL
DRAWING CHECKED K. KENDALL
DEPARTMENTAL PROJECT ENGINEER
PROJECT ENGINEER
PROJECT MANAGER

NEWFOUNDLAND HYDRO
CLIENT SUBTITLE
FUEL STORAGE AREA STUDY

FUEL STORAGE AREA STUDY
HOLYROOD THERMAL
GENERATING STATION
– EXISTING SITE
ILLUMINATION PLAN

SCALE AS SHOWN
SGE ACRES PROJECT NO. P16806.01
DRAWING NO. P16806-E-B1-001
SHEET 1 OF 1
REVISION A

ARCHITECTURAL | CIVIL | ELECTRICAL | ENVIRONMENTAL SERVICES | GEOTECHNICAL | HYDRAULIC | MECHANICAL | PROJECT SERVICES

HTGS Refurbishment of the Fuel Oil Storage Facility
Appendix B

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Purchase Spare Stator Winding for the Bay d'Espoir Hydroelectric Generating Station

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

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1 INTRODUCTION

Newfoundland and Labrador Hydro's (Hydro) largest hydroelectric generating station in the Island Interconnected grid is located at Bay d'Espoir. 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. Units 1 through 3 and Unit 4 were commissioned in 1967 and 1968, respectively and each unit has a rated capacity of 75 MW. Each generating unit is approximately three meters high with an approximate diameter of six meters. A generator consists of two main parts: a rotor and a stator. The rotor is connected to a turbine and therefore rotates because of the force of moving water on the turbine blades. The stator is the stationary part of the generator, and for Units 1 through 4, the stator is composed of a series of copper wire windings. When the rotor, which is a series of large magnets, rotates in a ring of copper coils, electricity is produced. The copper wiring in the stator windings on Units 1 through 4 is insulated with an asphalt tape system. This system is analogous to insulating bare copper strands with regular electric tape to prevent the strands from coming in contact with each other. Because of age, the asphalt tape insulation on the units has become dry and brittle and is prone to failure. A failure of any single coil will result in the entire machine having to be rewound. The process of replacing a single coil involves removing approximately 25 additional coils because of the complexity in the electric generator design that requires the inter-twining of various copper coils. Since the coils are very dry and brittle, a repair of this magnitude is expected to lead to failure of the winding as a whole.

From the experience and knowledge of Hydro personnel, there is no question that of stator windings will fail although the exact time cannot be accurately predicted. Hydro does not currently have a spare stator winding for these units. Therefore, a failure will cause a unit to be out of service for approximately 18 months. This length of extended outage cannot be accommodated by the system unless every other generation source

is one hundred percent available. By having a spare stator winding on hand, Hydro can reduce this downtime to approximately six months.

This report describes the justification for the purchase of one spare stator winding for operational support of Hydro's Bay d'Espoir Hydroelectric Generating Station.

2 PROJECT DESCRIPTION

As part of a 2007 approved capital project titled “Bay d’Espoir Units 1 - 4 Stator Winding Design Review”, Hydro commissioned General Electric Energy (GE) to inspect the condition of the existing stator winding for generating Units 1 through 4 at the Bay d’Espoir Hydroelectric Generating Station. Also, GE was directed to conduct a design review to ensure that the existing stator winding of Units 1 through 4 could be replaced with windings of modern copper bar construction.

This review confirmed that copper bars would be a suitable replacement for the existing wound coils that make up the stator of Units 1 through 4. However, the bars required for Units 1 through 4 differ slightly in physical size from the bars contained in Units 5 and 6. GE was directed to complete a full technical design outlining the materials and detailed procedures required to carry out the rewind of Units 1 through 4. This detailed design will be completed in 2008.

Once the design is complete, this proposed 2009 capital project will permit Hydro to purchase a new stator winding from GE, the original manufacturer and holder of the proprietary design rights to the generating units. Once purchased, this winding will be delivered to the Bay d’Espoir Generating Station where it will be tested and stored according to the manufacturer’s specifications. Stored under the correct conditions, this winding will maintain its integrity indefinitely, until the time of its installation.

3 EXISTING SYSTEM

The existing windings were thought to be in good condition for their age, having been run within their design capabilities for the past 40 years. However, an inspection conducted by GE in June 2007 found signs of wear in critical locations within the existing windings. This wear, along with results from electrical tests on the windings, indicate that the stator winding on Unit 2 is closer to failure than the windings on the other units. Electrical tests involve applying an increasing test voltage to the stator winding while monitoring the current flow in the winding. Under ideal conditions, voltages of greater than 25 kV can be applied to the winding without a significant increase in the current flow through the winding. However, during testing, an applied voltage as low as 13 kV produced sufficient current flow to halt the testing for fear of causing severe damage to the stator winding. The results of this test indicate significant deterioration in the stator winding insulation.

3.1 Age of Equipment or System

Generating Units 1 through 3 and Unit 4 were installed and commissioned in 1967 and 1968 respectively and are of wound stator construction. Units 5 and 6 (commissioned in 1969) and Unit 7 (commissioned in 1978) are of a more modern design using solid copper bars to form the stator winding.

3.2 Major Work or Upgrades

Table 1 shows the upgrades that have occurred on the generating units since installation.

Table 1
Major Work Upgrades

Year	Major Work/Upgrade	Cost ($000)
1993	Unit 2 Runner Replacement	1,381.0
1994	Unit 3 Runner Replacement	1,449.0
1994	Unit 4 Runner Replacement	1,387.0
1996	Unit 1 Runner Replacement	1,578.0
1997	Unit 2 DC Exciter Replacement	333.6
1997	Unit 3 DC Exciter Replacement	333.6
1998	Unit 1 DC Exciter Replacement	330.6
1998	Unit 4 DC Exciter Replacement	330.6
2001	Unit 1 Repair of Stator Windings	88.2

3.3 Anticipated Useful life

Hydroelectric generator stator windings are depreciated over 25 years. However, the windings can have an estimated service life of 40 years depending on operating conditions and maintenance.

3.4 Maintenance History

Since their installation in 1967 and 1968, the stator windings of Units 1 through 4 of the Bay d'Espoir Hydroelectric Generating Station have had minimal preventative maintenance costs associated with them. Typically, the preventative maintenance costs associated with the stator winding of each unit averaged $1,000 annually, and the maintenance was performed during scheduled outages. This maintenance generally included a visual inspection and the standard electrical tests.

The most recent corrective maintenance took place in 2001, when a failure during testing resulted in damage to a single stator winding coil in Unit 1. This repair involved the removal and replacement of one of the 180 coils which make up the stator winding,

at a cost of $88,175. Similar repairs were performed on Unit 1 in 1986 and Unit 2 in 1992. Other than these three major repairs, the only maintenance performed on the stator windings of Units 1 through 4 over the past 15 years has been cleaning and replacing wedges that keep the stator windings in place.

3.5 Outage Statistics

In the last five years, there have been no outages which were the direct result of the Stator Windings.

3.6 Industry Experience

This type of multi-turn coil stator winding was manufactured by General Electric between the years 1930 and 1968. This was the common design used in most hydroelectric generators built during this time period.

Multi-turn coil windings with asphalt insulation have varying service lives, which is highly dependant on operating conditions and regular maintenance. If the stator windings are not overstressed and the manufacturer's recommended maintenance is performed regularly, the service life of windings can range from 40 to 50 years. However, for the most part, this type of winding 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.

Since the stators on Units 1 to 4 have not yet failed, they have not yet undergone a rewind.

3.7 Maintenance or Support Arrangements

All maintenance performed on the stator windings has been done by Hydro personnel, with support and technical advice being provided by the manufacturer.

3.8 Vendor Recommendations

Since the existing stator windings have now been in service for over 40 years, the vendor recommends either that the stator windings be scheduled for replacement, or at least, a spare stator winding be purchased to replace the existing windings if they fail.

3.9 Availability of Replacement Parts

The manufacturer of the existing stator windings halted production of this type of winding in 1969, shortly after Bay d'Espoir Units 1 through 4 were installed. Hydro does have spare coils on hand, but these spares are also now over 40 years old. As discussed above, due to the condition and inter-twined configuration of the existing windings, the process of replacing a single coil in their current dry and brittle state is expected to lead to failure of the winding as a whole. Therefore, a spare stator winding is required.

3.10 Safety Performance

There are no specific safety issues related to this project.

3.11 Environmental Performance

There are no specific environmental issues related to this project.

3.12 Operating Regime

Units 1 through 4 of the Bay d'Espoir Generating Station are designed for continuous operation with varying loads to meet system requirements. With the exception of maintenance outages, these four units have been operating continuously, within their design capabilities, since they were commissioned in 1967-1968.

4 JUSTIFICATION

This project is justified on the requirement to maintain system reliability by having a spare stator winding on hand when there is a failure of the existing stator windings. Failure to have this spare on hand will impair Hydro's ability to provide least-cost, reliable electrical service.

The life expectancy for asphalt insulated stator windings is 40 years. However, it varies based on such operating conditions as temperature, number of starts and stops, maintenance and care and unit loading. Since the windings of Units 1 through 4 have reached the end of their 40 year useful lives, a planned replacement program is required. However, this project enables Hydro to optimize the remaining lives of the windings without compromising an acceptable level of unit availability.

Hydro has commissioned two independent reviews of the condition of the stator windings at Bay d'Espoir. The first consultant, GE Armstrong, estimated in 1998 that the remaining reliable service life of these windings was between seven and 15 years. It was further recommended that Hydro the purchase a spare winding as the risk of failure during operation and under test conditions is rapidly increasing.
During the summer of 2007, a second consultant, GE Energy, concluded that a failure of the Unit 2 winding is imminent. As well, the deterioration of the winding will continue and even if operated in a conservative manner, Units 1 through 4 are expected to fail within ten years.

4.1 Net Present Value

A net present value calculation was not performed in this instance as only one viable alternative exists.

4.2 Levelized Cost of Energy

The purchase of a spare stator winding will have no direct effect on the levelized cost of energy.

4.3 Cost Benefit Analysis

A cost benefit analysis is not applicable for this project.

4.4 Legislative or Regulatory Requirements

There are no specific legislative or regulatory requirements which affect this project.

4.5 Historical Information

There is no historical information associated with this proposal. This proposal is for a one time purchase of a spare stator winding.

4.6 Forecast Customer Growth

The forecasted customer load on the system has no affect on this project.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits anticipated from this project.

4.8 Losses during Construction

As this project involves the purchase only of a spare winding, there will be no anticipated losses during construction.

4.9 Status Quo

Presently the stator windings of Units 1 through 4 of the Bay d'Espoir Hydroelectric Generating Station are operating beyond their expected useful lives.

The inspection performed by GE in June 2007 shows wear in critical areas of the stator windings. For Unit 2 in particular, GE states that a failure of the stator winding is imminent. Such a failure could occur without warning, and likely under peak load conditions. It is imperative that Hydro purchase a spare winding to limit the duration of the potential outage. This purchase will ensure that Hydro has the ability to provide least-cost, reliable electrical service.

4.10 Alternatives

There are no viable alternatives to this project. The purchase of a spare stator winding, for installation when a failure occurs, is the only solution to prevent an extended outage when that failure occurs.

5 CONCLUSION

Units 1 through 4 of the Bay d'Espoir Hydroelectric Generating Station have been in service since their commissioning in 1967 – 1968. The stator windings of these units have now reached the end of their useful lives of 40 years, and according to a June 2007 inspection, failure is imminent for the Unit 2 winding. By not having a spare stator winding on hand if any one of Units 1 through 4 fail, Hydro's ability to provide least-cost, reliable electrical service will be impaired. For this reason, it is imperative that Hydro purchase a spare stator winding to have on hand if a failure occurs or through testing, it is deemed that a winding should be replaced immediately.

5.1 Budget Estimate

The estimate for the project is $2.8 million. Table 2 below summarizes the costs by year.

Table 2
Budget Estimate

Project Cost:($ x1,000)	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	0.0	2,110.0	0.0	2,110.0
Labour	26.0	35.8	0.0	61.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	6.2	6.2	0.0	12.4
O/H, AFUDC & Escln	4.3	435.8	0.0	440.1
Contingency	0.0	218.3	0.0	218.3
TOTAL	**36.5**	**2,806.1**	**0.0**	**2,842.6**

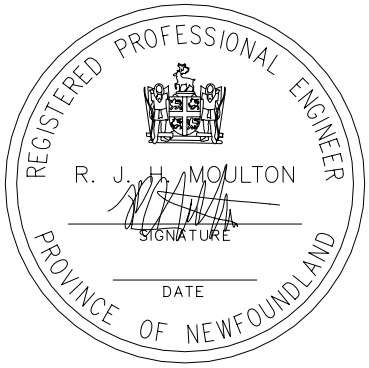
5.2 Project Schedule

Table 3
Project Schedule

Activity	Milestone
Design Complete	August 2008 (Part of the 2007 Capital Budget)
Equipment Ordered	March 2009
Factory Acceptance Testing	February 2010
Delivery of Windings and Storage on Site	April 2010
Project Completion	June 2010

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Labrador City
Voltage Conversion Terminals and Transmission Reconfiguration



Electrical
Mechanical
Civil
Protection & Control
Transmission & Distribution
Telecontrol
System Planning

HYDRO
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NEWFOUNDLAND AND LABRADOR HYDRO

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Appendices

A – Labrador City System Single Line Diagram
B – Labrador City Distribution Upgrading Study
C – Labrador City Proposed System Single Line Diagram
D – Labrador West Long-Term Load Forecast

1 INTRODUCTION

The Labrador City Distribution System (LBC) consists of a high-voltage 46 kV subtransmission system[1], and five medium-voltage 4.16 kV distribution systems. The subtransmission system consists of five 46 kV subtransmission feeders, L32, L33, L9, L10 and L11, and a 46 kV switching station (Townsite Switching Station). The function of this system is to supply bulk power to the 4.16 kV distribution systems. The medium-voltage distribution system supplies power directly to customers and consists of five 46/4.16 kV step-down substations, Bartlett Substation, Hudson Substation, Vanier Substation, Quartzite Substation, and Harrie Lake Substation, and twenty 4.16 kV distribution feeders, L1 to L8 and L12 to L23. In addition to the above, two customer-owned distribution feeders are supplied from the Harrie Lake and Hudson Distribution systems, one line extends westward from the Harrie Lake Substation to the Tamarack Lake Golf Course (Tamarack Line), and the second line extends from the Hudson Substation and supplies facilities along the Québec North Shore and Labrador Railway (QNS&L Line). A simplified single line diagram of the existing system is shown in Appendix A.

LBC is supplied from the Churchill Falls Generating Station via two 230 kV transmission lines. The transmission lines run from the 230 kV Switchyard at Churchill Falls to the 230/46 kV Wabush Terminal Station (WBH). The Wabush Terminal Station is owned by Twin Falls Power Company Ltd. (TWINCo) and is operated by Churchill Falls (Labrador) Corporation Ltd. (CF(L)Co). This station also feeds the Wabush Townsite Substation (WAB), as well as the mining facilities at Iron Ore Company of Canada (IOCC), and Wabush Mines (WM).

[1] Hydro's convention is that any systems with nominal voltages lower than 50 kV are considered distribution systems. The 46 kV system in Labrador City operates as a subtransmission system even though it is at distribution voltage.

Voltage regulation for the system is provided by two synchronous condensers located at WBH. The synchronous condensers regulate the voltage on the 46 kV bus to 46.6 kV (1.013 p.u.). There are no other voltage regulation devices located in this system.

A single 46 kV subtransmission line, L32, carries power to the Townsite Switching Station where power is then transmitted to the substations where the voltage is stepped-down to 4.16 kV for distribution to customers in Labrador City.

This budget proposal is being submitted in conjunction with *Upgrade Voltage Conversion Phase I - Labrador City* (see Section D, p. D-26) as part of a multi-year project to upgrade the distribution system in Labrador City to 25 kV. The 2009 budget will consist of the engineering of two 46/25 kV terminal stations, and ordering long delivery items such as power transformers. This is to ensure timely arrival of major equipment for installation. Actual station construction for the project is to begin in 2010, and be completed by the end of 2011.

Newfoundland and Labrador Hydro's (Hydro) Labrador City Upgrading Project has been developed to ensure that continued least-cost reliable service is provided to customers in Labrador City, and to provide the capacity to meet load growth. The present system was designed to supply approximately 52 MW of load. A study of the distribution system was conducted in the fall of 2007. It found that beyond 52 MW, the existing system would be subject to poor voltage regulation, low voltages, and more frequent component failures due to excessive heating. More detail on results of the study can be found in the Engineering Report entitled *Labrador City Distribution System Upgrading Study* found in Appendix B. The study determined that in order to serve additional load growth, it would be necessary to convert the system to a higher distribution voltage. Converting the distribution system to 25 kV will increase the power transfer capability, improve voltage regulation, and should improve the reliability of the system.

2 PROJECT DESCRIPTION

This project is required to upgrade the existing 4.16 kV distribution system in Labrador City to 25 kV. The new 25 kV distribution system will consist of two 46 kV subtransmission lines, two 46/25 kV substations, and nine 25 kV distribution feeders. A simplified single line diagram of the proposed system is shown in Appendix C. Most of the existing terminal stations are rated for a nominal voltage of 4.16 kV with the exception of the Vanier Terminal Station, which has bus work rated at 25 kV. The existing bus work at Vanier terminal station is sized to accommodate up to three breakers or reclosers. The structure will be extended to accommodate an additional two feeders. With the exception of the upgrade work at Vanier Terminal Station all work associated with this project will be new construction.

The 25 kV distribution system will be supplied from WBH by two 46 kV subtransmission lines. Each substation will be fed by a separate line and a normally open tie line will be connected between them for backup. The tie line will also be available for supply to or from Fermont in Québec in emergency situations. For improved fault protection and reliability, a 46 kV breaker will be installed at the termination of each subtransmission line.

The Vanier Substation and the Quartzite Substation will step the voltage down from 46 kV to 25 kV. Each substation is to consist of a 46 kV load transfer bus, two 15/20/25 MVA 46/25 kV power transformers with on load tap changers, and two 25 kV load transfer buses. Each 25 kV bus will have space for up to three 25 kV breakers. A total of nine 25 kV distribution feeders are required. It is expected that more load growth would occur near the Quartzite Substation than the Vanier Substation. Therefore, four 25 kV distribution feeders will be connected to the Quartzite Substation, and the remaining five will be connected to the Vanier Substation. As a provision for future expansion, two additional 25 kV breaker bays will be available at the Quartzite Substation, and one additional 25 kV breaker bay will be available at the Vanier Substation. Civil work will be completed in 2010 and the electrical equipment installation will be in 2011.

3 EXISTING SYSTEM

The existing distribution system consists of five substations supplied radially by a 46 kV subtransmission system. The substations step the voltage down from 46 kV to 4.16 kV nominal. Power is distributed to customers on twenty 4.16 kV distribution feeders.

The Labrador City Distribution System was taken over by Hydro from IOCC in 1992. At that time economic conditions were poor, since the mining operations were in decline. To meet the system requirements at the time, the distribution was upgraded to meet minimum standards (i.e. minimum acceptable voltage) and supply a peak load of 52 MW. The upgrades completed in 1992 are outlined in Section 3.2 of this report.

Today, the economic outlook for Labrador West is much different than it was in the early 1990s. The economy in the area has experienced revitalization, and the load in the region has started to grow. The forecasted load growth for the system is 0.9% per year on a year over year basis. People are moving to the area, the real-estate market is booming with the cost of housing in the area reaching record highs, enrolment is up in the schools, and service industries are expanding and setting up new operations. The growth in Labrador City is attributable to a number of factors as noted below.

High demand for iron ore on the world market has subsequently driven prices for this commodity to all time highs. Compelled by the high value of their product, IOCC and Wabush Mines have ramped up production. IOCC has announced a $500 million expansion plan to increase production capacity by 50% by 2011. The region's economy is driven mainly by the mining operations at IOCC and Wabush Mines and, as such, the local economy is benefiting from the spin-offs.

Following a similar trend in the rest of the country, the demographics of the area is changing. A large number of retirements are expected at the mining operations in the next few years as the baby boom generation starts to retire. It is expected that 50 to 65 percent of retirees will remain in the region. IOCC plans to hire an additional 200

employees to backfill positions vacated by retirement[2]. The combination of retirees choosing to stay in the region along with the additional new employees that come to Labrador West will result in a need for additional housing. An additional 250 construction workers for the expansion project will also drive an increased need for accommodations[3]. This has lead to a small boom in the region's real estate market with housing prices comparable to those in the St. John's metro region. Projections for housing requirements indicate that between 140 to 180 new homes may be required. Residential developments have been proposed for the area west of Labrador City and a number of new additions have gone into the Harrie Lake Trailer Park. In response to the increased demand for services, a number of new businesses have set up in the region, while others that were already present have expanded their operations. Table 1 below shows the number of new services connected in Labrador City from January 2003 to July 2008.

Table 1
New Services Connected in Labrador City 2003 – 2008

Year	New Service Connections		
	Domestic Service	General Service	Total
2003	7	4	11
2004	9	7	16
2005	18	10	28
2006	12	12	24
2007	56	16	72
2008	18	16	34
Total	120	65	185

Since 2003 there have been a total of 120 new domestic and 65 new general services connected to the system. The general trend shows a steady increase in the number of services connected each year and it is expected that this trend will continue for the foreseeable future. Most of the commercial/industrial development has been in the town's industrial park in the form of mine service industries. In addition to these developments, the Government of Newfoundland and Labrador plans to construct the

[2] IOCC 2007 Sustainable Development Report
[3] IOCC Expansion Quick Facts

new regional hospital and college in the town. The location of these facilities is currently under review, but is being proposed at a site just north of the town. Finally, if the new mining developments proposed for the Bloom Lake and LabMag Iron Ore deposits go ahead, they are expected to have a positive impact on the region in the form of direct and indirect employment opportunities.

The existing 4.16 kV distribution system was designed to serve a load of up to 52 MW. It has been operating near the limits of its capacity for several years, but the peak load has not increased in this time. The forecasted peak load for Labrador City is 51 MW in 2008, and is projected to exceed 52 MW in 2009 and continue to grow to 55 or 60 MW. At loads above 52 MW, the existing system will start to experience low voltage during peak conditions. During peak conditions the existing 4.16 kV distribution will be subject to a number of problems, this includes poor voltage regulation, high feeder currents, and difficulty in protecting against faults. Additional Information on the existing system can be found in the engineering report in Appendix B.

3.1 Age of Equipment or System

The Labrador City Distribution System was constructed and installed by the IOCC in the early 1960's. In 1992, Hydro took over the distribution system.

3.2 Major Work or Upgrades

At the time of the takeover, the distribution system was assessed by Hydro and IOCC and it was found to be in poor condition. To put it in perspective, customers were receiving voltages as low as 100 V, and secondary conductors were overloaded to the point that the insulation was melting. The system required significant upgrading to bring it to acceptable standards and make it safe to operate. This work included rebuilding the Bartlett and Hudson Substations, construction of the Vanier Substation, upgrading the distribution feeders, and reconfiguring the distribution to better share the load

between the stations. The original upgrades were initiated to address safety concerns and power quality issues. Table 2 below shows the major upgrades that have occurred since the system was taken over in 1992.

Table 2
Major Work or Upgrades Since 1992

Year	Major Work/Upgrade	Cost ($000)
1992	Purchase Spare Transformer	211.8
1992	Switching Center Upgrade/Gang Switch Installations	131.6
1992	Harrie Lake Upgrading	61.8
1992	Bartlett Feeder #1 and #2 Conversion	593.6
1993	Hudson Substation Reclosers	114.2
1993	Vanier Substation	790.0
1993	System Protection Improvements	130.1
1993	Transformer Purchases and Replacements	298.1
1994	Labrador City - Distribution Upgrading	1,562.2
1995	Labrador City - Distribution Upgrading	1,007.9
1996	Labrador City - Distribution Upgrading	51.3
1997	Bartlett Substation Upgrade	782.6
1998	Harrie Lake (Labrador City) - Upgrade Distribution System	407.3
1998	Cable Replacements - Quartzite and Harrie Lake Substations	97.4

The above upgrades were completed by Hydro over a six-year period following the acquisition of the system in 1992. The cost of this work was shared between Hydro and IOCC. The upgrading project, of which the table above is a subset, had a total cost of approximately $7.9 million, and IOCC contributed $2.5 million of this amount[4]. The last major upgrades were completed in 1998.

3.3 Anticipated Useful life

This project involves construction of two new terminal stations, and transmission line extensions. The anticipated useful life of terminal stations and transmission lines is 40 years.

[4] 2001 General Rate Application, LC-8

3.4 Maintenance History

The five-year maintenance history for the Labrador City Distribution System is shown in the Table 3 below.

Table 3
Maintenance History for the Labrador City Distribution System

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Non Maintenance ($000)	Total Maintenance ($000)
2007	24.4	74.4	88.0	186.8
2006	8.0	69.7	95.7	173.4
2005	15.2	84.7	100.4	200.3
2004	12.0	80.5	36.9	129.4
2003	1.0	58.3	30.1	89.4

Non-maintenance type work orders include charge-outs of consumable items (gloves, and coverall suits for instance), technical assessments, and studies, but it also includes emergency repairs. Therefore, non-maintenance costs on the distribution system have been included in this table.

Table 3 shows that the amount spent on corrective maintenance significantly exceeds the amount spent on preventative maintenance, which indicates a system operating near its maximum capability and prone to higher than normal component failure rates. In the past five years, $428,200 has been spent in preventative and corrective maintenance on the system.

3.5 Outage Statistics

Reliability of Hydro's distributions systems is tracked by industry standard indexes, SAIFI, and SAIDI. Service Continuity Indices for distribution are defined in Table 4 below.

Table 4
Hydro Distribution SAIDI and SAIFI

Index	Description	Detail
SAIFI	Indicates the average of sustained interruptions per customer served per year.	$\frac{\text{Total Customer Interruptions}}{\text{Total Customers Served}}$
SAIDI	Indicates System Average interruption duration for customers served per year.	$\frac{\text{Total Customer Hours of Interruptions}}{\text{Total Customers Served}}$

Listed in Table 5 below are the 2003 to 2007 average SAIFI and SAIDI data for Labrador City. The table also lists the 2003 to 2007 corporate value and the latest CEA five-year average (2002 to 2006) for comparison.

Table 5
Five Year Average Outage Statistics for
Labrador City Distribution System (2003 to 2007)

System	All Causes	
	SAIFI	SAIDI
Labrador City	6.27	8.36
Hydro Corporate	6.24	9.72
CEA (2002-2006)	2.35	6.43

The historical reliability performance of this distribution system has been good and the recent five-year average is similar to the corporate average for all of Hydro's systems. A series of 14 outages that occurred in 2007 raised public concerns about the reliability of the distribution systems in Labrador City and Wabush. Following this, Hydro conducted a review of the system to determine what was causing the decrease in reliability in Labrador West. Analysis of historical reliability data shows a substantial increase in outage rates over the past three years, and it shows a general trend of decreasing reliability. The TWINCo 230 kV/46 kV transmission system between Churchill Falls and Labrador West has been responsible for almost half of unplanned outages to customers in Labrador West in 2007. Hydro initiated discussions with

TWINCo and CF(L)Co regarding the reliability of the supply system to Labrador West, and they are planning and initiating upgrades to the transmission system and the Wabush Terminal Station that should improve the reliability. The project will replace aging distribution system equipment with new equipment and should improve the reliability of the distribution system.

3.6 Industry Experience

In general, larger distribution systems (in terms of maximum demand) transfer power at higher distribution voltages in the range of 12.5 kV, 13.2 kV, 13.8 kV, and 25 kV. Typically these voltages offer superior performance over 4.16 kV systems in terms of power transfer capability, and voltage regulation. For comparison purposes, the distribution system in Labrador City has a 2008 forecasted peak of 51 MW[5]. All the distribution in this system is supplied at 4.16 kV. Distribution areas in Newfoundland and Labrador with similar annual peaks to Labrador City are Happy Valley - Goose Bay, Corner Brook, and Stephenville. Happy Valley - Goose Bay has a 2008 forecasted peak of 58 MW[5] and it is supplied mainly at 25 kV with a small amount of 4.16 kV at the North Side of Canadian Forces Base 5 Wing Goose Bay. The 4.16 kV distribution system on the North Side of Goose Bay is a legacy voltage that dates back to when the distribution system was originally constructed during World War II, and only accounts for about 1.6 percent of total load on the system. Corner Brook has a 2008 forecasted peak of 75 MW[6]; the distribution system is supplied mainly at 12.5 kV with a small amount of 4.16 kV. Stephenville has a 2008 forecasted peak of 42 MW, and the distribution system here is supplied mainly at 12.5 kV[6]. These systems all supply power at a higher distribution voltage than the distribution system/voltage in Labrador City. This is mainly because operating the distribution system/voltage at 12.5 kV or 25 kV has greater capacity per feeder, and has better voltage regulation.

[5] Operating Load Forecast Hydro Rural Systems 2008-2013, Market Analysis Section System Planning Newfoundland and Labrador Hydro, Fall 2007
[6] Energy and Demand Supply Forecast, Newfoundland Power Inc., 2007

3.7 Maintenance or Support Arrangements

Since this distribution system was taken over from IOCC, Hydro has operated and maintained it using internal forces. It is expected that that Hydro will continue to operate and maintain the system in this manner.

3.8 Vendor Recommendations

There are no vendor recommendations regarding this asset.

3.9 Availability of Replacement Parts

There are no vendor recommendations regarding replacement parts for the distribution system. However sufficient spares for major assets such as power transformers will be retained on site to shorten downtimes in the event of a major component failure.

3.10 Safety Performance

Safety performance is not an issue with this project.

3.11 Environmental Performance

Environmental performance is not an issue with this project.

3.12 Operating Regime

The Labrador City Distribution System provides service to customers 24 hours per day, 365 days a year and outages must be planned to minimize the impact to customers.

4 JUSTIFICATION

This project is necessary to meet the growing electricity needs of customers in Labrador City and to ensure that a quality, safe, least-cost and reliable electrical service is delivered to Hydro's customers. Further details on the justification for this project, can be found in Appendix B of this report.

Continued operation with the status quo is not technically viable for the long-term operation of this system. The existing system was designed to supply a peak load of 52 MW. The system load is forecasted to exceed 52 MW in 2009 and continue growing to 55 - 60 MW. The distribution system is now at its operational limit. Continuing with the status quo will result in low voltages to customers, lower system reliability, and could compromise the ability to protect people and equipment when faults on the system occur.

As early as 1992, it was identified that a voltage conversion was the only practical means of meeting load growth and correcting problems on the existing system. For the past 15 years, there has been little or no load growth on this system. However, the load is now growing and the voltage conversion is required to provide acceptable service. Both 12.5 kV and 25 kV alternatives were evaluated and the 25 kV plan has been shown to be the least cost. This project ensures that load growth can be met in the long-term and will maintain the level of reliability the system has experienced in the past.

4.1 Net Present Value

The Net Present Value of the alternatives to the year 2040 for a terminal station in-service date of 2011 in 2008 dollars is shown in Table 6 below.

Table 6
Net Present Value of Alternatives (2008 Dollars)

Alternative	Net Present Value (NPV)	NPV Difference from Least Cost Alternative
Alternative 1 Upgrade Distribution to 25 kV	$9,312,403	$0
Alternative 2 Upgrade Distribution to 12.5 kV	$12,838,289	$3,525,886

A comparison of the Net Present Value of each alternative shows that the chosen alternative, Alternative 1 is $3,525,886 less costly than Alternative 2. Figure 1 below shows a plot of Alternative 1 versus Alternative 2. Again, this plot shows that there is no crossover point, and that Alternative 1 is the most cost effective solution.

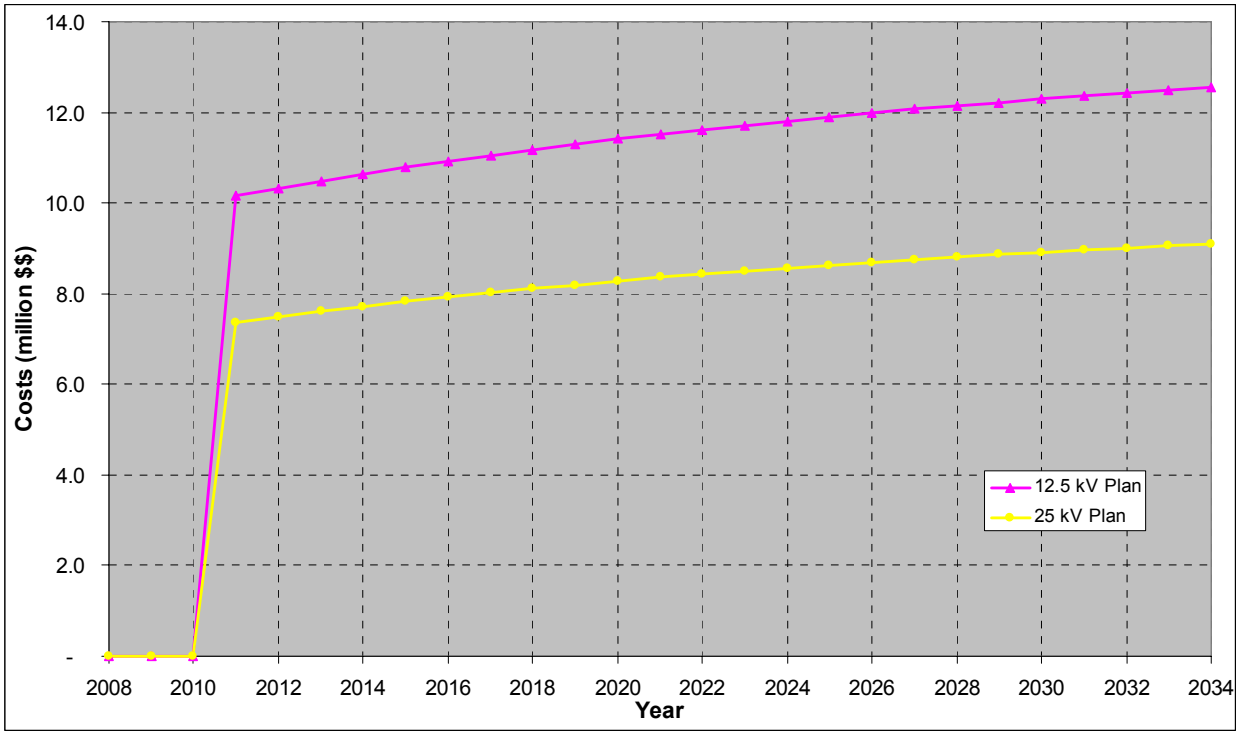

Figure 1: Net Present Value Comparison

4.2 Levelized Cost of Energy

The levelized cost of energy is a high level means to compare costs of developing two or more alternative generating sources. Therefore, the levelized cost of energy is not applicable in this case.

4.3 Cost Benefit Analysis

A cost benefit analysis was not necessary for this project since the alternatives were technically equivalent and offered the same benefits to the system.

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements.

4.5 Historical Information

This is not a recurring project, and Hydro has not performed any system voltage conversions in the past five years.

4.6 Forecast Customer Growth

The load forecast for Labrador City is based on a combination of historical data since 1992, the effects of increased mining activities, the impacts of the new college and hospital, a modest amount of new residential construction and electric heat conversions. The load forecast for the Labrador West Interconnected System is shown in Table 7 below, and the 20-year long-term load forecast projection for Labrador West is available in Appendix D.

Table 7
Labrador West Load Forecast

Labrador West Interconnected Load Forecast Spring 2008

		2008	2009	2010	2011	2012	2013
Labrador City							
	Gross Peak (kW)	51,158	52,120	53,280	53,323	53,381	53,528
	Gross Energy (MWh)	207,205	211,104	215,801	217,441	216,211	216,808
	Total Sales (MWh)	199,096	202,842	207,355	208,931	207,749	208,323
	Company Use (MWh)	0	0	0	0	0	0
Wabush							
	Gross Peak (kW)	16,311	16,635	16,992	17,235	17,397	17,560
	Gross Energy (MWh)	66,460	67,779	69,231	70,221	70,884	71,547
	Total Sales (MWh)	62,828	64,082	65,463	66,404	67,034	67,664
	Company Use (MWh)	350	350	350	350	350	350
Labrador West Sub-Total							
	Gross Peak (kW)	67,469	68,755	70,272	70,558	70,778	71,088
	Gross Energy (MWh)	273,665	278,883	285,033	287,663	287,095	288,355
	Total Sales (MWh)	261,924	266,924	272,818	275,335	274,783	275,986
	Company Use (MWh)	350	350	350	350	350	350

Gross peak or energy equates to bulk deliveries on interconnected systems.

The average year-on-year load growth for Labrador City is projected at 0.9 % per year and is projected to be 55.6 MW by 2027. While the load forecast represents the expected energy and demand growth on the Labrador City System, the risk of higher load growth exists due to several factors. A fully utilized housing stock along with the changing demographic in the region from retiree retention and new employees for the mining operations, along with the impacts of the IOCC expansion, and the Bloom Lake Development could potentially spawn new residential developments. In combination with approximately 2 MW of electric heat conversion potential in the region, the load could approach 60 MW over the next 20 years.

4.7 Energy Efficiency Benefits

Operating the system at a higher distribution voltage should result in approximately 1.1 MW of savings in line losses during peak load.

4.8 Losses during Construction

The distribution system is interconnected in such a way that it is possible to isolate small sections of the system during off peak periods while still maintaining service to the remaining customers on the feeder. This will allow outages to customers to be minimized while the work is conducted.

4.9 Status Quo

The status quo is not an option. The 4.16 kV distribution system that currently supplies the customers in Labrador City was designed to supply a peak load of 52 MW. The system load is forecasted to exceed 52 MW in 2009 and to continue to grow to 55 - 60 MW. The distribution system is now at its operational limit. Continuing with the status quo will result in low voltages to customers, lower system reliability, and could compromise the ability to protect people and equipment when faults on the system occur.

It is not practical to supply any significant additional load at the current distribution voltage. To ensure that the growing electrical needs of Hydro's customers in Labrador City can be accommodated upgrades to the system are necessary. The original upgrading plan of the 1990s identified a voltage conversion as the most efficient means of correcting the problems on the existing system. The original plan for a voltage conversion was deferred because the load at the time did not warrant it. The load in Labrador City has now grown to the level where the voltage conversion is warranted and should be completed as soon as possible to ensure adequate service to customers.

4.10 Alternatives

A voltage conversion was identified as the most efficient means to meet the growing electrical needs of customers, and to correct the problems on this system. Two

alternatives were considered in the design. Alternative 1 is to upgrade the distribution to 25 kV, and Alternative 2 is to upgrade the distribution to 12.5 kV. The 25 kV and 12.5 kV alternatives are both based on Hydro's standard design and operating practices. The 25 kV plan consists of a two substation system with nine 25 kV feeders. The 12.5 kV plan would consist of three substations with seventeen 12.5 kV feeders and a 46 kV switching station.

Both alternatives would provide good voltage regulation, and keep line currents at acceptable levels to ensure fault protection is adequate. They should also provide superior operational flexibility and improved reliability over the existing system. Load Flow Analysis of the two alternatives show that either will increase the system capacity enough to take the system out beyond 66 MW which is higher than the current forecast. Further details of the two alternatives and how they were developed can be found in Appendix B.

5 CONCLUSION

Converting the Labrador City distribution system to 25 kV is the most technically and economically feasible solution to address customer load growth in the long-term. In order to begin converting the distribution feeders in 2011, it is necessary to have at least one 25 kV terminal station in service by this date.

Continued operation with the status quo was ruled out as not technically viable for the long-term operation of this system.

The distribution system requires greater capacity to ensure that safe, least-cost, reliable electrical service is provided to customers. To increase the system capacity, the two alternative plans presented in Section 4.10 were developed. A comparison of the Net Present Value of each alternative over the 2011 to 2040 period (2008 $) shows that the chosen alternative, Alternative 1 is $3,525,886 less costly than Alternative 2.

It is recommended that the distribution system in Labrador City be upgraded to 25 kV to ensure that load growth from new customers can be accommodated and to ensure that voltage levels at customer service entrances do not drop below the minimum recommendations of CSA standard CAN3-C235-83 (R2006) - *Preferred Voltage Levels for AC Systems, 0 to 50,000 V*. In order to accomplish this project in time for the distribution conversion work to begin in 2011, it is necessary for the preliminary engineering of the substations ordering of and long delivery items to commence in 2009.

5.1 Budget Estimate

The construction estimate for two 46/25 kV terminal stations is $ 9.99 million. Table 8 below summarizes the cost by year.

Table 8
Project Estimate - LBC - Upgrade Distribution to 25 kV

Project Cost:($ x1,000)	**2009**	**2010**	**2011**	**TOTAL**
Material Supply	50.0	1,919.0	3,409.0	5,378.0
Labour	83.0	231.2	200.5	514.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	83.0	890.0	800.0	1,773.0
Other Direct Costs	15.0	67.5	89.2	171.7
O/H, AFUDC & Escln	29.1	476.3	864.0	1,369.4
Contingency	23.1	310.8	449.9	783.8
TOTAL	**283.2**	**3,894.8**	**5,812.6**	**9,990.6**

$2.8 million of the above costs are associated with power transformer purchases. Recent experience has shown that these costs vary considerably when each tender is issued. The cost of a power transformer is highly dependant on the timeline for delivery and manufacturer backlog at the time the quote is issued. Therefore, the above estimate may change.

5.2 Project Schedule

The project schedule is contingent on timely receipt of materials and equipment, and construction is limited by a short season. The entire project is expected to take six years to complete, however the station work is to be completed in 2010 and 2011. The removal of the old stations will commence as the distribution upgrades are completed and the subsequent 4.16 kV substations are taken out of service. Table 9 below summarizes the project timeline.

Table 9
Major Milestones

Activity	Milestone
Conduct Surveys and Purchase Land	December 2009
Conduct Preliminary Engineering Distribution	April 2009
Terminal Station Final Design	December 2009
Order Major Terminal Station Equipment	December 2009
Distribution System Final Design	April 2009
Complete 45 kV Line Work	September 2010
Install Quartzite Terminal Station Electrical/ Mechanical Systems	September 2011
Install Vanier Terminal Station Electrical/ Mechanical Systems	September 2011
Upgrade and Convert Distribution Feeders	September 2015

APPENDIX A

LABRADOR CITY SYSTEM SINGLE LINE DIAGRAM

Labrador City Voltage Conversion Terminals & Transmission Reconfiguration- Appendix A

LEGEND:

- Distribution Line 4.16, 12.5, or 25 kV
- Distribution Line 46 kV
- Fused Disconnect Switch
- Ganged Operated Disconnect Switch
- Normally Open Disconnect Switch
- Solid Blade Disconnect Switch
- Transformer - Delta - Wye Grounded shown
- Circuit Breaker with CTs
- Recloser with Bipass Switch
- Bartlett Feeder 1 (4.16 kV)
- Bartlett Feeder 2 (4.16 kV)
- Bartlett Feeder 3 (4.16 kV)
- Bartlett Feeder 4 (4.16 kV)
- Bartlett Feeder 5 (4.16 kV)
- Quartzite Feeder 6 (4.16 kV)
- Quartzite Feeder 7 (4.16 kV)
- Quartzite Feeder 8 (4.16 kV)
- Townsite Feeder 9 (46 kV)
- Townsite Feeder 10 (46 kV)
- Townsite Feeder 11 (46 kV)
- Quartzite Feeder 12 (4.16 kV)
- Quartzite Feeder 13 (4.16 kV)
- Quartzite Feeder 14 (4.16 kV)
- Hudson Feeder 15 (4.16 kV)
- Hudson Feeder 16 (4.16 kV)
- Hudson Feeder 17 (4.16 kV)
- Hudson Feeder 18 (4.16 kV)
- Harrie Lake Feeder 19 (4.16 kV)
- Harrie Lake Feeder 20 (4.16 kV)
- Vanier Feeder 21 (4.16 kV)
- Vanier Feeder 22 (4.16 kV)
- Vanier Feeder 23 (4.16 kV)
- Wabush Feeder 32 (46 kV)
- Wabush Feeder 33 (46 kV)

PROPOSED NEW HOSPITAL

PROPOSED NEW COLLEGE

WA33 46 kV

SMOKEY MOUNTAIN

PROPOSED RESIDENTIAL DEVELOPMENTS

QUARTZITE SUBSTATION

TS9 46 kV

QZ7 4.16 kV

QZ14 4.16 kV

QZ6 4.16 kV

QZ8 4.16 kV

QZ12 4.16 kV

QZ13 4.16 kV

HARRIE LAKE SUBSTATION

TS9 46 kV

QZ14 4.16 kV

HL19 4.16 kV

HL20 4.16 kV

TAMARACK GULF CLUB

VANIER SUBSTATION

VA21 4.16 kV

VA22 4.16 kV

VA23 4.16 kV

TS11 46 kV

HUDSON SUBSTATION

TS11 46 kV

HU15 4.16 kV

HU18 4.16 kV

HU17 4.16 kV

HU16 4.16 kV

QNS&L 23 kV

BA2 4.16 kV

BA1 4.16 kV

BA3 4.16 kV

HU17 4.16 kV

BARTLETT SUBSTATION

BA5 4.16 kV

BA4 4.16 kV

TS10 46 kV

TOWNSITE SWITCHING STATION

TS9 46 kV

TS10 46 kV

TS11 46 kV

WA32 46 kV

WA33 46 kV

WABUSH TERMINAL STATION

WA32 46 kV

WA33 46 kV

WA36 46 kV

WABUSH TOWNSITE SUBSTATION

PROPOSED COMMERCIAL AND INDUSTRIAL DEVELOPMENTS

SEPT ISLES

		SYS PLANNING:	CRW
		SYS OPERATIONS:	--
		TERM DESIGN:	--
		PROTECTION:	--

SHEET 1 OF 1
DATE: NOV 8, 2007
DRAWN BY: CRW
FILE: EXISTING 4.16 KV SYSTEM.SKF

APPENDIX B

LABRADOR CITY DISTRIBUTION UPGRADING STUDY

HYDRO
THE POWER OF COMMITMENT

LABRADOR CITY DISTRIBUTION SYSTEM UPGRADING STUDY

Electrical
Mechanical
Civil
Protection & Control
Transmission & Distribution
Telecontrol
System Planning

Approved for Release

Date

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SUMMARY

This document is a study of the ability of the distribution system in Labrador City to serve load growth.

The study determined that the existing system would not be able to meet future load requirements. In order to ensure that customers on the distribution receive acceptable power quality, will be necessary to upgrade the system.

The voltage conversion plan developed in 1992 was revisited. However, it was determined that this design would not adequately meet current requirements. Two alternative plans were developed to better address load growth and meet present day requirements to well beyond the forecast period.

One alternative is to upgrade the distribution system to 25 kV, and the other, because a considerable amount of infrastructure already exists, is to upgrade the distribution system to 12.5 kV.

The 25 kV alternative proved to be $3.9 million less costly than the 12.5 kV alternative. It also offers some superior performance benefits such as greater power transfer capability, and better motor starting performance over the 12.5 kV Upgrading Plan.

A number of recommendations have been made in the final section, which identify further work required and measures that can be taken to improve the system.

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LIST OF ABBREVIATIONS

LBC – Labrador City Distribution System
WBH – Wabush Terminal Station
WAB – Wabush Townsite Substation
NLH – Newfoundland and Labrador Hydro
IOCC – Iron Ore Company of Canada
QNS&L – Quebec North Shore and Labrador Railway
TWINCo – Twin Falls Power Company Ltd.
CFLCo – Churchill Falls Labrador Corporation Ltd.
A - Amperes
V - Volts
W - Watts
VA – Volt-Amperes
VAR – Volt-Amperes Reactive
kA - Kiloamperes
kV – Kilovolts – 1000 V
kW – Kilowatts – 1000 W
kVA – Kilovolt-Amperes – 1000 VA
kVAR – Kilovolt-Amperes Reactive 1000 VAR
MW – Megawatts – 1000000 W
MVA – Megavolt-Amperes – 1000000 VA
MVAR – Megavolt-Amperes Reactive 1000000 VAR
ASC – Aluminum Stranded Conductor
AASC – Aluminum Alloy Stranded Conductor
ACSR – Aluminum Conductor steel Reinforced
AAC – All Aluminum Conductor
AAAC – All Aluminum Alloy Conductor
OLTC – On Load Tap Changer
SCADA – Supervisory Control and Data Acquisition

INTRODUCTION

The Labrador City Distribution System (LBC) consists of five 46 kV subtransmission feeders, L32, L33, L9, L10, L11, a 46 kV switching station, Townsite Switching Station, five 46/4.16 kV step-down substations, Bartlett Substation, Hudson Substation, Vanier Substation, Quartzite Substation, and Harrie Lake Substation, and twenty 4.16 kV distribution feeders, L1 to L8 and L12 to L23. In addition to the above, two customer owned distribution feeders are supplied from the system, one line extends westward to the Tamarack Lake Golf Course (Tamarack Line), a second line supplies facilities along the Quebec North Shore and Labrador Railway (QNS&L Line). A simplified single line diagram of the present day distribution system can be found in Appendix A1.

The Labrador City System is supplied from Churchill Falls via two 230 kV transmission lines. The transmission lines run from the Switchyard at Churchill Falls to the 230/46 kV Wabush Terminal Station. The Wabush Terminal Station is owned by Twin Falls Power Company Ltd. (TWINCo) and operated by Churchill Falls Labrador Corporation Ltd. (CFLCo). This station also feeds the Wabush Townsite Substation (WAB), as well as the mining facilities at Iron Ore Company of Canada (IOCC), and Wabush Mines.

Voltage regulation for the system is provided by On Load Tap Changers (OLTCs) and two synchronous condensers at Wabush Terminal Station. The synchronous condensers regulate the voltage on the 46 kV bus to 46.6 kV (1.013 p.u.).

A 46 kV subtransmission line, L32, runs 1.74 km from Wabush Terminal Station to Townsite Switching Station. The line construction consists of 477 ASC Cosmos conductor, and has a rated capacity of 66.4 MVA at an ambient temperature of -30 °C.

A second 46 kV subtransmission line, L33, also runs by the Townsite Switching Station and from there another 24 km to Fermont Quebec. L33 is connected to the Townsite Switching Station by a normally open tie switch, WA32WA33-1. The line can serve as an alternate supply to Townsite Switching Station when L32 is unavailable. The line conductor is 477 ACSR Pelican, and similar to L32 it has a capacity of 66.4 MVA based on a -30 °C ambient temperature and a 50 °C conductor temperature. The line was built as an emergency tie line between Fermont, Quebec and Labrador West.

In the event of an outage to either system, power can be supplied on an emergency basis in either direction. Fermont is normally supplied power by the Hydro Quebec Grid via the Mont Wright Terminal Station. In the event that supply to Fermont is lost from Mont Wright, up to 15 MW of power can be transferred to Fermont from Wabush Terminal Station over L33. In a similar way, up to 5 MW of power can be supplied from Fermont to Labrador West. There is a 30° phase difference between the Hydro Quebec and Labrador West electrical systems. Therefore, the two system cannot be operated in parallel, and L33 is not tied to Fermont on a regular basis. When the line must be utilized, then either Fermont of the Labrador West Distribution must be completely isolated from its normal source of supply before the interconnection can be made. This

line is considered an emergency line and is not normally kept energized. In regards to the supply contract between NLH and Hydro Quebec, there are no stipulations regarding the amount of power that must be supplied over the Fermont Line.

L32 (or L33 during unusual circumstances) supply power to the Townsite Switching Station where power is distributed to the other substations.

1.1 TOWNSITE SWITCHING STATION

The Townsite Switching Station serves as a distribution and sectionalizing center for the 46 kV subtransmission system. The station consists of a 46 kV bus structure, three 46 kV oil circuit breakers, and a control cabinet. Its role in the system is to provide switching and protection to the substations within the system. Appendix A2 shows the single line diagram of the Townsite Switching Station.

The Townsite Switching Station connects three 46 kV subtransmission lines, L9, L10, and L11, which supply the distribution substations located throughout the town. L9 runs westward from Townsite along the southern part of town to the Quartzite and Harrie Lake Substations. The line is 3.85 km to Quartzite Substation and 3.75 km to the Harrie Lake Substation, this line uses 266.8 ACSR Partridge conductor and has a capacity of 47.9 MVA at -30 °C ambient temperature. L10 also runs in a generally westward direction to the Bartlett Substation in the center of town. This line is approximately 0.75 km long and is constructed of 266.8 ACSR Partridge conductor. L11 runs in a generally northern direction to the Hudson and Vanier Substations. The Hudson Substation is tapped off of L11 approximately 0.85 km down the line from the Townsite Switching Station. The line then extends from Hudson Substation 1.3 km to the Vanier Substation. The section of L11 running from Townsite to Hudson is constructed using 266.8 ACSR Partridge conductor, the section from Hudson to Vanier was constructed more recently and is built using 477 ASC Cosmos conductor. Based on historical breaker readings the load at Townsite Switching Station is distributed as shown in Table 1 below.

Table 1: Load Breakout at Townsite Switching Station

	INCOMING FEEDERS		OUTGOING FEEDERS		
	L32	L33	L9	L10	L11
TOTAL	100.0%	0%	35.9%	24.7%	39.3%
Φ_A	100.0%	0%	34.9%	24.6%	40.4%
Φ_B	100.0%	0%	35.6%	23.9%	40.5%
Φ_C	100.0%	0%	37.4%	25.6%	37.0%

As Table 1 above shows loads are relatively evenly distributed between the outgoing feeders that supply the 46/4.16 kV substations (L9 and L11 each feed two substations, a large one and a small one). Note however that L32 carries 100 % of the system load, rather than sharing the load with L33. As was stated above L33 is only considered an emergency feeder. The line is not normally energized; however, it may prove beneficial

to operate this line in parallel with L32 both from the point of view of a backup supply as well as in terms of reliability.

From the Townsite Switching Station power is distributed to the Bartlett, Hudson, Vanier, Quartzite, and Harrie Lake Substations.

1.2 SUBSTATIONS

There are five 46/4.16 kV substations located in Labrador City which distribute power to customers at 4.16 kV. The system total installed nameplate capacity is 65668 kVA, plus another 12500 kVA of uninstalled capacity. Table 2 below shows the expected undiversified substation peaks for the current year.

Table 2: Substation Breakout and 2007 Undiversified Forecasted Peak

	%TOTAL	Forecasted Peak (kW)
Bartlett Substation	23%	11708
Hudson Substation	26%	13395
Vanier Substation	14%	7402
Quartzite Substation	29%	14564
Harrie Lake Substation	8%	4020

As is shown in Table 2, the Bartlett, Hudson, and Quartzite Substations carry 78 % of the system load. A general description of the substations is provided below.

1.2.1 BARTLETT SUBSTATION

Bartlett Substation (BA) consists of two 46/4.16 kV step-down power transformers, T1 (5000/6667 kVA) and T2 (5000/6667 kVA), a 46/4.16 kV system spare transformer, SPARE (7500/10000/12500 kVA), switchgear building. The switchgear building contains 15 kV metal-clad type switchgear, there are three 2000 A breakers, B1T1 connects T1 to bus B1, B2T2 connects T2 to bus B2, and B1B2 is normally open and ties B1 to B2, connected off of B1 and B2 are six 1200 A feeder breakers. The breakers are designed to interrupt up to 25000 A of symmetrical fault current. The substation currently operates at 4.16 kV and is capable of operating at voltages up to 14.4 kV. Appendix A3 shows the single line diagram of the Bartlett Substation.

The Bartlett Substation connects six 4.16 kV distribution feeders, L1, L2, L3, L4, and L5. The feeders supply distribution customers in the southern and central part of the town. A sixth feeder L17 also connects to the Bartlett Substation by a normally open breaker, however, normally this line is fed from the Hudson Substation. L2, L4, and L5 supply mainly residential type loads. L1 supplies a combination of residential and apartment loads as wells as two schools. The feeder load breakout based on historical breaker readings at Bartlett Substation is shown below in Table 3.

Table 3: Bartlett Substation Feeder Breakout

FEEDER	%-OF-TOTAL	%-PH-A	%-PH-B	%-PH-C
L1	17%	25%	35%	40%
L2	22%	39%	34%	27%
L3	19%	32%	30%	37%
L4	23%	34%	28%	38%
L5	20%	31%	35%	33%

1.2.2 HUDSON SUBSTATION

Hudson Substation (HU) consists of a 44/4.16 kV step-down power transformer, T1 (7500 kVA), a 46/4.16 kV step-down power transformer, T2 (5000/6667 kVA), two 2.4/23-11.5 kV single-phase step-up power transformers, T3A (400 kVA) and T3B (400 kVA), and a switchgear building. The switchgear building contains 5 kV metal-clad type switchgear, there are three 2000 A breakers, T1B1 connects T1 to bus B1, T2B2 connects T2 to bus B2, and B1B2 is normally open and ties B1 to B2, connected off of B1 and B2 are five 1200 A feeder breakers. The breakers are designed to interrupt up to 25000 A of symmetrical fault current. Appendix A4 shows the single line diagram of the Hudson Substation.

The Hudson Substation connects four 4.16 kV distribution feeders and a customer owned line, L15, L16, L17, L18. The feeders supply distribution customers in the eastern part of town and the industrial park, a 23 kV customer owned feeder (QNS&L Line) is connected off of T3. L17 can be fed from either Bartlett or Hudson Substations however, it is normally fed from Hudson Substation, and the tie breaker BA22HU17-CB1 is left normally open. Over peak, Bartlett Substation does not have sufficient capacity to supply L17. Thus, its use is restricted to off peak periods. L15 supplies mainly residential customers in the central part of the town. L16, L17, L18 supply mainly commercial and industrial type loads. The feeder load breakout based on historical breaker readings at Hudson Substation is shown below in Table 4.

Table 4: Hudson Substation Feeder Breakout

FEEDER	%-OF-TOTAL	%-PH-A	%-PH-B	%-PH-C
L15	22%	31%	34%	35%
L16	23%	33%	33%	33%
L17	32%	32%	37%	31%
L18	16%	23%	45%	33%
QNS&L	6%	-	100%	-

1.2.3 VANIER SUBSTATION

Vanier Substation (VA) consists of a 46/4.16 kV step-down power transformer, T1 (7500/10000 kVA), a control building, and three 15 kV, 1120 A outdoor type reclosers, the reclosers are designed to interrupt up to 20000 A of symmetrical fault current. The

substation buswork has an insulation rating of 25 kV and operates at 4.16 kV. Appendix A5 shows the single line diagram of the Vanier Substation.

The Vanier Substation connects three 4.16 kV distribution feeders, L21, L22, and L23. L21 supplies the Captain William Jackman Memorial Hospital and the Ski Hill at Smokey Mountain. L22 supplies residential customers in the northern part of town. L23 supplies power to the Labrador Mall. The feeder load breakout based on historical breaker readings at Vanier Substation is shown below in Table 5.

Table 5: Vanier Substation Feeder Breakout

FEEDER	%-OF-TOTAL	%-PH-A	%-PH-B	%-PH-C
L21	34%	33%	35%	33%
L22	31%	38%	25%	37%
L23	35%	33%	29%	38%

1.2.4 QUARTZITE SUBSTATION

Quartzite Substation (QZ) consists of two 46/4.16 kV step-down power transformers, T1 (7500 kVA) and T2 (10000/13333/16667 kVA), and two switchgear buildings. The switchgear buildings contain 4.8 kV metal-clad type switchgear, there are three 2000 A breakers, B1T1 connects T1 to bus B1, B2T2 connects T2 to bus B2, and B1B2 is normally open and ties B1 to B2, connected off of B1 and B2 are six 1200 A feeder breakers. The breakers are designed to interrupt up to 29000 A of symmetrical fault current. Appendix A6 shows the single line diagram of the Quartzite Substation.

The Quartzite Substation connects six 4.16 kV distribution feeders, L6, L7, L8, L12, L13, and L14. L6, L7, L8, L12, and L13 supply residential customers in the western part of the town. L14 supplies residential customers in the Harrie Lake Trailer Court, as well as a small business district at Harrie Lake. The feeder load breakout based on historical breaker readings at Quartzite Substation is shown below in Table 6.

Table 6: Quartzite Substation Feeder Breakout

FEEDER	%-OF-TOTAL	%-PH-A	%-PH-B	%-PH-C
L6	16%	31%	35%	34%
L7	13%	39%	33%	27%
L8	20%	35%	31%	34%
L12	20%	23%	38%	40%
L13	22%	37%	33%	30%
L14	9%	30%	29%	41%

1.2.5 HARRIE LAKE SUBSTATION

Harrie Lake Substation (HL) consists of a 44/4.16 kV step-down power transformer, T1 (3000/4000 kVA), and a switchgear building. The switchgear building contains 4.8 kV metal-clad type switchgear, there is a 2000 A breaker, T1B1-1 that connects T1 to bus B1, connected off of B1 and B2 are two 1200 A feeder breakers. The breakers are the same as those installed at Quartzite Substation and are designed to interrupt up to 29000 A of symmetrical fault current. Appendix A7 shows the single line diagram of the Harrie Lake Substation.

The Harrie Lake Substation connects two 4.16 kV distribution feeders, L19, and L20. The feeders supply mainly residential customers at the Harrie Lake Trailer Court to the west of the main part of the town. A customer owned line to the Tamarack Golf Course is connected off of L20. The feeder load breakout based on historical breaker readings at Harrie Lake Substation is shown below in Table 7.

Table 7: Harrie Lake Substation Feeder Breakout

FEEDER	%-OF-TOTAL	%-PH-A	%-PH-B	%-PH-C
L19	51%	23%	41%	36%
L20	49%	34%	30%	36%

1.3 RECENT DEVELOPMENTS

The Labrador City Distribution System was taken over by NLH from IOCC in 1992. At that time, the system received extensive upgrades to bring it to standard: Bartlett and Hudson Substations were rebuilt, the Vanier Substation was constructed, a number of feeders were upgraded, and the distribution was reconfigured to better share the load between the stations. The original upgrades were initiated to address safety concerns and power quality issues. The last major upgrades the system received were completed in the mid to late nineteen-nineties. During this time, a voltage conversion to 12.5 kV to part of the system was contemplated. However, the load was not forecasted to change much.

In the early 1990s, the mining companies were essentially wrapping up their operations. The economy of the region depends heavily on iron ore mining, and it was expected that the shutdown of the mines would lead to a decline in load. As a result, the plans for a voltage conversion were deferred, and the 4.16 kV distribution systems were retained. When the decision was made not to carry out the voltage conversion, it was noted that because the existing system is operating so near its capacity limits should any load growth occur, a voltage conversion would become necessary in order to accommodate the growth. See Appendix B for further details.

Today, the economic outlook for Labrador West is much different than it was in the early 1990s. The economy in the area has experienced revitalization, and there are present signs of load growth appearing in the region. People are moving to the area, the real-estate market is booming, enrolment is up in the schools, and service industries are expanding and setting up new operations. This growth is attributable to a number of factors as noted below. High demand for iron ore on the world market has subsequently driven prices for this commodity to all time highs. Compelled by the high value of their product, these companies have maximized production to capitalize on their profits, and are planning further expansions. The regions economy is driven mainly by the mining operations at IOCC, and Wabush Mines, and as such the local economy is benefiting from the spin-offs. A larger number of retirements are expected at these operations in the next few years as the baby boom generation starts to retire on mass. A number of the retirees are deciding to remain in the region after retirement. As new people hired to replace the retirees come to Labrador West the demand for housing increases. In addition to new hires coming into the region, it seems that some of the population from Fermont, PQ have moved to the area apparently drawn by the low cost of electricity relative to that in Quebec. This has lead to a small boom in the regions real estate market. New residential developments have been proposed for the area west of Labrador City and a number of new additions have gone into the Harrie Lake Trailer Park. In response to the increased demand for services, a number of new businesses have setup in the region, while others that were already present have expanded their operations. Most of this commercial/industrial development has been in the town's industrial park. In addition to these developments the Government of Newfoundland and Labrador plans to construct a new hospital and college for the region

in the town. The location for these developments is not yet finalized, but they are being proposed at a site just north of the town.

The peak load for Labrador City now exceeds 51 MW. The operations at Wabush Mines and IOCC are at full production, and IOCC is planning an expansion. The region now has potential for considerable growth. The town itself has experienced a considerable amount of growth in the past year. New trailers and mini-homes are constructed in the Harrie Lake trailer court area, a residential development has been proposed to start off of Hudson Drive near the Quartzite Substation. New commercial/industrial lots have been released in the industrial park, this area would be served by L18 out of Hudson Substation. The new college and hospital for Labrador West have been announced, the proposed location for the hospital is off the Fermont Highway behind the Labrador Mall. While the location of the college has not been officially announced, it is being proposed to go adjacent to the new hospital with a shared facilities concept. These loads would be supplied either by a new substation or from the Vanier Substation.

1.4 LOAD FORECAST

Table 8 below shows the long term load forecast for Labrador City as provided by the Market Analysis Section of Newfoundland and Labrador Hydro's System Planning Department.

Table 8: Labrador City Long-term Load Forecast

Labrador City Load Forecast 2007-2027							
Labrador City	2007	2008	2009	2010	2011	2012	2013
Gross Peak (kW)[1]	51,089	51,345	52,367	52,349	52,446	52,783	52,922
Gross Energy (MWh)[1]	204,974	208,674	212,825	215,072	213,147	214,516	215,082
Total Sales (MWh)	197,489	201,054	205,054	207,219	205,364	206,683	207,228
Company Use (MWh)	0	0	0	0	0	0	0
	2014	2015	2016	2017	2018	2019	2020
Gross Peak (kW)[1]	53,105	53,229	53,353	53,478	53,602	53,726	53,850
Gross Energy (MWh)[1]	215,827	216,331	216,836	217,340	217,844	218,348	218,853
Total Sales (MWh)	207,953	208,440	208,926	209,412	209,899	210,385	210,871
Company Use (MWh)	0	0	0	0	0	0	0
	2021	2022	2023	2024	2025	2026	2027
Gross Peak (kW)[1]	53,974	54,098	54,222	54,346	54,470	54,594	54,718
Gross Energy (MWh)[1]	219,357	219,861	220,366	220,870	221,374	221,879	222,383
Total Sales (MWh)	211,357	211,844	212,330	212,816	213,303	213,789	214,275
Company Use (MWh)	0	0	0	0	0	0	0

1. Gross peak or energy equates to bulk deliveries on interconnected systems.
Source: Spring 2007 HROPLF with Summer 2007 Long Term Extension
System Planing Department
August 2007

The load forecast was plotted with the historic annual peaks from 1994 to the present. The results are shown below.

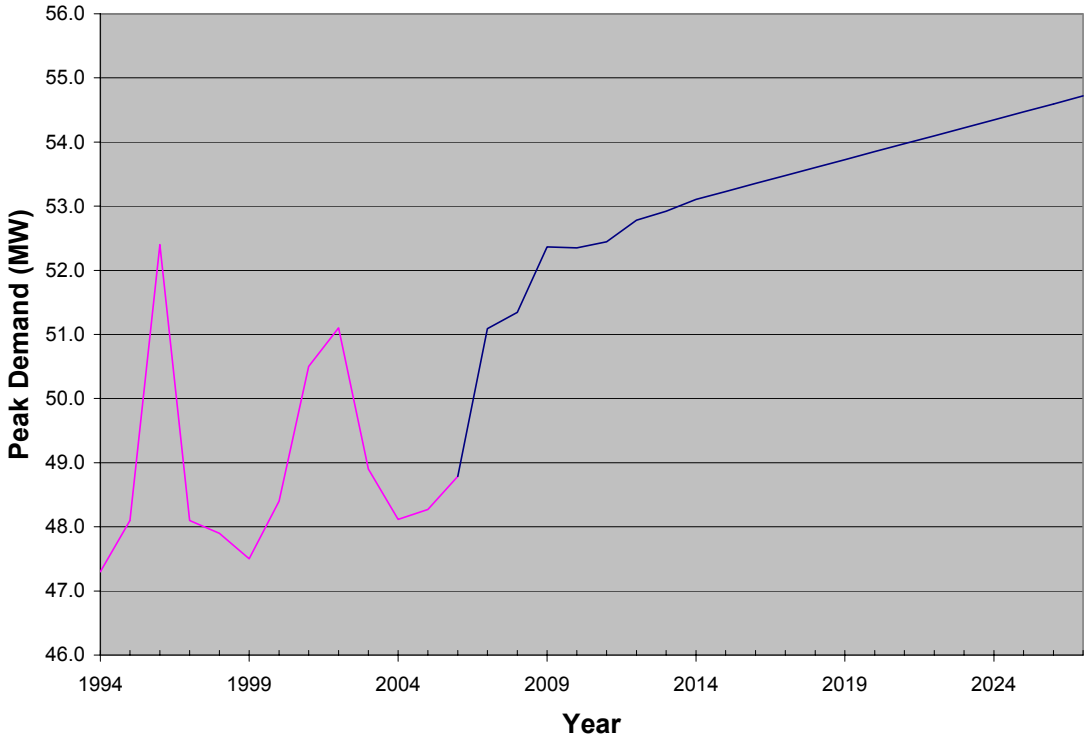


Figure 1: Peak Load History and Load Forecast Plot

Figure 1 above shows the system peak load history from 1994 to 2006, and the forecasted load out to 2027. The forecast shows the system load should go to approximately 55 MW by 2027. The existing system has several limitations which limit of the amount of additional power that can be supplied above present peak conditions. A brief discussion of these limitations on the existing system is given in the next section.

2 EXISTING SYSTEM

The existing 4.16 kV distribution system was designed to serve a load of up to 52 MW. It has been operating near the limits of its capacity for several years, but the peak load has not increased in this time. The 4.16 kV distribution system has a number of limitations that prevent it from supplying much load beyond 52 MW. These limitations are discussed briefly in this section.

The first limitation is voltage regulation. As a distribution voltage, 4.16 kV has capability to carry only a small amount of power over any distance because the voltage drop per unit length is larger in comparison to higher distribution voltages. For the same amount of power, more current is required at 4.16 kV than for say 12.5 kV or 25 kV. Since line current is higher, then the voltage drop through the line will also be greater. Therefore, the feeder length must be kept short to avoid having low voltages occur to customers on the distribution. Figure 2 below provides a comparison of the available reach over which power can be transmitted for a given operating voltage and constant line current. The chart shows the feeder length versus nominal system voltage that results in an end-of-line voltage of 96.7 % for a 100 % sending end voltage at 376 A line current. To model a distributed load, half the load is placed at the end of the line, and half was place halfway down the line. A line current of 376 A was chosen because this is representative of typical peak feeder currents that would be seen in Labrador City.

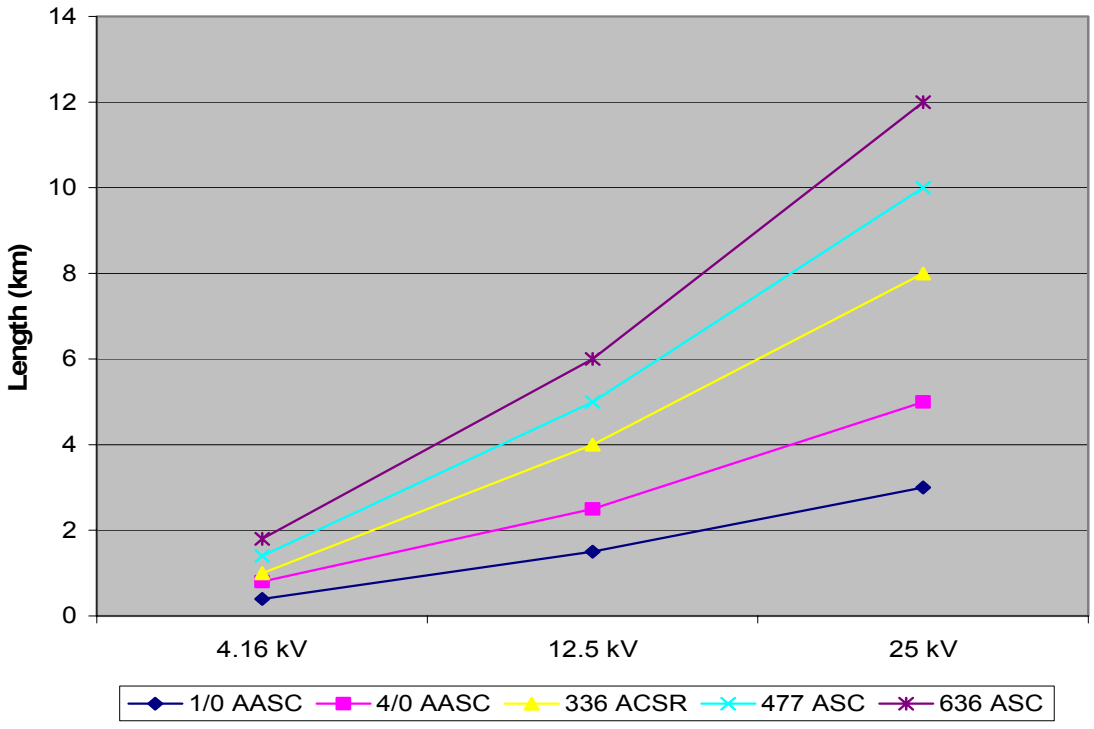


Figure 2: Line Length versus Nominal Voltage to give EOL Voltage of 116 V for a starting voltage of 120 V on a 120 V base and 376 A line current.

As Figure 2 shows, at higher nominal operating voltages a larger amount of power can be transmitted over a much larger distance than at a lower voltage. 336 ACSR is a very common size conductor in Labrador City, for a line current of 376 A, at 4.16 kV, about 2700 kVA of power can be transported a distance up to 1.8 km, in comparison at 25 kV, about 16200 kVA can be transported over a distance of 8 km. Therefore for the same size conductor up to six times the power can be transmitted over four times the distance at 25 kV as opposed to 4.16 kV. Not only does a higher system voltage allow more power to be transmitted over a longer distance, it also allows for use of smaller sized conductors and therefore cost savings when it comes to line construction.

The next is the limitation on operating a system at 4.16 kV is due to heat losses. This condition is associated with the relatively high currents that flow through the lines. Since the operating voltage is fixed within the range of regulation, in order to supply more power, more current must flow through the line. The high currents do not only cause larger voltage drops, it also causes more heating of components due to I^2R losses. If heating is excessive, it can stress and damage electrical equipment, and cause it to age prematurely. In general, 4.16 kV systems that supply large loads like that in Labrador City are less forgiving than similar size systems at higher operating voltages. The extra heating on the equipment will lead to failure more quickly and more often than a system operating at higher voltage for the same load. Preventing failures from becoming a regular occurrence requires a persistent and aggressive preventative maintenance program, and can require a considerable amount of the resources from the operations crew.

Another challenging aspect of supplying 50+ MW of load at 4.16 kV is adequately protecting the system from faults. Fault levels in Labrador City are very high (500 MVA at the substation high voltage bushings). Since the system operating voltage is rather low in comparison to more commonly used distribution voltages, very high fault currents are available at the substation low voltage bus. This is even with the choking effect of the substation power transformers. Due to the extremely high short circuit currents, operating restrictions prevent paralleling of transformers to keep fault levels below the interrupting rating of the breakers. As the distance from the substation increases the fault levels drop off quickly because the per unit system impedance is high. Therefore, as the distance increases the short circuit currents decrease, subsequently it can be more difficult to detect faults farther away from the substation. The problem can be compounded even further because the ground resistivity is very high in Labrador West (approximately 2000 Ωm). Impedance type faults can occur when a conductor (or conductors) contacts the ground, trees, or other objects and there is resistance to the flow of fault current. The most common type of fault is line-to-ground (i.e. when a single phase falls and contacts with the ground), and in general most of these faults are of the impedance type. When an impedance fault occurs on a 4.16 kV system, the current flowing into the fault can be very low. For example, a fault impedance of 40 Ω will only result in about fifty to sixty amperes of fault current. Such fault currents look no different than load current to a protective relay, and will not cause the devices to trip and clear the fault.

Typically, the protective relay phase-trip setting is twice the load current, up to a reasonable level of detection. The average undiversified feeder loads in Labrador City are approximately 2500 kW or about 350 A of line current. Basing the protection setting on the line current, the corresponding phase trip setting would be 700 A. The ground trip setting is typically set to be 50 % of the load current. Therefore, the corresponding ground trip setting is 175 A. For this protection setting, only faults with an impedance of less than 14 Ω would be detectable. For an impedance fault of 40 Ω, the fault current would be too low to trip the protective relay. Further details on distribution system overcurrent protection can be found in Appendix C.

Considering the above it seems the feeder loads in this system are at the point where increasing the protection settings any further to accommodate more load could compromise the ability to detect faults. Line to ground faults can become difficult to detect because the current flowing into the fault is low enough to be indistinguishable from normal load current. In such a case, breakers will not trip, and in the worst case, the fault may not burn clear and an energized line would be left on the ground. This can pose a considerable risk to the public. In Labrador City, the problem is further compounded by high load currents, which tend to mask more impedance faults.

The available fault current at the end of the line both limits the line length and the loading because the protection settings must be kept sufficiently low to ensure that most faults can be detected. This means that despite having additional thermal capacity on the system, very little additional load can be added to the system and still operate it safely. Ultimately, if any new loads are to be supplied at 4.16 kV in Labrador City, then this will require expansion of the existing substations, and construction of new feeders.

Operating the system is more difficult than with other systems. The system is complex because of the required number of substations and feeders. Therefore, maintenance requirements are demanding. Ensuring feeder loads are balanced to within 10 % is difficult due to small load variations having a large effect on line current.

The cost of the system is higher because equipment of higher ratings is required, larger conductors and circuit breakers must be used. Limiting feeder capacity to prevent low voltages and protection issues from arising will require more and more feeders. In many cases, this is impractical because the real estate is already built up or simply not available or the substation has already been expanded to its maximum capacity. All the additional work because of the switchgear requirement make the cost and timelines for such work very prohibitive when new loads come on stream.

2.1 OUTAGE STATISTICS

Reliability of NLHs distributions systems is tracked by industry standard indexes, SAIFI, and SAIDI. Service Continuity Indices for distribution are defined as shown below:

Table 9: NL Hydro Distribution SAIDI and SAIFI

Index	Description	Detail
SAIDI	Indicates System Average interruption duration for customers served per year.	$\frac{\text{TOTAL CUSTOMER - HOURS OF INTERRUPTIONS}}{\text{TOTAL CUSTOMERS SERVED}}$
SAIFI-S	Indicates the average of sustained interruptions per customer served per year.	$\frac{\text{TOTAL CUSTOMER - INTERRUPTIONS}}{\text{TOTAL CUSTOMERS SERVED}}$

Outages are tracked and stored in the Distribution Outage Reporting System (DORS).

Table 10: Labrador City Outage Statistics Summary

YEAR	NO OF CUSTOMERS	TOTAL SAIFI	TOTAL SAIDI	LOSS OF SUPPLY OUTAGES SAIFI	LOSS OF SUPPLY OUTAGES SAIDI
2002	3650	4.499	1.711	1.786	0.217
2003	3650	3.596	0.757	0.000	0.000
2004	3658	3.220	1.992	2.659	1.580
2005	3670	4.669	9.181	3.593	8.542
2006	3661	5.965	11.490	0.908	0.298
2007	3675*	10.881	14.652	2.810	4.814
LBC 5 YR AVG**		4.390	5.026	1.789	2.127
NLH 5 YR AVG**		6.888	10.707		

YEAR	NO OF CUSTOMERS	PLANNED OUTAGES SAIFI	PLANNED OUTAGES SAIDI	UNPLANNED OUTAGES Exclusive of Loss of Supply SAIFI	UNPLANNED OUTAGES Exclusive of Loss of Supply SAIDI
2002	3650	0.117	0.175	2.597	1.319
2003	3650	0.003	0.004	3.593	0.753
2004	3658	0.000	0.003	0.561	0.410
2005	3670	0.003	0.017	1.073	0.622
2006	3661	2.373	8.208	2.684	2.984
2007	3675*	1.406	2.789	6.665	7.048
LBC 5 YR AVG**		0.499	1.681	2.102	1.217
NLH 5 YR AVG**		1.555	3.399	5.333	7.308

*Number of customer forecasted at year end, exclusive of street lights. Provided by Market Analysis Section of Systems Planning Department.
**Five year average is for years ending 2002 to 2006.

In general the distribution system in Labrador City has performed well in the past from a reliability point of view. Although within the last three years, the outage rates have gone up substantially. Year-to-date SAIFI and SAIDI are more than twice the system five year average. The 2005 and 2006 statistics are up over previous years as well. If the outage reports for the year 2007 are indicative of the true reliability of the system, then customers in Labrador City can expect to experience almost eleven outages per year, and each outage could be up to fifteen hours in duration. The System Operations and Customers Services Department has received several complaints about the outages that have occurred in recent months. Given the relatively poor performance of the

system in recent years, and the general dissatisfaction of the customers, the system may require upgrading to improve the system reliability.

The are a number of possible causes for the increased outage rates. Until 2005, the outage rates were as good as or better than any other NLH distribution system. The last major upgrades to the distribution were completed in 1997, typically, new equipment is very reliable, and it will take approximately five years for the equipment to start to exhibit the true reliability of that component over its lifetime. Now that most of the components on this system have reached more than five years in service, it is possible that the statistics are reflecting the true reliability of the system. Second, the system operates with relatively high line currents for a distribution system. This in turn causes higher I^2R losses, and therefore, more heating. Heat stress tends to be hard on equipment, and can cause it to age prematurely. The result can be an increase in failure rates, and thus lower reliability.

2.2 LOAD FLOW ANALYSIS

Load Flow Analysis was conducted to determine present and future peak load conditions. The study assumes substation power transformer taps provide 2.5 % boost at the 4.16 kV bus. The distribution system model was updated using the information currently available, and should be representative of actual system conditions. The results described below will be confirmed when Load and Voltage Studies are conducted on the distribution system in the winters of 2008 and 2009.

2.2.1 LOAD FLOW ANALYSIS 2007 FORECASTED PEAK

The model was scaled to the 2007 peak load forecast of 51089 kW to project current conditions on the distribution system. The results of the load flows are shown in Table 11 and Table 12 below.

Table 11: Anticipated Feeder Current - 2007 Forecasted Peak Load

Name	|Ia|	|Ib|	|Ic|	|Iavg|	%IU
BA1	202	280	322	268	24.6%
BA2	410	358	286	351	18.7%
BA3	293	272	339	302	12.6%
BA4	375	303	419	366	17.1%
BA5	310	349	331	330	5.9%
QZ6	305	339	328	324	5.9%
QZ7	309	259	214	261	18.6%
QZ8	429	370	422	407	9.0%
QZ12	266	449	470	395	32.7%
QZ13	492	437	388	439	12.1%
QZ14	165	165	238	189	25.6%
HU15	377	429	440	415	9.3%
HU16	428	428	431	429	0.4%
HU17	565	667	553	595	12.2%
HU18	201	401	290	297	34.9%
B1T3	-	343	-	-	-
HL19	193	350	303	282	31.6%
HL20	274	249	300	274	9.4%
VA21	341	359	339	346	3.7%
VA22	362	234	357	318	26.4%
VA23	351	312	407	357	14.1%

Based on the results in Table 11, present day loads are considerably high. Most feeders carry in excess of 300 A, feeder HU17 is the most heavily loaded. The line carries more than 600 A on B-phase over peak. The feeders are also considerably unbalanced. More than half the lines are unbalanced by more than 10 %. The high load current and unbalance can be expected to cause poor voltage regulation and voltage unbalance on the feeders.

Table 12: Anticipated Worst Case Feeder Voltage - 2007 Forecasted Peak Load

Feeder	V_{MIN}	$V_{MIN\ (120\ Vbase)}$	Feeder	V_{MIN}	$V_{MIN\ (120\ Vbase)}$
BA1	98.4%	118.1	**HU15**	96.3%	115.6
BA2	97.8%	117.4	**HU16**	98.1%	117.7
BA3	98.8%	118.5	**HU17**	93.9%	112.7
BA4	96.9%	116.3	**HU18**	96.9%	116.3
BA5	97.5%	117.0	**HL19**	96.8%	116.2
QZ6	97.3%	116.8	**HL20**	95.2%	114.3
QZ7	95.1%	114.1	**VA21**	94.8%	113.8
QZ8	96.8%	116.2	**VA22**	98.5%	118.1
QZ12	96.0%	115.2	**VA23**	96.4%	115.7
QZ13	94.4%	113.2	**-**	-	-
QZ14	93.7%	112.4	**-**	-	-

Table 12 above shows the expected minimum voltage at the end of the 4.16 kV distribution feeders in Labrador City. The load flow analysis confirms that voltage regulation on this system is very poor. A number of feeders are at the lower limit of acceptable primary voltage according to NLH planning criteria. The worst case voltage

may be on feeder QZ14. The voltage at the end of this feeder may be as low as 93.7 % of nominal. It is expected that these problems will worsen as the system load grows.

2.2.2 LOAD FLOW ANALYSIS 2027 FORECASTED PEAK

The model was scaled to the 2027 peak load forecast of 54718 kW to project future conditions on the distribution system if nothing is done with the existing system. Again, it is expected that conditions on the 4.16 kV distribution systems will only worsen as time progresses. The results of the load flows are shown in Table 13 and Table 14 below.

Table 13: Anticipated Feeder Current - 2027 Forecasted Peak Load

Name	|Ia|	|Ib|	|Ic|	|Iavg|	%IU
BA1	217	300	345	287	24.7%
BA2	440	384	306	377	18.7%
BA3	314	292	364	323	12.6%
BA4	402	325	450	392	17.1%
BA5	333	374	356	354	6.0%
QZ6	327	364	352	348	5.9%
QZ7	333	278	229	280	18.8%
QZ8	460	397	453	437	9.1%
QZ12	285	483	505	424	32.8%
QZ13	530	469	417	472	12.3%
QZ14	177	177	256	203	25.9%
HU15	404	461	472	446	9.4%
HU16	459	460	462	460	0.4%
HU17	607	719	593	639	12.4%
HU18	216	431	310	319	35.1%
B1T3		368			
HL19	207	376	326	303	31.7%
HL20	294	267	323	294	9.5%
VA21	366	385	363	371	3.7%
VA22	389	250	383	341	26.5%
VA23	377	334	437	383	14.3%

Table 13 above shows that by 2027 most line currents could be in excess of 400 A per phase. This could have a negative impact on fault detection. High currents such as those shown in Table 13 indicate possible problems with cold load pick up. During a cold load pick up scenario line current could be double that seen above. Finally the higher currents will worsen voltage regulation even further and likely cause low voltages throughout the system.

Table 14: Anticipated Worst Case Feeder Voltage - 2027 Forecasted Peak Load

Feeder	V_{MIN}	$V_{MIN\ (120\ Vbase)}$	Feeder	V_{MIN}	$V_{MIN\ (120\ Vbase)}$
BA1	97.9%	117.5	**HU15**	95.7%	114.9
BA2	97.3%	116.8	**HU16**	97.5%	117.0
BA3	98.3%	118.0	**HU17**	93.5%	112.2
BA4	96.4%	115.7	**HU18**	96.4%	115.6
BA5	97.0%	116.4	**HL19**	96.3%	115.6
QZ6	96.8%	116.1	**HL20**	94.6%	113.5
QZ7	94.6%	113.5	**VA21**	94.1%	112.9
QZ8	96.2%	115.5	**VA22**	98.0%	117.6
QZ12	95.3%	114.4	**VA23**	95.7%	114.9
QZ13	93.6%	112.3	**-**	-	-
QZ14	92.8%	111.3	**-**	-	-

Table 14 above shows many feeders will have voltages which dip below 96.7 %. The worst case end of line voltage will be on QZ14 where the voltage could dip as low as 92.8 % during the system peak.

Given that the above analysis is for undiversified peaks, it is possible that the end of line voltages may be lower still on the 4.16 kV distribution system.

For a peak demand of 54718 kW the system losses are 1813 kW.

It is clear from the load flow analysis that the existing 4.16 kV distribution system does not have the ability to support future load growth without a significant amount of upgrading. Even if the existing system were expanded i.e. additional feeders and expanded substations, such upgrades may not be possible in all areas, and would not provide enough capacity to support load growth in the long term. Therefore, to address load growth in the long term, it is recommended that a voltage conversion be done on this system. The subsequent sections describe the options that were taken into consideration.

2.3 1992 12.5 KV UPGRADING PLAN

When the distribution system in Labrador City was taken over from IOCC a plan was developed to convert a portion of the system to 12.5 kV. This plan consisted of the conversion of the Bartlett System to 12.5 kV and picking up the bulk of the system load from the Bartlett substation. This would essentially have the distribution consisting of the core of the town at 12.5 kV, and the outer peripheral regions at 4.16 kV. The plan would significantly reduce feeder load currents allowing for improved system protection, and better ability to detect faults. It also should have improved the system reliability somewhat because the lower line currents would put less stress on the system components.

However, this plan does have some deficiencies when present planning criteria and design requirements are taken into account. The existing load in the developed areas

of the town is fairly saturated, and not much growth would be expected here. The expected regions of growth are focused on the undeveloped lands to the west and north of the town, and in the undeveloped lands around the Labrador City industrial park. Since the original upgrading plan proposed to leave the peripheral areas of the town at 4.16 kV, it would be a relatively short time until feeders in these areas became loaded to capacity. As more load is connected to the system, additional feeders and eventually substations would be required. This would lead to a short-term requirement to upgrade the system again in the near future. It should be noted that as a distribution operating voltage 4.16 kV is best suited to small compact loads. In places where the ground resistivity is high as it is in Labrador the line currents must be limited so as not to compromise the ability to detect faults, and because the voltage drop is higher due to the higher line current the feeder length must be kept short to prevent low voltages to customers.

In light of the above issues, an alternate upgrading plan would be necessary to better address load growth on this system and provide a higher level of operability and reliability for this system.

The previous upgrading plan was not intended to address growth in these areas as these parts of the town were to continue to operate at 4.16 kV, therefore an alternate plan was developed which takes into account the expected regions of growth, improve and ease the operability of the system for operations personnel, and to improve the system reliability.

3 2007 UPGRADING PLAN

Due to current deficiencies in the 1992 Upgrading Plan (requirements have changed since that time), two alternate plans are proposed which would better address expected load growth in the town. The first plan would upgrade the system to 25 kV, which is Hydro's current standard construction for distribution. The other plan builds on the previous 12.5 kV upgrading plan and makes use of some of the existing infrastructure that is capable of operating at 12.5 kV. Both plans have their own respective merits.

The 4.16 kV systems that currently supply the distribution have been pushed to its limits. In order to supply any significant additional load, it would be necessary to expand the substations and construct new feeders. In most cases, due to the location of the substation, and their construction, this is impractical. The load in Labrador West has started to grow, it is now necessary to develop a long-term upgrading plan for the distribution system.

Considering NLH Standards and the infrastructure that presently exists, there are two options for the Capital Plan; a 25 kV upgrading plan, and a 12.5 kV upgrading plan. The 25 kV Plan is based on Hydro standard design and operating practices, and consists of a two substation system with nine 25 kV feeders. A 12.5 kV option is also being examined because some of the existing infrastructure in the system is capable of operating at 12.5 kV. This plan would consist of three substations with seventeen 12.5 kV feeders and a 46 kV switching station.

Both plans are designed to provide good voltage regulation, and to keep line currents at acceptable levels, the plans also should provide operational flexibility, and improved reliability. Either option will take the system out beyond 66 MW which is higher than the current forecast. The following is a brief overview of the two options and the reasoning behind them.

3.1 DESIGN CONSTRAINTS

A number of issues must be accounted for in the design of the new distribution system in Labrador City.

System Planning carries out Load and Voltage Studies to determine the state of the system. The load and voltage study obtains a snapshot of the power flow on the system by recording the voltage and current on the feeders at different locations. This information is gathered using digital recording ammeters (DRAs) and digital recording voltmeters (DRVs). By placing the devices at strategic points along the feeder, the voltage levels and currents under peak loading conditions can be viewed. From the study the peak load, feeder voltage, currents, and load breakout is determined. This information is then entered into a model of the system, and then the model is used to

determine future loads, the effect of new loads, upgrades, etc. The upgraded system must meet the technical constraints outlined in the following sections.

3.1.1 VOLTAGE AND LOAD

3.1.1.1 Voltage Levels

Voltage levels on the system must stay within a specified range to ensure proper operation of devices connected to the system. Hydro uses the standard defined by CAN3-C235-83 (R2006) *Preferred Voltage Levels for AC Systems, 0 to 50 000 V*. The utility is responsible for voltages up to the customer service entrance. To ensure proper voltages at the service entrance, the voltages on the primary feeder must be high enough to account for the drops in the distribution transformer, secondary wire, and the service drop wire. Table 15 below shows the acceptable range of voltages at the service entrance under heavy and light load conditions.

Table 15: Voltage limits at Customer Service Entrance and on the Primary as per CSA C235-83.[1]

		Voltage (120 V Base)	
		Heavy Load	Light Load
Service Entrance Voltage		110	125
Voltage Drop at	Service Drop Wire	1	0.375
	Secondary Conductor	2	-
	Distribution Transformer	3	1.125
Total Voltage Drop from Primary to Service Entrance		6	1.5
Voltage at Primary		116	126.5

As Table 15 shows, the voltage on the primary should not go below 116 V on a 120 V nominal delivery voltage or 96.67 % of nominal. In some cases, it is known that the distribution transformer/secondary/service conductor voltage drop is less than 6 V. In such a case, a primary voltage of less than 116 V is acceptable. For light load conditions, the maximum allowable voltage on the primary is 126.5 V (105.4 %). For light load conditions the secondary conductor voltage drop not included since there are cases were secondary runs are not used (express drops).

3.1.1.2 Voltage Unbalance

Hydro calculates voltage unbalance as the maximum deviation of the phase voltage from the average voltage for all phases expressed as a percentage of the average voltage.

[1] Voltage drops are typical values for the equipment listed (1). Actual field measurements may in fact be lower depending on the impedance of the item in question. In cases where express service drops are used, the maximum allowable primary voltage during light load conditions is 126.5 V.

$$\%UV = \frac{MAX(\left|V_A - V_{avg}\right|, \left|V_B - V_{avg}\right|, \left|V_C - V_{avg}\right|)}{V_{avg}} \times 100\%$$

Voltage unbalance has the greatest effect on motors because circulating currents in the machine cause excessive heating. Subsequently motors supplied by unbalanced voltages must be derated. To minimize potential for damage to customers, Hydro limits the maximum allowable voltage unbalance to 2 %.

3.1.1.3 Current

Currents on the feeder must not exceed the maximum allowable ampacity for the conductors, transformers, and associated equipment. Exceeding allowable ampacities can cause damage to equipment, as well as unplanned outages.

3.1.1.4 Current Unbalance

Current unbalance is determined in a way similar to voltage unbalance as the maximum deviation from the average current as a percentage of the average current.

$$\%UI = \frac{MAX(\left|I_A - I_{avg}\right|, \left|I_B - I_{avg}\right|, \left|I_C - I_{avg}\right|)}{I_{avg}} \times 100\%$$

Unbalanced currents cause different voltage drops between the phase conductors and therefore, induce voltage unbalance. The unbalanced currents will flow in the system neutral. When neutral current is significant, corresponding protection settings will be higher to prevent nuisance tripping. Where line-to-ground fault levels are low, a high trip setting may compromise protection. For these reasons, NLH tends to limit the maximum permissible current unbalance to 10 %. However, there are situations where it is more feasible to correct for voltage unbalance with voltage regulators rather than by load balancing i.e. three-phase power may not be available in some areas. To improve protection it may necessary to install additional protective devices if load balancing is not possible.

3.1.2 INITIAL FEEDER LOADING

The system will be reconfigured to ensure that block loading on two adjacent feeders can be carried completely on one individual feeder.

The new system will be designed around NLHydro Distribution Standards for distribution lines and protection equipment. As a standard stock item, Hydro purchases distribution

circuit reclosers with 560 A continuous current rating. A typical recloser stocked by Hydro is the Cooper Power Systems VWVE27, this recloser has a rated operating voltage of 24.9 kV a rated maximum voltage of 27 kV, a continuous current rating of 560 A, and a typical symmetrical rms interrupting rating of 12000 A.

Typically, recloser trip settings are determined based on a setting of twice the peak load current. This is done to prevent nuisance tripping on the system. Give this information, and knowing that the maximum recloser trip setting is 560 A, and then the maximum acceptable recloser load (based on a 560 A trip setting) is 280 A which is 50 % of the recloser rating.

Unlike most other NLH distribution systems, the distribution system in Labrador City is heavily meshed with multiple tie points. Transferring load and sectionalizing the feeders to minimize outages is presently available on this system however, the low operating voltage coupled with high line currents restricts the ability to switch load over peak. Generally, switching operations on the current system are restricted to off-peak periods. It is desirable to retain this functionality because of the operational flexibility and reliability it offers.

The system will be redesigned such that any single feeder will be able to carry the load of any adjacent feeder at any time in a contingency or maintenance situation. Thus the design feeder load will be one-half the maximum desirable recloser load 140 A per phase.

Note: The recloser can be loaded to 350 A (approximately 60 % of recloser rating) on a continuous basis without causing nuisance tripping for a maximum trip setting of 560 A. Designing for an initial feeder load of 140 A per phase allows for an additional 25 % load growth on the feeders before additional feeders are required.

3.1.3 COLD LOAD PICKUP

Cold load pickup is a condition that occurs following a prolonged outage during cold temperatures. Immediately following restoration of service, loads will be highly coincident. This results in extremely high demand for a period following the outage. The duration and magnitude of cold load pickup is influenced by a number of factors. These include the weather and ambient temperature at the time of the outage, the duration of the outage, the amount of insulation in the buildings, and the penetration of electric heat and electric water heaters in the region. Where penetration of electric heat is high, and very low ambient temperatures are common, cold load pickup can be extremely high. When the condition occurs, equipment ratings and protection settings can be exceeded potentially causing damages, and false tripping of reclosers and breakers. This can cause difficulties to restore service to customers. Such is the case for interconnected systems in Labrador. According to conversations with T&D staff in Labrador, cold load pickup has been experienced for an outage as short as 30 minutes. Typically cold load pickup is assumed to be 200 % of the normal peak load current.

Where the system has insufficient capacity to handle cold load pickup, sectionalized switching is applied to reduce its magnitude. Therefore, to prevent possible damages and nuisance tripping, sufficient additional capacity must be retained to account for cold load pickup.

3.1.4 FAULT PROTECTION

Protection settings will be determined by standard techniques (2X peak load current). Full zone coverage will be provided. Settings will be sufficiently high to allow for cold load pickup, and to prevent nuisance tripping. To ensure sensitivity to faults is adequately maintained, feeder loads will be such that a line-to-ground fault with 40 Ω of impedance should be detectable.

3.1.5 OPERATIONAL FLEXIBILITY AND RELIABILITY

The upgraded distribution system will maintain equivalent or superior operational flexibility to the present system.

To provide further reliability, and reduce the requirement for planned outages for breaker and transformer maintenance, the 46 kV Subtransmission System will be upgraded to a looped system. Two lines will be available to supply each substation. This will allow for quick restoration of service in the event of a subtransmission line failure, and provide flexibility for line maintenance without the need for an outage.

3.1.6 POWER TRANSFORMERS

Transformers will be built to CSA standard CAN/CSA-C88-M90 (R2004) *Power Transformers and Reactors*.

If a transformer is to be equipped with an on load tap changer, it shall be installed on the high voltage windings. The on load tap changer should be designed to provide 15 % boost and 5 % buck in thirty-three tap positions. Having 20 % tap range in thirty-three positions gives 0.625 % per tap position. The 0.625 % resolution on the tap changer provides the same resolution for voltage adjustment as a distribution class voltage regulator. Voltage control at the 46 kV bus in Wabush Terminal Station is provided by synchronous condensers. The synchronous condensers regulate the voltage on the 46 kV bus to 46.6 kV (1.013 p.u.), the voltage is maintained at this level at the request of IOCC to maintain the voltage at the desired level within their 4.16 kV system. Under normal circumstances the voltage does not rise above 47.4 kV (1.030 p.u.) the only time the voltage is likely to get significantly higher would be during restoration of the power to Labrador West following an outage to the 230 kV transmission system. Under such circumstances, the distribution systems are isolated from the supply until the voltage on the 46 kV bus has been stabilized. Therefore, a 5

% buck capability on the tap changer is suitable for this application. For fixed tap changers the standard ±5 % taps in five tap positions should suffice.

3.1.7 FIRM CAPACITY

To provide an acceptable level of substation reliability and operability it is proposed that each substation have at least two power transformers. The transformers are to be sized such that for the loss of the largest unit in the system there will be sufficient capacity in the remaining units to carry the load of the entire system without the need for rotating outages.

Newfoundland and Labrador Hydro (NLH) has a back-up policy in place for transformer stations within its system (2). The policy groups transformer stations into three categories: Major Stations, Single Unit Stations, and Generation Stations. Generation station transformers go beyond the scope of this report, so they are not discussed here. Major Stations are those with multiple transformer installations and they handle large quantities of power. They often serve as points of supply to other smaller substations i.e. Hardwoods, Deer Lake, Oxen Pond, etc. Where the stations are linked with other major stations via transmission lines the group of stations are treated as looped systems where firm capacity is applied to the entire system. This type of station, because of the vital role it serves, is designed to withstand the loss of the largest unit. That is, the stations are planned based on firm capacity, the available capacity with the largest unit out of service. If the load reaches the firm capacity of the station then additional capacity is added to meet firm criteria. Single Unit Substations as the name implies have only one transformer unit. These stations typically serve small loads in the range of 50 kW to 10 MW. In the event that the transformer is lost from such a station NLH relies on a portable transformer unit to restore power to customers on a short-term basis, in the long-term a spare transformer unit would be mobilized and installed to supply customers.

For the distribution system in Labrador City, the same design criteria for major stations on the island will be applied as opposed to single unit stations. Most of NLHs substations on the island system are single unit stations. This is primarily because they only supply relatively small loads, and should a transformer failure occur, a portable transformer can be quickly mobilized and transported to the site to restore power. Typically, power can be restored to the systems on the island in less than two days. In Labrador, the situation is a little different. The extreme cold temperatures and severe winter weather further limit the time available to get power restored because things start to freeze very quickly. There is high dependence on electric heat in the region because of the low cost of energy. A major outage to the power system in winter would endanger property and maybe even lives. NLH does not stock a portable transformer with a 46 kV high voltage winding. The vast geographic distances and terrain of Labrador coupled with the lack of road infrastructure and severe weather would hamper the ability to mobilize a portable unit. This in turn would lengthen restoration time as well as costs. Finally, the required size of transformer (minimum 10 MVA) would be

difficult to retain as a portable unit. Such factors make implementing the island back-up policy for single unit stations nonviable for systems in interconnected Labrador. One other factor worth noting here is the relative size of the system in question. Labrador City has a peak load of approximately 50 MW at present and the load is growing. The summertime minimum load is approximately 7 MW (this is larger than the peaks for most of NLHs island systems). Given the relative size of the load in Labrador City the system can be treated as a major load and thus warrants major substation backup capability.

Applying firm capacity criteria (N-1) for major substations to the Labrador City System for each substation two transformers will be installed to provide reliability and flexibility for switching operations and substation maintenance.

For a two substation system with two units per substation and a long term forecasted load of 54.7 MW in 2027 the minimum required transformer size based on a 0.99 lagging power factor will be 54.7 MW / 0.99 / (4 -1) = 18.4 MVA. Adding 20 % additional capacity for a safety factor, the required transformer nameplate capacity is 22.1 MVA, thus a 15/20/25 MVA transformer size should be suitable for a two-substation system.

For a three substation system the minimum required transformer size would be 54.7 MW / 0.99 / (6 – 1) = 11.1 MVA. Again, adding 20 % additional capacity for a safety factor, the required transformer nameplate capacity is 13.3 MVA. Therefore, a 10/13.3/16.7 MVA power transformer should be suitable to serve a three-substation system.

4 2007 LABRADOR CITY 25 KV UPGRADING PLAN

The 2007 25 kV upgrading plan for Labrador City will upgrade the system to NLH Standards for distribution such that load growth is addressed to well beyond the planning horizon. Recognizing that a 25 kV feeder can safely carry much more power than a 4.16 kV feeder, the number of feeders, and subsequently the number of substations in the system can be reduced. The result will be a simpler system with lower annual operation and maintenance costs.

Using the criteria noted in Section 3.1.2, the initial feeder current will be 140 A. Therefore the average 25 kV feeder load will be, 25 kV * 140 A * $\sqrt{3} \approx 6000$ kVA under normal operating conditions. Under abnormal operating conditions (recloser failure for instance) the expected feeder load will be approximately 12000 kVA or twice the normal feeder load. Designing for this initial feeder load will leave sufficient capacity to accommodate cold load pickup and handle contingencies (i.e. carry 100 % of the load of an adjacent feeder). An additional 25 % to 30 % capacity will remain for load growth if the maximum continuous ampacity is based on use of a standard recloser with 560 A continuous current rating.

The forecasted peak load for 2007 is 51089 kW, assuming a system power factor of 0.99 lagging over peak, the required number of feeders are:

$$N = \frac{51089\,\text{kW}}{0.99 \times 6000\,\text{kVA}} \cong 9$$

Therefore, at least nine 25 kV feeders are required to supply the system.

4.1 SUBSTATIONS

Allowing for up to six feeders per substation, then two substations will be required for a 25 kV Labrador City Distribution System.

As a minimum the distribution system can be supplied with two substations at 25 kV (nine feeders at 5.7 MW each) for a 51 MW peak load.

Given there are six substations in the present system there is an opportunity to select the optimal sites to convert to 25 kV. The optimal sites have the following characteristics:

- The substation must have sufficient space to contain at least two 46 kV circuit breakers, two power transformers, a control building, three 25 kV circuit breakers, up to six feeder breakers or reclosers, and room for future expansions.

- The substation should be located in close proximity to the existing distribution feeders to allow easy connection to them, and it should be in close proximity to the areas where most load growth is expected to occur.
- The age of the existing equipment and the presence of any infrastructure that could be reused. This could reduce the cost of the upgrades.

Hudson Substation is located at the Eastern side of town near the Labrador City Industrial Park. It is a smaller substation, and the yard is relatively congested. There is no additional room for expansion. Some growth is expected in this area, mainly in the industrial park. The substation connects four 4.16 kV distribution feeders (L15, L16, L17, and L18) and a 23 kV customer owned line (QNSL21). It was rebuilt in the mid 1990s however, the buswork is insulated for 4.16 kV. Hudson Substation was ruled out due to the lack of available expansion space in the yard, and the fact that the existing equipment will require replacement for a voltage conversion.

Harrie Lake Substation is located at the western edge of town just before the entry to the Harrie Lake Trailer Court. The lands surrounding the substation are vacant and acquiring the necessary lands to expand the substation should be possible. The expansion would require a significant amount of civil work due to the small size of the existing substation. This substation currently connects two feeders 4.16 kV distribution feeders (L19 and L20). A third feeder L14 from the Quartzite Substation passes nearby. It would be necessary to construct two additional feeders approximately 1.3 km long to connect to the remaining Labrador City Feeders connected to the Quartzite Substation. Due to the amount of work needed, the Harrie Lake Substation was ruled out since its location would require construction of a number of feeders to pickup the existing distribution feeders around Quartzite Substation.

Vanier Substation is located in the northern end of the town. Sufficient vacant land surrounds the substation, and the required amount of line construction to connect the feeders is minimal. is strategically located in relatively close proximity to where the new hospital and college are being proposed, and the substation is situated relatively close to several of the system feeders (L6, L15, and L18). In order to pick up these lines the substation will have to be expanded. The substation was constructed in the mid 1990s, and the low voltage buswork is insulated for 25 kV (to be confirmed in the field), the reclosers in the substation have a maximum rated voltage of 15 kV and are capable of operating at 12.5 kV. A conversion to 25 kV would require installation of new switchgear and power transformers as well as expanding this substation. The existing 15 kV switchgear could possibly be reused at another location.

The Quartzite Substation is located in an area just to the west of town. The substation yard was recently expanded and is surrounded by a large tract of undeveloped lands. If necessary, more lands can be acquired to expand the substation. Quartzite Substation is also situated close to areas of expected growth. The undeveloped land in this area is zoned for residential development, and subdivision developments have been proposed on this land. In the Harrie Lake Trailer Park, a mini-home subdivision development is underway, and IOCC has proposed to construct a 300-person bunkhouse there as well.

This part of Harrie Lake is fed from Quartzite feeder L14. The substation connects six distribution feeders (L6, L7, L8, L12, L13, and L14) and is located in a good area to serve new loads arising from residential developments. Most of the equipment in this substation was originally installed by IOCC. There are two metal clad 4.16 kV switchgear buildings. These are filled to capacity, and due to the lack of available breaker space, a considerable amount of work would be required to bring additional 4.16 kV feeders out of the substation. A conversion to 25 kV would require a complete rebuild of this substation and replacement of the 4.16 kV switchgear. However, given the existing 4.16 kV equipment is in excess of 30 years old, and it will soon be reaching the age of obsolescence. The operations personnel have had trouble racking the breakers into the switchgear bays. A rebuild of this substation was likely to have occurred in the near future. Based on the location, the existing feeder infrastructure already around the substation, and the fact that it would likely have required major work in the near future anyway, the Quartzite Substation was selected as one of the stations to retain in the 25 kV upgrading plan.

The Bartlett Substation is located centrally in the town; therefore, it is located suitably to supply a large portion of the central part of town. Bartlett Substation was rebuilt in the mid 1990s and at that time the yard was expanded as part of the original 1992 12.5 kV Upgrading Plan. Also installed at the time was metal clad switchgear rated for operation at 12.5 kV. This substation connects five distribution feeders (L1, L2, L3, L4, and L5) and there are already a number of tie points available, which allow picking up most of the town distribution feeders. A conversion to 25 kV would require a complete rebuild or the removal of this substation. Its location in a built up area of the town however does not allow much space for bringing feeders into new areas of development. Any additions to the system near the Bartlett Substation would have to be accommodated on the existing feeders.

The Townsite Switching Station is located on the southeastern edge of the town. This station is a switching center that provides sectionalizing of each the of the 46 kV subtransmission lines supplying the substations. There are sufficient lands surrounding this station to allow its expansion. The station does not connect any 4.16 kV distribution feeders, however much of the remaining lands around the Labrador City Industrial Park are situated around, or close to the Townsite Switching Center. Some load growth is expected to occur in the industrial park. There should be right-of-ways to allow for connection into the existing nearby feeders. This station is one of the older stations in the system and like the Quartzite Substation; it will soon be due for a major overhaul. A considerable amount of civil work and feeder construction would be required to upgrade the station to accommodate the power transformers and switchgear.

Based on the above information the Vanier and Quartzite Substations were selected as the optimal locations to retain for conversion to 25 kV. These locations will provide the greatest flexibility for system operation, and for future system expansion.

As was discussed previously in Section 3.1.7, 15/20/25 MVA 46/25 kV power transformers would be of suitable size for a two-substation system. This should leave

sufficient capacity to supply the system with the largest transformer out of service. With the system load carried between two substations, voltage regulation on the high voltage (46kV) distribution system may be of concern during contingency. Therefore, the substation power transformers should be equipped with on load tap changers (OLTCs) on the high voltage winding. The on load tap changer should be designed to regulate from a minimum voltage of 39.1 kV (15 % boost) to a maximum voltage of 48.3 kV (5 % buck) in thirty-three tap positions.

4.2 SUBTRANSMISSION SYSTEM

At present the 46 kV Subtransmission System is radial. In the present configuration the loss of a line results in the loss of at least an entire substation.

For the loss of a single substation in Labrador City based on the 2007 forecasted system peak of 51089 kW and a two substation system, the maximum acceptable downtime based on the unsupplied energy criteria would be 1.4 days.

As a side note, for the current system, for the loss of supply from the Townsite Switching Center or feeder L32 then the maximum acceptable downtime based on the unsupplied energy criteria is 16 hours.

In such a case the duration of the outage depends on the nature of the problem and the time it will take operations crews to make the necessary repairs. For a major component failure, the acceptable downtimes based on the unsupplied energy criteria will be violated. Therefore other measures are necessary to ensure that power can be restored to customers within an acceptable timeframe.

A 46 kV tie line will be connected between the substations so that an alternate supply is available to each substation. If the main supply to a particular substation is unavailable, then the substation can be fed from the alternate line. This will prevent or minimize outages to customers and allow operations crews to prioritize repairs.

The layout of the current system provides opportunities for low cost construction of a looped subtransmission system. Specifically 46 kV feeders L33 and L9 form a quasi-loop that surrounds Labrador City. The Vanier Substation and the Quartzite Substation are located less than 500 m from this loop. Therefore the time to restore substation power at the Vanier and Quartzite substations can be improved by construction of new 46 kV taps off of L33, and L9. A tap from L33 to Vanier Substation would be approximately 450 m long. The same can be accomplished at Quartzite Substation with construction of a 300 m tap from L9. L9 would be opened between the new tap and the existing tap to the station and the original tap would be connected to L33. Breakers will be installed at the line terminations in each substation to provide sectionalizing and protection from faults. This would turn the section of L33 between Vanier and Quartzite Substations into a 46 kV tie line.

Due to high ground impedance and low line-to-ground fault levels, the subtransmission system will be operated as an open loop. This is to ensure that line to ground faults can be properly detected and cleared. The section of L33 which runs from Vanier Substation to Fermont will be energized from Vanier Substation via a normally-closed breaker. A normally-open breaker installed at the line termination in Quartzite Substation will provide means for an alternate supply from L33.

Since two 46 kV feeders are available (L32, and L33) from Wabush Terminal Station, it would no longer be necessary to retain the Townsite Switching Station.

Under normal conditions each substation will be fed by a separate line. When either L32 or L33 is unavailable the tie line will be used to supply both substations through the remaining line.

4.3 FINAL 25 KV DISTRIBUTION SYSTEM

Based on the above information, the new 25 kV distribution system will consist of two 46 kV subtransmission lines, two 46/25 kV substations, and nine 25 kV distribution feeders. A simplified single line diagram of the proposed distribution system is shown in Appendix D1.

Subtransmission lines L32, and L33 from Wabush Terminal Station will be the primary supply to the 25 kV distribution system. L32 will run to the Quartzite Substation, L33 will run to the Vanier Substation. A 46 kV subtransmission tie line will be connected between the two substations. The tie line will also be available for supply to Fermont in an emergency. For improved fault protection and reliability, a 46 kV breaker will be installed at the termination of each subtransmission line. A simplified single line diagram of the proposed subtransmission system is shown in Appendix D2.

The Vanier Substation and the Quartzite Substation will step the voltage down from 46 kV the 25 kV. Each substation is to consist of a 46 kV load transfer bus, two 15/20/25 MVA 46/25 kV power transformers with on load tap changers, and two 25 kV load transfer buses. Each 25 kV bus will have space for up to three 25 kV breakers. A total of nine 25 kV distribution feeders are required. It is expected that more load growth would occur near the Quartzite Substation then the Vanier Substation. Therefore, four 25 kV distribution feeders will be connected to the Quartzite Substation, and the remaining five will be connected to the Vanier Substation. As a provision for future expansion, two 25 kV breaker bays will be available at Quartzite Substation, and one additional 25 kV breaker bay for will be available at Vanier Substation. A simplified single line diagram of the proposed 25 kV Quartzite Substation is shown in Appendix D3. A simplified single line diagram of the proposed 25 kV Vanier Substation is shown in Appendix D4.

All 4.16 kV feeders (with the exception of the Smokey Mountain Line) will be upgraded to 25 kV nominal system voltage. It is recommended that existing 4.16 kV primary

services, underground services, and pad-mounted transformers be supplied by overhead step-down transformers. This should be less costly than replacing these services with overhead services.

A general scope of work for this project is defined in Appendix E. The work involves upgrades at the Vanier Substation and the Quartzite Substation, the conversion of the 4.16 kV distribution feeders to 25 kV, and the upgrading of the 46 kV subtransmission system to an open looped system for improved reliability and operational flexibility.

4.4 LOAD FLOW ANALYSIS - 2027 LOAD FORECAST

Load Flow Analysis was ran to determine the ability of the proposed 25 kV system to accommodate future load growth. The study assumes that substation power transformer OLTCs are set to regulate the voltage at the 25 kV bus to 102.5 % within a 2.5 % bandwidth. Complete model proofing has yet to be completed since Load and Voltage Study data must first be collected. Load and Voltage data will be acquired in the winter of 2008. Model data is currently based on studies more than ten years old, along with (incomplete) pole line drawings, and semi-monthly breaker readings. Caution must be used when drawing conclusions from the load flow results. However the results should provide a reasonable picture of how the proposed system should behave.

Table 16: 25 kV Plan - Feeder Current - 2027 Forecasted Peak Load

Name	|Ia|	|Ib|	|Ic|	|Iavg|	%IU
QZ8	119	109	134	121	10.8%
QZ12	127	156	149	144	11.7%
QZ13	149	131	142	140	7.0%
QZ14	110	130	142	128	13.7%
VA15	125	143	129	132	8.2%
VA18	147	160	119	142	16.3%
VA21	130	153	132	138	10.4%
VA22	146	122	150	139	12.1%
VA23	129	139	142	137	5.6%
WA32	306	295	312	304	3.1%
WA33	379	401	389	390	2.9%
VA33	2	2	2	2	0.0%

Table 17: 25 kV Plan - Worst Case Feeder Voltage - 2027 Forecasted Peak Load

Feeder	V_{MIN}	$V_{MIN\ (120\ Vbase)}$
WBH-B15	101.2%	121.5
QZ-B3	100.1%	120.1
QZ12	101.6%	121.9
QZ13	101.0%	121.2
QZ14	101.1%	121.3
VA-B3	100.1%	120.1
VA15	100.2%	120.2
VA18	100.8%	121.0
VA21	101.2%	121.4
VA22	101.6%	121.9
VA23	100.1%	120.2

Table 18: 25 kV Plan - Transformer Load - 2027 Forecasted Peak Load

Unit	P (MW)	S (MVA)
QZ-T1	12.4	12.7
QZ-T2	18.1	18.5
VA-T1	12.0	12.2
VA-T2	11.8	12.1

With the distribution system upgraded to 25 kV, the system losses at 54718 kW are 695 kW. This represents a savings of approximately 1100 kW over the 4.16 kV distribution system. The saved losses on the distribution system will in turn result in loss savings on the transmission system. While cost of losses are low in interconnected Labrador, they power can generate revenues in the form of recall sales.

4.5 CONTINGENCY ANALYSIS

A contingency analysis was performed to verify the system meets all required criteria under contingency. The main contingencies considered for analysis are for the loss of a subtransmission line, loss of the largest power transformer, and the loss of a feeder recloser. While there are many different possible cases for each contingency, a single case was modeled that is representative of worst case conditions. All the analysis below were conducted with the system load scaled to the 2027 forecasted peak of 54718 kW and the bus voltage at Wabush Terminal Station set to 1.013 per unit. The transformer OLTCs are set to regulate the voltage to 1.025 per unit with a 2.5 per unit bandwidth.

4.5.1 LOSS OF A SUBTRANSMISSION LINE

Load flow analysis was conducted to verify the behavior of the system with a subtransmission line out of service. For the loss of the main subtransmission line to either substation, the substation that is out of service can be alternately fed from the remaining substation via the tie line. The worst case for loss of a subtransmission line would be loss of L33 from Wabush Terminal Station. For this case the Vanier Substation would be alternately supplied via the tie line from Quartzite Substation. For this case the Vanier Substation is approximately 11 km (electrically) from Wabush Terminal Station. Since Vanier Substation will have five feeders and Quartzite Substation will have four feeders, it is expected that more of the load will be towards the end of the line. The results of the load flows are shown in Table 19, Table 20, and Table 21 below.

Table 19: Contingency - 25 kV Plan - Feeder Current - L33 Out of Service

Name	|Ia|	|Ib|	|Ic|	|Iavg|	%IU
QZ8	122	112	137	124	10.8%
QZ12	130	160	153	148	11.8%
QZ13	153	134	145	144	6.9%
QZ14	113	134	146	131	13.8%
VA15	124	142	126	130	8.8%
VA18	151	164	122	146	16.2%
VA21	134	158	137	143	10.4%
VA22	150	126	155	144	12.0%
VA23	132	143	146	140	5.7%
WA32	705	717	721	714	1.3%
WA33	0	0	0	0	-
VA33	394	417	404	405	3.0%

Table 20: Contingency - 25 kV Plan - Feeder Voltage - L33 Out of Service

Feeder	V_{MIN}	$V_{MIN\ (120\ Vbase)}$
WBH-B15	101.2%	121.5
QZ-B3	98.2%	117.8
QZ8	101.3%	121.5
QZ12	101.6%	121.9
QZ13	101.0%	121.2
QZ14	101.1%	121.3
VA-B3	96.3%	115.5
VA15	100.2%	120.2
VA18	100.8%	121.0
VA21	101.2%	121.4
VA22	101.6%	121.9
VA23	100.1%	120.2

Table 21: Contingency - 25 kV Plan - Transformer Load - L33 Out of Service

Unit	P (MW)	S (MVA)
QZ-T1	12.0	12.2
QZ-T2	11.8	12.1
VA-T1	18.1	18.5
VA-T2	12.4	12.7

As the results in Table 19, Table 20, and Table 21 above show, there are no expected adverse impacts if a main subtransmission line were the go out of service.

During peak, the load will exceed the capacity of the 266.8 ACSR conductor section of L32 (formerly L9). Therefore, approximately 4.5 km of L32 will have to be reconductored to 477 ASC Cosmos.

4.5.2 LOSS OF A TRANSFORMER

This case models the system behavior with the largest transformer out of service. Load flows were run to determine the effect of feeder switching operations on line loading and voltage. Since all transformers for the proposed system are to be the same size, the contingency analysis was conducted with the most heavily loaded unit out of service. For the case of the loss of the largest transformer in the system the following procedure is to apply. The damaged transformer is isolated from the rest of the system. Transfer one feeder from the failed unit to another substation via a tie switch. Close the bus tie breaker to restore power to the remaining feeders. If cold load pickup is believed to be of concern, then sectionalized switching is to be applied. For this case VA-T1 has failed. Feeder VA23 has been transferred to feeder QZ8 via tie switch QZ6-D4, and bus tie breaker VA-B1B2 has been closed. The results of the load flows are shown in Table 22, Table 23 and Table 24 below.

Table 22: Contingency - 25 kV Plan - Feeder Current –VA-T1 Out of Service

Name	|Ia|	|Ib|	|Ic|	|Iavg|	%IU
QZ8	256	255	285	265	7.3%
QZ12	131	161	154	149	11.8%
QZ13	153	134	145	144	7.0%
QZ14	113	134	146	131	13.7%
VA15	122	140	124	129	8.7%
VA18	149	162	120	144	16.3%
VA21	132	156	134	141	10.9%
VA22	148	125	152	142	11.6%
VA23	0	0	0	0	-
WA32	386	374	396	385	2.9%
WA33	158	156	157	157	0.7%
VA33	2	2	2	2	0.1%

Table 23: Contingency - 25 kV Plan - Feeder Voltage – VA-T1 Out of Service

Feeder	V_{MIN}	$V_{MIN\ (120\ Vbase)}$
WBH-B15	101.2%	121.5
QZ-B3	99.7%	119.6
QZ8	100.5%	120.6
QZ12	101.2%	121.4
QZ13	101.1%	121.4
QZ14	101.3%	121.6
VA-B3	100.2%	120.3
VA15	101.6%	121.9
VA18	102.3%	122.7
VA21	101.4%	121.7
VA22	102.7%	123.2
VA23	100.3%	120.3

Table 24: Contingency - 25 kV Plan - Transformer Load – VA-T1 Out of Service

Unit	P (MW)	S (MVA)
QZ-T1	12.0	12.2
QZ-T2	18.0	18.4
VA-T1	0.0	0.0
VA-T2	12.4	12.7

4.5.3 LOSS OF A RECLOSER

A recloser failure will result in a feeder being transferred to another line. This effectively doubles the load on that line as well as increases its length. Load flows were run to determine the effect of feeder switching operations on line loading and voltage. As a typical case the load and voltages are shown for feeder VA21 transferred to feeder VA18. The results of the load flows are shown in Table 25, Table 26, and Table 27 below.

Table 25: Contingency - 25 kV Plan - Feeder Current – VA21-R1 Out of Service

Name	|Ia|	|Ib|	|Ic|	|Iavg|	%IU
QZ8	121	111	136	123	10.8%
QZ12	130	159	152	147	11.7%
QZ13	152	133	145	143	7.0%
QZ14	112	133	145	130	13.7%
VA15	123	142	125	130	8.9%
VA18	285	323	258	289	12.0%
VA21	0	0	0	0	-
VA22	149	125	153	142	12.1%
VA23	132	143	145	140	5.7%
WA32	306	295	312	304	3.1%
WA33	382	406	392	393	3.2%
VA33	2	2	2	2	0.1%

Table 26: Contingency - 25 kV Plan - Feeder Voltage - VA21-R1 Out of Service

Feeder	V_{MIN}	$V_{MIN\ (120\ Vbase)}$
WBH-B15	101.2%	121.5
QZ-B3	100.1%	120.1
QZ8	101.9%	122.2
QZ12	102.2%	122.7
QZ13	101.6%	121.9
QZ14	101.7%	122.1
VA-B3	100.0%	120.0
VA15	100.4%	120.5
VA18	101.2%	121.4
VA21	99.8%	119.7
VA22	102.1%	122.5
VA23	100.4%	120.5

Table 27: Contingency - 25 kV Plan - Transformer Load - VA21-R1 Out of Service

Unit	P (MW)	S (MVA)
QZ-T1	12.0	12.2
QZ-T2	11.8	12.1
VA-T1	24.3	25.1
VA-T2	6.2	6.3

5 2007 LABRADOR CITY 12.5 KV UPGRADING PLAN

The presence of infrastructure within the current system warrants the consideration of a 12.5 kV upgrading plan. The existing system infrastructure includes 15 kV switchgear located at Bartlett and Vanier Substations, a 46/12.5-4.16 kV power transformer is located at Quartzite Substation, and there are a number of dual-voltage (7200-2400 V primary) distribution transformers installed throughout the distribution system. The 2007 12.5 kV upgrading plan for Labrador City will upgrade the system utilizing some of the existing infrastructure such that load growth is addressed to well beyond the planning horizon.

Recognizing that a 12.5 kV feeder can safely carry much more power than a 4.16 kV feeder the number of substations in the system can be reduced.

Using the criteria noted in Section 3.1.2, the initial feeder current will be 140 A. Therefore the average 12.5 kV feeder capacity will be, 12.5 kV * 140 A * $\sqrt{3} \approx 3000$ kVA under normal operating conditions. Under abnormal operating conditions (recloser failure for instance) the expected feeder load will be approximately 6000 kVA or twice the normal feeder load.

The forecasted peak load for 2007 is 51089 kW, assuming a system power factor of 0.99 lagging over peak, the required number of feeders are:

$$N = \frac{51089\,\text{kW}}{0.99 \times 3000\,\text{kVA}} = 17$$

Therefore, at least seventeen feeders are required operating at 12.5 kV to supply the system.

5.1 SUBSTATIONS

Allowing for six feeders per substation, then in total three substations will be required for a 12.5 kV Labrador City Distribution System.

The switchgear installations at the Bartlett and Vanier Substations are rated at 15 kV. Therefore, they could easily be converted to operate at 12.5 kV.

In terms of strategic location, the Vanier Substation is located in relatively close proximity to where new hospital and college infrastructure are being planned. In addition to the feeders connected to the substation (L21, L22, and L23), it is situated relatively close to several of the system feeders (L6, L15, and L18). The substation will have to be expanded to pick up these feeders; however, only about 500 m of line construction is necessary to tie into these feeders. This substation would be converted

to a 12.5 kV substation because of its existing infrastructure, space for expansion, and strategic location.

The Bartlett Substation connects six distribution feeders (L1, L2, L3, L4, L5, and L17. The substation is located in the center of town and there are already a considerable number of tie points available, which allow picking up most of the town distribution from the substation. The Bartlett Substation would also be converted to 12.5 kV since upgrading costs would be reduced because of the existing infrastructure located at this substation, and its central location.

Of the remaining stations, the Quartzite Substation is best suited for a conversion to 12.5 kV. The substation is located on the Western Side of town and connects six distribution feeders (L6, L7, L8, L12, L13, and L14). The location is situated in close proximity to expected areas of residential development. One of the power transformers at this substation is a dual voltage unit capable of operating at 12.5 kV. There is no other equipment in this substation capable of operating at 12.5 kV, however the existing 4.16 kV equipment is rather old and will soon be reaching the age of obsolescence. Therefore given that the substation is in a strategic location and will be due for an upgrade soon, it is proposed that this be the third substation for the 12.5 kV upgrade.

As was discussed previously in the Section 3.1.6, a 10/13.3/16.7 MVA power transformer would be of suitable size for a three-substation system. This should leave sufficient capacity to supply the system with the largest transformer out of service. With the load shared relatively evenly between three substations, voltage regulation on the high voltage (46kV) distribution system is not expected to be of concern. Therefore, standard fixed taps (±5 % in 2.5 % per step) will be suitable for these units. Since the plan proposes to upgrade the system to what not an NLH standard distribution voltage the transformers should have dual low voltage windings to allow operation at both 12.5 kV and 25 kV. This will provide the provision for a future conversion to 25 kV should there be higher than expected load growth.

The time to restore substation power at the Vanier and Quartzite substations can be improved by construction of new 46 kV taps off of L33, and L9. A tap from L33 to Vanier Substation would be approximately 450 m long creating a 46 kV loop to that substation. The same can be accomplished at Quartzite with construction of a 300 m tap from L9 to the substation. L9 would be opened between the new tap and the existing tap to the substation and the old tap would be supplied from L33. The difficult part comes with getting a second 46 kV tap between Bartlett Substation and one of the other substations as this region of the system is already built up.

Retaining three stations in this system will require retention of the Townsite Switching Substation since only two lines come from Wabush Terminal Station and three circuits are required. The present load-transfer-bus configuration with a single primary feeder and an emergency feeder that must be tied in manually is unsuitable by today's standards from both a voltage regulation, security of supply, and operability point of view. In order to address these issues to a reasonable degree, the Townsite Switching

Station will be reconstructed as a ring bus. A ring bus will provide the required level of reliability for a looped system of this size and improve voltage regulation between Wabush Terminal Station and Townsite Switching Station. The ring bus arrangement may however prove to be costly due to the breaker requirement. A less costly alternative to rebuilding the Townsite Switching Station is to construct a third 46 kV feeder (assuming sufficient space is available) from Wabush Terminal Station to Townsite Switching Station. The line would be approximately 1.75 km long and constructed of 477 ASC Cosmos conductor. If this option is a viable one, the switching station could then be removed, and the three substations would be supplied by three 46 kV subtransmission lines from Wabush Terminal Station.

5.2 SUBTRANSMISSION SYSTEM

At present the 46 kV Subtransmission System is radial. In the present configuration the loss of a line results in the loss of at least an entire substation.

For the loss of a single substation in Labrador City based on the 2007 forecasted system peak of 51089 kW and a three substation system, then for the loss of a single substation the maximum acceptable downtime based on the unsupplied energy criteria would be two days.

As a side note, for the current system, for the loss of supply from the Townsite Switching Center or feeder L32 then the maximum acceptable downtime based on the unsupplied energy criteria is 16 hours.

In such a case the duration of the outage depends on the nature of the problem and the time it will take operations crews to make the necessary repairs. For a major component failure, the acceptable downtimes based on the unsupplied energy criteria will likely be violated. Therefore other measures are necessary to ensure that power can be restored to customers within an acceptable timeframe.

A 46 kV tie line will be connected between the substations to bring an alternate supply to each substation. If the main supply to a particular substation is unavailable, then the substation can be fed through the alternate line. This will prevent or minimize outages to customers and allow operations crews to prioritize repairs.

The layout of the current system provides opportunities for construction of a looped subtransmission system. Specifically 46 kV feeders L33 and L9 form a quasi-loop around the system. The Vanier and Quartzite substations are located less than 500 m from this loop. Therefore the time to restore substation power at the Vanier and Quartzite substations can be improved by construction of new 46 kV taps off of L33, and L9. A tap from L33 to Vanier Substation would be approximately 450 m long and create a 46 kV tie line to that substation. The same can be accomplished at Quartzite with construction of a 300 m tap from L9 to the substation. L9 would be opened between the new tap and the existing tap to the substation and the old tap would be supplied from

L33. The final tie line will be constructed between Bartlett and Vanier Substations. The exact routing of the line is yet to be determined; however the distance is estimated to be 1.25 km. Breakers will be installed at the line terminations in each substation to provide sectionalizing and protection from faults. Due to high ground impedance and low line-to-ground fault levels, the subtransmission system will be operated as an open loop. The Vanier-Quartzite tie line will be energized from Vanier Substation via a normally-closed breaker. A normally-open breaker installed at Quartzite Substation will provide means for an alternate supply from L33. The Bartlett-Vanier tie line will be energized from Bartlett Substation and connected to Vanier Substation via a normally-open breaker.

Three 46 kV feeders are required to supply the three 46/12.5 kV substations. Since two 46 kV feeders are available (L32, and L33) from WBH, it will be necessary to retain the Townsite Switching Station. 46 kV feeders L32 and L33 will operate in parallel to supply the Townsite Switching Station. The Townsite Switching Station will serve as the primary point of supply for the Bartlett, Vanier, and Quartzite Substations. Note it may be possible to eliminate the need for a switching station if a third circuit can be constructed from Wabush Terminal Station to the Townsite Switching Station. The viability of this option will require field verification to determine that sufficient right-of-way is available for a third line.

Under normal conditions each substation will be fed by a separate line. When either of the main lines is unavailable, the tie line will be used to supply two substations through the remaining line.

5.3 FINAL 12.5 KV DISTRIBUTION SYSTEM

Based on the above information, the new 12.5 kV distribution system will consist of five 46 kV subtransmission lines, a 46 kV ring bus, three 46/12.5 kV substations, and seventeen 12.5 kV distribution feeders. All construction and equipment for the 12.5 kV plan is to be compatible with 25 kV standards. A simplified single line diagram of the proposed distribution system is shown in Appendix F1.

Subtransmission lines WA32, and WA33 from Wabush Terminal Station will be the primary supply to the 46 kV ring bus at the Townsite Switching Station. A single line diagram of the proposed new Townsite Switching Station is shown in Appendix F2. The ring bus will supply three 46 kV subtransmission lines TS9, TS10, and TS33. TS9 supplies the Quartzite Substation, TS10 supplies the Bartlett Substation, and TS33 supplies the Vanier Substation. A 46 kV subtransmission tie line will be connected between the Vanier Substation and the Quartzite Substation. This tie line will also be available for emergency supply to Fermont. A second 46 kV tie line will be connected between the Bartlett Substation and the Vanier Substation. For improved fault protection and reliability, a 46 kV breaker will be installed at the termination of each subtransmission line. A simplified single line diagram of the proposed subtransmission system is shown in Appendix F3.

If a 3rd circuit can be constructed from Wabush Terminal Station and the Townsite Switching Station, then the ring bus will not be necessary. Then, the Townsite Switching Station can be removed. This would be a considerable cost savings for the 12.5 kV upgrading plan. It will be necessary to verify that enough space is in the existing corridor for an additional circuit.

The Bartlett Substation, the Vanier Substation, and the Quartzite Substation will step the subtransmission voltage down from 46 kV the 12.5 kV. Each substation is to consist of a 46 kV load transfer bus, two 10/13/16 MVA 46/25-12.5 kV power transformers with on load tap changers, and two 12.5 kV load transfer buses. Each 12.5 kV bus will have space for up to three 12.5 kV breakers.

A total of seventeen 12.5 kV distribution feeders are required. Therefore, six distribution feeders will be connected to each of the Bartlett Substation, and the Quartzite Substation, and the remaining five distribution feeders will be connected to the Vanier Substation. Simplified single line diagrams of the proposed 12.5 kV Bartlett Substation, the proposed 12.5 kV Quartzite Substation, and the proposed 12.5 kV Vanier Substation is shown in Appendices F4, F5, and F6 respectively.

All 4.16 kV feeders (with the exception of the Smokey Mountain Line) will be upgraded to 12.5 kV nominal system voltage. It is recommended that existing 4.16 kV primary services, underground services, and pad-mounted transformers be supplied by overhead step-down transformers. This should be less costly than replacing these services with overhead services.

A general scope of work for this project is defined in Appendix G. The work involves upgrades at the Bartlett Substation, the Vanier Substation, and the Quartzite Substation, the conversion of the 4.16 kV distribution feeders to 12.5 kV, and the upgrading of the 46 kV subtransmission system to an open looped system for improved reliability and operational flexibility.

5.4 LOAD FLOW ANALYSIS - 2027 LOAD FORECAST

Load Flow Analysis was ran to determine the ability of the proposed 12.5 kV system to accommodate future load growth. The study assumes that substation power transformers are set nominal taps. Complete model proofing has yet to be completed since Load and Voltage Study data must first be collected. Load and Voltage data will be acquired in the winter of 2008. Model data is currently based on studies more than ten years old, along with (incomplete) pole line drawings, and semi-monthly breaker readings. Caution must be used when drawing conclusions from the load flow results. However the results in Table 28, Table 29, and Table 30 should provide a reasonable picture of the expected behavior of the proposed system.

Table 28: 12.5 kV Plan - Feeder Current - 2027 Forecasted Peak Load

Name	|Ia|	|Ib|	|Ic|	|Iavg|	%IU
WA32	343	349	352	348	1.4%
WA33	341	347	350	346	1.4%
TS9	248	242	259	250	3.6%
TS10	231	251	241	241	4.1%
TS33	206	203	204	204	0.9%
BA1	108	165	183	152	28.9%
BA2	170	144	129	148	15.1%
BA3	118	134	138	130	9.4%
BA4	189	196	117	167	29.9%
BA5	155	129	162	149	13.5%
BA17	127	174	130	144	21.2%
QZ6	136	157	173	155	12.4%
QZ7	131	164	147	147	11.2%
QZ8	156	136	153	148	8.2%
QZ12	98	161	172	144	31.9%
QZ13	175	160	142	159	10.9%
QZ14	162	150	192	168	14.4%
VA15	163	148	151	154	5.9%
VA18	138	170	154	154	10.5%
VA21	148	165	145	153	7.9%
VA22	180	144	170	165	12.6%
VA23	128	113	145	129	12.6%

As shown in Table 28 there are no expected overloads on any system feeders. The analysis does indicate load unbalance on some distribution feeders. Therefore, it may be necessary to initiate load rebalancing as part of the feeder reconfigurations.

Table 29: 12.5 kV Plan - Feeder Voltage - 2027 Forecasted Peak Load

Feeder	V_{MIN}	$V_{MIN\ (120\ Vbase)}$
BA1	98.5%	118.2
BA2	98.8%	118.5
BA3	98.9%	118.7
BA4	97.3%	116.7
BA5	98.1%	117.7
BA17	98.1%	117.7
QZ6	97.7%	117.2
QZ7	97.4%	116.9
QZ8	97.7%	117.3
QZ12	97.8%	117.4
QZ13	97.7%	117.3
QZ14	96.6%	115.9
VA15	98.3%	118.0
VA18	98.8%	118.6
VA21	97.3%	116.7
VA22	99.1%	118.9
VA23	98.5%	118.2

Table 29 show voltages are within tolerance, although at the lower end of the acceptable range. By 2027 voltages at the end of feeder QZ14 could be just below 96.7 %. This will probably be improved by a program of load rebalancing. However, given that most voltages are in the lower range, it is recommended that the substation power transformers be operated in 2.5 % boost; this will ensure voltages remain within standard to well beyond the planning horizon.

Table 30: 12.5 kV Plan - Transformer Load - 2027 Forecasted Peak Load

Unit	P (MW)	S (MVA)
BA-T1	9.2	9.4
BA-T2	9.7	9.9
QZ-T1	9.9	10.2
QZ-T2	9.5	9.7
VA-T1	6.8	6.9
VA-T2	9.3	9.5

Table 30 shows the substation power transformers will be loaded to base ratings. No problems are expected.

With the distribution system upgraded to 12.5 kV, the system losses at 54718 kW are 733 kW. This represents a savings of approximately 1100 kW over the 4.16 kV distribution system. The saved losses on the distribution system will in turn result in loss savings on the transmission system. While cost of losses are low in interconnected Labrador, they power can generate revenues in the form of recall sales.

5.5 CONTINGENCY ANALYSIS

A contingency analysis was performed to verify the system meets all required criteria under contingency. The main contingencies considered for analysis are for the loss of a subtransmission line, loss of the largest power transformer, and the loss of a feeder breaker. While there are many different possible cases for each contingency, a single case was modeled that is representative of worst case conditions. All the analysis below were conducted with the system load scaled to the 2027 forecasted peak of 54718 kW and the bus voltage at Wabush Terminal Station set to 1.013 per unit. The substation power transformer fixed taps were set to boost the voltage by 2.5 %.

5.5.1 LOSS OF A SUBTRANSMISSION LINE

Load flow analysis was conducted to verify the behavior of the system with a subtransmission line out of service. For the loss of the main subtransmission line to either substation, the substation that is out of service can be alternately fed from the remaining substation via the tie line. The worst case for loss of a subtransmission line would be loss of TS9 from Townsite Switching Station. For this case the Quartzite Substation would be alternately supplied via the tie line from Vanier Substation VA33. For this case the Quartzite Substation is approximately 10 km (electrically) from Wabush Terminal Station. Since Vanier Substation will have five feeders and Quartzite Substation will have six feeders, it is expected that more of the load will be towards the end of the line. The results of the load flows are shown in Table 31, Table 32, and Table 33 below.

Table 31: Contingency - 12.5 kV Plan - Feeder Current – L9 Out of Service

Name	I(a)	I(b)	I(c)	|Iavg|	%IU
WA32	345	350	354	350	1.4%
WA33	343	348	352	348	1.4%
TS9	0	0	0	0	-
TS10	231	250	241	241	4.0%
TS33	457	448	465	457	1.9%
BA10	0	0	0	0	0.1%
VA33	250	244	261	252	3.6%
BA1	105	161	178	148	28.9%
BA2	166	140	126	144	15.1%
BA3	115	131	135	127	9.4%
BA4	184	191	114	163	29.9%
BA5	151	125	158	145	13.5%
BA17	124	170	126	140	21.2%
QZ6	134	154	170	153	12.4%
QZ7	129	161	145	145	11.2%
QZ8	153	134	150	146	8.3%
QZ12	96	159	169	141	31.9%
QZ13	173	157	139	156	10.8%
QZ14	159	148	189	165	14.4%
VA15	160	145	147	151	5.9%
VA18	135	166	151	151	10.5%
VA21	145	161	142	149	7.8%
VA22	176	141	166	161	12.6%
VA23	125	111	142	126	12.6%

As shown in Table 31, there are no expected overloads on any system feeders or subtransmission lines with a subtransmission line out of service.

Table 32: Contingency - 12.5 kV Plan - Feeder Voltage - L9 Out of Service

Feeder	V_{MIN}	$V_{MIN\ (120\ Vbase)}$
BA1	101.1%	121.4
BA2	101.4%	121.7
BA3	101.5%	121.8
BA4	100.0%	120.0
BA5	100.8%	120.9
BA17	100.8%	120.9
QZ6	99.2%	119.0
QZ7	99.0%	118.9
QZ8	99.2%	119.1
QZ12	99.3%	119.2
QZ13	99.2%	119.1
QZ14	98.1%	117.7
VA15	100.5%	120.6
VA18	101.0%	121.2
VA21	96.8%	116.2
VA22	101.3%	121.5
VA23	100.7%	120.8

Table 32 shows that with a subtransmission line out of service, and the transformers in 2.5 % boost; voltages should remain within tolerance for the foreseeable future.

Table 33: Contingency - 12.5 kV Plan - Transformer Load - L9 Out of Service

Unit	P (MW)	S (MVA)
BA-T1	9.2	9.3
BA-T2	9.7	9.9
QZ-T1	9.9	10.1
QZ-T2	9.5	9.7
VA-T1	6.8	6.9
VA-T2	9.3	9.5

Table 33 shows the substation power transformers will be loaded to base ratings. No problems are expected.

As the results in Table 31, Table 32, and Table 33 above show, there are no expected adverse impacts if a main subtransmission line were to go out of service.

5.5.2 LOSS OF A TRANSFORMER

This case models the system behavior with the largest transformer out of service. Load flows were run to determine the effect of feeder switching operations on line loading and voltage. Since all transformers for the proposed system are to be the same size, the contingency analysis was conducted with the most heavily loaded unit out of service. For the case of the loss of the largest transformer in the system the following procedure is to apply. The damaged transformer is isolated from the rest of the system. Transfer one feeder from the failed unit to another substation via a tie switch. Close the bus tie breaker to restore power to the remaining feeders. If cold load pickup is believed to be of concern, then sectionalized switching is to be applied. For this case QZ-T1 has failed. Feeder QZ6 has been transferred to feeder VA15 via tie switch QZ6HU18-1, and bus tie breaker QZ-B1B2 has been closed. The results of the load flows are shown in Table 34, Table 35 and Table 36 below.

Table 34: Contingency - 12.5 kV Plan - Feeder Current – QZ-T1 Out of Service

Name	I(a)	I(b)	I(c)	|Iavg|	%IU
WA32	344	350	354	349	1.5%
WA33	342	348	352	347	1.5%
TS9	208	205	216	210	3.1%
TS10	231	250	241	241	4.0%
TS33	248	243	249	247	1.5%
BA10	0	0	0	0	0.1%
VA33	2	2	2	2	0.1%
BA1	105	161	178	148	28.9%
BA2	166	140	126	144	15.1%
BA3	115	131	135	127	9.4%
BA4	184	191	114	163	29.8%
BA5	151	125	158	145	13.5%
BA17	124	170	126	140	21.2%
QZ6	0	0	0	0	-
QZ7	129	161	145	145	11.3%
QZ8	153	134	151	146	8.2%
QZ12	96	159	169	142	31.9%
QZ13	173	157	139	156	10.9%
QZ14	159	148	189	165	14.4%
VA15	293	299	317	303	4.6%
VA18	135	167	151	151	10.5%
VA21	145	161	141	149	7.9%
VA22	175	140	166	160	12.6%
VA23	126	111	143	127	12.7%

As shown in Table 34, there are no expected overloads on any system feeders or subtransmission lines with a power transformer out of service.

Table 35: Contingency - 12.5 kV Plan - Feeder Voltage - QZ-T1 Out of Service

Feeder	V_{MIN}	$V_{MIN\ (120\ Vbase)}$
BA1	101.1%	121.4
BA2	101.4%	121.7
BA3	101.5%	121.8
BA4	100.0%	119.9
BA5	100.8%	120.9
BA17	100.8%	120.9
QZ6	100.1%	120.1
QZ7	98.9%	118.7
QZ8	99.1%	118.9
QZ12	99.3%	119.2
QZ13	99.2%	119.1
QZ14	98.1%	117.7
VA15	100.1%	120.1
VA18	100.7%	120.8
VA21	97.2%	116.6
VA22	101.6%	121.9
VA23	100.3%	120.4

Table 35 shows that with a power transformer out of service; voltages should remain within tolerance for the foreseeable future.

Table 36: Contingency - 12.5 kV Plan - Transformer Load - QZ-T1 Out of Service

Unit	P (MW)	S (MVA)
BA-T1	9.2	9.3
BA-T2	9.7	9.9
QZ-T1	0.0	0.0
QZ-T2	16.2	16.7
VA-T1	6.8	6.9
VA-T2	12.6	12.9

Table 36 shows that with transformer QZ-T1 out of service, transformer QZ-T2 will be loaded to 100 % of its nameplate rating over peak. The remaining units will be loaded to approximately base ratings. No problems are expected. There is sufficient capacity to carry the system through peak periods.

As the results in Table 34, Table 35, and Table 36 above show, there are no expected adverse impacts if a main power transformer were to go out of service.

5.5.3 LOSS OF A FEEDER BREAKER

A feeder breaker failure will result in a feeder being transferred to another line. This effectively doubles the load on that line as well as increases its length. Load flows were run to determine the effect of feeder switching operations on line loading and voltage. As a typical case, the load and voltages for a failure of feeder breaker QZ7-CB1 have been computed. For this case, feeder QZ7 is transferred to feeder VA22 by closing the disconnect QZ7-D2. The results of the load flows are shown in Table 37, Table 38, and Table 39 below.

Table 37: Contingency - 12.5 kV Plan - Feeder Current - QZ7-CB1 Out of Service

Name	|Ia|	|Ib|	|Ic|	|Iavg|	%IU
WA32	343	349	352	348	1.4%
WA33	341	347	350	346	1.4%
TS9	210	201	215	209	3.6%
TS10	231	250	241	241	4.0%
TS33	244	244	246	245	0.7%
BA10	0	0	0	0	0.1%
VA33	2	2	2	2	0.1%
BA1	105	161	178	148	28.9%
BA2	166	140	126	144	15.1%
BA3	115	131	135	127	9.4%
BA4	184	191	114	163	29.9%
BA5	151	125	158	145	13.5%
BA17	124	170	126	140	21.2%
QZ6	132	152	167	150	12.3%
QZ7	0	0	0	0	-
QZ8	151	131	148	143	8.3%
QZ12	95	157	167	140	31.9%
QZ13	171	155	138	155	10.9%
QZ14	157	146	187	163	14.3%
VA15	157	141	158	152	7.2%
VA18	134	166	150	150	10.5%
VA21	145	162	142	150	8.0%
VA22	304	303	310	306	1.4%
VA23	128	114	131	124	7.8%

As shown in Table 37, there are no expected overloads on any system feeders or subtransmission lines with a feeder breaker out of service.

Table 38: Contingency - 12.5 kV Plan - Feeder Voltage - QZ7-CB1 Out of Service

Feeder	V_{MIN}	$V_{MIN\ (120\ Vbase)}$
BA1	101.2%	121.4
BA17	100.8%	120.9
BA2	101.4%	121.7
BA3	101.5%	121.9
BA4	100.0%	120.0
BA5	100.8%	120.9
QZ12	100.6%	120.8
QZ13	100.5%	120.6
QZ14	99.4%	119.3
QZ6	101.0%	121.2
QZ7	98.7%	118.4
QZ8	101.1%	121.3
VA15	100.9%	121.1
VA18	101.4%	121.7
VA21	96.4%	115.7
VA22	100.8%	121.0
VA23	101.1%	121.3

Table 35 shows that with a feeder breaker out of service, and two feeders tied together; voltages should remain within tolerance for the foreseeable future.

Table 39: Contingency - 12.5 kV Plan - Transformer Load - QZ7-CB1 Out of Service

Unit	P (MW)	S (MVA)
BA-T1	9.2	9.3
BA-T2	9.7	9.9
QZ-T1	9.9	10.1
QZ-T2	6.4	6.5
VA-T1	9.9	10.1
VA-T2	9.3	9.5

Table 39 shows the substation power transformers will be loaded to base ratings. No problems are expected.

As the results in Table 37, Table 38, and Table 39 above show, there are no expected adverse impacts if a feeder breaker were to go out of service.

6 CONCLUSIONS AND RECOMMENDATIONS

The Labrador City Distribution System has generally performed well since it was taken over from IOCC in 1992. Initially, a voltage conversion to 12.5 kV for part of the system was being planned. However, lack load growth resulted in deferral of this plan. The 4.16 kV distribution systems were then redesigned to support a peak load of up to 52 MW.

Recent developments in Labrador West and a strengthening in world markets for iron ore have changed this outlook. Now there is potential for a considerable amount of growth on this system.

Generally, in the past, the reliability of this system has been good. However, in the past three years there has been a considerable decline in the system reliability. The reliability indices have steadily increased in the past three years. The exact cause of many of these outages is not entirely clear, however a large number of outages are attributed to loss of supply, and the causes behind the remaining outages is now under investigation. It is apparent from the events experienced in 2007 that the problems be identified and necessary work done to improve the system reliability.

As was previously identified in the past, load flow analysis indicates the present day system is not capable supporting additional load growth in the long term.

It is now necessary to initiate an upgrading plan for this distribution system, so that load growth can be addressed for the foreseeable future.

The past upgrading plan was reviewed, but it was determined that it would not sufficiently meet present day needs.

Out of the system review, two alternative plans were developed: A 25 kV Upgrading Plan, and a modified 12.5 kV Upgrading Plan. The 25 kV option only requires nine feeders in two substations to serve the system. For the 12.5 kV option the system will require seventeen feeders, three substations, and a switching station. In both cases, the upgrades will address the problems encountered on the existing system, as well as bring a higher level of reliability and operational flexibility to the system.

In Labrador, extreme weather and temperatures are common, and when coupled with the difficulty to mobilize any portable or spare equipment such as power transformers, this has the potential for high risk to customers and equipment when major component failures occur. This means the distribution system in Labrador City will require a more robust design than typical distribution systems found on the island. Therefore, the substations will be dual unit substations, and the system will have firm capacity installed. To ensure quick restoration of service in the event of a line failure, at least two subtransmission lines will be available to each substation, and full switching

capabilities will be available on the distribution feeders. The two options developed in this study meet these requirements.

Comparisons of system losses for the two options show the difference to be negligible. Over the present system approximately 1100 kW of loses can be saved. While the loss savings are negligible because the cost of energy from Churchill Falls is very low, this will also result loss savings on the transmission system. The savings in losses could generate additional revenues in the form of recall sales.

Ultimately, the selected option will come down to a matter of economics. However, should there be little difference between the costs of these two plans, and then the option offering the most benefits to Hydro and its customers should be selected. The following section provides a comparison of the two options.

6.1 COMPARISON OF ALTERNATIVES 25 KV VERSUS 12.5 KV

Functionally the two plans will meet the requirements of the system, and either option will carry the system to well beyond the forecast period. Each has its own respective merits.

The 25 kV plan will be a simpler system, and therefore it will be easier to operate. However, since the system design will have only nine feeders and two substations, it will have less switching capabilities than the 12.5 kV option, and therefore, is operationally less flexible.

This system should perform at a higher level of reliability because it would contain less equipment; therefore a lower failure rate can be expected. Additionally, since the system is simpler, there will be less potential for human error. Again, this will result in fewer outages. In general, outages should be less frequent than they are now. However, there will be more customers per feeder and substation. So even though outages will be less frequent, when they do occur more customers will be affected.

25 kV distribution feeders will provide the best line voltage regulation over the lower distribution voltages. Superior line voltage regulation also means better motor starting performance.

Voltage regulation in the form of OLTCs will be installed on the substation power transformers. This will make the distribution system independent of regulation at Wabush Terminal Station, and it will mitigate the effects of voltage regulation on the subtransmission system. Having voltage regulation available in the substations also means that if the Hydro Quebec System can deliver it, then it would be possible to get more than 5 MW over L33 from Fermont.

The firm capacity for the 25 kV plan is 75 MVA installed. This allows for a 36 % margin over the 2027 load forecast.

The system will consist of two substations. Since there are fewer components in this system, the annual maintenance costs should be lower.

The 12.5 kV distribution system would be more complex than a 25 kV distribution system. In comparison to the present system, the 12.5 kV design will be much simpler, and given the experience operations crew, the complexity of a three-substation system should not be of concern. Since the system has more feeders and substations, it will have more options for switching load.

Similar to the 25 kV plan, the 12.5 kV plan should provide a higher level of reliability. Fewer customers should be affected by an outage because there will be less customers on a feeder, and restoring customers will be easier since there are more switching options. The system will have more equipment, and therefore failure rates could be higher. The additional complexity of this option means the potential for human error is greater. In general, outages may be more frequent on the 12.5 kV system then the 25 kV system. However, there will be fewer customers affected, and they are more likely to be restored quickly. So even though outages may be more frequent, when they do occur fewer customers are affected.

Line voltage regulation will not be as good on the 12.5 kV system as on 25 kV system. No voltage regulation will be available in the substations, so this option depends on voltage regulation at Wabush Terminal Station.

The firm capacity for the 12.5 kV plan is 83 MVA installed. This allows for a 51 % margin over the 2027 load forecast.

The 25 kV plan may be superior to the 12.5 kV plan in that it offers better voltage regulation, greater line capacity, and better motor starting capabilities. It may also provide a system where fewer outages occur, but because the system does not possess the switching flexibility of the 12.5 kV plan, it may take longer to restore customers following an outage.

6.2 ECONOMIC ANALYSIS

The project has been broken down into the following major components: Terminal Station and Line Construction. Distribution feeder upgrades and conversions.

The distribution feeder upgrades and conversions is a common item to both alternatives, and as such, the costs associated with this work should be the same. As was already stated in Section 5 there are some dual-voltage 7200-2400 V distribution transformers installed on the distribution system. However, after conducting a survey of the distribution transformers it was found that dual-voltage units account only for approximately 12 % of the total. Details of the Transformer Survey can be found in

Appendix H. Therefore, the associated cost difference between the two alternatives will be negligible.

The major difference in cost for the two alternatives is for the station and line construction.

As was discussed in Section 4 above the 25 kV alternative will consist of two 46/25 kV substations. Each station is to consist of two 15/20/25 MVA 46/25 kV power transformers and associated switchgear.

The estimate for the terminal station construction portion of the 25 kV alternative is shown in Table 40 below. The cost estimate for 25 kV alternative is $ 10.0 million.

Table 40: Project Estimate - Station Work for 25 kV Alternative

Project Cost: ($ x1,000)	2009	2010	2011	TOTAL
Material Supply	50.0	1,919.0	3,409.0	5,378.0
Labour	83.0	231.2	200.5	514.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	83.0	890.0	800.0	1,773.0
Other Direct Costs	15.0	67.5	89.2	171.7
O/H, AFUDC & Escln.	29.1	476.3	864.0	1,369.4
Contingency	23.1	310.8	449.9	783.8
TOTAL	283.2	3,894.8	5,812.6	9,990.6

The bulk of the above costs are associated with power transformer purchases. Recent experience has shown that these costs vary considerably when tenders are issued, and is highly dependant on the timeline for delivery and the manufacturer backlog at the time the quote is issued. The above estimate could change once the tender is awarded.

The estimate for the line work portion of this alternative (exclusive of the distribution upgrades and conversions) is shown in Table 41 below. This work is estimated to cost $ 207.4 thousand.

Table 41: Project Estimate - Line Work for 25 kV Alternative

Description	Quantity	Unit Cost	Total ($ x1,000)
25 kV distribution line construction	0.500 km	$ 100,000/km	$50.0
46 kV subtransmission line construction	0.750 km	$ 119,850/km	$89.9
46 kV subtransmission line reconductoring	4.500 km	$ 15,000/km	$67.5
		TOTAL ($ x1,000)	$207.4

The total cost of station and line work for the 25 kV alternative is $ 10.2 million. This estimate does not include the cost of feeder conversions as stated earlier; it also does

not include environmental cleanup costs associated with removal of the existing substations.

As was discussed in Section 5 above the 12.5 kV alternative will consist of three 46/12.5 kV substations and a 46 kV switching station. Each substation is to consist of two 10/13.3/16.7 MVA 46/25 kV power transformers and associated switchgear. The switching station will consist of five 46 kV breakers arranged in a ring bus configuration.

The estimate for the terminal station construction portion of the 12.5 kV alternative is shown in Table 42 below. The cost estimate for 12.5 kV alternative is $ 13.8 million.

Table 42: Project Estimate - Station Work for 12.5 kV Alternative

Project Cost: ($ x1,000)	2009	2010	2011	TOTAL
Material Supply	450.0	2,319.0	4,975.0	7,744.0
Labour	113.0	287.2	203.5	603.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	383.0	1,100.0	800.0	2,283.0
Other Direct Costs	15.0	74.5	89.2	178.7
O/H, AFUDC & Escln.	124.2	593.9	1,163.2	1,881.3
Contingency	96.1	378.1	606.8	1,081.0
TOTAL	1,181.3	4,752.7	7,837.7	13,771.7

Again, the bulk of the above costs are associated with power transformer purchases. Recent experience has shown that these costs vary considerably when tenders are issued, and is highly dependant on the timeline for delivery and the manufacturer backlog at the time the quote is issued. The above estimate could change once the tender is awarded.

The estimate for the line work portion of this alternative (exclusive of the distribution upgrades and conversions) is shown in Table 43 below. This work is estimated to cost $ 459.7 thousand.

Table 43: Project Estimate - Line Work for 12.5 kV Alternative

Description	Quantity	Unit Cost	Total ($ x1,000)
25 kV distribution line construction	2.200 km	$ 100,000/km	$220.0
46 kV subtransmission line construction	2.000 km	$ 119,850/km	$239.7
		TOTAL ($ x1,000)	$459.7

The total cost of station and line work for the 12.5 kV alternative is $ 14.2 million. This estimate does not include the cost of feeder conversions as stated earlier; it also does not include environmental cleanup costs associated with removal of the existing substations.

As stated above, distribution upgrading and conversions is common to both alternatives and are expected to have the same cost. Detailed cost estimates for this component of the project is not included in report. This work requires a formal system survey and assessment to perform an accurate estimate. Due to time and budgetary constraints, the survey cannot be completed until 2009. A capital budget proposal will be submitted in 2008 to complete the distribution survey and assessment in 2009. The study is to be completed in time for the 2009 capital budget process so that detailed estimates for the distribution-upgrading portion of the project can be submitted for the 2010 budget year.

The cost estimates for the two alternatives considered in this study are summarized below:

Alternative 1: Upgrade Distribution System to 25 kV - $10,200,000
Alternative 2: Upgrade Distribution System to 12.5 kV - $14,200,000

From a technical point of view, either alternative will suffice; however, the capital cost of upgrading the distribution system to 25 kV is $4,000,000 lower than upgrading the distribution system to 12.5 kV. Therefore, Alternative #1 – *Upgrade Distribution to 25 kV- $10,200,000* is the most cost-effective alternative.

6.2.1 Net Present Value

The Net Present Value of the alternatives to the year 2040 for a terminal station in-service date of 2011 in 2008 dollars is shown in Table 44 below:

Table 44: Net Present Value of Alternatives (2008 Dollars)

Alternative	Net Present Value (NPV)	NPV Difference from Least Cost Alternative
Alternative #1 Upgrade Distribution to 25 kV	$9,312,403	$0
Alternative #2 Upgrade Distribution to 12.5 kV	$12,838,289	$3,525,886

A comparison of the Net Present Value of each alternative shows that the chosen alternative, Alternative #1 is $3,774,712 less costly than Alternative #2. Figure 3 below shows a plot of the Alternative #1 versus Alternative #2. Again, this plot shows that there is no crossover point, and that Alternative #1 is the most cost effective solution.

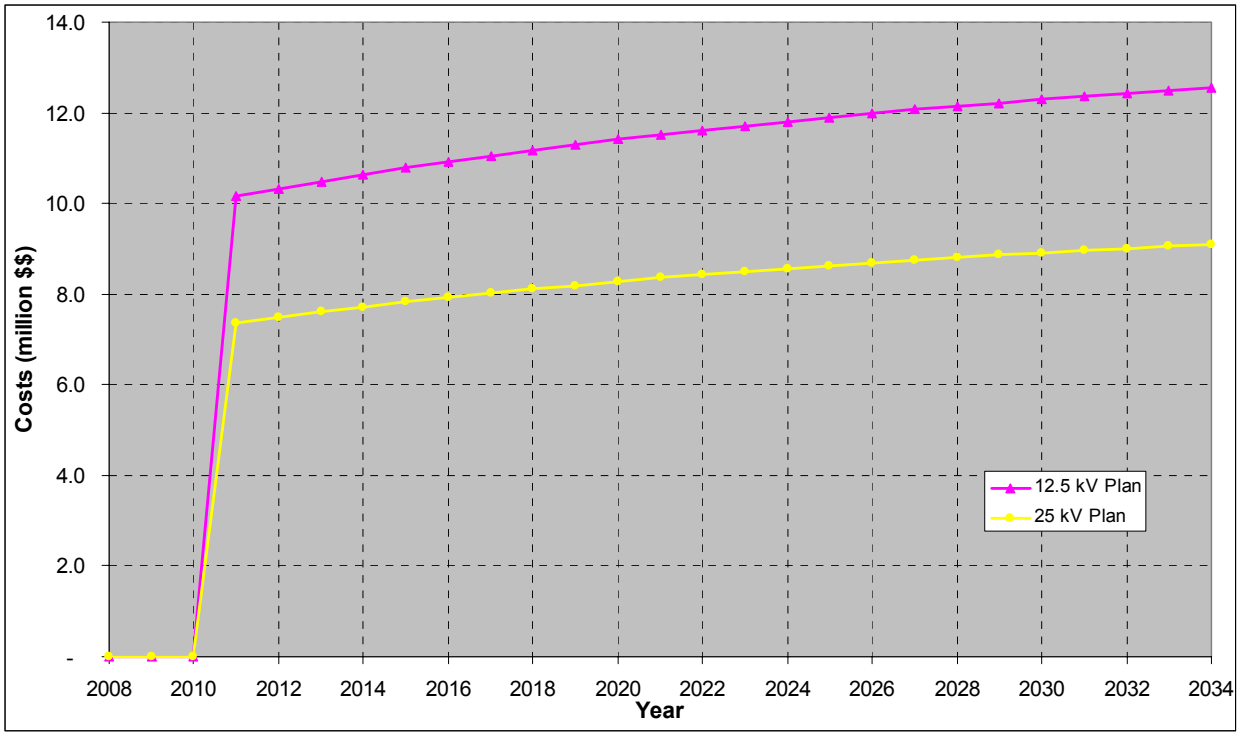


Figure 3: Net Present Value Comparison

A cost benefit analysis was not necessary for this project since the alternatives were technically equivalent and offered the same benefits to the system.

6.3 RECOMMENDATIONS

This study has found that the distribution system that exists in Labrador City is incapable of serving load growth in the long-term. Continued operation with the status-quo will result in customers receiving voltages outside those recommended in CSA Standard CAN3-C235-83 (R2006) *Preferred Voltage Levels for AC Systems, 0 to 50 000 V*.

In order to address this issue two alternatives were examined, converting the distribution voltage to 25 kV, and converting the distribution voltage to 12.5 kV. An analysis of the cost of each project showed that the 25 kV alternative is $3,774,712 less costly than the 12.5 kV alternative. Therefore, the 25 kV upgrading plan is selected as the favoured alternative.

The following recommendations are intended to assist in completion of the work involving this study, and to aid in selecting and implementing the favored option.

To date, load and voltage studies have been carried out on the Quartzite and Vanier distribution systems. The remaining systems, Bartlett, Hudson, Harrie Lake, and the 46 kV subtransmission system have not had studies conducted in several years.

Therefore, it is recommended that studies be conducted on these systems in the winter of 2009. The data from these studies will provide information on load profiles, diversity, and will be necessary in proofing the recently developed model of the distribution system.

When the system was taken over in the 1992, as a cost saving measure, easements were not acquired on the 4.16 kV distribution lines. In some cases easements have been acquired when a property is sold, for the remaining land prescriptive rights are all that exist on these lines. The Wabush staff has expressed concerns of customers constructing buildings very close to or directly underneath the power lines. In such cases the customers have had to sign waivers to protect Hydro from potential liabilities. The presence of structures in the line right-of-ways may cause difficulties in gaining access for the upgrades. Therefore, it is recommended that easements be acquired on all the distribution system.

A number of underground, padmount distribution transformers, and 4.16 kV primary services in Labrador City. The cost of upgrading these services to a higher primary voltage could be significant. Therefore, it is necessary to determine the exact number of these services that are in the system. This is so that the number of 25/4.16 kV or 12.5/4.16 kV step-down transformers can be found.

All the substation equipment associated with the 12.5 kV upgrading plan is intended to be upwards compatible to 25 kV. This is to provide a provision for conversion to 25 kV in the future if load growth were higher than expected. Therefore, long-term distribution transformer replacements on the 12.5 kV distribution system should be dual voltage type with a 14.4 kV - 7.2 kV primary winding.

There is the possibility that at some point in the future, a second 230 kV terminal station will be constructed in Labrador West. The location of this facility will depend on the nature of the load initiating the upgrade. If the new station is initiated primarily due to town load, then a suitable location would to the west of the system in the general area of the intersection of the Fermont Highway and Circular Road. A property of suitable size could be secured in that area.

Most of the switchgear in the substations is indoor metal clad type. Generally the operations staff has expressed a preference for this type of switchgear because the buildings provide a warm and comfortable space for carrying out maintenance work, and the rack mounted configuration allows easy access the feeder breakers. Given the favourable experience that TRO Labrador has had with this type of switchgear, and considering the working conditions with the severe winter climate in Labrador West, it is recommended that the continued use of metal clad type switchgear versus outdoor type switchgear be taken into consideration.

Problems have been experienced with carrying out investigations into the causes of a number of outages on the distribution system. The most common issue has been the general lack of information about system conditions at the time of the incidents due to a

lack of metering. The only metering currently available are MW, and kV readings at Wabush Terminal Station. The System Operations Department has expressed an interest in having SCADA installed at each of these substations. It is recommended that this be done with the new distribution system. Telemetry can be provided by optical fiber or most economical available means.

The Fermont Line, L33, can serve as an emergency supply to Labrador West or Fermont in Quebec. It can also be used as a backup subtransmission line when there is trouble with L32. However, utilizing this line is cumbersome. Prior to energizing the line, notice must be sent to Hydro Quebec informing of this. Until an acknowledgement is received from Hydro Quebec, the line can't be energized. As well the protection settings on L33 are lower than the settings on L32. In order to supply Labrador City from L33, the protection settings would have to be changed. Both the above items make utilizing L33 a time consuming and cumbersome process. It is recommended that a different operating arrangement be made on this line. There is a disconnect switch, WA33-D3 at the Quebec/Labrador border. If this switch were opened the line could remain energized at all times. For emergency supply, the switch would be closed. Doing this would allow the line to be utilized for the distribution system, and the protection settings could be adjusted appropriately. This will have the benefits of improved voltage regulation on the 46 kV subtransmission system, and better reliability for Hydro's customers.

REFERENCES

1. CEA 29, CEA Distribution Planner's Manual, Sept. 1983

2. INT 31, Newfoundland & Labrador Hydro's Transformer Back-up Policy, July 1991

APPENDICIES

APPENDIX A

SINGLE LINE DIAGRAMS

A1

LABRADOR CITY DISTRIBUTION SINGLE LINE DIAGRAM

LEGEND:

- Distribution Line 4.16, 12.5, or 25 kV
- Distribution Line 46 kV
- Fused Disconnect Switch
- Ganged Operated Disconnect Switch
- Normally Open Disconnect Switch
- Solid Blade Disconnect Switch
- Transformer - Delta - Wye Grounded shown
- Circuit Breaker with CTs
- Recloser with Bipass Switch
- Bartlett Feeder 1 (4.16 kV)
- Bartlett Feeder 2 (4.16 kV)
- Bartlett Feeder 3 (4.16 kV)
- Bartlett Feeder 4 (4.16 kV)
- Bartlett Feeder 5 (4.16 kV)
- Quartzite Feeder 6 (4.16 kV)
- Quartzite Feeder 7 (4.16 kV)
- Quartzite Feeder 8 (4.16 kV)
- Townsite Feeder 9 (46 kV)
- Townsite Feeder 10 (46 kV)
- Townsite Feeder 11 (46 kV)
- Quartzite Feeder 12 (4.16 kV)
- Quartzite Feeder 13 (4.16 kV)
- Quartzite Feeder 14 (4.16 kV)
- Hudson Feeder 15 (4.16 kV)
- Hudson Feeder 16 (4.16 kV)
- Hudson Feeder 17 (4.16 kV)
- Hudson Feeder 18 (4.16 kV)
- Harrie Lake Feeder 19 (4.16 kV)
- Harrie Lake Feeder 20 (4.16 kV)
- Vanier Feeder 21 (4.16 kV)
- Vanier Feeder 22 (4.16 kV)
- Vanier Feeder 23 (4.16 kV)
- Wabush Feeder 32 (46 kV)
- Wabush Feeder 33 (46 kV)

PROPOSED NEW HOSPITAL

PROPOSED NEW COLLEGE

WA33 46 kV

SMOKEY MOUNTAIN

PROPOSED RESIDENTIAL DEVELOPMENTS

QUARTZITE SUBSTATION

TS9 46 kV

QZ7 4.16 kV

QZ14 4.16 kV

QZ6 4.16 kV

QZ8 4.16 kV

QZ12 4.16 kV

QZ13 4.16 kV

HARRIE LAKE SUBSTATION

TS9 46 kV

QZ14 4.16 kV

HL19 4.16 kV

HL20 4.16 kV

TAMARACK GULF CLUB

VANIER SUBSTATION

VA21 4.16 kV

VA22 4.16 kV

VA23 4.16 kV

TS11 46 kV

HUDSON SUBSTATION

TS11 46 kV

HU15 4.16 kV

HU18 4.16 kV

HU17 4.16 kV

HU16 4.16 kV

QNS&L 23 kV

BARTLETT SUBSTATION

BA2 4.16 kV

BA1 4.16 kV

BA3 4.16 kV

HU17 4.16 kV

BA5 4.16 kV

BA4 4.16 kV

TS10 46 kV

TOWNSITE SWITCHING STATION

TS10 46 kV

TS9 46 kV

TS11 46 kV

WA32 46 kV

WA33 46 kV

WABUSH TERMINAL STATION

WA32 46 kV

WA33 46 kV

WA36 46 kV

WABUSH TOWNSITE SUBSTATION

PROPOSED COMMERCIAL AND INDUSTRIAL DEVELOPMENTS

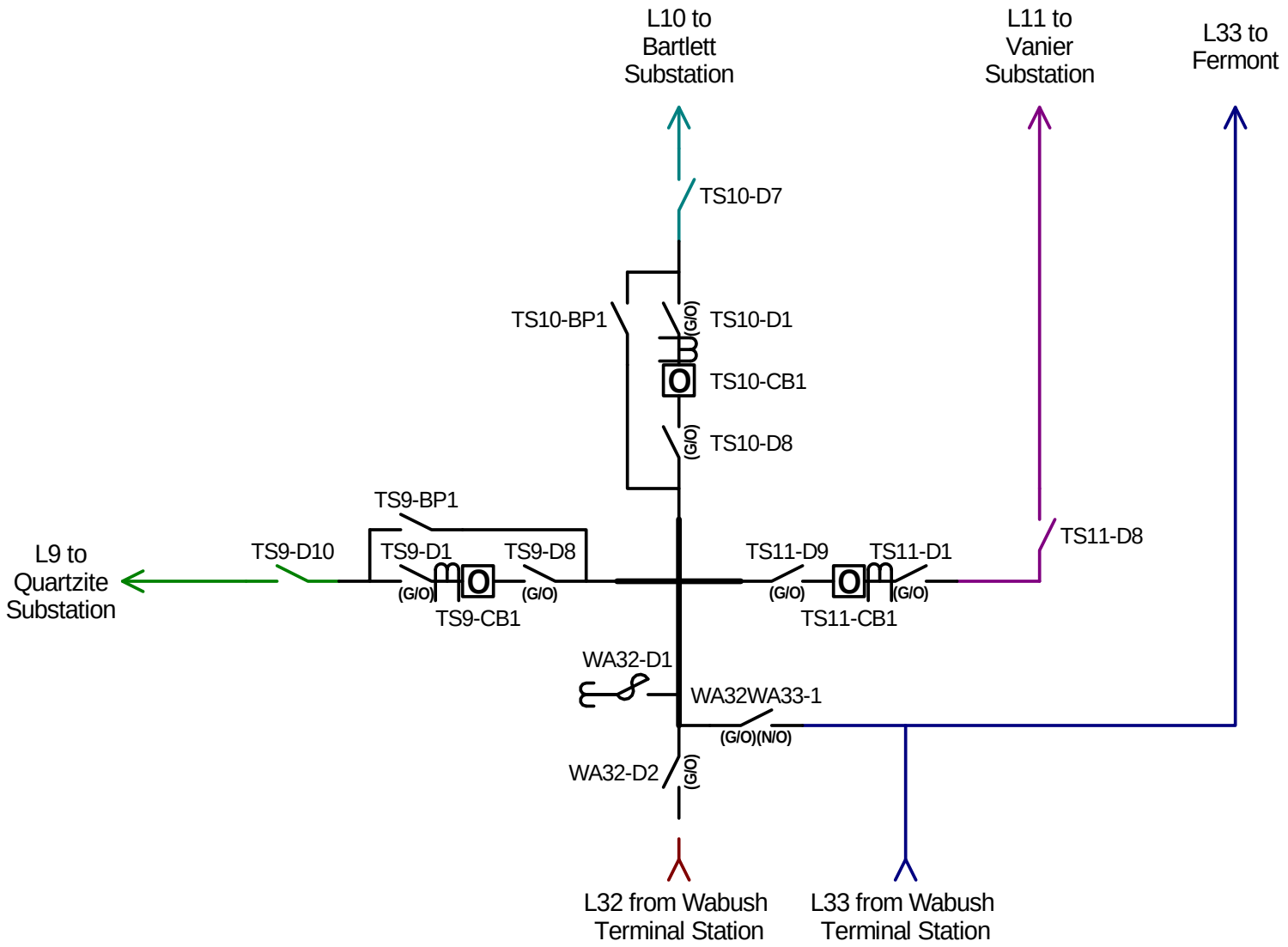
SEPT ISLES

SYS PLANNING:	CRW	SHEET 1 OF 1	
SYS OPERATIONS:	--	DATE: NOV 8, 2007	
TERM DESIGN:	--	DRAWN BY: CRW	
PROTECTION:	--	FILE: EXISTING 4.16 KV SYSTEM.SKF	

A2

TOWNSITE SWITCHING STATION

EXISTING
TOWNSITE SWITCHING STATION



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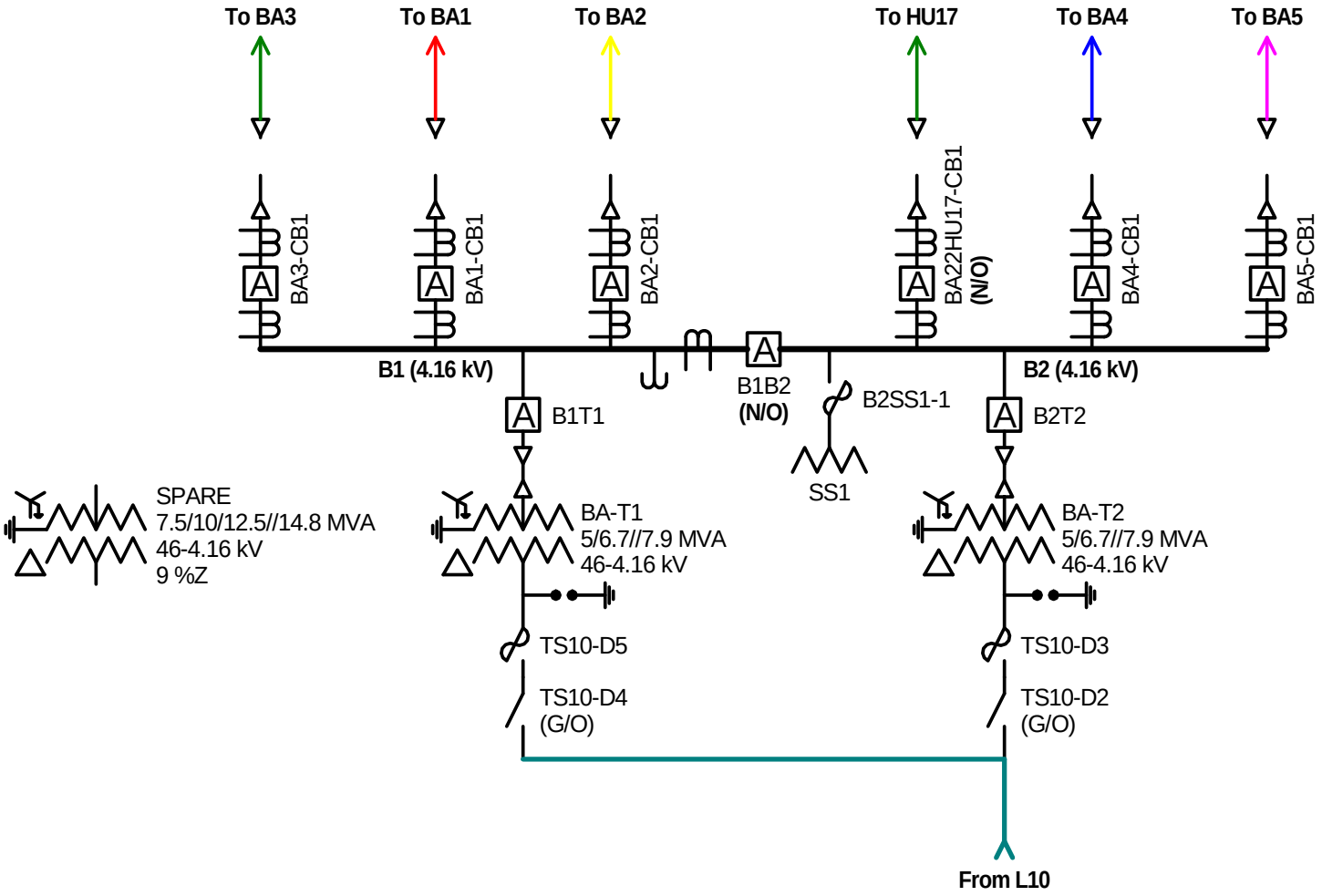
A3

BARTLETT SUBSTATION

EXISTING BARTLETT 4.16 kV SUBSTATION



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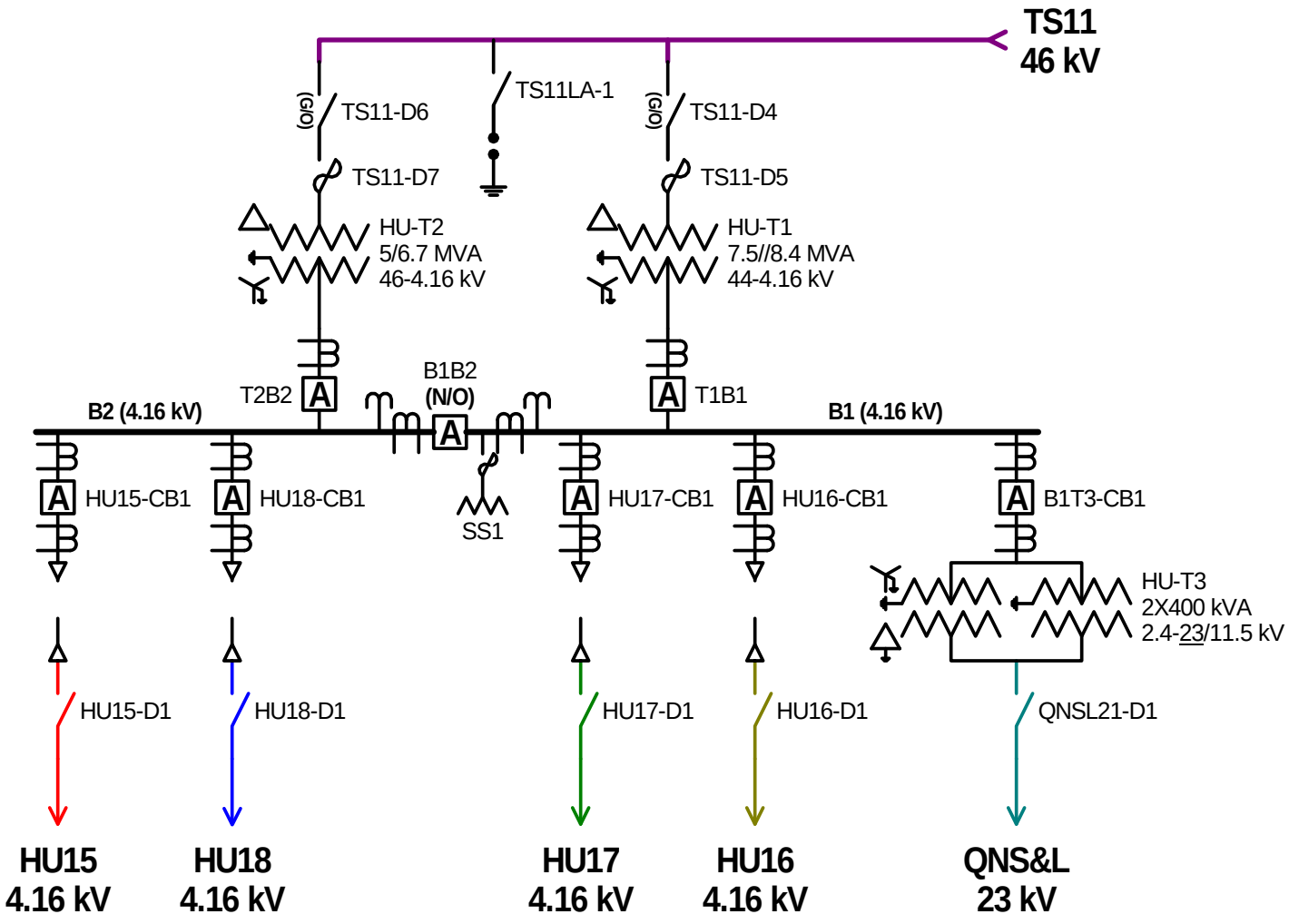
A4

HUDSON SUBSTATION

EXISTING HUDSON 4.16 kV SUBSTATION



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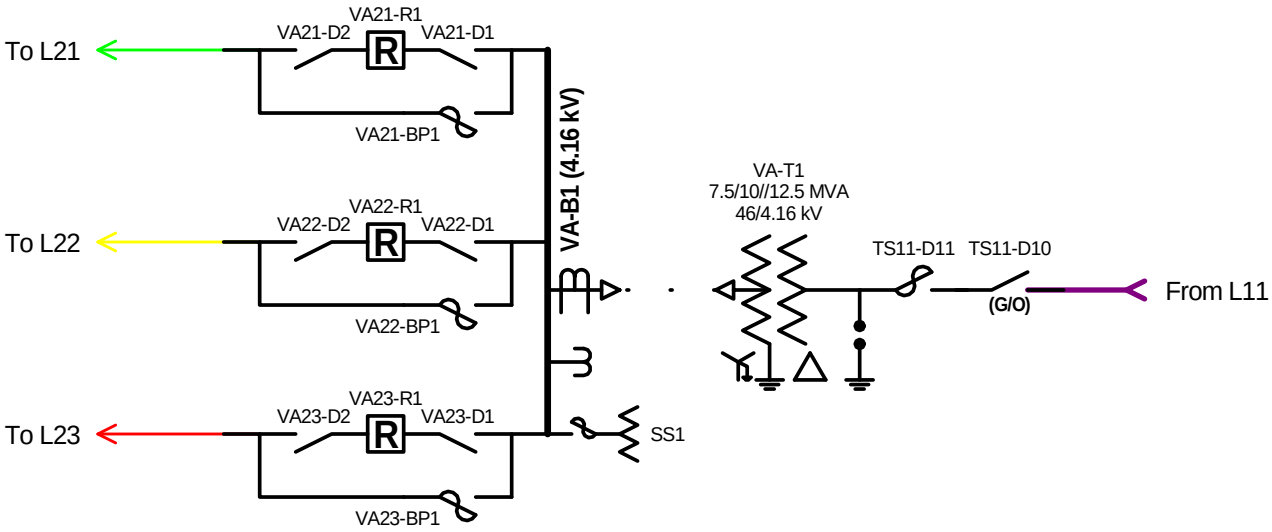
A5

VANIER SUBSTATION

EXISTING VANIER SUBSTATION



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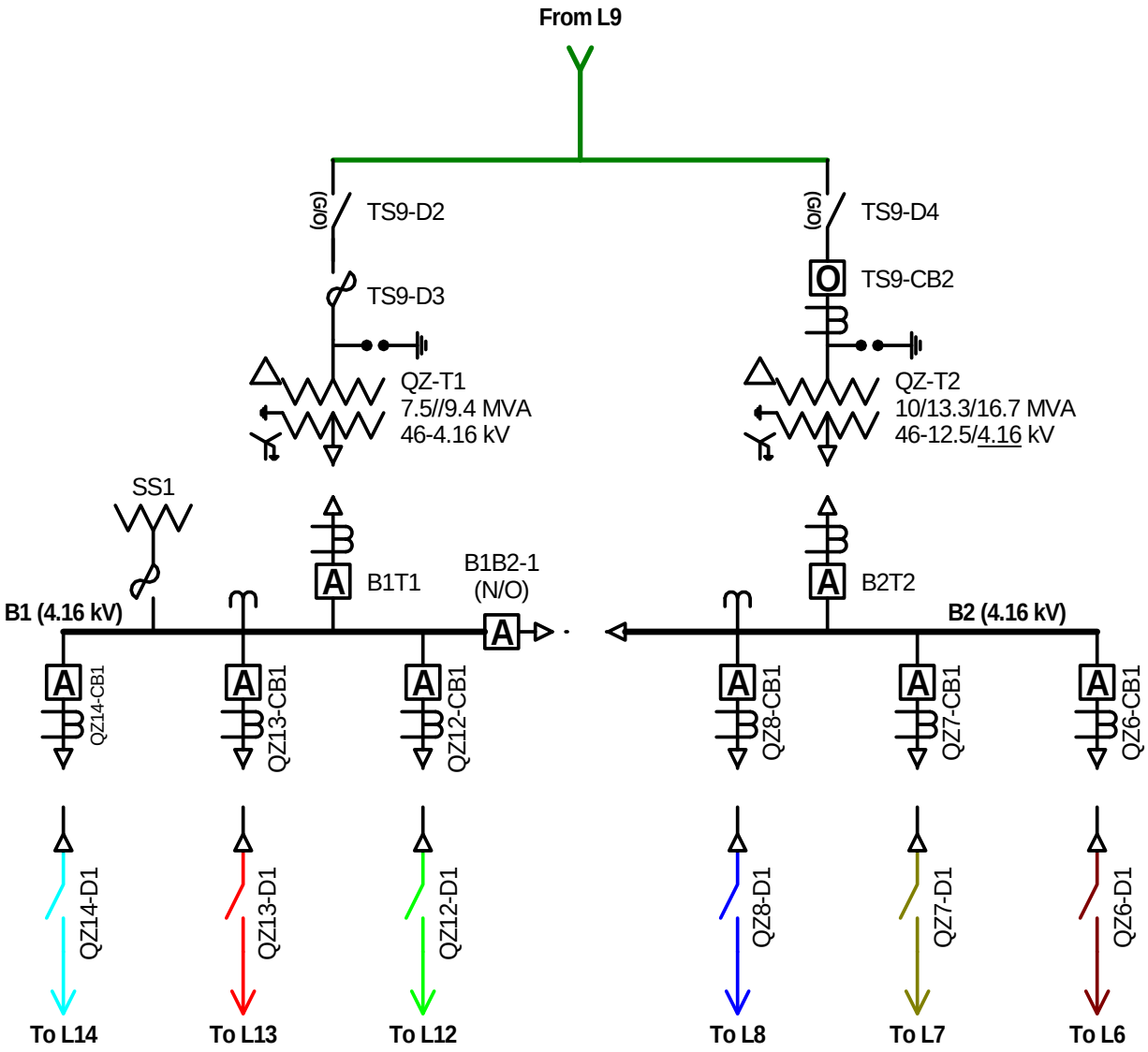
A6

QUARTZITE SUBSTATION

EXISTING QUARTZITE SUBSTATION



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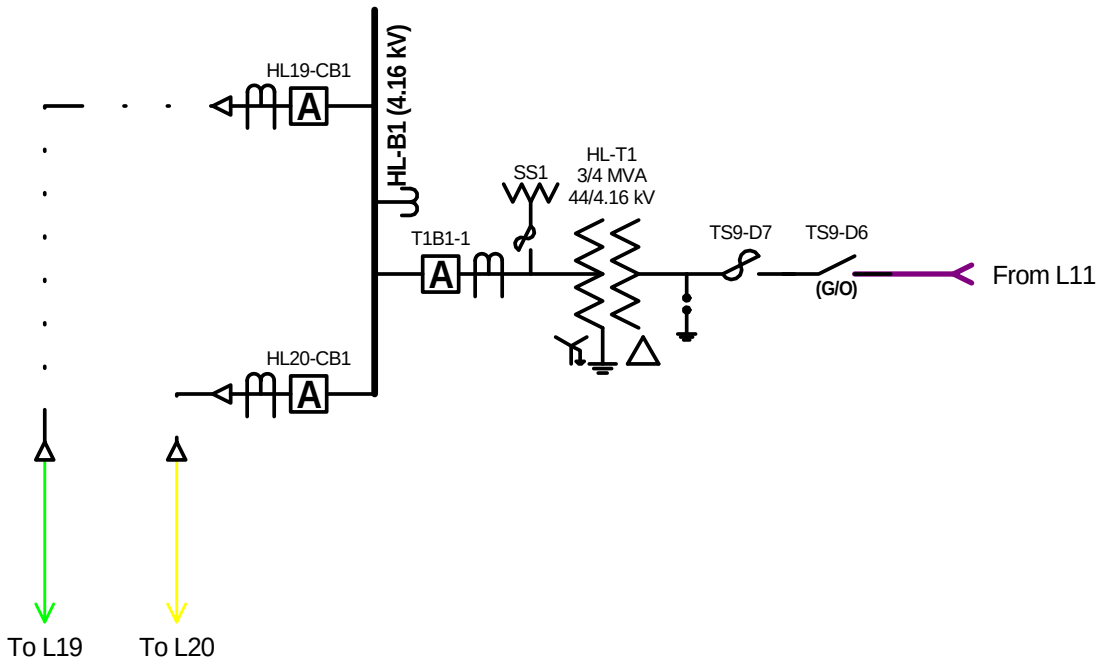
A7

HARRIE LAKE SUBSTATION

EXISTING HARRIE LAKE SUBSTATION



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		SYS OPERATIONS: --	DATE: NOV 6, 2007
		TERM DESIGN: --	DRAWN BY: CRW
		PROTECTION: --	FILE: HARRIE LAKE 4.16 KV SUBSTATION.SKF

APPENDIX B

MEMO FR. DAVID HARRIS RE. 4.16 KV UPGRADING PLAN

TS 2.63-10/04

David

INTEROFFICE MEMORANDUM

DATE: January 29, 1992

MEMO TO: Harvey Young

FROM: David Harris

SUBJECT: CAPITAL COST ESTIMATES - 4.16 KV CAPITAL PLAN

Concerns have been expressed regarding the requirement of 12.5 kV conversion in Labrador City, particularly in light of the less than forecast peak for this year. In response to these concerns, the capital plan for the community has been again examined. In particular, the system was examined for operation at a 48 MW peak as opposed to 52.5 MW. After considerable time and effort, a plan has been developed allowing the system to remain at 4.16 kV while providing marginally acceptable voltages. By marginally acceptable, it is meant that all feeder minimum voltages may not necessarily meet Hydro's voltage standards, but come close enough to be within the accuracy of our models. Let me state at the outset, however, that while the 4.16 kV plan can meet the technical requirements of the system, it provides absolute bare minimum feeder voltages and limited reliability. The 4.16 kV plan does not offer near the same flexibility as the 12.5 kV plan.

Attached is a list of work required for the 4.16 kV plan. Please provide rough cost estimates for this work. When the estimates have been prepared, please contact or have someone contact either myself or Keith Boone to discuss possible scheduling of the work in order to provide guidance in preparing the cash flows. For comparison purposes, please provide the cost estimates using the same assumptions as were made for the 12.5 kV program. As well, please provide the cost for the work assuming Hydro stands to the cost of pole replacement, and the scenario in which Newfoundland Telephone stands to the cost of pole replacement.

As you are well aware, the date for the hearing on Labrador City is soon approaching. If

the rough estimates could be prepared by February 6, 1992, it would be greatly appreciated.

If you have any comments or questions regarding the plan, please contact me at extension 1964. Thanks.

David Harris

David Harris, Planning Engineer
Generation and Rural

DH:cfh

cc Keith Boone
Peter Nell
Bob Whitehorne
File 752.63.10/04

Attachment

LABRADOR CITY 4.16 KV CAPITAL PLAN

46 KV TRANSMISSION:

- Reconductor existing 266.8 MCM conductor with 477 MCM ASC.
- Reconductor 266.8 MCM, 46 kV buswork in the Townsite Switching Centre with 477 MCM ASC.
- Provide 46 kV switching capability between the existing Townsite line and the 477 MCM Fermont emergency line. See attached single line diagram SK-1.
- Construct a 1.5 km, 3 Phase, 46 kV, 266.8 MCM ACSR line from the Hudson Substation to the location of the new Vanier Substation.

SUBSTATIONS:

- Construct a new 46:4.16 kV substation near the Labrador Mall (Vanier Substation). See attached single line diagram SK-2.
- Replace the 3/4 MVA transformer in the Bartlett Substation with a 5/6.67 MVA unit.
- Extend the Quartzite Substation, buswork, etc., to allow addition of a 7.5/10/12.5 MVA unit. See attached single line diagram SK-3.
- Move feeders Quartzite 1 and Quartzite 2 onto transformer QZ-TH-1.
- Move feeders Quartzite 3 and Quartzite 4 onto transformer QZ-TH-2.
- Move feeders Quartzite 5 and Quartzite 6 onto transformer QZ-TH-3.
- Improve buswork in Bartlett Substation to Hydro standards.
- Improve buswork in Hudson Substation to Hydro standards.
- Install three 1-Phase, 400 Amp, 4.16 kV voltage regulators in the Quartzite Substation for use with feeder Quartzite 6.
- Install a circuit switcher on the incoming 46 kV line to Hudson Substation.
- Install a circuit switcher on the incoming 46 kV line to Quartzite Substation.
- Install a circuit switcher on the incoming 46 kV line to Harrie Lake Substation.

PRIMARY DISTRIBUTION LINES:

- Reconductor approximately 500 m of feeder Bartlett 2 (from the substation to 601 Bartlett Drive) with 266.8 MCM ACSR.

- Reconductor approximately 200 m of feeder Bartlett 3 (from the substation to 424 Grenfell Crescent) with 266.8 MCM ACSR.

- Reconductor approximately 1 km of feeder Bartlett 5 (from the substation to 703 Tamarack Drive) with 477 MCM ASC.

- Reconductor approximately 750 m of feeder Bartlett 5 (from 703 Tamarack Drive to 733 Willow Drive, and from 709 Tamarack Drive to 751 Tamarack Drive) with 266.8 MCM ACSR.

- Reconductor approximately 600 m of feeder Bartlett 5 (from 703 Tamarack Drive to 722 Bartlett Drive) with 266.8 MCM ACSR.

- Install a 3-Phase, 266.8 MCM, 200 m line connecting Quartzite feeder 5 to Vanier feeder 1.

- Install 3-Phase, 600 Amp cutouts on Quartzite feeder 6 at 805 Churchill Street.

- Construct a 3-Phase, 500 m, 477 MCM line connecting feeder Quartzite 6 at 604 McPharland Street to Vanier feeder 2. Reconductor the branch between 401 and 419 Montagais Avenue with 3-Phase, 477 MCM conductor (approximately 250 m).

- Construct a 3-Phase, 1.1 km, 477 MCM line on existing structures from Vanier feeder 3 to 802 Carol Drive. See attached diagram SK-4. Reconductor the branch between 833 and 819 Cook Street with 3-Phase, 477 MCM conductor (approximately 250 m).

- Construct a 3-Phase, 100 m, 477 MCM line connecting Quartzite feeder 4 to 823 Hamilton Street. See attached diagram SK-4. Reconductor the branch between 823 and 801 Hamilton Street with 3-Phase, 477 MCM conductor (approximately 300 m).

- Add 266.8 MCM conductor to branch running from 413 Centennial Drive to 420 Massey Crescent in order to make the branch 3-Phase (approximately 500 m).

- Reconductor the branch between Quartzite feeder 6 at the substation and 829 Carol Drive using 3-Phase, 477 MCM ASC (approximately 700 m).

- Construct a 3-Phase, 477 MCM ASC, 1.1 km line from Hudson feeder 2 at the substation to the industrial area, terminating near City Motors.

- Install a 3-Phase, 300 kVAR, 2.4 kV L-N capacitor bank at the relay station in the Hudson feeder 2 industrial area.

- Install a 3-Phase, 300 kVAR, 2.4 kV L-N capacitor bank on Hudson feeder 2 near the Lumber Mart.

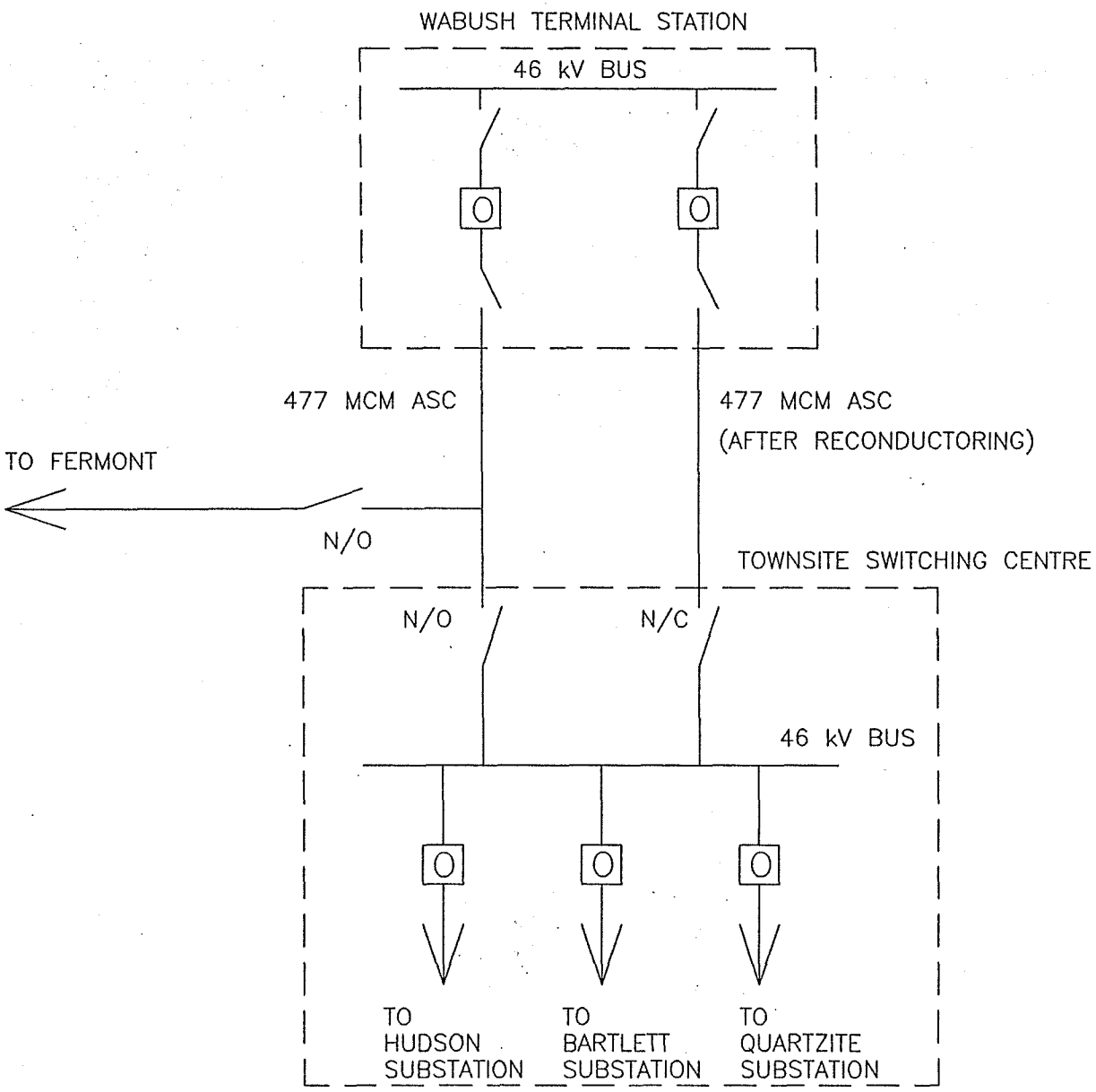
- Install a 3-Phase, 300 kVAR, 2.4 kV L-N capacitor bank on Bartlett feeder 5 near 714 Bartlett Drive.

- Install a 3-Phase, 300 kVAR, 2.4 kV L-N capacitor bank on Quartzite feeder 2 near 764 Tamarack Drive.

- Install a 3-Phase, 600 kVAR, 2.4 kV L-N capacitor bank on Quartzite feeder 3 near 816 Lakeside Drive.

- Install a 3-Phase, 300 kVAR, 2.4 kV L-N capacitor bank on Quartzite feeder 4 near 727 Bartlett Drive.

- Install a 3-Phase, 150 kVAR, 2.4 kV L-N capacitor bank on Quartzite feeder 4 near 768 Stirling Crescent.

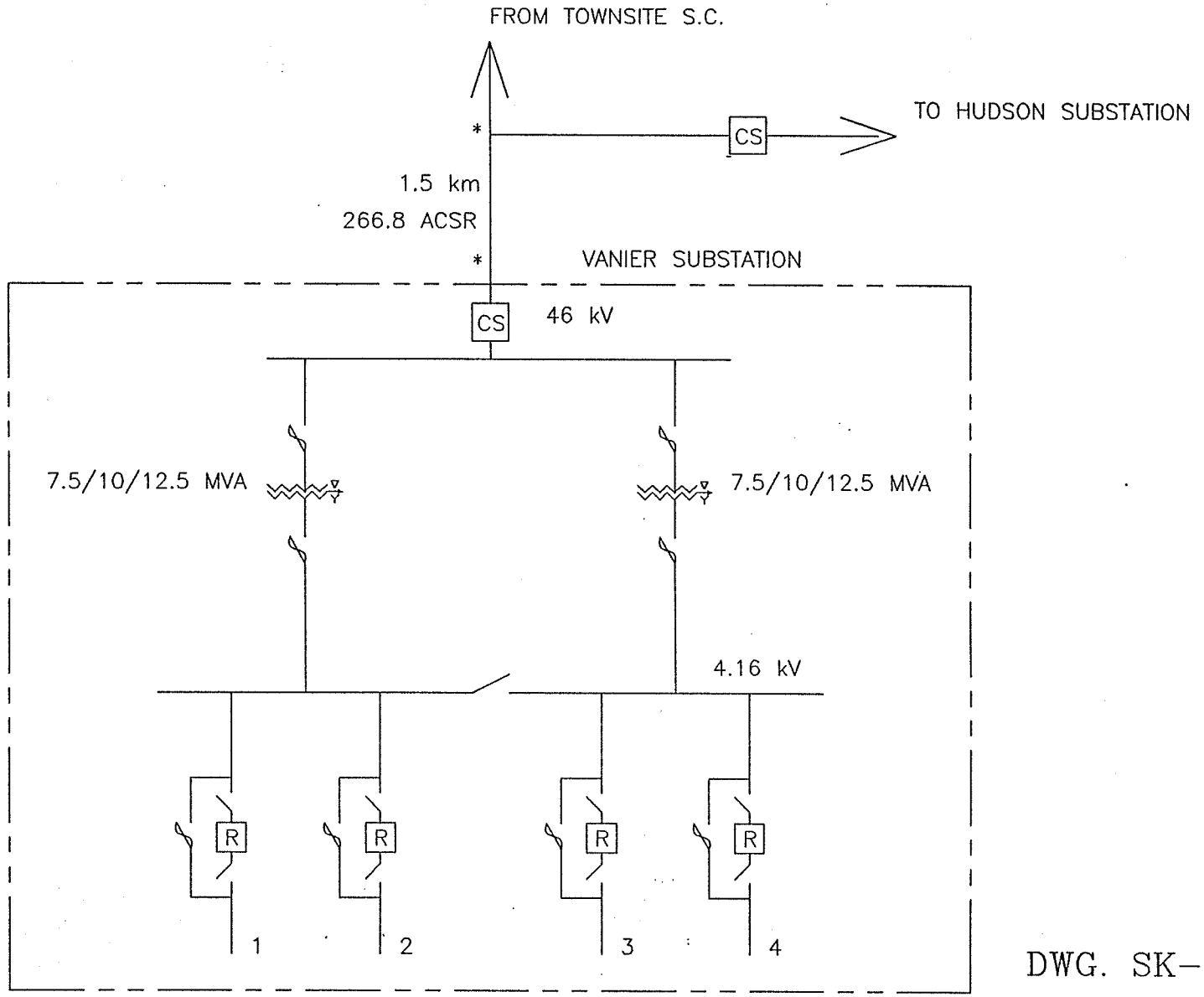


DWG. SK-1

HYDRO

TITLE: LABRADOR CITY 4.16 kV CAPITAL PLAN
PROPOSED SWITCHING ARRANGEMENT – T.S.C.

SHEET 1 OF 1
DRAWN: D. HARRIS
DATE: JANUARY 28, 1992

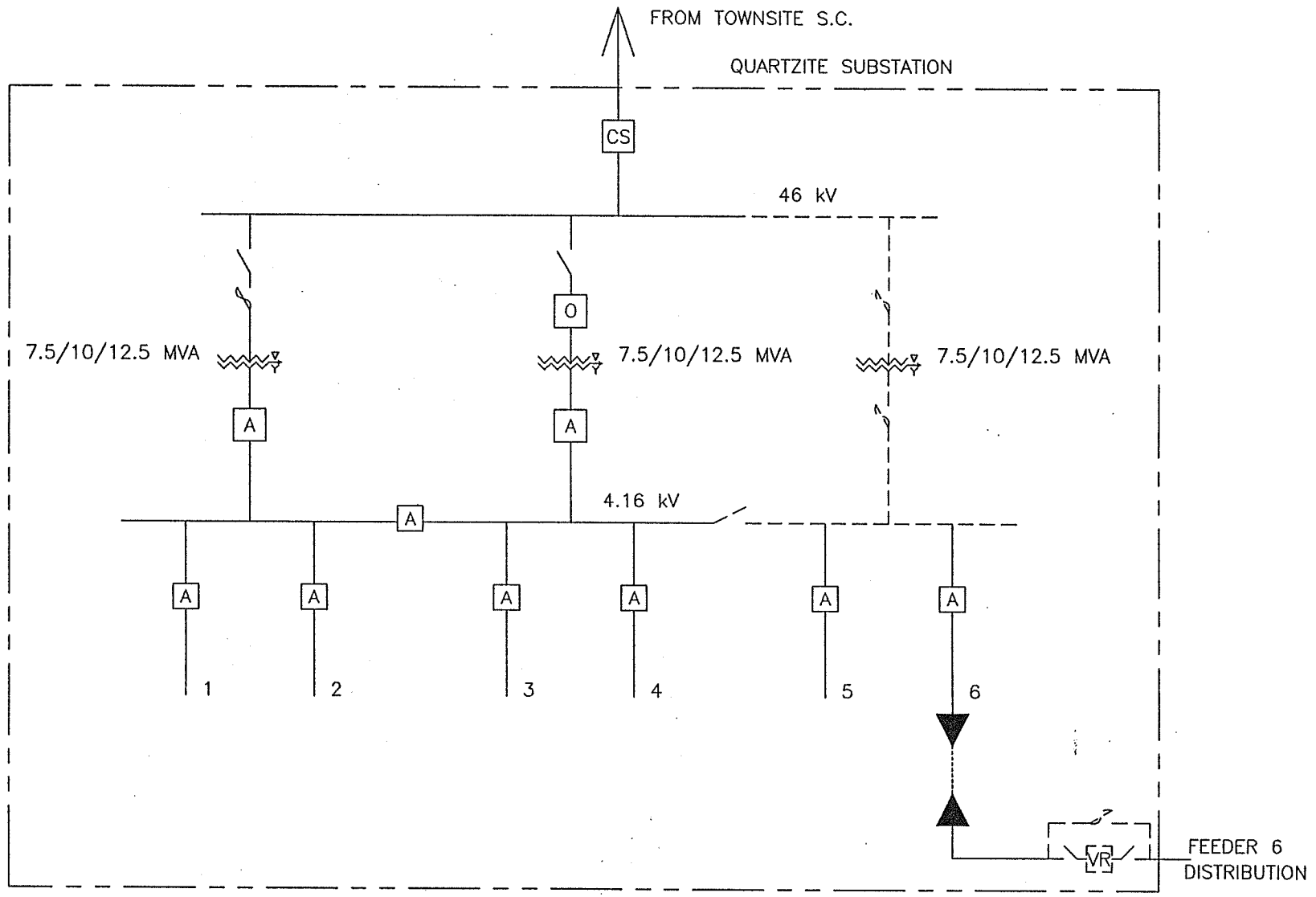


DWG. SK-2

HYDRO

TITLE: LABRADOR CITY 4.16 kV CAPITAL PLAN
PROPOSED VANIER SUBSTATION SINGLE LINE DIAGRAM

SHEET 1 OF 1
DRAWN: D. HARRIS
DATE: JANUARY 28, 1992



DWG. SK-3

HYDRO	TITLE: LABRADOR CITY 4.16 kV CAPITAL PLAN PROPOSED QUARTZITE SUBSTATION SINGLE LINE	SHEET 1 OF 1 DRAWN: D. HARRIS DATE: JANUARY 28, 1992

APPENDIX C

RURAL (ISOLATED) DISTRIBUTION SYSTEMS

OVERCURRENT PROTECTION UPGRADE

Rural (Isolated) Distribution Systems
Overcurrent Protection Upgrade

Introduction

The distribution system is a vital contributor to the overall power system function of providing quality electrical service to its customers. To fulfill this role, the design and operation of the distribution system must take into account the basis fundamentals of system fault overcurrent protection. The questions that arise from this type of analysis are as follows:

(1) What are the distribution system fault overcurrent problems?
(2) What protective equipment is available to deal with these problems?
(3) How is the protective equipment applied to the distribution system?

Distribution System Faults

The operator of any distribution system must anticipate a variety of operating conditions which may interfere with normal operation. One of the predominant abnormal conditions on distribution systems are overhead line faults. These line faults are normally caused by adverse weather conditions such as strong winds which can whip phase conductors together or which blow tree branches onto the overhead primary line(s). As well, freezing rain can produce a gradual buildup of ice on an overhead line and eventually one or more conductors may break and fall to the ground. Most of these fault conditions are considered as line to ground faults with significant levels of fault impedance, such as the ice on the conductor or the tree branch that is in contact with one of the overhead conductors. In fact, on a 3-phase wye grounded distribution system some 80% of the overhead line faults are line-to-ground in nature. These types of faults are well know for the distribution systems within Newfoundland and Labrador, both for grid interconnected and isolated diesel distribution systems.

The fault overcurrent protection design for all distribution systems must therefore minimize the severe effects that a hostile environment can have on owner's as well as customer's electrical equipment.

Types of Faults

The types of system faults that can occur on any 3-phase, multi-grounded distribution line are as follows:

(1) Three-Phase
(2) Line-to-Line
(3) Line-to-Ground
(4) Double Line-to-Ground

For the two types of ground faults listed above if one or more of the line conductors does not contact the system neutral wire (ie. bolted fault) the level of fault current that results is much dependant on the magnitude of the fault impedance involved, as well as the integrity of the system grounding for the soil resistivity involved. A fault impedance

Rural (Isolated) Distribution Systems
Overcurrent Protection Upgrade

value of 20 to 80 ohms would be typical for the line-to-ground fault calculations in order to determine expected line-to-ground fault current level(s) for the distribution system involved, and based on minimum generation source. This fault impedance is a more significant factor for lower voltage distribution systems such as 4.16 kV, than those operating at 12.5 or 25 kV. At this point the emphasis for system fault overcurrent protection will concentrate on the single line-to-ground fault, and in particular those involving a fault impedance.

Isolated Distribution Systems

For an isolated 3-phase, 4-wire wye grounded distribution system with diesel generation, the magnitude of the line-to-ground fault current will not only depend on the ohmic value of the fault impedance, but also the number and size of diesel generating units operating at the time of the system fault. It is very common for one diesel unit to be operating under system off peak conditions, which would be considered as a worst case scenario should a system line-to-ground fault occur at that time. Calculated values for these distribution systems using a fault impedance show line-to-ground fault levels as low as 80 amps. Many of these isolated distribution systems have only phase overcurrent protection which would be the step-up transformer's high voltage fuses, thus no type of sensitive line-to-ground protection exists. Typically the line-to-ground overcurrent protection for any distribution system would be in the range of 10% to 50% of the phase overcurrent value depending on feeder load unbalance. Existing high voltage fuses on the 4.16 kV side of the step-up transformer bank are designed to melt at 200% of their rating thus a 50 amp fuse will melt at 100 amps, which is well above this line-to-ground fault level. The step-up transformer bank's delta/wye grounded connection configuration is a block to zero sequence current, thus any phase overcurrent protection on the 600V generation side is not sensitive enough to detect these lower fault levels.

Protection Upgrade Program

The grid interconnected distribution systems have protective devices such as three phase and single phase electronic reclosers which are designed with line-to-ground fault sensing capability. These same protective devices do exist on many of the isolated diesel distribution systems as well, with the remainder having only high voltage fused cutouts. Thus of the twenty-six (26) prime power diesel plants that Hydro operates, there are twelve(12) that require line-to-ground protection upgrading, as listed in the table that follows. This would involve the installation of sensing transformers on the high side of the step-up power transformer bank and a solid state protective relay, which would trip the plant's main breaker. For those plants that do not have a main breaker which is compatible for the protective relay application, then an electronic recloser installation is proposed. For example, the main breaker at both the Little Bay Islands and St. Brendan's diesel plants has no shunt trip and the cost to upgrade these breakers for the protection upgrade using the solid state protective relay option is higher in cost than the electronic recloser option. The system outage time involved in upgrading these main breakers is also prohibitive. Please note as well for the electronic recloser installation that its control panel will be brought inside the diesel plant for ease of access by the operator.

Rural (Isolated) Distribution Systems
Overcurrent Protection Upgrade

The schedule proposed for the overcurrent protection upgrade project(s) is based on work commencing immediately in 2002 for two (2) of the rural distribution systems involved and completing the remaining ten (10) in the budget year 2003.

Diesel Plant Location	Protective Relay Installation	Electronic Recloser Installation	Budget Year	Budget Estimate *($ x1000)*
Central Region:				
Little Bay Islands		*	2002	79.0
St. Brendan's		*	2002	79.0
Grey River	*		2003	52.7
Francois	*		2003	52.7
Petites	*		2003	52.7
McCallum	*		2003	52.7
Northern Region:				
St. Lewis		*	2003	84.2
William's Hbr.	*		2003	52.7
Norman Bay	*		2003	52.7
Labrador Region:				
Black Tickle		*	2003	105.1
Postville		*	2003	84.2
Paradise River	*		2003	52.7

APPENDIX D

25 KV DISTRIBUTION UPGRADING PLAN

SINGLE LINE DIAGRAMS

D1

LABRADOR CITY 25 KV CAPITAL PLAN 2007

LEGEND:

- Distribution Line 4.16, 12.5, or 25 kV
- Distribution Line 46 kV
- Fused Disconnect Switch
- Ganged Operated Disconnect Switch
- Normally Open Disconnect Switch
- Solid Blade Disconnect Switch
- On Load Tap Changing Transformer Delta - Wye Grounded shown
- Circuit Breaker with CTs
- Recloser with Bipass Switch
- Quartzite Feeder 8 (25 kV)
- Quartzite Feeder 12 (25 kV)
- Quartzite Feeder 13 (25 kV)
- Quartzite Feeder 14 (25 kV)
- Vanier Feeder 15 (25 kV)
- Vanier Feeder 18 (25 kV)
- Vanier Feeder 21 (25 kV)
- Vanier Feeder 22 (25 kV)
- Vanier Feeder 23 (25 kV)
- Wabush Feeder 32 (46 kV)
- Wabush Feeder 33 (46 kV)
- Vanier Feeder 33 (46 kV)

TO FERMONT (EMERGENCY BI-DIRECTIONAL SUPPLY)

VANIER FEEDER 33 VA33 46 kV

Install disconnects on Fermont Line at Tap to Quartzite Substation.

PROPOSED NEW HOSPITAL

PROPOSED NEW COLLEGE

Possible System Expansion
New Hospital and New College
Distance: ~2000m
Conductor: 4/0 AASC

Construct ~450 m of 46 kV line from Fermont Line to Vanier Substation using 477 ASC conductor.
Tie L11 from near TS11-D12 to L33.
Remove Section of L33 between the two new tap locations.

VANIER FEEDER 33 VA33 46 kV

WABUSH FEEDER 33 WA33 46 kV

SMOKEY MOUNTAIN

Install 25/4.16 kV Transformer at start of tap to Smokey Mountain Ski Hill. Transformer Size to be Determined.

Vanier Substation
Remove the existing 4.16 kV equipment.
Install two new 15/20/25 MVA, Delta-Wye-Grounded, 46/25 kV Power Transformers with on load tap changers.
The tap changers should have 15 % boost and 5 % buck capabilities in 33 tap positions.
Construct new 46 kV buswork with two breaker bays.
Install two new 46 kV breakers.
Install two new 25 kV circuit breakers on transformer load side, and a 25 kV bus tie breaker between B1 and B2.
Install five 25 kV reclosers along with all necessary buswork, disconnects, etc.
Leave provision for an additional recloser.

VA21 25 kV

VA22 25 kV

VA23 25 kV

VA15 25 kV

VA18 25 kV

Open L18 at Str. 536.
Construct ~90 m of 3-phase line from Vanier Substation to Str. 536 using 477 ASC cosmos conductor.

Construct ~60 m of double circuit line from Str. 543 behind 807 to Str. 544 behind 807 Carol Drive.

Construct ~90 m of 3-phase line from Vanier Substation to Str. 535 using 477 ASC cosmos conductor.

Extend L15 ~80m from Str. 385 (behind 618 Carol Drive) to Str. 691 on L6 (behind 621 Carol Drive) using 477 ASC Cosmos conductor.

Extend L15 ~80m from Str. 363 (behind 512 Carol Drive) to Str. 544 on L18 using 477 ASC Cosmos conductor.

Upgrade ~180 m of feeder 15 to 3-Phase from Str. 360 to Str. 363.

Str. 380

Str. 205

REMOVE L15 FROM DOUBLE CIRCUIT

HUDSON SUBSTATION

Remove the Hudson Substation.

Remove the QNS&L Feeder as far as the QNS&L Rail Yard.

PROPOSED RESIDENTIAL DEVELOPMENTS

VANIER FEEDER 33 VA33 46 kV

WABUSH FEEDER 32 WA32 46 kV

QUARTZITE SUBSTATION

QZ14 25 kV

QZ13 25 kV

QZ12 25 kV

QZ8 25 kV

TAMARACK GULF CLUB (CUSTOMER OWNED LINE)

Install 25/4.16 kV Transformer at start of Tamarak Golf Course Customer Owned Line.
Transformer Size to be Determined.

Harrie Lake Substation to be decommissioned and removed.

Quartzite Substation
Remove the existing 4.16 kV equipment.
Install two new 15/20/25 MVA, Delta-Wye-Grounded, 46/25 kV Power Transformers with On Load Tap Changers.
The tap changers should have 15 % boost and 5 % buck capabilities in 33 positions.
Construct new 46 kV buswork with two breaker bays.
Install two new 46 kV breakers.
Install two new 25 kV transformer load side circuit breakers, and a 25 kV bus tie breaker between B1 and B2.
Install five 25 kV reclosers along with all necessary buswork, disconnects, etc.
Leave provision for two additional reclosers.

BARTLETT SUBSTATION

Remove the Bartlett Substation

Bartlett Substation Feeders 4 and 5 to be removed as far as behind 404 Bartlett Drive.

Install new Normally Open Disconnect behind 404 Bartlett Drive.
Remove double circuit structure on Bartlett Feeders 4 and 5.

Remove Townsite Switching Station.
Remove 46 kV Feeders 10 and 11 along with all associated hardware, disconnects, etc.

WABUSH FEEDER 32 WA32 46 kV

WABUSH FEEDER 33 WA33 46 kV

WABUSH TERMINAL STATION

Install new disconnect on WA33.

WABUSH TOWNSITE SUBSTATION

NEW (N/O)

PROPOSED COMMERCIAL AND INDUSTRIAL DEVELOPMENTS

QNS&L Feeder
Install new 1.25 MVA, 25/23-11.5 kV Single-phase center tapped power transformer at QNS&L Switchyard.
Install 25 kV recloser along with all necessary buswork, metering, etc.
New line construction required to tap into existing QNS&L line (distance to be confirmed).

SEPT ISLES

		SYS PLANNING:	CRW
		SYS OPERATIONS:	--
		TERM DESIGN:	--
		PROTECTION:	--

SHEET 1 OF 1

DATE: NOV 2, 2007

DRAWN BY: CRW

FILE: LABRADOR CITY 25 kV CAPITAL PLAN 2007.SKF

D2

PROPOSED 46 KV SUB-TRANSMISSION UPGRADES

LEGEND:

- Distribution Line 4.16, 12.5, or 25 kV
- Distribution Line 46 kV
- Fused Disconnect Switch
- Ganged Operated Disconnect Switch
- Normally Open Disconnect Switch
- Solid Blade Disconnect Switch
- On Load Tap Changing Transformer Delta - Wye Grounded shown
- Circuit Breaker with CTs
- Recloser with Bypass Switch
- Wabush Feeder 32 (46 kV)
- Wabush Feeder 33 (46 kV)
- Vanier Feeder 33 (46 kV)

Install disconnects on Fermont Line at Tap to Quartzite Substation.

Construct ~450 m of 46 kV line from Fermont Line to Vanier Substation using 477 ASC conductor.
Tie L11 from near TS11-D12 to L33.
Remove Section of L33 between the two new tap locations.

VANIER FEEDER 33
VA33
46 kV

VANIER SUBSTATION

Disconnect switches TS9WA33-1 and TS9-D5 to be removed.

Construct New 46 kV line 477 ASC conductor 300 m in length

QUARTZITE SUBSTATION

Remove Section of L9 between the two new tap locations.

Remove the Townsite Substation.
Remove the Bartlett Substaion.
Remove the Hudson Substation.
Remove the Harrie Lake Substation.
Remove Townsite Feeder 10.
Remove Townsite Feeder 11.

WABUSH FEEDER 33
WA33
46 kV

WABUSH FEEDER 32
WA32
46 kV

Reconductor 266.8 ACSR conductor on TS9 to 477 ASC (~4.5 km).
Rename TS9 to WA32.

Install new disconnect on WA33.

WABUSH TERMINAL STATION

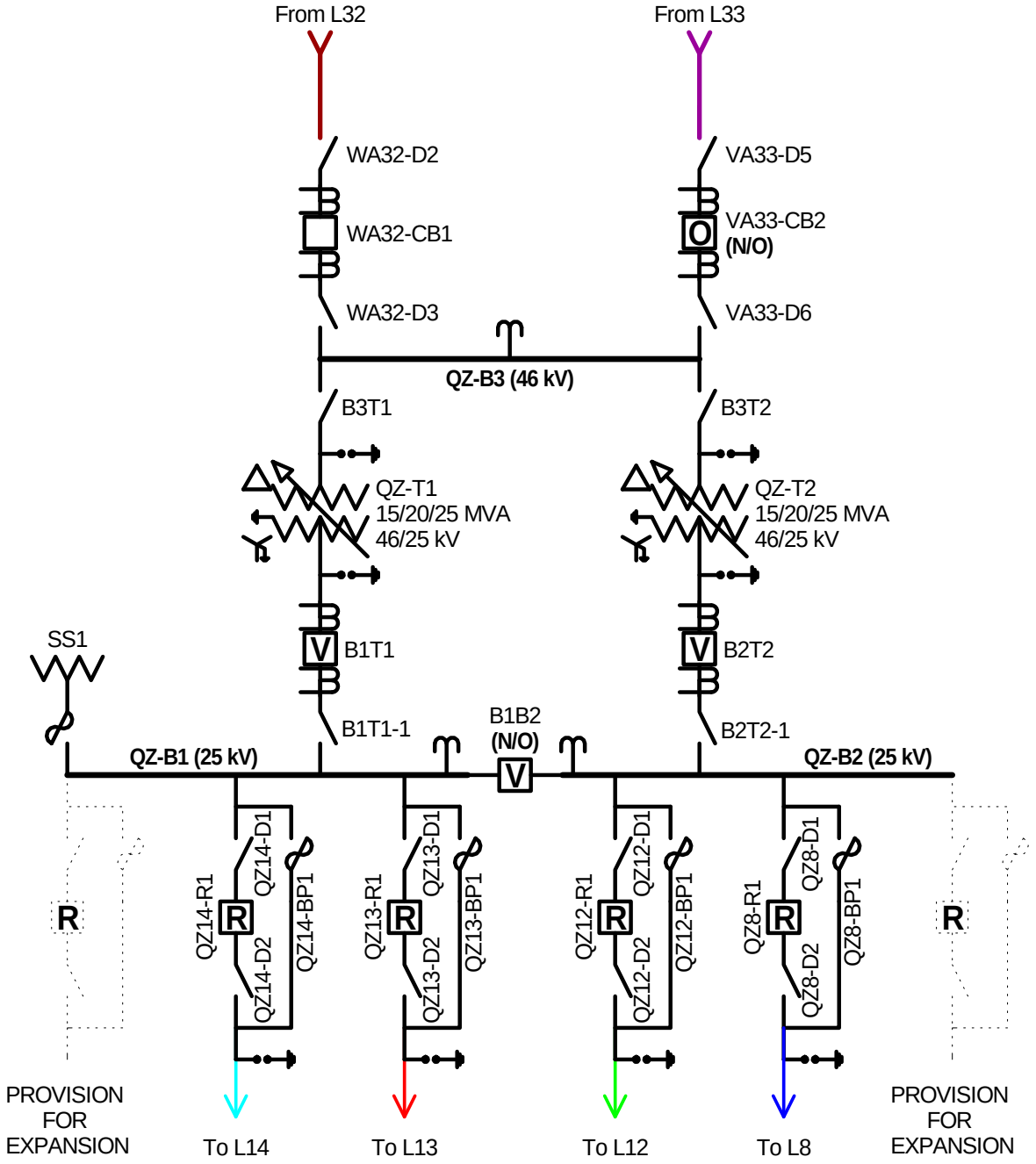
WABUSH TOWNSITE SUBSTATION

		SYS PLANNING: CRW	SHEET 1 OF 1
		SYS OPERATIONS: --	DATE: NOV 2, 2007
		TERM DESIGN: --	DRAWN BY: CRW
		PROTECTION: --	FILE: PROPOSED 46 KV SUB-TRANSMISSION UPGRADES.SKF

D3

PROPOSED QUARTZITE 25 KV SUBSTATION

PROPOSED QUARTZITE 25 kV SUBSTATION

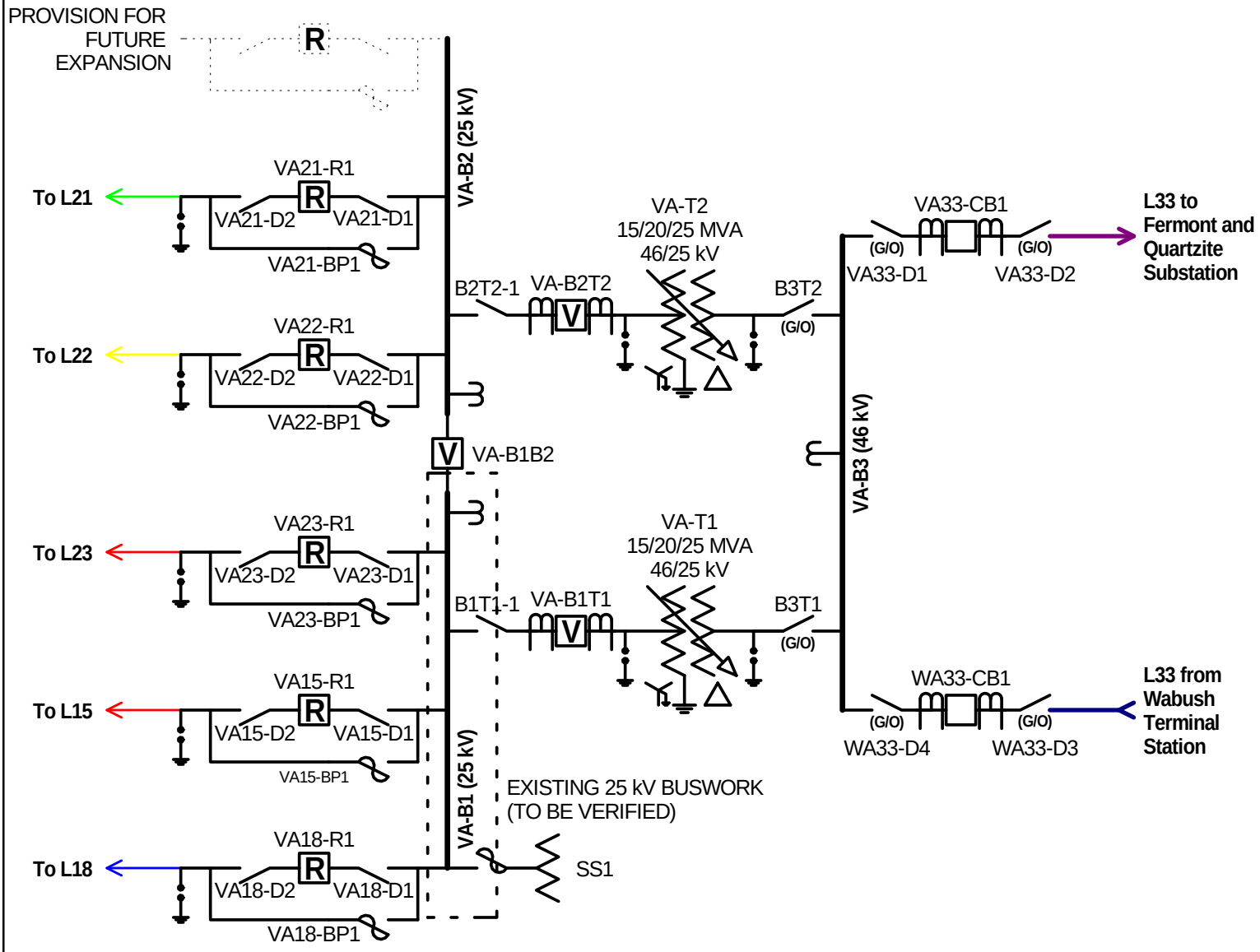


		SYS PLANNING: CRW	SHEET 1 OF 1
		SYS OPERATIONS: --	DATE: NOV 2, 2007
		TERM DESIGN: --	DRAWN BY: CRW
		PROTECTION: --	FILE: PROPOSED QUARTZITE 25 KV SUBSTATION.SKF

D4

PROPOSED VANIER 25 KV SUBSTATION

PROPOSED VANIER 25 kV SUBSTATION



		SYS PLANNING: CRW	SHEET 1 OF 1
		SYS OPERATIONS: --	DATE: NOV 2, 2007
		TERM DESIGN: --	DRAWN BY: CRW
		PROTECTION: --	FILE: PROPOSED VANIER 25 KV SUBSTATION.SKF

APPENDIX E

SCOPE OF WORK FOR THE 25 KV UPGRADING PLAN

SCOPE OF WORK FOR THE 25 KV UPGRADING PLAN

Due to the complexity of this plan and the amount of work required to implement it, it is recommended the upgrades be performed over a number of years. The first phase of the plan will be the upgrading of the Vanier Substation and the portion of Quartzite Substation associated with T2 to 25 kV, the conversion of feeders L6, L7, L8, L21, L22, and L23, the construction of a tie line between Vanier and Quartzite Substation, and reconnecting the Vanier Substation to L33. The second phase would include upgrading the remaining half of the Quartzite Substation to 25 kV, converting feeders L12, L13, L14, L19, and L20 to 25 kV, and the removal of the Harrie Lake Substation from service. The third phase of the upgrades would include converting feeders L1, L2, L3, L4, L5, L15, L16, L17, and L18 to 25 kV, and removing the Bartlett Substation and the Hudson Substation. The final phase of the upgrades will involve removing of the Townsite Switching Station. Once completed the Vanier substation and Quartzite Substation would remain and the Bartlett, Harrie Lake, Hudson, and Townsite Switching Substations would be removed.

Note max foreseeable fault levels for breaker sizing are provided. This takes the following upgrades and conditions into consideration. Maximum foreseeable fault levels include the installation of the third synchronous condenser at Wabush Terminal Station, a third 230 kV circuit into Labrador West, all 46 kV tie switches/breakers closed, and the 25 kV bus tie breaker in the substations closed. Transformer impedances were assumed to be approximately 6 %, similar to Quartzite Transformer No. 2.

1.1 VANIER SUBSTATION

Extend and upgrade the Vanier Substation:

- Extend the Vanier Substation Northward.
- Remove the existing 4.16 kV equipment.
- Install a new control building of suitable size.
- Construct a new transformer pad.
- Construct a 46 kV box structure complete with 46 kV bus and two breakers bays. The structure should be laid out such that and additional breaker can be accommodated in the future.
- Purchase and install two 46 kV breakers.
    - As a minimum the breakers should have the following capabilities:
        - Symmetrical Interrupting Rating: 10631 A, 847 MVA
        - Continuous Current Rating: 941 A.
- Purchase and install two 46/25 kV, 15/20/25 MVA power transformers.
    - Transformers are to be fitted with On Load Tap Changers having 33 positions at 0.625 % per tap. The taps are to have a range from 39.1 kV (0.85) to 48.3 kV (1.05).
- Construct a 25 kV box structure, adjacent to the existing structure.

  - The structure is to contain a 25 kV bus, and three 25 kV breaker bays.
  - The structure is to be laid out such that sufficient space is available for a bus tie breaker, and the transformer load side breakers.
- Purchase three new 25 kV circuit breakers,
  - Two of the breakers will be installed between the transformer load side bushings and the 25 kV bus.
  - The third breaker will be installed as a bus-tie breaker between B1 and B2.
  - As a minimum the breakers should have the following capabilities:
    - Symmetrical Interrupting Rating: 7066 A, 306 MVA
    - Continuous Current Rating: 686 A.
- Purchase and install five reclosers, along with all necessary buswork, etc.
  - As a minimum the reclosers should have the following capabilities:
    - Symmetrical Interrupting Rating: 7066 AIC, 306 MVA,
    - Continuous Current Rating: 560 A.
- Leave the provision for an additional recloser.
- Purchase and install all necessary metering and RTUs to provide full SCADA capabilities to EMS control.
- A total of six 941 A 46 kV disconnect switches will be required.
- A total of two 686 A 25 kV class disconnects will required for isolation of the power transformer and low voltage circuit breaker.
- A total of fifteen 560 A 25 kV class disconnects will required for isolation and the recloser bypass switches.

1.2 QUARTZITE SUBSTATION

Rebuild and upgrade the Quartzite Substation:

- Remove the existing 4.16 kV equipment.
- Install a new control building of suitable size.
- Construct a 46 kV box structure complete with 46 kV bus and two breakers bays. The structure should be laid out such that and additional breaker can be accommodated in the future.
- Purchase and install two 46 kV breakers.
  - As a minimum the breakers should have the following capabilities:
    - Symmetrical Interrupting Rating: 9765 A, 778 MVA.
    - Continuous Current Rating: 941 A.
- Purchase and install two 46/25 kV, 15/20/25 MVA power transformers.
  - Transformers are to be fitted with On Load Tap Changers having 32 tap positions at 0.625 % per tap. The taps are to have a range from 39.1 kV (0.85) to 48.3 kV (1.05).
- Construct two 25 kV box structures.
  - Each structure is to contain a 25 kV bus, and three 25 kV breaker bays.
  - The structures are to be laid out such that sufficient space is available for a bus tie breaker, and for transformer load side breakers.

- Purchase three new 25 kV circuit breakers, two of the breakers will be installed between the transformer load side bushings and each 25 kV bus, the third breaker will be installed as a bus-tie breaker between B1 and B2.
    - As a minimum the breakers should have the following capabilities:
        - Symmetrical Interrupting Rating: 6851 A, 297 MVA.
        - Continuous Current Rating: 686 A.
- Purchase and install four new reclosers, along with all necessary buswork, disconnects, etc.
    - As a minimum the reclosers should have the following capabilities:
        - Symmetrical Interrupting Rating: 6851 A, 297 MVA.
        - Continuous Current Rating: 560 A.
- Leave the provision for two additional reclosers.
- Purchase and install all necessary metering and RTUs to provide full SCADA capabilities to EMS control.
- A total of six 941 A 46 kV disconnect switches will be required.
- A total of two 686 A 25 kV class disconnects will required for isolation of the power transformer and low voltage circuit breaker.
- A total of eighteen 560 A 25 kV class disconnects will required for isolation and the recloser bypass switches.

1.3 DISTRIBUTION FEEDER UPGRADES

1.3.1 Line Extensions/Upgrades

- Construct ~60 m of double circuit line from structure 543 behind 807 Carol Drive to structure 544 behind 807 Carol Drive.
- Extend L15 ~80m from structure 363 (behind 512 Carol Drive) to structure 544 on L18 using 477 ASC Cosmos conductor.
- Upgrade ~180 m of feeder 15 from structure 360 to structure 363 to 3-Phase.
- Extend L15 ~80m from structure 385 (behind 618 Carol Drive) to structure 691 on L6 (behind 621 Carol Drive) using 477 ASC Cosmos conductor.
- Open L18 between structure 535 and structure 536 near the Vanier Substation.
- Construct ~90 m of 3-Phase line from the Vanier Substation to structure 536.
- Construct ~90 m of 3-Phase line from the Vanier Substation to structure 535.

The total required line extensions and upgrades to the low voltage distribution system is approximately 580 m. Since the system will be designed for contingency switching ability, and to remain consistent with the existing infrastructure, the type of conductor to be used for the above noted upgrades should be 477 ASC Cosmos.

1.3.2 Feeder Reconfigurations

Since the number of feeders will be reduced, some of the existing lines will have to be reconfigured. Most of this work will involve transferring existing feeders or sections of feeders to new 25 kV lines. The majority of the reconfigurations can be done using existing disconnects and tie switches. Load and Voltage Study results are required before feeder configurations can be finalized. The following describes a proposed reconfiguration based on the information currently available to provide roughly equal loading on each line. This work assumes that the line construction and upgrades described in the preceding section have already been completed, and that the voltage conversions on the respective line sections will be completed at the time they are transferred.

- Open feeder VA23 at structure 546. Reconnect the section of VA23 that feeds the Labrador City Mall to feeder VA22.
- Open disconnect QZ7-D2. Reconnect the section of QZ7 from Centennial Drive to Churchill Street to feeder VA22 by closing tie switch QZ7VA22-1.
- Open disconnect QZ6-D4, and close tie switches HU18VA23-1 and QZ6HU18-1 to transfer a section of feeder HU18 and feeder QZ6 to feeder VA23.
- Open L15 at structure 380 on both the source and load sides. Close tie switch BA2HU15-1 and open disconnect BA2-D4 to transfer the bulk of feeder BA2 to the new feeder VA23.
- Open disconnect BA1-D1, and close tie switch BA1BA2-1 to transfer the whole of feeder BA1 to the new feeder VA23.
- Open disconnect QZ8-D8, and close the tie switch BA1QZ8-1 to transfer the respective section of feeder QZ8 to the new feeder VA23.
- Open L15 at structure 338. Transfer the whole of feeder HU15 to the new feeder VA15 by closing the disconnect HU15-D6.
- Transfer feeder BA3 to the new feeder VA15 by closing the tie switch BA3HU15-1.
- Transfer the remainder of feeder BA2 to the new feeder VA15 by jumpering the lines together at structure 183.
- Open the disconnect HU17-D10. Jumper the lines sections of BA1, BA2, BA3, and HU17 just outside the Bartlett Substation together to transfer the respective section of feeder HU17 to the new feeder VA15.
- Open disconnect HU17-D12 and transfer the section of feeder HU17 bounded by HU17-D10 and HU17-D12 to the new feeder VA15.
- Transfer the sections of feeder HU18 bounded by HU18VA21-2, HU18-D2, HU18-D7 and the industrial park to feeder VA21.
- Open feeder HU16 and install a normally open disconnect at structure 1439. Reconnect the section of L16 bounded by Airport Road and Humphrey Avenue to the new feeder VA21 by closing tie switch HU16HU18-1.
- Transfer the remainder of feeder HU18 from Vanier Substation to Hudson Substation to the new feeder VA18.
- Transfer the remainder of feeder HU17 to the new feeder VA18 by jumpering the lines near the Hudson Substation.

- Transfer the remainder of feeder HU16 to the new feeder VA18 by closing the tie switch HU16HU17-1.
- Transfer feeder QZ6 to the new feeder QZ8 by closing the tie switch QZ6QZ8-1.
- Transfer the remainder of feeder QZ7 to the new feeder QZ8 by jumpering the lines together at structure 580.
- Transfer the remaining of section feeder HU15 bounded by tie switch QZ6HU15-1 and structure 380.
- Transfer a section of feeder QZ13 to feeder QZ12 by opening the disconnect QZ13-D4 and closing the tie switch QZ12QZ13-1.
- Transfer a section of feeder QZ8 to feeder QZ12 by opening the disconnect QZ8-D6 and closing the tie switch QZ8QZ12-2.
- Transfer a section of feeder BA5 to feeder QZ12 by opening the disconnect BA5-D3 and closing the tie switch BA5QZ12-1.
- Transfer a section of feeder BA5 to feeder QZ12 by opening the disconnect BA5-D5 and closing the tie switch BA5QZ12-3.
- Transfer a section of feeder BA4 to feeder QZ13 by opening the disconnect BA4-D8 and closing the tie switch BA4QZ13-2.
- Transfer the remainder of feeders BA4 and BA5 to feeder QZ13 by opening disconnects BA4-D1 and BA5-D1, closing the tie switch BA4QZ13-1 and jumpering BA4 and BA5 together at structure 246.
- Install a normally open disconnect between the new feeders QZ13 and VA15 at the structure behind 404 Bartlett Drive.
- Transfer feeder HL19 to feeder QZ14 by opening the disconnect HL19-D1 and closing the tie switch QZ14HL19-1.
- Transfer feeder HL20 to feeder QZ14 by opening the disconnect HL20-D1 and closing the tie switch QZ14HL20-1.

The above work will complete the conversion and reconfiguration of the 4.16 kV distribution feeders to the new 25 kV distribution system. The reconfiguration will off load the Bartlett, Hudson, and Harrie Lake Substations and will allow them to be removed from service.

1.3.3 Primary and Underground Services

There are a number of primary, underground, and customer owned services in Labrador City. The system will have to be surveyed to determine the exact number. The previous plan determined that most of the customers are willing to be switched to overhead services. However, as this would involve replacement of underground cables, removal of padmount and indoor transformers, and replacement of service entrances, completely converting the services to overhead may prove to be costly. An alternate solution to serve these customers is to install pole mounted 25/4.16 kV step-down transformers and continue to supply these customers at 4.16 kV, therefore the underground services could remain intact.

The Smokey Mountain line is a section of feeder Vanier 21, it runs from the Beverly Lake Water Supply to the Smokey Mountain Ski Hill. Much of this line is not constructed to NL Hydro Standards and to convert it would require significant upgrading of approximately 5.7 km of distribution line. To lower the cost of conversions a step down transformer should be installed so that the line can continue to be operated at 4.16 kV.

The Labrador City Mall is fed by five underground primary services which run under the mall parking lot to indoor transformers (1 MVA) inside the building. Pole/platform mounted transformers should be installed to avoid complete replacement of the existing customer owned equipment.

1.3.4 QNS&L Railway Feeder

The Quebec North Shore and Labrador Railway (QNS&L) line is a 23/11.5 kV single-phase center-tapped customer owned line. The line runs from Labrador City, NL to Sept Isles, PQ, and is constructed with two hot conductors and uses a ground return path for phase to neutral connected loads. Currently this line is fed from the Hudson Substation via a pair of 2.4/23-11.5 kV single-phase power transformers (400 kVA each). The center-tap connection on the transformers is grounded to provide the neutral return path for the line.

The line is metered at the substation and demand readings show this line has exceeded the capacity of the transformers by 19 % of the rated nameplate capacity. The load on this customer owned line will require a capacity increase. It is recommended to replace the existing transformers with two 25/23-11.5 kV, 1 MVA units once the conversion of L16 to 25 kV is completed. The transformers will no longer be located at Hudson Substation as it is slated for removal. Instead the transformers will be located within QNSLs railway yard in the Labrador City Industrial Park. The supply will come off of two phases of L16 (i.e. line-to-line), and will be connected to the line section of L16 that is operated by the QNS&L Railway. The section of the QNS&L line that is located between the Hudson and the new QNS&L substation is to be removed.

1.4 46 KV SUBTRANSMISSION FEEDER UPGRADES

The present 46 kV system in Labrador City consists of a single 46 kV line (L32) from Wabush Terminal Station to the Townsite Switching Station, and three radial feeders (L9, L10, and L11) which serve the 46/4.16 kV substations. A second feeder from Wabush Terminal Station (L33) runs to Fermont, Quebec. There are tie points on this line near the Townsite, Hudson, Vanier, and Harrie Lake Substations. This forms a quasi-looped system. However utilizing this loop requires manual switching operations by the regions line crews, and since only a

single feed runs into the individual substations the effectiveness of this configuration is somewhat limited.

To improve the operability of this system, the 46 kV subtransmission system will be upgraded to a looped system similar to the electrical systems in Corner Brook, and Stephenville. At least two feeds will be brought into each substation, with control provided by the high voltage breakers in the substations.

The line to ground fault levels on the 46 kV system in Labrador West are limited to approximately 24 MVA (300 A). This is for purposes of protecting the machinery at the mine sites. Additionally the ground resistivity in the region is rather high; therefore to adequately protect the system from line-to-ground faults it will be necessary to operate the system as an open loop.

Since two substations will remain in the 25 kV system, a single tie line will be constructed between Vanier Substation and Quartzite Substation.

The work to upgrade the 46 kV subtransmission system to an open loop will involve the following:

- Construct approximately 300 m of 46 kV (3ART Structure Type, 477 ASC – Cosmos) line from the Quartzite Substation to the nearest point on L9 (near the intersection of Cavendish Crescent and Bartlett Drive).
- Remove the section of L9 between the new tap to the substation and the existing tap to the substation (two to three spans).
- Under contingency the 266.8 ACSR Partridge conductor on L9 does not have sufficient capacity to supply the Labrador City Distribution and Fermont. Therefore this line (~4.5 km) will be reconductored to 477 ASC Cosmos.
- Construct approximately 450 m of 46 kV (3ART Structure Type, 477 ASC – Cosmos) line from the Vanier Substation to the nearest point on L33 (near the Beverley Lake Pumping Station where L11 and L33 separate).
- Open and remove switch TS11-D12. Jumper over switch TS11WA33-2 and remove the tie switch. The Vanier Substation will be fed via L33.
- Remove the section of L33 between the two taps to the Vanier Substation (approximately one span).
- Purchase and install three disconnect switches on L33 at the Fermont-Harrie Lake tap. The switches may be gang operated and capable of carrying up to 81 MW of power.
- Purchase and install a 46 kV disconnect on L33 just after the tie switch WA33WA36-1.

To enable energizing of L33 while still remaining isolated from Fermont. The border switch WA33-D3 will be kept normally open. The health of this line will be monitored as far as the border switch by the breaker at Vanier Substation, VA33-CB1. It will be necessary to inform Hydro Quebec of the proposed new operating arrangement, so they can arrange for monitoring the health of the line at their end.

Upon completion of the above noted work on the 46 kV System the following equipment is to be removed:

- Remove 46 kV disconnects and tie switches TS11WA33-1, TS9TS10-1, TS11-D2, TS11-D12, TS11WA33-2, TS9-D5, TS9WA33-1, WA33-D2.
- Remove L11 and all associated hardware.
- Remove L10 and all associated hardware.

1.5 ASSET RETIREMENTS

Upon completion of this work the following assets are to be retired:

- Remove 46 kV disconnects and tie switches TS11WA33-1, TS9TS10-1, TS11-D2, TS11-D12, TS11WA33-2, TS9-D5, TS9WA33-1, WA33-D2.
- Remove L10 and all associated hardware.
- Remove L11 and all associated hardware.
- Feeder L9 is to be retired, this asset will be transferred to L32.
- Remove the Bartlett Substation and all associated hardware.
- Remove the Hudson Substation and all associated hardware.
- Remove the Harrie Lake Substation and all associated hardware.
- Remove the double circuit on BA4 and BA5.

APPENDIX F

12.5 KV DISTRIBUTION UPGRADING PLAN

SINGLE LINE DIAGRAMS

F1

LABRADOR CITY 12.5 KV CAPITAL PLAN 2007

LEGEND:

- Distribution Line 4.16, 12.5, or 25 kV.
- New Construction.
- Equipment to be removed.
- Distribution Line 46 kV.
- Fused Disconnect Switch.
- Ganged Operated Disconnect Switch.
- Normally Open Disconnect Switch.
- Solid Balde Disconnect Switch
- Transformer - Delta - Wye Grounded shown.
- Circuit Breaker with CTs.
- Recloser with Bipass Switch.
- Bartlett Feeder 1 (12.5 kV)
- Bartlett Feeder 2 (12.5 kV)
- Bartlett Feeder 3 (12.5 kV)
- Bartlett Feeder 4 (12.5 kV)
- Bartlett Feeder 5 (12.5 kV)
- Bartlett Feeder 17 (12.5 kV)
- Quartzite Feeder 6 (12.5 kV)
- Quartzite Feeder 7 (12.5 kV)
- Quartzite Feeder 8 (12.5 kV)
- Townsite Feeder 9 (46 kV)
- Townsite Feeder 10 (46 kV)
- Townsite Feeder 33 (46 kV)
- Quartzite Feeder 12 (12.5 kV)
- Quartzite Feeder 13 (12.5 kV)
- Quartzite Feeder 14 (12.5 kV)
- Vanier Feeder 15 (12.5 kV)
- Vanier Feeder 18 (12.5 kV)
- Vanier Feeder 21 (12.5 kV)
- Vanier Feeder 22 (12.5 kV)
- Vanier Feeder 23 (12.5 kV)
- Wabush Feeder 32 (46 kV)
- Wabush Feeder 33 (46 kV)

Install disconnects on Fermont Line at Tap to Quartzite Substation.

PROPOSED NEW HOSPITAL

PROPOSED NEW COLLEGE

Possible System Expansion
New Hospital and New College
Distance: ~2000m
Conductor: 4/0 AASC

Construct ~450 m of 46 kV line from Fermont Line to Vanier Substation using 477 ASC conductor.
Tie L11 from near TS11-D12 to L33.
Remove Section of L33 between the two new tap locations.

SMOKEY MOUNTAIN

Install 25-12.5/4.16 kV Transformer at start of tap to Smokey Mountain Ski Hill. Transformer Size to be Determined.

PROPOSED RESIDENTIAL DEVELOPMENTS

Quartzite Substation
Remove the existing 4.16 kV equipment.
Reconfigure transformer T2 (10/13.3/16.7 MVA, 46/12.5-4.16 kV) to 12.5 kV operation.
Install new 10/13.3/16.7 MVA, 46/25-12.5 kV Power Transformer.
Construct a 46 kV buswork with two 46 kV circuit breaker bays.
Install two 46 kV Circuit Breakers.
Install two new circuit breakers on transformer load side, and bus tie breaker between B1 and B2.
Install six reclosers along with all necessary buswork, etc.

QUARTZITE SUBSTATION

Construct ~1300m of 3-phase distribution line from Quartzite Substation to Harrie Lake Trailer Park using 477 ASC Cosmos conductor.

Remove Harrie Lake Substation

TAMARACK GULF CLUB
(CUSTOMER OWNED LINE)

Install 25-12.5/4.16 kV Transformer at start of Tamarak Golf Course Customer Owned Line.
Transformer Size to be Determined.

QZ14 12.5 kV
QZ13 12.5 kV
QZ12 4.16 kV
QZ8 12.5 kV
QZ7 12.5 kV
QZ6 12.5 kV

VA21 12.5 kV
VA22 12.5 kV
VA23 12.5 kV
VA15 12.5 kV
VA18 12.5 kV

VANIER SUBSTATION

Vanier Substation
Remove the existing 46/4.16 kV transformer.
Install two new 10/13.3/16.7 MVA, 46/25-12.5 kV Power Transformers.
Existing reclosers to be reconfigured for 12.5 kV operation.
Construct new buswork B2.
Construct a 46 kV buswork with three 46 kV circuit breaker bays.
Install three 46 kV Circuit Breakers.
Install two new circuit breakers on transformer load side, and a bus tie breaker between B1 and B2.
Install two new circuit reclosers, along with all necessary buswork, etc.
Leave provision for an additional recloser.

New line construction, ~90m, 477 ASC

EXISTING EQUIPMENT 25 kV Buswork 15 kV Reclosers

Extend L15 ~80m from Str. 363 (behind 512 Carol Drive) to Str. 544 on L18 using 477 ASC Cosmos conductor.

OPEN LINE 18 NEAREST VANIER SUBSTATION.

Upgrade ~180 m of L15 to 3-Phase from Str. 360 to Str. 363.

Str. 380

Str. 205

Reconnect section of L15 to L3.

HUDSON SUBSTATION

Remove Hudson Substation.

Remove QNS&L Feeder as far as new stepup transformer.

BA2 12.5 kV
BA1 12.5 kV
BA3 12.5 kV
BA17 12.5 kV
BA10 46 kV
BA5 12.5 kV
BA4 12.5 kV
TS10 46 kV

BARTLETT SUBSTATION

Bartlett Substation
Remove the existing 46/4.16 kV transformers.
Install two new 10/13.3/16.7 MVA, 46/25-12.5 kV Power Transformers.
Construct a 46 kV buswork with two 46 kV circuit breaker bays.
Install two 46 kV Circuit Breakers.
Existing Switchgear to be reconfigured for 12.5 kV operation.
Power cables to either be replaced with 15 kV rated cables or changed to overhead takeoffs.

LINE EXTENSION AP LOW SCHOOL TO BEHIND 8 ELM CRESCENT. ~70m, 477 ASC

New Feeder Construction
Bartlett Feeder 4 behind 200 Lakeside Drive to Labrador City Industrial Park
Distance: ~700m
Conductor: 477 ASC

PROPOSED COMMERCIAL AND INDUSTRIAL DEVELOPMENTS

QNS&L Feeder
Install new 1.25 MVA, 25-12.5 kV/23-11.5 kV Single-phase center tapped power transformer at QNS&L Switchyard.
Install 25 kV recloser along with all necessary buswork, metering, etc.
New line construction required to tap into existing QNS&L line (distance to be confirmed).

TS9 46 kV
WA33 46 kV
WA32 46 kV
TS33 46 kV

TOWNSITE SWITCHING STATION

Townsite Switching Station
Construct ring bus.
Install five 46 kV circuit breakers.
Connect WA32 and WA33 into ringbus.
Connect L9, L10, and outgoing L33 into ringbus.
Leave the provision for a additional section in the ring.

WABUSH TERMINAL STATION

Alternate to rebuilding of Townsite Switching Station.
Install 46 kV circuit breaker at Wabush Terminal Station.
Construct ~1.75 km of 3-phase 46 kV distribution line from Wabush Terminal Station to Townsite Switching Station.
Remove Townsite Switching Station.

WA36 46 kV

Install new disconnect on WA33.

WABUSH TOWNSITE SUBSTATION

SEPT ISLES

SYS PLANNING:	CRW	SHEET 1 OF 1	
SYS OPERATIONS:	--	DATE: NOV 6, 2007	
TERM DESIGN:	--	DRAWN BY: CRW	
PROTECTION:	--	FILE: LABRADOR CITY 12.5 kV CAPITAL PLAN 2007.SKF	

F2

PROPOSED 46 KV SUB-TRANSMISSION UPGRADES

LEGEND:

- Distribution Line 4.16, 12.5, or 25 kV.
- New Construction.
- Equipment to be removed.
- Distribution Line 46 kV.
- Fused Disconnect Switch.
- Ganged Operated Disconnect Switch.
- Normally Open Disconnect Switch.
- Solid Balde Disconnect Switch
- Transformer - Delta - Wye Grounded shown.
- Circuit Breaker with CTs.
- Recloser with Bipass Switch.
- Townsite Feeder 9 (46 kV)
- Townsite Feeder 10 (46 kV)
- Townsite Feeder 33 (46 kV)
- Wabush Feeder 32 (46 kV)
- Wabush Feeder 33 (46 kV)
- Vanier Feeder 33 (46 kV)

Install disconnects on Fermont Line at Tap to Quartzite Substation.

VA33 46 kV

46 kV Tie line between Vanier Substation, Quartzite Substation, and Fermont.

VANIER FEEDER 33 VA33 46 kV

Construct ~450 m of 46 kV line from Fermont Line to Vanier Substation using 477 ASC conductor.
Tie L11 from near TS11-D12 to L33.
Remove Section of L33 between the two new tap locations.

New 46 kV line construction. ~450m, 477 ASC

Vanier Substation
Existing transformer to be removed.
Install two new 10/13.3/16.7 MVA, 46/25-12.5 kV Power Transformers.
Existing reclosers to be reconfigured for 12.5 kV operation.
Construct new buswork.
Install two new circuit breakers on transformer high side.
Install two new circuit breakers on transformer load side, and bus tie breaker between B1 and B2.
Install two new reclosers, along with all necessary buswork, etc.
Leave provision for an additional recloser.

VANIER SUBSTATION

TS33 46 kV

BA10 46 kV

New 46 kV line construction. ~1.25 km, 477 ASC

46 kV Tie line between Vanier Substation, and Bartlett Substation.

Disconnect switches TS9WA33-1 and TS9-D5 to be removed.

Construct New 46 kV line 477 ASC conductor 300 m in length

TS9 46 kV

QUARTZITE SUBSTATION

VA33 46 kV

Quartzite Substation
Existing 4.16 kV equipment to be removed.
Reconfigure Transformer T2 (10/13.3/16.7 MVA, 46/12.5-4.16 kV) for 12.5 kV operation.
Install new 10/13.3/16.7 MVA, 46/25-12.5 kV Power Transformer.
Install two new circuit breakers on transformer high side.
Install two new circuit breakers on transformer load side, and bus tie breaker between B1 and B2.
Install six reclosers along with all necessary buswork, etc.

Remove Section of L9 between the two new tap locations.

Bartlett Substation
Existing transformers to be removed.
Install two new 10/13.3/16.7 MVA, 46/25-12.5 kV power transformers.
Install two new circuit breakers on transformer high side.
Reconfigured existing switchgear for 12.5 kV operation.
Power cables to either be replaced with 15 kV rated cables or changed to overhead takeoffs.

BARTLETT SUBSTATION

BARTLETT FEEDER 10 BA10 46 kV

TS10 46 kV

Remove L11 along with all associated hardware, disconnects, etc.

Remove disconnect switch TS9TS10-1.

TOWNSITE FEEDER 10 TS10 46 kV

TOWNSITE FEEDER 33 TS33 46 kV

TOWNSITE FEEDER 9 TS9 46 kV

TOWNSITE SWITCHING STATION

WABUSH FEEDER 33 WA33 46 kV

WABUSH FEEDER 32 WA32 46 kV

WABUSH TERMINAL STATION

Townsite Switching Station
Ring bus fed via WA32 and WA33.

Install new disconnect on WA33.

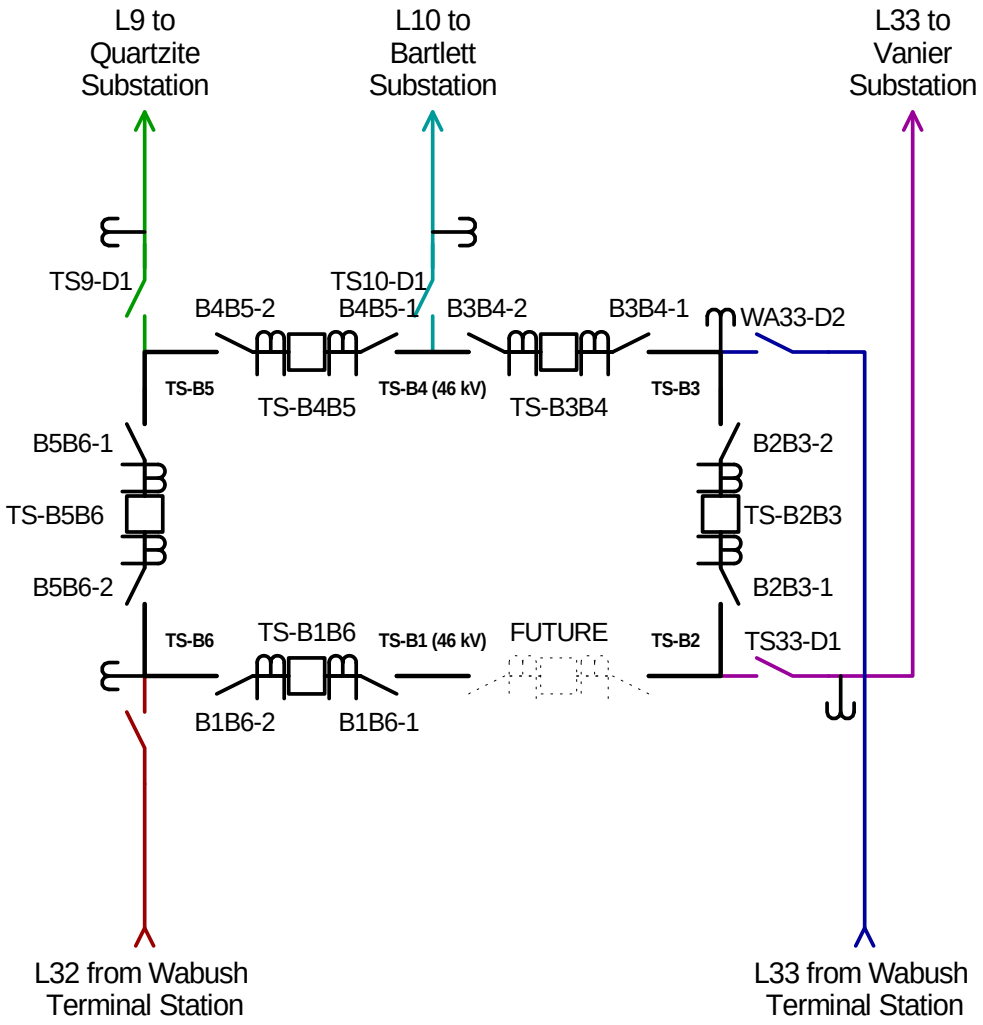
WABUSH TOWNSITE SUBSTATION

SYS PLANNING:	CRW	SHEET 1 OF 1	
SYS OPERATIONS:	--	DATE: NOV 6, 2007	
TERM DESIGN:	--	DRAWN BY: CRW	
PROTECTION:	--	FILE: PROPOSED 46KV SUB-TRANSMISSION UPGRADES.SKF	

F3

PROPOSED TOWNSITE SWITCHING SUBSTATION

PROPOSED
TOWNSITE SWITCHING SUBSTATION



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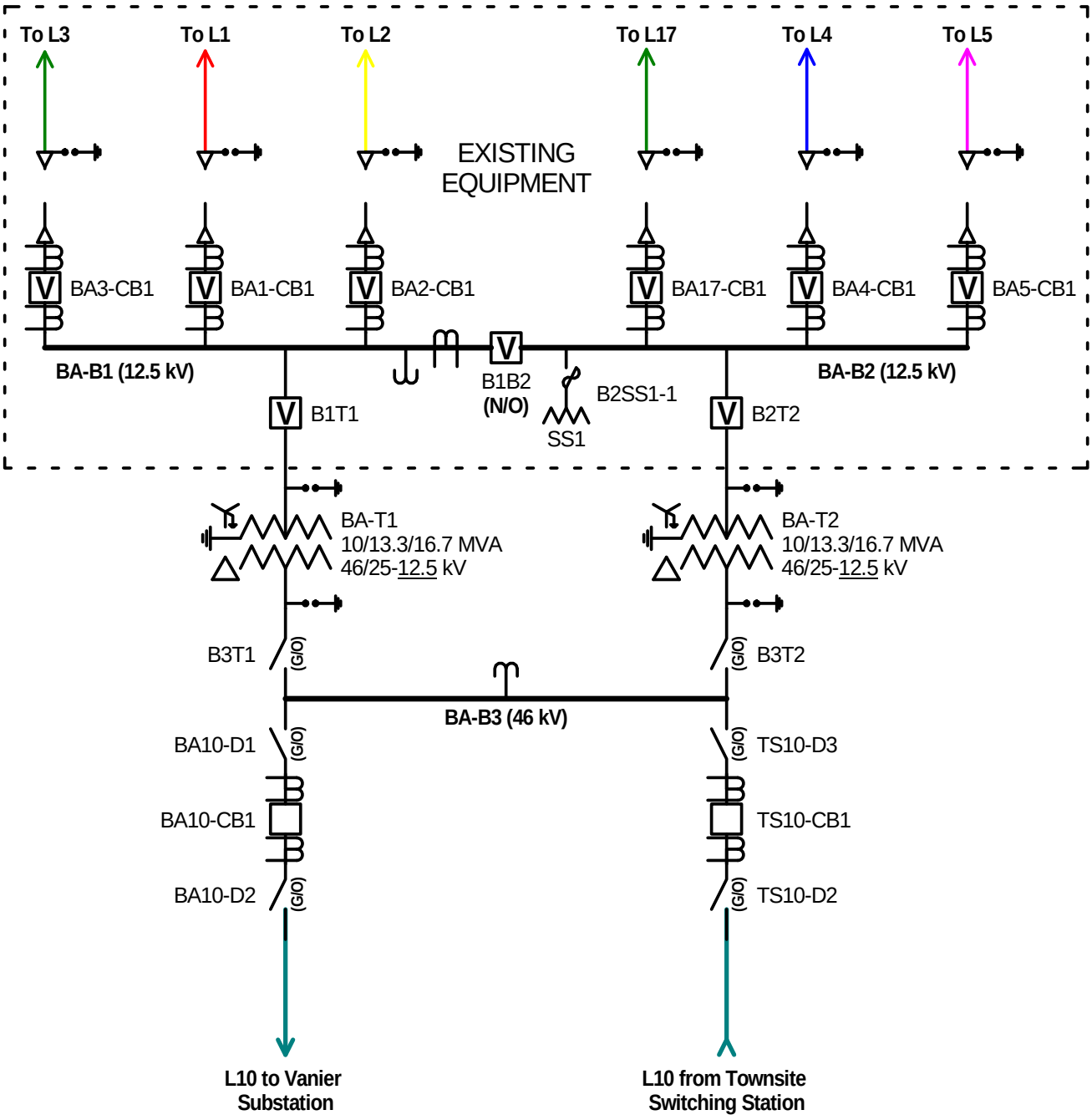
F4

PROPOSED BARTLETT 12.5 KV SUBSTATION

PROPOSED BARTLETT 12.5 kV SUBSTATION



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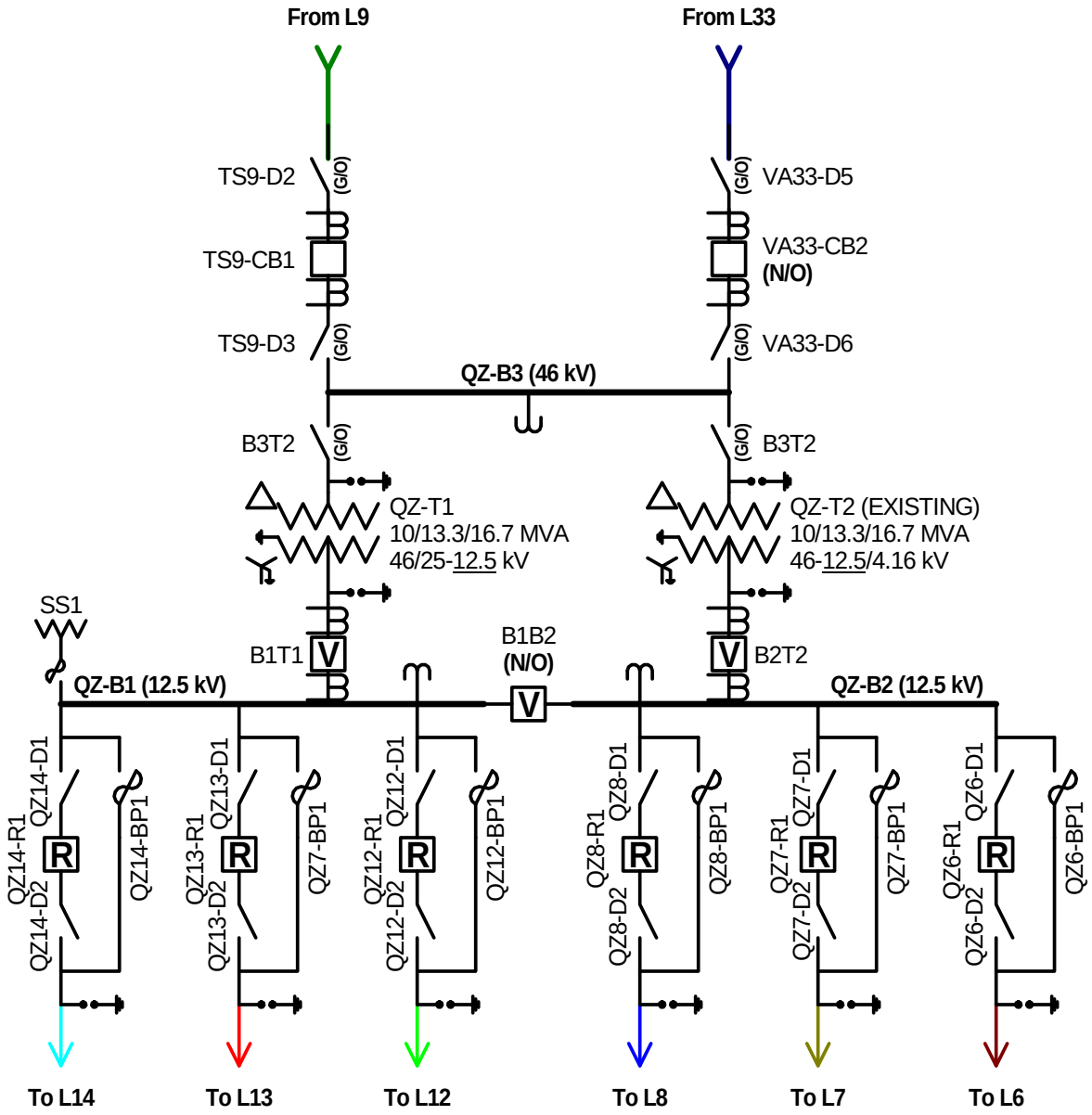
F5

PROPOSED QUARTZITE 12.5 KV SUBSTATION

PROPOSED QUARTZITE 12.5 kV SUBSTATION



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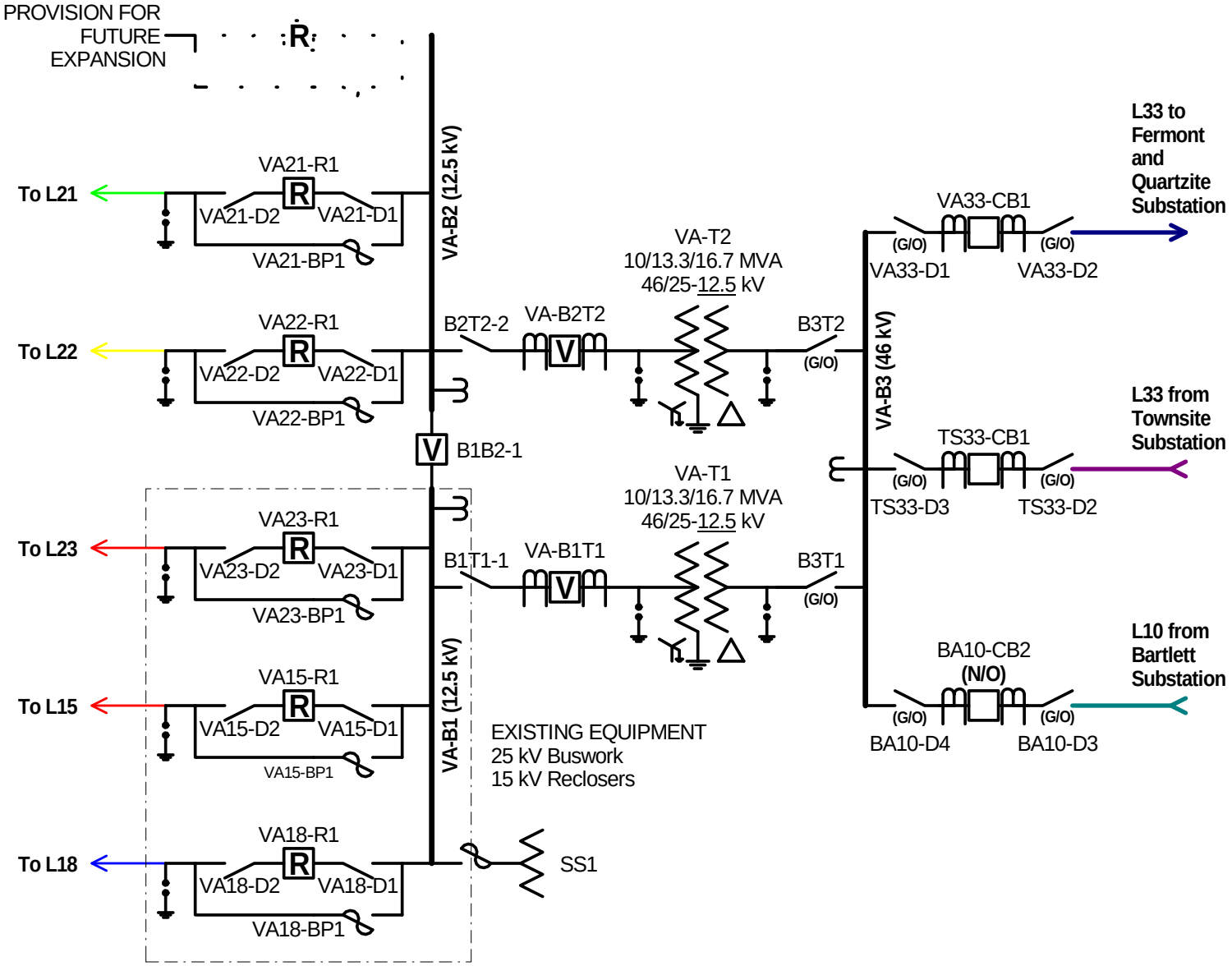
F6

PROPOSED VANIER 12.5 KV SUBSTATION

PROPOSED VANIER 12.5 kV SUBSTATION



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APPENDIX G

SCOPE OF WORK FOR THE 12.5 KV UPGRADING PLAN

SCOPE OF WORK FOR THE 12.5 KV UPGRADING PLAN

Due to the complexity of this plan and the amount of work required to implement it, it is recommended the upgrades be performed over a number of years. The first phase of the plan will be the upgrading of the Vanier Substation and the portion of Quartzite Substation associated with T2 to 12.5 kV, the conversion of feeders L6, L7, L8, L21, L22, and L23 to 12.5 kV, the construction of a 46 kV tie line between Vanier and Quartzite Substation, and reconnecting the Vanier Substation to L33. The second phase would include upgrading the remaining half of the Quartzite Substation to 12.5 kV, construction of a distribution line from Quartzite Substation to Harrie Lake Substation, converting feeders L12, L13, L14, L19, and L20 to 12.5 kV, and the removal of the Harrie Lake Substation from service. The third phase of upgrading will include the following work: Constructing a 46 kV tie line between the Bartlett Substation and the Vanier Substation. Converting feeders L1, L2, L3, L4, and L5 to 12.5 kV, and upgrading the Bartlett Substation to 12.5 kV, upon conversion of Bartlett Substation, feeders L15, L16, L17, and L18 will be converted to 12.5 kV and the Hudson Substation could then be removed from service. The final phase of the upgrades will involve reconstruction of the Townsite Switching Station to a ring bus. Once completed the Bartlett Substation, Vanier Substation, and Quartzite Substation would remain in service, and the Harrie Lake Substation and Hudson Substation would be removed.

All construction associated with the 12.5 kV upgrading plan is to be built to 25 kV standards. This will allow the provision for a future conversion of the 12.5 kV system to 25 kV should phenomenal load growth occur.

Note max foreseeable fault levels for breaker sizing are provided. This takes the following upgrades and conditions into consideration. Maximum foreseeable fault levels include the installation of the third synchronous condenser at Wabush Terminal Station, a third 230 kV circuit into Labrador West, all 46 kV tie switches/breakers closed, and the 25 kV bus tie breaker in the substations closed. Transformer impedances were assumed to be approximately 6 %, similar to Quartzite Transformer No. 2.

1.1 VANIER SUBSTATION

Extend and Upgrade the Vanier Substation:

- Extend the Vanier Substation Northward.
- Remove the existing 4.16 kV equipment.
- Install a new control building of suitable size.
- Install new transformer pad.
- Construct a 46 kV box structure complete with 46 kV bus and three breakers bays.

- Purchase and install 3x46 kV breakers.
    - As a minimum the breakers should have the following capabilities:
        - Symmetrical Interrupting Rating: 12502 A, 996 MVA.
        - Continuous Current Rating: 838 A.
- Purchase and install two 46/25-12.5 kV, 10/13.3/16.7 MVA power transformers.
    - Transformers are to be fitted with fixed taps having 2 raise and 2 lower at 2.5 % per tap.
- Reconfigure the existing reclosers for 12.5 kV operation.
- Construct a 25 kV box structure, adjacent to the existing structure.
    - The structure is to contain a 12.5 kV bus, and three 25 kV class breaker bays.
    - The structure is to be laid out such that sufficient space is available for a bus tie breaker, and the transformer load side breakers.
- Purchase three new 12.5 kV circuit breakers.
    - Two of the breakers will be installed between the transformer load side bushings and the 12.5 kV bus.
    - The third breaker will be installed as a bus-tie breaker between B1 and B2.
    - As a minimum the breakers should have the following capabilities:
        - Symmetrical Interrupting Rating: 11155 A, 483 MVA.
        - Continuous Current Rating: 916 A.
- Purchase and install two new feeder breakers, along with all necessary buswork, disconnects, etc.
    - As a minimum the breakers should have the following capabilities:
        - Symmetrical Interrupting Rating: 11155 A, 483 MVA.
    - Continuous Current Rating: 560 A.
- Leave the provision for an additional breaker.
- Purchase and install all necessary metering and RTUs to provide full SCADA capabilities to EMS control.
- A total of eight 838 A 46 kV disconnect switches will be required.
- A total of two 916 A 25 kV class disconnects will required for isolation of the power transformer and low voltage circuit breaker.
- A total of fifteen 560 A 25 kV class disconnects will required for isolation and the recloser bypass switches.

1.2 QUARTZITE SUBSTATION

Rebuild and upgrade the Quartzite Substation:

- Remove the existing 4.16 kV equipment.
- Install a new control building of suitable size.
- Construct a 46 kV box structure complete with 46 kV bus and two breakers bays.
- Purchase and install two 46 kV breakers.

  - As a minimum the breakers should have the following capabilities:
    - Symmetrical Interrupting Rating: 9739 A, 776 MVA.
    - Continuous Current Rating: 838 A.
- Purchase and install one 46/25-12.5 kV, 10/13.3/16.7 MVA power transformer along with all associated buswork, isolation, etc.
  - Transformer is to be fitted with fixed taps having 2 raise and 2 lower at 2.5 % per tap.
- Reconfigure the windings on Transformer T2 (10/13.3/16.7 MVA, 46/12.5-4.16 kV) to 12.5 kV operation.
- Construct two 25 kV box structures.
  - The structure is to contain a 12.5 kV bus, and three 25 kV class breaker bays.
  - The structure is to be laid out such that sufficient space is available for a bus tie breaker, and the transformer load side breakers.
- Purchase three new 12.5 kV circuit breakers.
  - Two of the breakers will be installed between the transformer load side bushings and the 12.5 kV bus.
  - The third breaker will be installed as a bus-tie breaker between B1 and B2.
  - As a minimum the breakers should have the following capabilities:
    - Symmetrical Interrupting Rating: 10459 A, 453 MVA.
    - Continuous Current Rating: 916 A.
- Purchase and install six new feeder breakers, along with all necessary buswork, disconnects, etc.
  - As a minimum the breakers should have the following capabilities:
    - Symmetrical Interrupting Rating: 10459 A, 453 MVA.
    - Continuous Current Rating: 560 A.
- Leave the provision for an additional breaker.
- Purchase and install all necessary metering and RTUs to provide full SCADA capabilities to EMS control.
- A total of six 838 A 46 kV disconnect switches will be required.
- A total of two 916 A 25 kV class disconnects will required for isolation of the power transformer and low voltage circuit breaker.
- A total of eighteen 560 A 25 kV class disconnects will required for isolation and the recloser bypass switches.

1.3 BARTLETT SUBSTATION

Upgrade the Bartlett Substation:

- Remove the existing 46/4.16 kV power transformers and associated equipment.
- Install a new control building of suitable size if there is insufficient space in the existing switchgear building to accommodate the necessary controls associated with the 46 kV breakers.

- Construct a 46 kV box structure complete with 46 kV bus and two breaker bays.
- Purchase and install two 46 kV breakers.
    - As a minimum the breakers should have the following capabilities:
        - Symmetrical Interrupting Rating: 13353 A, 1064 MVA.
        - Continuous Current Rating: 838 A.
- Purchase and install two 46/25-12.5 kV, 10/13.3/16.7 MVA power transformers.
    - Transformers are to be fitted with fixed taps having 2 raise and 2 lower at 2.5 % per tap.
- Reconfigure the existing switchgear to operate at 12.5 kV.
- Purchase and install all necessary metering and RTUs to provide full SCADA capabilities to EMS control.
- A total of six 838 A 46 kV disconnect switches will be required.
- Replace the existing 5 kV power cables 25 kV rated power cables.

1.4 TOWNSITE SWITCHING STATION

Rebuild the Townsite Switching Station:

- Construct a ring bus at Townsite Switching Station.
- Install a new control building of suitable size.
- Purchase and install five 46 kV breakers.
    - As a minimum the breakers should have the following capabilities:
        - Symmetrical Interrupting Rating: 15581 A, 1241 MVA.
        - Continuous Current Rating: 1048 A.
- Each breaker will require two disconnect switches having a minimum continuous current rating of 1027 A. In total, ten disconnects will be required for purposes of isolating breakers for maintenance.
- Leave the provision for a sixth breaker and feeder takeoff in the ring bus.
- For the purposes of isolation, install a disconnect switch at the terminations of each feeder at the Townsite Switching Station. Five disconnects in total will be required, each is to have capacity to carry up to 1048 A of current.
- Purchase and install all necessary metering and RTUs to provide full SCADA capabilities to EMS control.

1.5 DISTRIBUTION FEEDER UPGRADES

1.5.1 Line Extensions/Upgrades

- Construct an approximately 80 m 3Φ line extension from structure 544 on L18 to structure 383 on L15 (behind 512 Carol Drive).
- Upgrade the section of line between structure 205 and structure 383 on L15 to 3Φ (approximately 60 m).

- Construct an approximately 70 m 3Φ line extension from the end of L1 near the A.P. Low School to behind 8 Elm Crescent.
- Construct an approximately 700 m 3Φ line extension from behind 200 Lakeside Drive to L16 in the Labrador City Industrial Park.
- Construct an approximately 1300 m 3Φ line extension from the Quartzite Substation to the four-pole structure at the Harrie Lake Substation.

The total required line extensions and upgrades to the low voltage distribution system is approximately 2.2 km. Since the system will be designed for contingency switching ability, and to remain consistent with the existing infrastructure, the type of conductor to be used for the above noted upgrades should be 477 kcmil ASC Cosmos.

1.5.2 Feeder Reconfigurations

Since the number of feeders will be reduced, some of the existing lines will have to be reconfigured. Most of this work will involve transferring existing feeders or sections of feeders to new 12.5 kV lines. The majority of the reconfigurations can be done using existing disconnects and tie switches. Load and Voltage Study results are required before feeder configurations can be finalized. The following describes a proposed reconfiguration based on the information currently available to provide roughly equal loading on each line. This work assumes that the line construction and upgrades described in the preceding section have already been completed, and that the voltage conversions on the respective line sections will be completed at the time they are transferred.

- Transfer the section of feeder BA5 bounded by BA5-D3 and BA5QZ12-1 to feeder BA1 via a new line section between AP Low School and behind 8 Elm Crescent.
- Open L15 at structure 380 on both the source and load sides. Close tie switch BA2HU15-1 to transfer the section of feeder HU15 connected through disconnect HU15-D6 to feeder BA2.
- Transfer the section of feeder HU15 between structure 205 and structure 380 to feeder BA3. The tie switch BA3HU15-1 is to remain in its current state.
- Transfer feeder HU16 (as far as structure 1439) to feeder BA4 via the new line section from structure 235 to structure 1446 behind UAP.
- Open feeder HU16 and install a normally open disconnect at structure 1439.
- Transfer the section of feeder BA4 west of structure 223 to feeder BA5 by jumpering the double circuit together beyond that point.
- Transfer feeder HU17 to Bartlett Substation by closing breaker BA22HU17-CB1.
- Transfer the section of feeder HU15 bounded by tie switch QZ6HU15-1 and structure 380 to feeder QZ6 by closing tie switch QZ6HU15-1.
- Transfer feeder HL20 to feeder QZ7 by the new line from QZ7 near Quartzite Substation to the Harrie Lake Trailer Park.

- Transfer feeder HL19 to feeder QZ14 by opening the disconnect HL19-D1 and closing the tie switch QZ14HL19-1.
-
- Transfer feeder HU15 to the new feeder VA15 by closing the disconnect HU15-D6.
- Transfer the section of feeder HU17 as far as HU17-D10 to the new feeder VA15 by opening disconnect HU17-D10 and jumpering the lines near the Hudson Substation.
- Transfer the feeder HU18 to the new feeder VA18 from Vanier Substation to Hudson Substation.
- Transfer a section of feeder VA21 to feeder VA18 by opening the disconnect VA21-D3 and closing the tie switch HU18VA21-1.
- Transfer the section of feeder HU18 (the industrial park) to feeder VA21 by opening the disconnect HU18-D2, and closing the tie switch HU18VA21-2.
- Transfer the remainder of feeder HU16 to the new feeder VA21 by closing the tie switch HU16HU18-1 and opening the newly installed disconnect at structure 1439.
- Open disconnect QZ7-D2. Reconnect the section of QZ7 from Centennial Drive to Churchill Street to feeder VA22 by closing tie switch QZ7VA22-1.

The above work will complete the conversion and reconfiguration of the 4.16 kV distribution feeders to the new 12.5 kV distribution system. The reconfiguration will off load the Hudson and Harrie Lake Substations and will allow them to be removed from service.

1.5.3 Primary and Underground Services

There are a number of primary, underground, and customer owned services in Labrador City. The system will have to be surveyed to determine the exact number. The previous plan determined that most of the customers are willing to be switched to overhead services. However, as this would involve replacement of underground cables, removal of padmount and indoor transformers, and replace ment of service entrances, completely converting the services to overhead may prove to be costly. An alternate solution to serve these customers is to install pole mounted 25/4.16 kV step-down transformers and continue to supply these customers at 4.16 kV, therefore the underground services could remain intact.

The Smokey Mountain line is a section of feeder Vanier 21, it runs from the Beverly Lake Water Supply to the Smokey Mountain Ski Hill. Much of this line is not constructed to NL Hydro Standards and to convert it would require significant upgrading of approximately 5.7 km of distribution line. To lower the cost of conversions a step down transformer should be installed so that the line can continue to be operated at 4.16 kV.

The Labrador City Mall is fed by five underground primary services which run under the mall parking lot to indoor transformers (1 MVA) inside the building. Pole/platform mounted transformers should be installed to avoid complete replacement of the existing customer owned equipment.

1.5.4 QNS&L Railway Feeder

The Quebec North Shore and Labrador Railway (QNS&L) line is a 23/11.5 kV single-phase center-tapped customer owned line. The line runs from Labrador City, NL to Sept Isles, PQ, and is constructed with two hot conductors and uses a ground return path for phase to neutral connected loads. Currently this line is fed from the Hudson Substation via a pair of 2.4/23-11.5 kV single-phase power transformers (400 kVA each). The center-tap connection on the transformers is grounded to provide the neutral return path for the line.

The line is metered at the substation and demand readings show this line has exceeded the capacity of the transformers by 19 % of the rated nameplate capacity. The load on this customer owned line will require a capacity increase. It is recommended to replace the existing transformers with two 25-12.5 / 23-11.5 kV, 1 MVA units once the conversion of L16 to 12.5 kV is completed. The transformers will no longer be located at Hudson Substation as this substation is slated for removal. Instead the transformers will be located within QNSLs own yard in the Labrador City Industrial Park. The supply will come off of two phases of L16 (i.e. line-to-line), and will be connected to the line section of L16 that is operated by the QNS&L Railway. The section of the QNS&L line that is located between the Hudson and the new substation is to be removed.

1.6 46 KV SUBTRANSMISSION FEEDER UPGRADES

The present 46 kV system in Labrador City consists of a single 46 kV line (L32) from Wabush Terminal Station to the Townsite Switching Station, and three radial feeders (L9, L10, and L11) which serve the 46/4.16 kV substations. A second feeder from Wabush Terminal Station (L33) runs to Fermont, Quebec. There are tie points on this line near the Townsite, Hudson, Vanier, and Harrie Lake Substations. This forms a quasi-looped system. However utilizing this loop requires manual switching operations by line crews, and since only a single feed runs into the individual substations the effectiveness of this configuration is somewhat limited.

To improve the operability of this system, the 46 kV subtransmission system will be upgraded to a looped system similar to the electrical systems in Corner Brook, and Stephenville. At least two feeds will be brought into each substation, with control provided by the high voltage breakers in the substations.

The line to ground fault levels on the 46 kV system in Labrador West are limited to approximately 24 MVA (300 A). This is for purposes of protecting the machinery at the mine sites. Additionally the ground resistivity in the region is rather high; therefore to adequately protect the system from line-to-ground faults it will be necessary to operate the system as an open loop.

Since three substations will be retained tie lines will be constructed between Bartlett substation and Vanier Substation, and between Vanier Substation and Quartzite Substation.

The work to upgrade the 46 kV subtransmission system to an open loop will involve the following:

- Construct approximately 300 m of 46 kV (3ART Structure Type, 477 ASC – Cosmos) line from the Quartzite Substation to the nearest point on L9 (near the intersection of Cavendish Crescent and Bartlett Drive).
- Remove the section of L9 between the new tap to the substation and the existing tap to the substation (two to three spans).
- Construct approximately 450 m of 46 kV (3ART Structure Type, 477 ASC – Cosmos) line from the Vanier Substation to the nearest point on L33 (near the Beverley Lake Pumping Station where L11 and L33 separate).
- Open and remove switch TS11-D12. Jumper over switch TS11WA33-2 and remove the tie switch. The Vanier Substation will be fed via L33.
- Remove the section of L11 between the two taps to the Vanier Substation (approximately one span).
- Construct approximately 1.25 km of 46 kV line (3ART Structure Type, 477 ASC – Cosmos) between the Bartlett and Vanier Substations. The area between Bartlett and Vanier Substation has already built up, therefore it may necessary to over-build this line on the existing low voltage feeders L3, and L15 in order to obtain a route between the two.
- Purchase and install three disconnect switches on L33 at the Fermont-Harrie Lake tap. The switches may be gang operated and capable of carrying up to 59 MW of power.
- Purchase and install a 46 kV disconnect on L33 just after the tie switch WA33WA36-1.

To enable energizing of L33 while still remaining isolated from Fermont. The border switch WA33-D3 will be kept normally open. The health of this line will be monitored as the border by the breaker at Vanier Substation, VA33-CB1. It will be necessary to inform Hydro Quebec of the proposed new operating arrangement, so that they can arrange for monitoring the health of the line at their end.

Upon completion of the above noted work on the 46 kV System the following equipment is to be removed:

- Remove 46 kV disconnects and tie switches TS11WA33-1, TS9TS10-1, TS11-D2, TS11-D12, TS11WA33-2, TS9-D5, TS9WA33-1, WA33-D2.

- Remove L11 and all associated hardware.

1.7 ASSET RETIREMENTS

Upon completion of this work on the 46 kV System the following assets are to be retired:

- Remove 46 kV disconnects and tie switches TS11WA33-1, TS9TS10-1, TS11-D2, TS11-D12, TS11WA33-2, TS9-D5, TS9WA33-1, WA33-D2.
- Remove L11 and all associated hardware.
- Remove the Hudson Substation and all associated hardware.
- Remove the Harrie Lake Substation and all associated hardware.
- Remove the double circuit on BA4 and BA5.

APPENDIX H

TRANSFORMER SURVEY

Parent Number	SUBSTATION	FEEDER	Item #	T-NUMBER	Serial #	Description	LOCATION	Remarks Line 2	M Class	M Year	HIGH VOLTAGE	LOW VOLTAGE	
270704	BARTLETT	1	258966	T-12220	435745	TRANSFORMER,25kVA	MCMANUS PK LOT - BRISTOL	UNIQUE POLE #: 13593691	WES		2400	120/240	
270704	BARTLETT	1	252248	T-12222	LL13769	TRANSFORMER,100kVA	503 BARTLETT	UNIQUE POLE : 13522060	WES	84	2400	120/240	
270704	BARTLETT	1	248892	T-09864	ATL1307-9	TRANSFORMER,100kVA	527 BARTLETT	UNIQUE POLE #: 13521723	MAE	92	2400	120/240	
270704	BARTLETT	1	252220	T-11303	A1866-25	TRANSFORMER,25kVA	MENIHEK/LAKESIDE	UNIQUE POLE #:	MEC	95	2400	120/240	
270704	BARTLETT	1	252225	T-12221	LC25241	TRANSFORMER,100kVA	516- 518 BRISTOL	UNIQUE POLE #: 13521817	WES	77	2400		
270704	BARTLETT	1	252246	T-11050	LG25001	TRANSFORMER,50kVA	500 BARTLETT	UNIQUE POLE #: 13554890	WES	81	2400	120/240	
270704	BARTLETT	1	252236	T-12219	LD53587	TRANSFORMER,15kVA	600 DINEEN PARKING LOT	UNIQUE POLE #: 13554796	WES	78	2400	120/240	
270704	BARTLETT	1	263626	T-12201	2-179772	TRANSFORMER,75kVA	600 DINEEN	UNIQUE POLE #: 13558112	FPT	80	2400	347/600	
270704	BARTLETT	1	263627	T-12202	2-179774	TRANSFORMER,75kVA	600 DINEEN	UNIQUE POLE#: 13558112	FPT	80	2400	347/600	
270704	BARTLETT	1	263628	T-12200	2-179773	TRANSFORMER,75kVA	600 DINEEN	UNIQUE POLE #: 13558112	FPT	80	2400	347/600	
270704	BARTLETT	1	252258	T-11010	541956	TRANSFORMER,50kVA	DINEEN EMBASSY PLG	UNIQUE NO: 13555979	WES		2400	120/240	
270706	BARTLETT	2	248921	T-10944	LFI7698	TRANSFORMER,100kVA	APT 420 AVALON	UNIQUE POLE #: 13575877	WES	80	2400		
270706	BARTLETT	2	248921	T-10944	LFI7698	TRANSFORMER,100kVA	APT 420 AVALON	UNIQUE POLE #: 13575877	WES	80	2400	120/240	
270706	BARTLETT	2	248902	T-10938	LL11101	TRANSFORMER,75kVA	707 FIELD	UNIQUE POLE #: 13508796	WES	84	2400	120/240	
270706	BARTLETT	2	248908	T-10942	LJ33018	TRANSFORMER,75kVA	208 HOWLEY	UNIQUE POLE #: 13505617	WES	82	2400	120/240	
270706	BARTLETT	2	248924	T-12204	937344	TRANSFORMER,75kVA	427 GRENFELL	UNIQUE POLE #: 13576020	WES	75	2400	120/240	
270706	BARTLETT	2	248906	T-10941	L0107-2	TRANSFORMER,100kVA	714 STIRLING	UNIQUEPOLE #: 13505429	CAR	83	2400	120/240	
270706	BARTLETT	2	248909	T-10947	LC25242	TRANSFORMER,100kVA	F110 CARTIER	UNIQUE POLE: 13593597	WES	77	2400	120/240	
270706	BARTLETT	2	248910	T-10952	L0107-1	TRANSFORMER,100kVA	709 ROCHE (BEHIND)	UNIQUE POLE #: 13505241	CAR	83	2400	120/240	
270706	BARTLETT	2	248922	T-10943	LC25243	TRANSFORMER,100kVA	APT 440 AVALON	UNIQUE POLE #: 13575783	WES	77	2400	120/240	
270706	BARTLETT	2	248934	T-12208	LC25247	TRANSFORMER,100kVA	130 MATTHEW	UNIQUE POLE #:: 13506518	WES	77	2400	120/240	
270706	BARTLETT	2	248923	T-12203	467556	TRANSFORMER,50kVA	APT BLDG 400 AVALON	UNIQUE POLE #: 13575689	WES		2400	120/240	
270706	BARTLETT	2	272405	T-14044	A2401-59	TRANSFORMER,50kVA	717 FIELD	UNIQUE POLE #: 13508890	MAE	02	2400		
270706	BARTLETT	2	252583	T-09852	A1298-6	TRANSFORMER,100kVA	BALLARD BLDG		MAE	92	2400	347/600	
270706	BARTLETT	2	252584	T-09854	A1298-7	TRANSFORMER,100kVA	350 AVALON	UNIQUE POLE #:	MAE	92	2400	347/600	
270706	BARTLETT	2	252585	T-09858	A1298-3	TRANSFORMER,100kVA	350 AVALON	UNIQUE POLE #:	MAE	92	2400	347/600	
270706	BARTLETT	2	258965	T-11704	A1932-11	TRANSFORMER,25kVA	YOUTH CENTER	UNIQUE POLE #: 13572892	MEC	96	2400	120/240	
270706	BARTLETT	2	248894	T-7997	ATL1306-10	TRANSFORMER,50kVA	222 MATTHEW	UNIQUE POLE #: 13506048	MEC	92	2400	120/240	
270706	BARTLETT	2	253153	T-12206	760436	TRANSFORMER,167kVA	MCMANUS	UNIQUE NO: 13522154	WES	72	2400	120/240	
270706	BARTLETT	2	248903	T-10940	937560	TRANSFORMER,100kVA	718 ROCHE	UNIQUE POLE #: 13509409	WES	75	2400	120/240	
270706	BARTLETT	2	248938	T-12209	LC25246	TRANSFORMER,100kVA	112 MATTHEW	UNIQUE POLE #: 13506706	WES	77	2400	120/240	
270706	BARTLETT	2	248919	T-10958	LJ33019	TRANSFORMER,75kVA	407 GRENFELL	UNIQUE POLE #: 13576302	WES	82	2400	120/240	
270706	BARTLETT	2	248933	T-12207	937341	TRANSFORMER,75kVA	132 MATTTHEW	UNIQUE POLE #: 13506424	WES	75	2400	120/240	
270710	BARTLETT	3	253211	T-10992	LF26215	TRANSFORMER,50kVA	BEHIND CLSC	UNIQUE POLE #: 13591795	WES	80	2400	120/240	
270710	BARTLETT	3	253211	T-10992	LF26215	TRANSFORMER,50kVA	BEHIND CLSC	UNIQUE POLE #: 13591795	WES	80	2400	120/240	
270710	BARTLETT	3	258967	T-12216	LC38198	TRANSFORMER,50kVA	ROYAL THEATRE (BANK)	UNIQUE POLE #: 13592126	WES		2400	600	
270710	BARTLETT	3	253196	T-12215	LB24711	TRANSFORMER,167kVA	PENTECOSTAL CHURCH, HUDSON	UNIQUE POLE #: 13590606	WES	76	2400	120/208	
270710	BARTLETT	3	253201	T-12214	LB24710	TRANSFORMER,167kVA	610 HUDSON	UNIQUE NO: 13590606	WES	76	2400	120/240	
270710	BARTLETT	3	253202	T-12213	LB24712	TRANSFORMER,167kVA	610 HUDSON	UNIQUE NO: 13590606	WES	76	2400	120/208	
270710	BARTLETT	3	257862	T-12674	T3060-10	TRANSFORMER,333kVA	WESTLAB SHOPPING CTR-CENTRAL	UNIQUE POLE #: 20613343	MEC	01	2400	347	
270710	BARTLETT	3	262515	T-12670	T3060-13	TRANSFORMER,333kVA	WESTLAB SHOPPING CTR-WESTERN	UNIQUE POLE # 20613249	MAE	01	2400	347/600	
270710	BARTLETT	3	262516	T-12671	T3060-14	TRANSFORMER,333kVA	WESTLAB SHOPPING CTR-WESTERN	UNIQUE POLE #: 20613249	MEC	01	2400	347/600	
270710	BARTLETT	3	262517	T-12678	T3060-11	TRANSFORMER,333kVA	WESTLAB SHOPPING CTR-WESTERN	UNIQUE POLE#: 20613249	MEC	01	2400	347/600	
270710	BARTLETT	3	253221	T-10754	951038437	TRANSFORMER,100kVA	308 HUDSON	UNIQUE NO: 13592032	CME	95	2400	120/240	
270710	BARTLETT	3	258968			TRANSFORMER,50kVA	SCHOOL LANE/GRENFELL	UNIQUE NO: 13592126	WES		2400	600	
270710	BARTLETT	3	253224	T-10945	2-34797	TRANSFORMER,25kVA	REAR OF CATHOLIC CHURCH	UNIQUE POLE #: 13579857	WES		2400	120/240	
270710	BARTLETT	3	253213	T-10946	LJ31902	TRANSFORMER,100kVA	PENTECOSTAL CHURCH HOUSE	UNIQUE POLE #: 13590700	WES	82	2400	120/240	
270710	BARTLETT	3	253249	T-10964	704640	TRANSFORMER,50kVA	BEHIND CLSC	UNIQUE POLE #: 13591319	WES	79	2400	120/240	
270710	BARTLETT	3	254793	T-10931	839835	TRANSFORMER,50kVA	UNITED CHURCH 703 HUDSON	UNIQUE POLE #: 13590894	WES	73	2400	120/240	
270710	BARTLETT	3	258970	T-12844	LC38200	TRANSFORMER,50kVA	ROYAL THEATRE	UNIQUE POLE #: 13592126	WES		2400	600	
270713	BARTLETT	4	249030	T-12217	LC25239	TRANSFORMER,100kVA	202 LAKESIDE	UNIQUE POLE #: 13557023	WES	77	2400	120/240	
270713	BARTLETT	4	249049	T-12234	C886-12	TRANSFORMER,100kVA	710 TAMARACK	UNIQUE POLE #: 11629972	CAR	75	2400	120/240	
270713	BARTLETT	4	249058	T-12238	C886-7	TRANSFORMER,100kVA	800 TAMARACK	UNIQUE POLE #:: 11629784	CAR	75	2400	120/240	
270713	BARTLETT	4	249060	T-12239	C886-3	TRANSFORMER,100kVA	790 TAMARACK	UNIQUE POLE #: 11629690	CAR	75	2400	120/240	
270713	BARTLETT	4	249080	T-12241	C886-16	TRANSFORMER,100kVA	756 TAMARACK	UNIQUE POLE #: 11623056	CAR	75	2400	120/240	
270713	BARTLETT	4	249085	T-12243	C886-14	TRANSFORMER,100kVA	750 TAMARACK	UNIQUE POLE #: 11629596	CAR	75	2400	120/240	
270713	BARTLETT	4	249044	T-12230	934116	TRANSFORMER,167kVA	526 TAMARACK	UNIQUE POLE #: 11625898	WES	75	2400	120/240	
270713	BARTLETT	4	249088	T-12262	LA18905	TRANSFORMER,167kVA	307 TAMARACK	UNIQUE POLE #:	WES	70	2400	120/240	
270713	BARTLETT	4	249023	T-10980	L130931	TRANSFORMER,50kVA	713 TAMARACK	UNIQUE POLE #: 13546220	WES	80	2400	120/240	
270713	BARTLETT	4	249023	T-10980	L130931	TRANSFORMER,50kVA	713 TAMARACK	UNIQUE POLE #: 13546220	WES	80	2400	120/240	
270713	BARTLETT	4	249046	T-12231	937335	TRANSFORMER,167kVA	602 TAMARACK	UNIQUE POLE #: 11626041	WES	75	2400	120/240	
270713	BARTLETT	4	249089	T-12263	LA18898	TRANSFORMER,167kVA	325 TAMARACK	UNIQUE POLE #:	WES	76	2400	120/240	
270713	BARTLETT	4	249090	T-12264	LA18904	TRANSFORMER,167kVA	411 TAMARACK	UNIQUE POLE #:	WES	76	2400	120/240	
270713	BARTLETT	4	249092	T-12265	934109	TRANSFORMER,167kVA	429 TAMARACK	UNIQUE POLE #:	WES	76	2400	120/240	
270713	BARTLETT	4	249093	T-12276	934111	TRANSFORMER,167kVA	511 TAMARACK	UNIQUE POLE #:	WES	76	2400	120/240	
270713	BARTLETT	4	249026	T-10983	LE30945	TRANSFORMER,50kVA	739 TAMARACK	UNIQUE POLE #: 13546032	WES	80	2400	120/240	
270713	BARTLETT	4	249038	T-12226	LG25028	TRANSFORMER,100kVA	405 BARTLETT	UNIQUE POLE #: 13557687	WES	81	2400	120/240	
270713	BARTLETT	4	248982	T-7981	LG29850	TRANSFORMER,75kVA	311 BARTLETT	UNIQUE POLE #: 13557305	WES	81	2400	120/240	
270713	BARTLETT	4	274980	T-00974	61850.10	TRANSFORMER,75kVA	519 TAMARACK	UNIQUE POLE #: 13557969	ONA	94	2400	120/240	
270713	BARTLETT	4	248984	T-10752	951039201	TRANSFORMER,100kVA	727 TAMARACK (BEHIND)	UNIQUEPOLE #: 13545795	CME	95	2400	120/240	
270713	BARTLETT	4	248985	T-10755	951039200	TRANSFORMER,100kVA	433 TAMARACK	UNIQUE POLE #: 13557875	CME	95	2400	120/240	
270713	BARTLETT	4	249029	T-10986	ATL1307-24	TRANSFORMER,100kVA	751 TAMARACK	UNIQUE POLE #: 13544894	MEC	92	2400	120/240	
270713	BARTLETT	4	249035	T-12225	ATL1307-11	TRANSFORMER,100kVA	303 LAKESIDE	UNIQUE POLE #: 13558870	MEC	92	2400	120/240	

270713	BARTLETT	4	262981	T-13149	A2401-40	TRANSFORMER,50kVA	735 TAMARACK	W/O# 583164	MEC	01	2400	120/240	
270713	BARTLETT	4	250363	T-12859	LJ31903	TRANSFORMER,100kVA	531 TAMARACK	UNIQUE POLE #: 13543423		82	2400	120/240	
270713	BARTLETT	4	249057	T-12237	C886-13	TRANSFORMER,100kVA	734 TAMARACK	UNIQUE POLE #: 11625516	CAR	75	2400	120/240	
270713	BARTLETT	4	249050	T-12235	C886-15	TRANSFORMER,100kVA	720 TAMARACK	UNIQUE POLE #: 11625328	CAR	75	2400	120/240	
270713	BARTLETT	4	249084	T-12242	C886-22	TRANSFORMER,100kVA	746 TAMARACK	UNIQUE POLE #: 11625610	CAR	75	2400	120/240	
270713	BARTLETT	4	249087	T-12244	C886-6	TRANSFORMER,100kVA	780 TAMARACK	UNIQUE POLE #: 11626605	CAR	75	2400	120/240	
270713	BARTLETT	4	249048	T-12233	C886-23	TRANSFORMER,100kVA	706 TAMARACK	UNIQUE POLE #: 11629878	CAR	75	2400	120/240	
270713	BARTLETT	4	249032	T-12218	718903	TRANSFORMER,50kVA	208LAKESIDE	UNIQUE POLE #: 13556880	WES		2400	120/240	
270713	BARTLETT	4	249041	T-12229	934110	TRANSFORMER,167kVA	430 TAMARACK	UNIQUE POLE #: 11627130	WES	75	2400	120/240	
270716	BARTLETT	5	249063	T-10972	LF35166	TRANSFORMER,100kVA	6 MAPLE	UNIQUE POLE #: 13553325	WES	81	2400	120/240	
270716	BARTLETT	5	249174	T-12257	73TH168001	TRANSFORMER,100kVA	669 TAMARACK	UNIQUE POLE #: 13543705	MEP		2400	120/208	
270716	BARTLETT	5	249178	T-12258	73TH168006	TRANSFORMER,100kVA	669 TAMARACK	UNIQUE POLE #: 13543705	MEP		2400	120/208	
270716	BARTLETT	5	249172	T-12256	73TH168004	TRANSFORMER,100kVA	669 TAMARACK	UNIQUE POLE #: 13543705	MEP		2400	120/208	
270716	BARTLETT	5	249152	T-12246	LF17694	TRANSFORMER,100kVA	409 DINEEN	UNIQUE POLE #: 13570708	WES	80	2400	120/240	
270716	BARTLETT	5	249187	T-12259	ATL1307-21	TRANSFORMER,100kVA	715 WILLOW	UNIQUE POLE #: 13542616	MEP		2400		
270716	BARTLETT	5	249149	T-10978	LE30949	TRANSFORMER,50kVA	731 WILLOW	UNIQUE POLE #: 13542146	WES	80	2400	120/240	
270716	BARTLETT	5	249150	T-10979	758297	TRANSFORMER,50kVA	706 BALSAM	UNIQUE POLE #: 13542052	WES	72	2400	120/240	
270716	BARTLETT	5	249153	T-12248	LC27711	TRANSFORMER,50kVA	6 ELM	UNIQUE POLE #: 13553513	WES	77	2400	120/208	
270716	BARTLETT	5	249154	T-12249	LC27717	TRANSFORMER,50kVA	6 ELM	UNIQUE POLE #: 13553513	WES	77	2400	120/208	
270716	BARTLETT	5	249155	T-12250	LC27659	TRANSFORMER,50kVA	6 ELM	UNIQUE POLE #: 13553513	WES	77	2400	120/208	
270716	BARTLETT	5	249016	T-10912	951037697	TRANSFORMER,75kVA	708/710 LAKESIDE	UNIQUE POLE #: 13543047	CME	95	2400	120/240	
270716	BARTLETT	5	249064	T-10973	951037701	TRANSFORMER,75kVA	17 JUNIPER	UNIQUEPOLE #: 13553043	CME	95	2400	120/240	
270716	BARTLETT	5	248986	T-09872	ATL1307-39	TRANSFORMER,100kVA	10 JUNIPER	UNIQUE POLE #: 13552706	MEC	92	2400	120/240	
270716	BARTLETT	5	248986	T-09872	ATL1307-39	TRANSFORMER,100kVA	10 JUNIPER	UNIQUE POLE #: 13552706	MEC	92	2400	120/240	
270716	BARTLETT	5	248987	T-09873	ATL1307-43	TRANSFORMER,100kVA	4 JUNIPER	UNIQUE POLE #: 13552330	MEC	92	2400	120/240	
270716	BARTLETT	5	248995	T-10768	951039206	TRANSFORMER,100kVA	7 EMBASSY /406 DINEEN	UNIQUE POLE #: 13558206	CME	95	2400	120/240	
270716	BARTLETT	5	249001	T-10772	951038429	TRANSFORMER,100kVA	721 WILLOW	UNIQUE POLE # 13542240	CME	95	2400	120/240	
270716	BARTLETT	5	249007	T-10779	951037256	TRANSFORMER,100kVA	700 LAKESIDE	UNIQUE POLE #: 13543141	CME	95	2400	120/240	
270716	BARTLETT	5	249019	T-10921	951037252	TRANSFORMER,100kVA	731 BIRCH/728 BARTLETT	UNIQUE POLE #: 13547785	CME	95	2400	120/240	
270716	BARTLETT	5	249164	T-12252	ATL1307-15	TRANSFORMER,100kVA	10-12 ELM	UNIQUE POLE #: 13553701	MEC	92	2400	120/240	
270716	BARTLETT	5	249166	T-12253	ATL1307-7	TRANSFORMER,100kVA	704 BARTLETT	UNIQUE POLE #: 13548686	MEC	92	2400	120/240	
270716	BARTLETT	5	249171	T-12255	ATL1307-18	TRANSFORMER,100kVA	9-11 POPLAR	UNIQUE POLE #: 13551805	MEC	92	2400	120/240	
270716	BARTLETT	5	249190	T-12260	ATL1307-27	TRANSFORMER,100kVA	701 BALSAM	UNIQUE POLE #: 13546696	MEP	92	2400	120/240	
270716	BARTLETT	5	249192	T-12261	ATL1307-22	TRANSFORMER,100kVA	802 LAKESIDE	UNIQUE POLE #: 13547027	MEP	92	2400	120/240	
270716	BARTLETT	5	300479	T-16286	A3818-10	TRANSFORMER25kVA	698 LAKESIDE		MEC	06	2400	347	
270716	BARTLETT	5	301203	T-16287	A3818-11	TRANSFORMER,25kVA	698 LAKESIDE	UNIQUE POLE #:	MEC	06	2400	347	
270716	BARTLETT	5	301204	T-16285	A3818-9	TRANSFORMER,25kVA	698 LAKESIDE		MEC	06	2400	347	
270716	BARTLETT	5	249161	T-12251	ATL1306-7	TRANSFORMER,50kVA	8 ELM	UNIQUE POLE #: 13553607	MEC	92	2400	120/240	
45974	HARRIE LAKE	19	269561	T-12682	741095958	TRANSFORMER,100kVA	3047 WALSH	UNIQUE POLE #: 02318	RTE		2400	120/240	
45974	HARRIE LAKE	19	274357	T-12868	741097040	TRANSFORMER,100kVA	3061 WALSH RIVER RD	UNIQUE POLE #: 14771507	RTE		2400	120/240	
45974	HARRIE LAKE	19	274359	T-12891	876022	TRANSFORMER,50kVA	3012 BARTLETT	UNIQUE POLE #: 11629214	WES	74	2400	120/240	
45974	HARRIE LAKE	19	274362	T-12861	876025	TRANSFORMER,50kVA	3002 BARTLETT (BEHIND)	UNIQUE POEL #: 14778002	WES		2400	120/240	
45974	HARRIE LAKE	19	274361	T-12271	874210	TRANSFORMER,50kVA	3027 BARTLETT	UNIQUE POLE #: 14159969	WES	74	2400	120/240	
45974	HARRIE LAKE	19	274686	T-12890	876470	TRANSFORMER,50kVA	3000 FLORA	UNIQUE POLE #: 14155607	WES	74	2400	120/240	
45974	HARRIE LAKE	19	274358	T-12680	276008	TRANSFORMER,50kVA	3016 FLORA	UNIQUE POLE #: 14160158	WES	74	2400	120/240	
45974	HARRIE LAKE	19	251590	T-12658	876013	TRANSFORMER,50kVA	3020 WALSH	UNIQUE POLE #: 14778196	WES	74	2400	120/240	
45974	HARRIE LAKE	19	251588	T-12648	875979	TRANSFORMER,50kVA	3044 HARRIE LAKE	UNIQUE POEL #: 14771131	WES	74	2400	120/240	
45974	HARRIE LAKE	19	251596	T-12649	741096673	TRANSFORMER,100kVA	3019 WALSH	UNIQUE POLE #: 14154424			2400	120/240	
45974	HARRIE LAKE	19	251594	T-12639	902184	TRANSFORMER,50kVA	4007 CANNING	UNIQUE POLE #: 14776676	WES		2400	120/240	
270724	HUDSON	15	285768	T-3-1825	427367	TRANSFORMER,50kVA	303 CAROL	UNIQUE POLE#: 13580140	WES		2400		
270724	HUDSON	15	275349	T-10022	484629	TRANSFORMER,50kVA	333 VIKING	UNIQUE POLE # 13584120	WES		2400		
270724	HUDSON	15	285842	T-14210	427362	TRANSFORMER,50kVA	305 GILBERT	UNIQUE POLE #: 13581135	WES		2400		
270724	HUDSON	15	285769	T-3-1857	937551	TRANSFORMER,100kVA	; 337 VIKING	UNIQUE POLE #: 13584214	WES	75	2400		
270724	HUDSON	15	257176	T-13519	A2404-2	TRANSFORMER,75kVA	TOWN HALL, LAB CITY	UNIQUE POLE #: 14774210	MEC	00	2400	347	
270724	HUDSON	15	257177	T-13520	A2404-5	TRANSFORMER,75kVA	TOWN HALL, LAB CITY	UNIQUE POLE #: 14774210	MEC	00	2400	347	
270724	HUDSON	15	257178	T-13518	A2404-6	TRANSFORMER,75kVA	TOWN HALL, LAB CITY	UNIQUE POLE #: 14774210	MEC	00	2400	347	
270724	HUDSON	15	275347	T-09867	ALT-1307-38	TRANSFORMER,100kVA	320 ELIZABETH	UNIQUE POLE #: 13583407	MAE	92	2400		
270724	HUDSON	15	272403	T-14043	A2401-58	TRANSFORMER,50kVA	TOWN HALL LBC		MAE	02	2400		
270724	HUDSON	15	285845	T-3-1826	937552	TRANSFORMER,100kVA	312 ELIZABETH	UNIQUE POLE #: 13583313	WES	75	2400		
270724	HUDSON	15	285843	T-14209	839870	TRANSFORMER,50kVA	307 GILBERT	UNIQUE POLE # 13581605	WES	75	2400		
270724	HUDSON	15	285841	T-14295	937561	TRANSFORMER,100kVA	308 GILBERT	UNIQUE POLE #: 13582130	WES	75	2400		
270728	HUDSON	16	265008	T-13515	A2404-4	TRANSFORMER,75kVA	106 AIRPORT RD	UNIQUE POLE #:	MEC	00	2400	347	
270728	HUDSON	16	265009	T-13517	A2404-3	TRANSFORMER,75kVA	J&B BUSSING	UNIQUE POLE #:	MEC	00	2400	347	
270728	HUDSON	16	265010	T-13665	A2404-8	TRANSFORMER,75kVA	102 AIRPORT RD	UNIQUE POLE #:	MEC	01	2400	347	
270728	HUDSON	16	254585	T-11908	A1953-4	TRANSFORMER,50kVA	HEDDY'S RESTAURANT	UNIQUE POLE #: 13595111	MEC	97	2400	120/208	
270728	HUDSON	16	255193	T-11550	A1906-12	TRANSFORMER,50kVA	211 DRAKE	UNIQUE NO: 13595111	MEC	96	2400	120/208	
270728	HUDSON	16	255197	T-11892	A1953-22	TRANSFORMER,50kVA	HEDDYS RESTAURANT	UNIQUE POLE #: 13595111	MEC	97	2400	120/208	
270728	HUDSON	16	263624	T-12272	701106	TRANSFORMER,75kVA	NORTHERN AUTO BODY	UNIQUE POLE #: 14242529	WES	70	2400	600	
270728	HUDSON	16	263623	T-12900	722360	TRANSFORMER,75kVA	NORTHERN AUTO BODY	UNIQUE POLE #: 14242529	WES	71	2400	600	
270728	HUDSON	16	263625	T-12633	712105	TRANSFORMER,75kVA	NORTHERN AUTO BODY	UNIQUE POLE #: 14242529	WES	71	2400	600	
270733	HUDSON	17	248350	T-12897	718911	TRANSFORMER,50kVA	205 LAKESIDE	UNIQUE POLE #: 13559107	WES	71	2400	120/240	
270733	HUDSON	17	285945	T-14438	A 2401-82	TRANSFORMER,50kVA	123 CABOT, LAB CITY	UNIQUE POLE #:	MAE	03	2400		
270733	HUDSON	17	285967	T-3-1827	ALT 1293-2	TRANSFORMER,25kVA	DEPOT, 390 TAMARACK	UNIQUE POLE NO::	MAE	92	2400		
270733	HUDSON	17	255189	T-11893	A1953-21	TRANSFORMER,50kVA	203 AMHERST	UNIQUE POLE #: 13576684	MEC	97	2400	120/240	

270733	HUDSON	17	262983	T-13148	A2401-41	TRANSFORMER,50kVA	89 Tamarack		MEC	01	2400	120/240	
270733	HUDSON	17	275408	T-10675	951034756	TRANSFORMER,50kVA	BRACE'S BLDG, 211 AMHERST	UNIQUE POLE #: 13577679	CME	95	2400		
270733	HUDSON	17	275423	T-10837	951037583	TRANSFORMER,50kVA	SUPERETTE, 119 AVALON	UNIQUE POLE #: 13576872	CME	98	2400		
270733	HUDSON	17	275424	T-10839	951037585	TRANSFORMER,50kVA	JUBBERS BLDG	UNIQUE POLE #: 13576872	CME	98	2400		
270733	HUDSON	17	286333	T-14208	LG29849	TRANSFORMER,75kVA	TOWN GARAGE MAIN LINE TAMARACK	UNIQUE NO:13594116/13594780	WES	81	2400		
270733	HUDSON	17	248963	T-12266	LL16175	TRANSFORMER,100kVA	109 MARCONI	UNIQUE POLE #: 13571139	WES	84	2400		
270733	HUDSON	17	285965	T-14203	422974	TRANSFORMER,50kVA	ASHUANIPI AVIATION	UNIQUE NO:13593973	WES		2400		
270733	HUDSON	17	286334	T-14207	LJ33004	TRANSFORMER,75kVA	TOWN GARAGE, TAMARACK	UNIQUE NO:13594116/13594780	WES	82	2400		
270733	HUDSON	17	255191	T-7976	681573	TRANSFORMER,50kVA	CRAFTER'S ATTIC	UNIQUE POLE #: 14770512	WES	70	2400	120/240	
270733	HUDSON	17	285952	T-14259	519105	TRANSFORMER,50kVA	122 DRAKE	UNIQUE POLE #: 13571897	WES		2400		
270733	HUDSON	17	285953	T-14279	423493	TRANSFORMER,50kVA	112 DRAKE	UNIQUE POLE #: 13572040	WES		2400		
270733	HUDSON	17	248876	T-10127	661252	TRANSFORMER,50kVA	CHN ENTERPRISES, 300 AVALON	UNIQUE POLE #: 13575119	WES	79	2400	120/240	
270733	HUDSON	17	269492	T-10038	432500	TRANSFORMER,50kVA	CRRS	UNIQUE POLE #: 13578956	WES		2400	120/240	
270733	HUDSON	17	263619	T-11011	LB24661	TRANSFORMER,75kVA	221 BARTLETT	UNIQUE POLE #: 13571609	WES	76	2400	120/240	
270733	HUDSON	17	263621	T-11013	LC23274	TRANSFORMER,37.5kVA	221 BARTLETT	UNIQUE POLE #: 13571609	WES	77	2400	120/240	
270733	HUDSON	17	263622	T-11012	LC23270	TRANSFORMER,37.5kVA	221 BARTLETT	UNIQUE POLE #: 13571609	WES	77	2400	120/240	
270738	HUDSON	18	250480	T-11813	A1939-6	TRANSFORMER,100kVA	321BEVERLY	UNIQUE POLE #: 13517985	MEC	93	2400	120/240	
270738	HUDSON	18	260076	T-13146	A2402-9	TRANSFORMER,50kVA	RSM, LUCE ST	UNIQUE POLE #: 20612630	MEC	01	2400		
270738	HUDSON	18	265006	T-13327	A2402-10	TRANSFORMER,50kVA	RSM, LUCE ST	UNIQUE POLE #: 20611353	MEC	02	2400	347	
270738	HUDSON	18	265007	T-13328	A2402-11	TRANSFORMER,50kVA	RSM, LUCE ST	UNIQUE POLE #: 20611353	MEC	01	2400	347	
270738	HUDSON	18	271889	T-13667	A2404-7	TRANSFORMER,75kVA	BOWRINGER, LUCE ST	UNIQUE POLE #: 20610452	MEC	01	2400	347	
270738	HUDSON	18	271890	T-13669	A2404-9	TRANSFORMER,75kVA	BOWRINGER, LUCE ST	UNIQUE POLE #: 20610152	MEC	01	2400	347	
270738	HUDSON	18	271891	T-13516	A2404-1	TRANSFORMER,75kVA	BOWRINGER, LUCE ST	UNIQUE POLE #: 20610452	MEC	01	2400	347	
270738	HUDSON	18	285946	T-14283	LD5359	TRANSFORMER,50kVA	IOCC GATE	UNIQUE POLE #: 14244237	WES	78	2400		
270738	HUDSON	18	285874	T-14211	839846	TRANSFORMER,50kVA	322 BEVERLY	UNIQUE NO: 13519311	WES	73	2400		
270738	HUDSON	18	285876	T-14272	LG24948	TRANSFORMER,100kVA	? 307 BEVERLY	UNIQUE NO: 13516990	WES	81	2400		
270738	HUDSON	18	256360	T-10908	937347	TRANSFORMER,75kVA	309 CAROL	UNIQUE POLE #: 12582318	WES	75	2400	120/240	
270756	QUARTZITE	6	254453	T-10117	575452	TRANSFORMER,50kVA	804 CHURCHILL	UNIQUE POLE #: 13533421	WES		2400	120/240	
270756	QUARTZITE	6	254447	T-10136	436137	TRANSFORMER,50kVA	811 COOK	UNIQUE POLE #: 13537031	WES	70	2400	120/240	
270756	QUARTZITE	6	254439	T-10110	LJ20537	TRANSFORMER,100kVA	814 CAROL	UNIQUE POLE #: 13534704	WES	82	2400	120/240	
270756	QUARTZITE	6	254433	T-10111	937327	TRANSFORMER,75kVA	814 CORMACK	UNIQUE POLE #: 13535041	WES	75	2400	120/240	
270756	QUARTZITE	6	254452	T-10137	484630	TRANSFORMER,50kVA	835 CAROL	UNIQUE POLE #: 13531249	WES	78	2400	120/240	
270756	QUARTZITE	6	254456	T-10112	895942	TRANSFORMER,50kVA	841 HUDSON	UNIQUE POLE #: 13531907	WES	76	2400	120/240	
270756	QUARTZITE	6	254442	T-10113	424672	TRANSFORMER,50kVA	843 CAROL	UNIQUE POLE #: 13531531	WES		2400	120/240	
270756	QUARTZITE	6	254454	T-10104	700936	TRANSFORMER,50kVA	801 COOK	UNIQUE POLE #: 13537125	WES	70	2400	120/240	
270756	QUARTZITE	6	254435	T-10036	LC25240	TRANSFORMER,100kVA	715 CAROL	UNIQUE POLE #: 13533615	WES	77	2400	120/240	
270756	QUARTZITE	6	254436	T-10037	LE30947	TRANSFORMER,50kVA	603 CAROL	UNIQUE POLE #: 13585685	WES	80	2400	120/240	
270760	QUARTZITE	7	275027	T-10000	A1294-27	TRANSFORMER,75kVA	411 PROWSE	UNIQUE POLE #: 13569297	MEC	92	2400	120/240	
270760	QUARTZITE	7	275030	T-10014	A1294-21	TRANSFORMER,75kVA	424 MASSEY	UNIQUE POLE #: 13563985		92	2400	120/240	
270760	QUARTZITE	7	250808	T-12451	A2401-2	TRANSFORMER,50kVA	828 RETTY	UNIQUE POLE #: 13530724	MEC	99	2400	120/240	
270760	QUARTZITE	7	254469	T-11902	A1953-6	TRANSFORMER,50kVA	SCOUT LODGE	UNIQUE POLE #:	MEC	97	2400	120/240	
270760	QUARTZITE	7	275024	T-10007	ATL1306-17	TRANSFORMER,50kVA	841 D'AIGLE	UNIQUE POLE #: 13569861	MEC	92	2400	120/240	
270760	QUARTZITE	7	275029	T-10009	ATL1306-16	TRANSFORMER,50kVA	425 CENTENNIAL	UNIQUE POLE #: 13563603	MAE	92	2400	120/240	
270760	QUARTZITE	7	264358	T-10120	637671	TRANSFORMER,50kVA	834 D'AIGLE	UNIQUE POLE #: 13569391	WES		2400	120/240	
270760	QUARTZITE	7	269542	T-10123	484669	TRANSFORMER,50kVA	443 CENTENNIAL	UNIQUE POLE #: 13564410	WES		2400	120/240	
270760	QUARTZITE	7	275026	T-10030	839855	TRANSFORMER,50kVA	402 PROWSE	UNIQUE POLE #: 13568960	WES	73	2400	120/240	
270760	QUARTZITE	7	269683	T-10021	937334	TRANSFORMER,75kVA	408 PROWSE	UNIQUE POLE #: 13568866	WES	75	2400	120/240	
270760	QUARTZITE	7	269543	T-10034	575451	TRANSFORMER,50kVA	403 PROWSE	UNIQUE POLE #: 13569579	WES		2400	120/240	
270760	QUARTZITE	7	269491	T-10139	3P0287-08	TRANSFORMER,100kVA	412 CENTENNIAL	UNIQUE POLE #: 13569009	WES	82	2400	120/240	
270760	QUARTZITE	7	269502	T-10140	475920	TRANSFORMER,50kVA	432 MASSEY	UNIQUE POLE #: 13564316	WES		2400	120/240	
270760	QUARTZITE	7	269501	T-10141	467594	TRANSFORMER,50kVA	409 CENTENNIAL	UNIQUE POLE #: 13562990	WES		2400	120/240	
270764	QUARTZITE	8	264829	T-10029	LF26196	TRANSFORMER,50kVA	727 STIRLING	UNIQUE POLE #:	WES	80	2400	120/240	
270764	QUARTZITE	8	248353	T-10108	43160	TRANSFORMER,50kVA	832 HUDSON	UNIQUE POLE #: 13502914	WES		2400	120/240	
270764	QUARTZITE	8	263732	T-10906	LC25248	TRANSFORMER,100kVA	716 FIELD	UNIQUE POLE #: 13507895	WES	77	2400	120/240	
270764	QUARTZITE	8	269769	T-12688	937349	TRANSFORMER,75kVA	709 BARTLETT	UNIQUE POLE #:	WES	75	2400	120/240	
270768	QUARTZITE	12	255783	T-10955	575237	TRANSFORMER,50kVA	6 CEDAR	UNIQUE POLE #: 13550904	WES		2400	120/240	
270768	QUARTZITE	12	255795	T-10784	758-290	TRANSFORMER,50kVA	818 LAKESIDE	UNIQUE POLE #: 13529689			2400	120/240	
270768	QUARTZITE	12	248344	T-10067	LJ20541	TRANSFORMER,100kVA	809 WILLOW	UNIQUE POLE #: 13541527	WES	82	2400	120/240	
270772	QUARTZITE	13	248868	T-12274	LB24474	TRANSFORMER,75kVA	1027 CAVENDISH	UNIQUE POLE #NO: 13526228	WES	76	2400	120/240	
270772	QUARTZITE	13	248875	T-12267	LB24468	TRANSFORMER,75kVA	1063 ARTLETT	UNIQUE POLE #: 13526604	WES	76	2400	120/240	
270772	QUARTZITE	13	254629	T-12296	LB24458	TRANSFORMER,75kVA	1037 BARTLETT	UNIQUE POLE #: 13526134	WES	76	2400	120/240	
270772	QUARTZITE	13	255224	T-12287	LB24472	TRANSFORMER,75kVA	1063 CAVENDISH	UNIQUE POLE #: 13527981	WES	76	2400	120/240	
270772	QUARTZITE	13	255261	T-12283	LB24476	TRANSFORMER,75kVA	1039 CAVENDISH	UNIQUE POLE #: 13527505	WES	76	2400	120/240	
270772	QUARTZITE	13	255272	T-12285	LB24477	TRANSFORMER,75kVA	1057 CAVENDISH	UNIQUE POLE #: 13527877	WES	76	2400	120/240	
270772	QUARTZITE	13	254482	T-12605	C886-5	TRANSFORMER,100kVA	876 TAMARACK	UNIQUE POLE #: 11624051	CAR	75	2400	120/240	
270772	QUARTZITE	13	254525	T-12609	C886-18	TRANSFORMER,100kVA	912 TAMARACK	UNIQUE POLE #: 11623808	CAR	75	2400	120/240	
270772	QUARTZITE	13	255302	T-12610	LJ20519	TRANSFORMER,100kVA	926 TAMARACK	UNIQUE POLE #: 13527035	WES	82	2400	120/240	
270772	QUARTZITE	13	254539	T-12291	LA18912	TRANSFORMER,167kVA	1019 CAVENDISH	UNIQUE POLE #: 13527129	WES	76	2400	120/240	
270772	QUARTZITE	13	254645	T-12297	LB24464	TRANSFORMER,75kVA	1024 CAVENDISH	UNIQUE POLE #: 13525421	WES	76	2400	120/240	
270772	QUARTZITE	13	254646	T-12621	LB24465	TRANSFORMER,75kVA	1075 BARTLETT	UNIQUE POLE #: 13526798	WES	76	2400	120/240	
270772	QUARTZITE	13	254682	T-12618	LB24467	TRANSFORMER,75kVA	1044 CAVENDISH	UNIQUE POLE #: 13525233		76	2400	120/240	
270772	QUARTZITE	13	255222	T-12294	LB24469	TRANSFORMER,75kVA	1053 BARTLETT	UNIQUE POLE #: 13526322	WES	76	2400	120/240	
270772	QUARTZITE	13	255283	T-12288	LB24479	TRANSFORMER,75kVA	1071 CAVENDISH	UNIQUE POLE #: 13528030	WES	76	2400	120/240	
270772	QUARTZITE	13	254581	T-12292	LB17301	TRANSFORMER,100kVA	1021 CAVENDISH	UNIQUE POLE #: 13527223	WES	76	2400	120/240	

270772	QUARTZITE	13	254627	T-12298	LB19105	TRANSFORMER,50kVA	1018 CAVENDISH	UNIQUE POLE #: 13525327	WES	76	2400	120/240	
270772	QUARTZITE	13	254647	T-12284	LB24466	TRANSFORMER,75kVA	1043 CAVENDISH	UNIQUE POLE #: 13537699	WES	76	2400	120/240	
270772	QUARTZITE	13	254533	T-12290	LA18897	TRANSFORMER,167kVA	1001 BARTLETT	UNIQUE POLE #: 13525897	WES	76	2400	120/240	
270772	QUARTZITE	13	255223	T-12281	LB24470	TRANSFORMER,75kVA	1031 CAVENDISH	UNIQUE POLE #: 13527411	WES	76	2400	120/240	
270772	QUARTZITE	13	254644	T-12293	LB24463	TRANSFORMER,75kVA	1069 BARTLETT	UNIQUE NO: 13526510	WES	76	2400	120/240	
270772	QUARTZITE	13	255238	T-12224	LB24475	TRANSFORMER,75kVA	1032 CAVENDISH	UNIQUE NO: 13525515	WES	76	2400	120/240	
270772	QUARTZITE	13	248849	T-12273	951039207	TRANSFORMER,50kVA	821 TAMARACK	UNIQUE NO: 13545131	CME	95	2400	120/240	
270772	QUARTZITE	13	255301	T-12619	LB24481	TRANSFORMER,75kVA	1050 CAVENDISH	UNIQUE POLE: 13525045	WES	76	2400	120/240	
270772	QUARTZITE	13	254527	T-12602	C886-17	TRANSFORMER,100kVA	854 TAMARACK	UNIQUE POLE #: 11624709	CAR	75	2400	120/240	
270772	QUARTZITE	13	254641	T-12299	LB24461	TRANSFORMER,75kVA	1002 CAVENDISH	UNIQUE POLE #: 13525609	WES	76	2400	120/240	
270772	QUARTZITE	13	254522	T-12601	C886-11	TRANSFORMER,100kVA	840 TAMARACK	UNIQUE POLE #: 11624521	CAR	75	2400	120/240	
270772	QUARTZITE	13	254530	T-12600	C886-21	TRANSFORMER,100kVA	814 TAMARACK	UNIQUE POLE#: 11629308	CAR	75	2400	120/240	
270772	QUARTZITE	13	254575	T-12617	LA19104	TRANSFORMER,50kVA	1040 CAVENDISH	UNIQUE NO: 13525139	WES	76	2400	120/240	
270772	QUARTZITE	13	254630	T-12286	LB24459	TRANSFORMER,75kVA	1053 CAVENDISH	UNIQUE POLE #: 13527793	WES	76	2400	120/240	
270772	QUARTZITE	13	254635	T-12620	LB24460	TRANSFORMER,75kVA	1012 CAVENDISH	UNIQUE POLE #: 13525703	WES	76	2400	120/240	
270772	QUARTZITE	13	254479	T-12606	C 886-2	TRANSFORMER,100kVA	882 TAMARACK	UNIQUE POLE #: 11624145	CAR	75	2400	120/240	
270772	QUARTZITE	13	254480	T-12604	C886-1	TRANSFORMER,100kVA	870 TAMARACK	UNIQUE POLE #: 1162206	CAR	75	2400	120/240	
270772	QUARTZITE	13	254481	T-12603	C886-4	TRANSFORMER,100kVA	860 TAMARACK	UNIQUEPOLE #: 11624803	CAR	75	2400	120/240	
270772	QUARTZITE	13	254537	T-12608	C886-10	TRANSFORMER,100kVA	904 TAMARACK	UNIQUE POLE #: 11624333	CAR	75	2400	120/240	
270772	QUARTZITE	13	254559	T-12289	LA19102	TRANSFORMER,50kVA	1103 CAVENDISH	UNIQUE POLE #: 13528124	WES	76	2400	120/240	
270772	QUARTZITE	13	254628	T-12282	LB24457	TRANSFORMER,75kVA	1027 CAVENDISH	UNIQUE POLE #: 13527317	WES	76	2400	120/240	
270772	QUARTZITE	13	255276	T-12295	LB24478	TRANSFORMER,75kVA	1043 BARTLETT	UNIQUE POLE #: 13526416	WES	76	2400	120/240	
270772	QUARTZITE	13	248846	T-12879	LA18903	TRANSFORMER,167kVA	1161 CAVENDISH	UNIQUE POLE #:: 13524426	WES	76	2400	120/240	
270772	QUARTZITE	13	248845	T-10052	LL11098	TRANSFORMER,100kVA	918 ALDERDICEE	UNIQUE POLE # 13528694	WES	84	2400	120/240	
270776	QUARTZITE	14	272402	T-14042	A2401-57	TRANSFORMER,50kVA	FISH MARKET		MAE	02	2400	120/240	
270776	QUARTZITE	14	251563	T-12643	741096677	TRANSFORMER,100kVA	3007 TANYA	UNIQUE NO: 14775963			2400	120/240	
270776	QUARTZITE	14	251593	T-12653	902172	TRANSFORMER,50kVA	4011 HARRIE LAKE	UNIQUE NO: 14778572	WES	74	2400	120/240	
270776	QUARTZITE	14	251553	T-12642	741098020	TRANSFORMER,100kVA	3007 HARRIE LAKE	UNIQUE POLE #: 14774686	RTE		2400	120/240	
270780	VANIER	21	262980	T-13271	A2398-18	TRANSFORMER,10kVA	SMOKEY HEAT TRACE		MAE	02	2400		
270780	VANIER	21	285683	T-14492	A2398-24	TRANSFORMER,10kVA	BEV LAKE STLIGHTS		MAE	00	2400		
270780	VANIER	21	262506	T-13143	A2399-88	TRANSFORMER,25kVA	ROD&GUN CLUB	UNIQUE POLE #: 14772314	MEC	01	2400	120/240	
270780	VANIER	21	262984	T-13165	A2401-46	TRANSFORMER,50kVA	AGTEWAY	UNIQUE POLE #:	MEC	01	2400	120/240	
270784	VANIER	22	256352	T-10988	700972	TRANSFORMER,50kVA	410 NASCOPIE	UNIQUE POLE #:			2400	120/240	
270784	VANIER	22	286427	T-10923	951037704	TRANSFORMER,75kVA	701 CHURCHILL	UNIQUE POLE #: 13590042	CME	95	2400		
270784	VANIER	22	269541	T-10116	484668	TRANSFORMER,50kVA	410 MACDONALD	UNIQUE POLE #: 13561143	WES		2400	120/240	
271168	VANIER	23	255800	T-10966	422955	TRANSFORMER,50kVA	413 VANIER	UNIQUE POLE #:	WES		2400	120	
271168	VANIER	23	255803	T-10967	436126	TRANSFORMER,50kVA	ORANGE LODGE	UNIQUE POLE #:	WES		2400	120/240	
271168	VANIER	23	255801	T-10991	424680	TRANSFORMER,50kVA	619 MCPARLAND	UNIQUE POLE #:	WES		2400	120/240	
271168	VANIER	23	258526	T-4-0121	632976	TRANSFORMER,50kVA	627 MCPARLAND	W/O# 583164	WES		2400	120/240	
271168	VANIER	23	255806	T-10928	637701	TRANSFORMER,50kVA	611 MCPARLAND	UNIQUE POLE #:			2400	120/240	
270716	BARTLETT	5	249169	T-12254	577116	TRANSFORMER,100kVA	7 MAPLE	UNIQUE POLE #: 13554038	WES		4160	120/240	
270716	BARTLETT	5	249151	T-12245	2-178368	TRANSFORMER,225kVA	500 DINEEN	UNIQUE POLE #: 13555409	FPT	80	4160	347/600	
270733	HUDSON	17	286330	T-14200	J1098-3	TRANSFORMER,167kVA	SEWAGE PLANT, TAMARACK	UNIQUE NO: 13594592/13594498	CAR	82	4160		
270733	HUDSON	17	286331	T-14202	J1098-2	TRANSFORMER,167kVA	SEWAGE PLANT, TAMARACK	UNIQUE NO:13594592/13594498	CAR	82	4160		
270772	QUARTZITE	13	248877	T-14239	LA19060	TRANSFORMER,75kVA	LIFT STATION/HERITGE	UNIQUE POLE #: 13525991	WES	76	4160	347/600	3-Phase Transformer
270704	BARTLETT	1	252242	T-12205	LE20054	TRANSFORMER,167kVA	12 EMBASSY (BEHIND)	UNIQUE POLE #:	WES	80	2400/4160	120/240	
270706	BARTLETT	2	255775	T-10901	937539	TRANSFORMER,100kVA	709 STIRLING	UNIQUE POLE #: 13500454			2400/4160	120/240	
270706	BARTLETT	2	255771	T-10902	LD62040	TRANSFORMER,100kVA	714 HUDSON	UNIQUE POLE #: 13500548			2400/4160	120/240	
270710	BARTLETT	3	257863	T-12673	T3060-9	TRANSFORMER,333kVA	WESTLAB SHOPPING CTR-CENTRAL	UNIQUE POLE #: 20613343	MEC	01	2400/4160	347/600	
270710	BARTLETT	3	257865	T-12672	T3060-8	TRANSFORMER,333kVA	WESTLAB SHOPPING CTR-CENTRAL	UNIQUE POLE #: 20613343	MEC	01	2400/4160	347/600	
270713	BARTLETT	4	249039	T-12227	876995	TRANSFORMER,75kVA	INDIAN POINT LIFT STATION	UNIQUE POLE #:	WES	74	2400/4160	347/600	
270713	BARTLETT	4	249047	T-12232	2-17120	TRANSFORMER,75kVA	530 TAMARACK	UNIQUE POLE #:	FPT		2400/4160	600	
45974	HARRIE LAKE	19	251591	T-12647	902165	TRANSFORMER,50kVA	3045 BARTLETT	UNIQUE POLE #: 14773215	WES	74	2400/4160	120/240	
45974	HARRIE LAKE	19	251583	T-12656	741098022	TRANSFORMER,100kVA	4014 WALSH	UNIQUE POLE #: 14772126	RTE		2400/4160	120/240	
45974	HARRIE LAKE	19	251551	T-12657	741096288	TRANSFORMER,100kVA	4000 WALSH	UNIQUE POLE #: 14156320	RTE		2400/4160	120/240	
45974	HARRIE LAKE	19	251318	T-12646	741095956	TRANSFORMER,100kVA	3025 WALSH RIVER	UNIQUE POLE #: 14778290	RTE		2400/4160	120/240	
45974	HARRIE LAKE	19	251556	T-12652	741096289	TRANSFORMER,100kVA	3005 WALSH	UNIQUE POEL#: 14775681	RTE		2400/4160	120/240	
45974	HARRIE LAKE	19	251558	T-12640	741096292	TRANSFORMER,100kVA	4036 HARRIE LAKE	UNIQUE POLE #: 14774780	RTE		2400/4160	120/240	
270749	HARRIE LAKE	20	251585	T-12659	741098023	TRANSFORMER,100kVA	4009 DULEY	UNIQUE POLE #: 14771225	RTE		2400/4160	120/240	
270749	HARRIE LAKE	20	251586	T-12661	741101458	TRANSFORMER,100kVA	3014 MILLS CRES	UNIQUE POLE #: 14776958			2400/4160	120/240	
270749	HARRIE LAKE	20	251587	T-12660	741101455	TRANSFORMER,100kVA	4002 DULEY	UNIQUE POLE #: 14779661	RTE		2400/4160	120/240	
270749	HARRIE LAKE	20	251296	T-12662	741097725	TRANSFORMER,100kVA	4016 DULEY	UNIQUE POLE #: 14777483	RTE		2400/4160	120/240	
270749	HARRIE LAKE	20	251299	T-12663	741098019	TRANSFORMER,100kVA	4056 FULRY	UNIQUE POLE #: 14770606	RTE		2400/4160	120/240	
270749	HARRIE LAKE	20	251577	T-12664	741097718	TRANSFORMER,100kVA	4028 ASHUANIPI	UNIQUE POLE #: 14773879	RTE		2400/4160	120/240	
270749	HARRIE LAKE	20	251597	T-12665	741097717	TRANSFORMER,100kVA	3028 BARTLETT	UNIQUE POLE #:	RTE		2400/4160	120/240	
270749	HARRIE LAKE	20	251598	T-12666	741096675	TRANSFORMER,100kVA	4018 BARTLETT	UNIUE POLE #:	RTE		2400/4160	120/240	
270749	HARRIE LAKE	20	251576	T-12668	741097715	TRANSFORMER,100kVA	4028 BARTLETT	UNIQUE POLE #: 14772502	RTE		2400/4160	120/240	
270749	HARRIE LAKE	20	251584	T-12667	741098021	TRANSFORMER,100kVA	4008 ASHUANIPI	UNIQUE POLE #: 14779379	RTE		2400/4160	120/240	
270728	HUDSON	16	288633	T-14459	A2404-15	TRANSFORMER,75kVA	CAPITAL CRANE, 1050 LORRAINE	UNIQUE POLE #:	MAE	03	2400/4160		
270738	HUDSON	18	257169	T-09181	G-8113-4	TRANSFORMER,167kVA	ARENA, BOOTH AVE	UNIQUE POLE #: 20530071	FPE	91	2400/4160	347/600	
270738	HUDSON	18	260077	T-13145	A2402-8	TRANSFORMER,50kVA	RSM, LUCE ST	UNIQUE POLE #: 20612630	MEC	01	2400/4160	347	
270738	HUDSON	18	260078	T-13105	A2402-5	TRANSFORMER,50kVA	RSM, LUCE ST	UNIQUE POLE #: 20612630	MEC	01	2400/4160	347	
270738	HUDSON	18	265005	T-13147	A2402-7	TRANSFORMER,50kVA	RSM LUCE ST	UNIQUE POLE #: 20611353	MEC	01	2400/4160	347	
270738	HUDSON	18	257249	T-7983	LL23740	TRANSFORMER,75kVA	334 BEVERLEY	UNIQUE POLE #: 13518886	WES	85	2400/4160	120/240	

270768	QUARTZITE	12	248356	T-12896	LG24982	TRANSFORMER,100kVA	833 WILLOW	UNIQUE POLE #: 13540814	WES	81	2400/4160	120/240	
270768	QUARTZITE	12	255794	T-10787	741096674	TRANSFORMER,100kVA	815 SPRUCE	UNIQUE POLE #: 13529971			2400/4160	120/240	
270768	QUARTZITE	12	248355	T-10064	LJ33013	TRANSFORMER,75kVA	825 WILLOW	UNIQUE POLE #:	WES	82	2400/4160	120/240	
270776	QUARTZITE	14	251541	T-12655	741095959	TRANSFORMER,100kVA	4040 TANYA	UNIQUE NO: 14152434			2400/4160	120/240	
270776	QUARTZITE	14	251566	T-12644	741097714	TRANSFORMER,100kVA	4006 QZ/4007 TANYA	UNIQUE POLE #: 14772978	RTE		2400/4160	120/240	
270776	QUARTZITE	14	251578	T-12645	741097719	TRANSFORMER,100kVA	3010 QUARTZITE	UNIQUE POLE #: 14151627			2400/4160	120/240	
270776	QUARTZITE	14	251546	T-12654	741097722	TRANSFORMER,100kVA	4048 TANYA	UNIQUE NO: 14772032			2400/4160	120/240	
271168	VANIER	23	255799	T-6903	P0614-4	TRANSFORMER,100kVA	419 VANIER	UNIQUE POLE #: 13586674	CAR	86	2400/4160	120/240	
270704	BARTLETT	1	251535	T-10306	61923.1	TRANSFORMER,167kVA	AP LOW SCHOOL	UNIQUE POLE #:	FPT	94	2400/7200	347/600	
270704	BARTLETT	1	251536	T-10305	61923.3	TRANSFORMER,167kVA	AP LOW SCHOOL	UNIQUE POLE #:	FPT	94	2400/7200	347/600	
270704	BARTLETT	1	251537	T-10304	61923.5	TRANSFORMER,167kVA	AP LOW SCHOOL	UNIQUE POLE #::	FPT	94	2400/7200	120/240	
270706	BARTLETT	2	248897	T-10001	A1294-22	TRANSFORMER,75kVA	710 ROCHE	UNIQUE POLE #: 13509503	MEC	92	2400/7200	120/240	
270706	BARTLETT	2	248896	T-7998	ATL1307-13	TRANSFORMER,100kVA	216 MATTHEW	UNIQUE POLE #: 13506142	MEC	92	2400/7200	120/240	
270706	BARTLETT	2	248920	T-10916	951036612	TRANSFORMER,100kVA	725 FIELD	UNIQUE POLE#: 13508984	CME	95	2400/7200	120/240	
270710	BARTLETT	3	248348	T-7996	ATL1307-10	TRANSFORMER,100kVA	420 GRENFELL	UNIQUE POLE #: 13593121	MAE	92	2400/7200	120/240	
270710	BARTLETT	3	257184	T-13030	A2784-1	TRANSFORMER,100kVA	WESTLAB SHOPPING CTR-EASTERN	UNIQUE POLE #: 20613061	MEC	01	2400/7200	347	
270710	BARTLETT	3	257185	T-13029	A2784-2	TRANSFORMER,100kVA	WESTLAB SHOPPING CTR-EASTERN	UNIQUE POLE#: 20613061	MEC	01	2400/7200		
270710	BARTLETT	3	257192	T-13034	A2784-8	TRANSFORMER,100kVA	WESTLAB SHOPPING CTR-EASTERN	UNIQUE POLE #: 20613061	MEC	01	2400/7200	347	
270710	BARTLETT	3	248959	T-12210	ATL1306-2	TRANSFORMER,50kVA	430 GENFELL	UNIQUE POLE #: 13592790	MEC	92	2400/7200	120/240	
270713	BARTLETT	4	249034	T-10981	LL16176	TRANSFORMER,100kVA	717 TAMARACK	UNIQUE POLE #: 13546408	WES	84	2400/7200	120/240	
270713	BARTLETT	4	249021	T-10766	951036131	TRANSFORMER,100kVA	4 BEAVER	UNIQUE POLE #: 13558682	CME	95	2400/7200	120/240	
270713	BARTLETT	4	249029	T-10986	ATL1307-24	TRANSFORMER,100kVA	751 TAMARACK	UNIQUE POLE #: 13544894	MEC	92	2400/7200	120/240	
270713	BARTLETT	4	248983	T-09862	ATL1306-1	TRANSFORMER,50kVA	430 TAMARACK	UNIQUE POLE #: 11627036	MEC	92	2400/7200	120/240	
270716	BARTLETT	5	248993	T-09971	61850:12	TRANSFORMER,75kVA	709 WILLOW	UNIQUE POLE #: 13542428	FPT	94	2400/7200	120/240	
270716	BARTLETT	5	249017	T-10914	951036132	TRANSFORMER,100kVA	712 BARTLETT	UNIQUE POLE #: 13548874	CME	95	2400/7200	120/240	
270716	BARTLETT	5	249018	T-10919	951036610	TRANSFORMER,100kVA	724 BARTLETT /727 BIRCH	UNIQUE POLE #: 13547691	CME	95	2400/7200	120/240	
270724	HUDSON	15	275348	T-09978	61850-2	TRANSFORMER,75kVA	305 VIKING	UNIQUEPOLE #: 13584596	FPT	94	2400/7200		
270724	HUDSON	15	275344	T-10770	951037253	TRANSFORMER,100kVA	318 CARSON	UNIQUE POLE #:: 13582794	COO	95	2400/7200		
270724	HUDSON	15	275345	T-09835	ALT-1307-34	TRANSFORMER,100kVA	513 HUDSON	UNIQUE POLE #: 13582506	MAE	92	2400/7200		
270724	HUDSON	15	275350	T-09818	ALT 1307-33	TRANSFORMER,100kVA	615 CARIBOU	UNIQUE POLE #: 13585497	MAE	92	2400/7200		
270724	HUDSON	15	275351	T-09880	ALT 1307-46	TRANSFORMER,100kVA	615 HUDSON	UNIQUE POLE #: 13584784	MAE	92	2400/7200		
270724	HUDSON	15	275352	T-09834	ALT-1307-32	TRANSFORMER,100kVA	621 HUDSON	UNIQUE POLE #: 13538214	MAE	92	2400/7200		
270724	HUDSON	15	275353	T-10134	ALT 1307-3	TRANSFORMER,100kVA	711 HUDSON	UNIQUE POLE #: 13537789	MAE	92	2400/7200		
270724	HUDSON	15	275354	T-09885	ALT 1307-53	TRANSFORMER,100kVA	703 RICHARDS	UNIQUE POLE #: 13537883	MAE	92	2400/7200		
270728	HUDSON	16	254540	T-10285	61891.3	TRANSFORMER,75kVA	114 AIRPORT RD	UNIQUE NO: 14241816	FPT	94	2400/7200	347	
270728	HUDSON	16	254558	T-11530	62308.3	TRANSFORMER,75kVA	CO-OP BLDG	UNIQUE POLE #: 14241816	FPT	96	2400/7200	120/240	
270728	HUDSON	16	254592	T-11535	62308.4	TRANSFORMER,75kVA	CO-OP BLDG	UNIQUE POLE #: 14241816	FPT	96	2400/7200	120/240	
270728	HUDSON	16	254518	T-6361	310641	TRANSFORMER,100kVA	CAROL WABUSH DISTRIBUTING	UNIQUE POLE #: 1424435	MEP	84	2400/7200	347/600	
270728	HUDSON	16	254519	T-11547	A1900-2	TRANSFORMER,100kVA	L16 LBC	UNIQUE POLE#: 14242435	MEC	96	2400/7200	347/600	
270728	HUDSON	16	254538	T-09989	61851:2	TRANSFORMER,100kVA	CAROL WABUSH DISTRIBUTING	UNIQUE POLE #: 14242435	FPT	94	2400/7200	347/600	
270728	HUDSON	16	254582	T-12843	951034737	TRANSFORMER,50kVA	SHELL CANADA	UNIQUE POLE #:	CME	96	2400/7200	347/600	
270728	HUDSON	16	254584	T-11400	961001028	TRANSFORMER,100kVA	L16 LBC	UNIQUE POLE #: 14245044	CME	96	2400/7200	347/600	
270733	HUDSON	17	262511	T-10568	62068:6	TRANSFORMER,75kVA	ROYAL CARPET	UNIQUE POLE #: 20614620	FPT	95	2400/7200	120/240	
270733	HUDSON	17	257175	T-11801	A1939-11	TRANSFORMER,100kVA	130 MARCONI	UNIQUE POLE #: 13574124	MEC	97	2400/7200	120/240	
270733	HUDSON	17	255217	T-12614	33030-0001	TRANSFORMER,167kVA	90 AVALON	UNIQUE POLE #: 14778854	ABB	99	2400/7200	347	
270733	HUDSON	17	255218	T-12615	33030-0002	TRANSFORMER,167kVA	MCDONALD'S 90 AVALON	UNIQUE POLE #: 14778854	ABB	99	2400/7200	347	
270733	HUDSON	17	255219	T-12616	33030-0003	TRANSFORMER,167kVA	90 AVALON	UNIQUE NO: 14778854	ABB	99	2400/7200	347	
270733	HUDSON	17	254919	T-11680	A1932-23	TRANSFORMER,25kVA	217 DRAKE	UNIQUE POLE #: 14248311	MEC	95	2400/7200	120/240	
270733	HUDSON	17	285966	T-14204	ALT-1293-1	TRANSFORMER,25kVA	TOWN GARAGE, TAMARACK	UNIQUE POLE #: 13594968	MAE	92	2400/7200		
270738	HUDSON	18	262513	T-10571	62068:2	TRANSFORMER,75kVA	HOPE HAVEN		FPT	95	2400/7200	120/240	
270738	HUDSON	18	257179	T-13510	A2438-1	TRANSFORMER,167kVA	ARENA (BANK)	UNIQUE POLE #: 20530071	MEC	00	2400/7200	347	
270738	HUDSON	18	257180	T-13513	A2438-2	TRANSFORMER,167kVA	ARENA, BOOTH AVE	UNIQUE POLE #: 20530071	MEC	00	2400/7200	347	
270738	HUDSON	18	248357	T-12430	A2401-1	TRANSFORMER,50kVA	CAROL AUTO	UNIQUE POLE #: 13596394	MAE		2400/7200	120/240	
270738	HUDSON	18	255220	T-12177	A1954-1	TRANSFORMER,50kVA	CAROL AUTO 55 AVALON	UNIQUE POLE #: 14245420	MEC	97	2400/7200		
270756	QUARTZITE	6	254425	T-10146	A1294-5	TRANSFORMER,75kVA	803 HUDSON	UNIQUE POLE #: 13536600	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254426	T-10132	A1294-11	TRANSFORMER,75kVA	318 CURTIS	UNIQUE POLE #: 13535987	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254427	T-10011	A1294-18	TRANSFORMER,75kVA	819 CAROL	UNIQUE POLE #: 13532808	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254428	T-10133	A1294-25	TRANSFORMER,75kVA	710 CAROL	UNIQUE POLE #: 13535605	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254430	T-10013	A1294-26	TRANSFORMER,75kVA	833 HUDSON	UNIQUE POLE #: 13531719	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254432	T-10131	A1294-23	TRANSFORMER,75kVA	718 CAROL	UNIQUEPOLE #: 13535417	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254431	T-09879	ATL1307-49	TRANSFORMER,100kVA	822 RETTY	UNIQUE POLE #: 13530818	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254441	T-7992	ATL1307-4	TRANSFORMER,100kVA	819 HUDSON	UNIQUE POLE #: 13536318	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254444	T-10145	ATL1307-23	TRANSFORMER,100kVA	805 CORMACK	UNIQUE POLE #: 13538308	MEP	92	2400/7200	120/240	
270756	QUARTZITE	6	254446	T-10144	ATL1307-26	TRANSFORMER,100kVA	815 CORMACK	UNIQUE POLE #: 13538784	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254449	T-09883	ATL1307-35	TRANSFORMER,100kVA	619 CAROL	UNIQUE POLE #: 13534234	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254451	T-09868	ATL1307-37	TRANSFORMER,100kVA	707 CAROL	UNIQUE POLE #: 13533997	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254458	T-09878	ATL1307-44	TRANSFORMER,100kVA	703 CAROL	UNIQUE POLE #: 13534046	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254459	T-09881	ATL1307-42	TRANSFORMER,100kVA	834 CAROL	UNIQUE POLE #: 13534328	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254462	T-09876	ATL1307-40	TRANSFORMER,100kVA	310 CURTIS	UNIQUE POLE #: 13539021	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	257522	T-13039	A2785-1	TRANSFORMER,100kVA	609 CAROL	UNIQUE POLE #:	MEC	01	2400/7200	120/240	
270756	QUARTZITE	6	254434	T-10018	ATL1306-3	TRANSFORMER,50kVA	808 CHURCHILL	UNIQUE POLE #: 13533333	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254437	T-10019	ATL1306-6	TRANSFORMER,50kVA	827 CAROL	UNIQUE POLE #: 13530630	MEC	92	2400/7200	120/240	
270756	QUARTZITE	6	254440	T-10020	ATL1306-19	TRANSFORMER,50kVA	812 CHURCHILL	UNIQUE POLE #: 13533051	MEC	92	2400/7200	120/240	
270760	QUARTZITE	7	254473	T-11225	951102068	TRANSFORMER,100kVA	823 D'AIGLE	UNIQUE POLE #: 13567207	CME	95	2400/7200	120/240	

270764	QUARTZITE	8	262510	T-10567	62068:9	TRANSFORMER,75kVA	840 HUDSON	UNIQUE NO: 13503157	FPT	95	2400/7200	120/240	
270768	QUARTZITE	12	255797	T-10756	951037700	TRANSFORMER,75kVA	867 HUDSON	UNIQUE NO: 13522624	ONA		2400/7200	120/240	
270768	QUARTZITE	12	257174	T-11793	A1939-1	TRANSFORMER,100kVA	816 LAKESIDE	UNIQUE POLE #:	MAE	97	2400/7200	120/240	
270780	VANIER	21	257289	T-6255	3106426	TRANSFORMER,100kVA	RED LIFT SMOKEY	UNIQUE POLE #:	MEP	84	2400/7200	600	
270780	VANIER	21	257272	T-6209	310642-4	TRANSFORMER,100kVA	RED LIFT SMOKEY	UNIQUE POLE #:	MEP	94	2400/7200	600	
270784	VANIER	22	256353	T-10774	951038435	TRANSFORMER,100kVA	412 VANIER	UNIQUE POLE #:	ONA		2400/7200	120/240	
270784	VANIER	22	256354	T-10771	951038438	TRANSFORMER,100kVA	410 MONTAGNAIS	UNIQUE POLE #:	ONA		2400/7200	120/240	
270784	VANIER	22	256355	T-10773	951039204	TRANSFORMER,100kVA	404 MONTAGNAIS	UNIQUE POLE #:	ONA		2400/7200	120/240	
270784	VANIER	22	262512	T-10576	62068:7	TRANSFORMER,75kVA	415 MASSEY	UNIQUE POLE #:	FPT	95	2400/7200	120/240	
270784	VANIER	22	257206	T-3-0111	975586	TRANSFORMER,75kVA	408 MURPHY	UNIQUE POLE #:	GEI	75	2400/7200	120/240	
271168	VANIER	23	255798	T-10016	A1294-24	TRANSFORMER,75kVA	431 VANIER	UNIQUE POLE #: 13587011	MEC	92	2400/7200	120/240	
45974	HARRIE LAKE	19	269556	T-3-1819	741095955	TRANSFORMER,100kVA	3027 HARRIE LAKE	UNIQUE POLE #:	RTE				
270724	HUDSON	15	275349	T-10022	484629	TRANSFORMER,50kVA	333 VIKING	UNIQUE POLE # 13584120	WES				
270724	HUDSON	15	275346	T-09977		TRANSFORMER,75kVA	513 GUY	UNIQUE POLE #: 13583125					
270724	HUDSON	15	275343	T-09871	ATL-1307-47	TRANSFORMER,100kVA	501 HUDSON	UNIQUE POLE #: 13582224	MAE	92			
270724	HUDSON	15	275351	T-09880	ALT 1307-46	TRANSFORMER,100kVA	615 HUDSON	UNIQUE POLE #: 13584784	MAE	92			
270724	HUDSON	15	269377	T-10135	LC25245	TRANSFORMER,100kVA	704 RICHARD	UNIQUE POLE #: 13539497	WES	77			
270724	HUDSON	15	269768	T-10076	937565	TRANSFORMER,100kVA	306 CAROL	UNIQUE POLE #: 13581799	WES	75			
270724	HUDSON	15	269383	T-10077	LG25025	TRANSFORMER,100kVA	321 ELIZABETH	UNIQUE POLE #: 13582982	WES	81			
270724	HUDSON	15	269479	T-10048	LJ20518	TRANSFORMER,100kVA	502 CAROL	UNIQUE POLE #: 13583977	WES	82			
270724	HUDSON	15	269681	T-10138	839860	TRANSFORMER,50kVA	621 HUDSON	UNIQUE POLE #: 13585303	WES	73			
270728	HUDSON	16	275398	T-10103	718904	TRANSFORMER,50kVA	101 STATION RD	UNIQUE POLE #: 14241534	WES	71			
270728	HUDSON	16	275400	T-10834	551034750	TRANSFORMER,50kVA	SHELL BULK PLANT	UNIQUE POLE #: 14245138	CME	95			
270728	HUDSON	16	275404	T-10915	951037301	TRANSFORMER,100kVA	BRUNO PLAZA	UNIQUE NO: 14242811/14242717	CME	95			
270728	HUDSON	16	248981	T-7993	ALT 1306-12	TRANSFORMER,100kVA	HOLLOWAY ENT 105 AIRPORT RD	UNIQUE NO:14243712	CAR	94		120/240	
270728	HUDSON	16	275367	T-11905	A1953-5	TRANSFORMER,50kVA	PEACE PARK/AVALON	UNIQUEPOLE #:	MAE	97			
270728	HUDSON	16	275369	T-09981	61851:1	TRANSFORMER,100kVA	LAB MOTORS AVALON	UNIQUE POLE #:	FPT	94			
270728	HUDSON	16	275370	T-09988	61851:3	TRANSFORMER,100kVA	LAB MOTORS/AVALON	UNIQUE POLE #:	FPT	94			
270728	HUDSON	16	275372	T-10760	951037300	TRANSFORMER,100kVA	CITY TIRE/STAT RD	UNIQUE POE #: 14241348	CME	95			
270728	HUDSON	16	275375	T-10920	951037303	TRANSFORMER,100kVA	CITY TIRE/STAT RD	UNIQUEPOLE #: 14241346	CME	95			
270728	HUDSON	16	275379	T-10758	951037305	TRANSFORMER,100kVA	CITY TIRE/STAT RD	UNIQUE POLE #: 14241348	CME	95			
270728	HUDSON	16	275399	T-10846	951034749	TRANSFORMER,50kVA	SHELL BULK PLANT	UNIQUEPOLE #: 14245138	CME	95			
270728	HUDSON	16	275401	T-10684	951034748	TRANSFORMER,50kVA	SHELL BULK PLANT	UNIQUE POLE #: 14245138	CME	95			
270728	HUDSON	16	275402	T-10751	951037304	TRANSFORMER,100kVA	BRUNO PLAZA	UNIQUE NO: 14242811/14242717	CME	95			
270728	HUDSON	16	275403	T-10922	951037302	TRANSFORMER,100kVA	BRUNO PLAZA	UNIQUE NO: 14242811/14242717	CME	95			
270728	HUDSON	16	269503	T-10960	484647	TRANSFORMER,50kVA	218 HUMPHREY	UNIQUE POLE #: 14241158	WES				
270733	HUDSON	17	275440	T-10099	ATL 1307-2	TRANSFORMER,100kVA	211 LAKESIDE	UNIQUE POLE #: 13559489	MAE	92			
270733	HUDSON	17	275410	T-10005	A1294-17	TRANSFORMER,75kVA	MARY BROWNS, 210 DRAKE	UNIQUE POLE #: 13577203	MAE	92			
270733	HUDSON	17	275412	T-7994	ALT 1307-14	TRANSFORMER,100kVA	MARY BROWNS, 210 DRAKE	UNIQUE POLE #: 13577015	MAE	92			
270733	HUDSON	17	275430	T-10101	ATL1307-12	TRANSFORMER,100kVA	131 CABOT	UNIQUE POLE #: 13575401	MAE	92			
270733	HUDSON	17	275434	T-10130	ALT 1307-1	TRANSFORMER,100kVA	120 AVALON	UNIQUE POLE #: 13571421	MAE	92		120/240	
270733	HUDSON	17	275435	T-10142	ATL1307-29	TRANSFORMER,100kVA	121 MARCONI	UNIQUE POLE: 13571233	MAE	92			
270733	HUDSON	17	275437	T-09969	618 50-5	TRANSFORMER,75kVA	111 DRAKE	UNIQUE POLE #: 13573223	FPT	94			
270733	HUDSON	17	275444	T-10098	ATL1307-30	TRANSFORMER,100kVA	311 BARTLETT	UNIQUE POLE #: 13574500	MAE	92			
270733	HUDSON	17	275406	T-10673	951034752	TRANSFORMER,50kVA	BRACE'S BLDG, 211 AMHERST	UNIQUE POLE #: 13577679	CME	95			
270733	HUDSON	17	275407	T-10682	951034757	TRANSFORMER,50kVA	BRACES BLDG, 211 AMHERST	UNIQUE POLE #: 13577679	CME	95		347	
270733	HUDSON	17	275414	T-10681	951034755	TRANSFORMER,50kVA	CITY AUTO PARTS 207 AMHERST	UNIQUE POLE #: 13577109	CME	95			
270733	HUDSON	17	275422	T-10680	951034742	TRANSFORMER,50kVA	CITY AUTO, AMHERST	UNIQUE POLE #: 13577109	CME	95			
270733	HUDSON	17	275438	T-10097	ATL 1306-4	TRANSFORMER,50kVA	222 BARTLETT	UNIQUE POLE #: 13559771	MAE	92			
270733	HUDSON	17	275439	T-10096	ATL 1306-18	TRANSFORMER,50kVA	230 BARTLETT	UNIQUE POLE #: 13559583	MAE	92			
270733	HUDSON	17	275441	T-10095	ATL 1306-20	TRANSFORMER,50kVA	302 BARTLETT	UNIQUE POLE #: 13570520	MAE	92			
270733	HUDSON	17	269381	T-14274	LF26207	TRANSFORMER,50kVA	GALLERY 201	UNIQUE POLE #: 13577961	WES	80			
270733	HUDSON	17	269540	T-10100	484654	TRANSFORMER,50kVA	120 MARCONI	UNIQUE POLE #: 13574030	WES				
270738	HUDSON	18	275449	T-12689	535228	TRANSFORMER,50kVA	302 BERERLY	UNIQUE POLE #: 13516702	WES				
270738	HUDSON	18	269378	T-10949	LE30946	TRANSFORMER,50kVA	507 CAROL	UNIQUE POLE #: 13586110	WES	80			
270760	QUARTZITE	7	275025	T-11560	A1906-10	TRANSFORMER,50kVA	422 CENTENNIAL	UNIQUE POLE #: 13568490	MAE	96			
270760	QUARTZITE	7	275028	T-11232	951102064	TRANSFORMER,100kVA	417 CENTENNIAL	UNIQUE POLE #: 13563133	COO	95		120/240	
270764	QUARTZITE	8	269682	T-10109	937322	TRANSFORMER,75kVA	816 HUDSON	UNIQUE POLE #: 13502538	WES	75			
270764	QUARTZITE	8	269765	T-10106	937550	TRANSFORMER,100kVA	715 DURRELL	UNIQUE NO: 13503345	WES	75			
270764	QUARTZITE	8	269478	T-10118	LG25026	TRANSFORMER,75kVA	804 BEOTHUCK	UNIQUE POLE #: 13520446	WES	81			
270768	QUARTZITE	12	248410	T-12872	LJ33017	TRANSFORMER,75kVA	841 WILLOW	UNIQUE POLE #:	WES	82			
270768	QUARTZITE	12	255796	T-10783	839882	TRANSFORMER,50kVA	1003 PINE	UNIQUE POLE #: O: 13547403	WES				
270768	QUARTZITE	12	269376	T-10062	L0107-3	TRANSFORMER,100kVA	815 WILLOW	UNIQUE POLE #: 13541715	CAR	83			
270772	QUARTZITE	13	269544	T-10054	700956	TRANSFORMER,50kVA	841 TAMARACK	UNIQUE POLE #: 13541245	WES	70			
270780	VANIER	21	269499	T-10059	432681	TRANSFORMER,25kVA	TAP TO GATEWAY	UNIQUE POLE #:	WES				
270784	VANIER	22	269767	T-10050	937559	TRANSFORMER,100kVA	405 MASSEY	UNIQUE POLE #:	WES	75			
270784	VANIER	22	269766	T-10043	937553	TRANSFORMER,100kVA	405 MURPHY	UNIQUE POLE #: 13561425	WES	75			
271168	VANIER	23	255802	T-10990	427369	TRANSFORMER,50kVA	705 MCPARLAND	UNIQUE POLE #:	WES				

APPENDIX C

LABRADOR CITY

PROPOSED SYSTEM SINGLE LINE DIAGRAM

Labrador City Voltage Conversion Terminals & Transmission Reconfiguration - Appendix C

LEGEND:

- Distribution Line 4.16, 12.5, or 25 kV
- Distribution Line 46 kV
- Fused Disconnect Switch
- Ganged Operated Disconnect Switch
- Normally Open Disconnect Switch
- Solid Blade Disconnect Switch
- On Load Tap Changing Transformer Delta - Wye Grounded shown
- Circuit Breaker with CTs
- Recloser with Bipass Switch
- Quartzite Feeder 8 (25 kV)
- Quartzite Feeder 12 (25 kV)
- Quartzite Feeder 13 (25 kV)
- Quartzite Feeder 14 (25 kV)
- Vanier Feeder 15 (25 kV)
- Vanier Feeder 18 (25 kV)
- Vanier Feeder 21 (25 kV)
- Vanier Feeder 22 (25 kV)
- Vanier Feeder 23 (25 kV)
- Wabush Feeder 32 (46 kV)
- Wabush Feeder 33 (46 kV)
- Vanier Feeder 33 (46 kV)

TO FERMONT (EMERGENCY BI-DIRECTIONAL SUPPLY)

VANIER FEEDER 33 VA33 46 kV

PROPOSED NEW HOSPITAL

PROPOSED NEW COLLEGE

PROPOSED RESIDENTIAL DEVELOPMENTS

VANIER FEEDER 33 VA33 46 kV

WABUSH FEEDER 32 WA32 46 kV

QUARTZITE SUBSTATION

QZ14 25 kV

QZ13 25 kV

QZ12 25 kV

QZ8 25 kV

TAMARACK GULF CLUB (CUSTOMER OWNED LINE)

VANIER FEEDER 33 VA33 46 kV

VA21 25 kV

VA22 25 kV

VA23 25 kV

VA15 25 kV

VA18 25 kV

(EXISTING 25 kV BUSWORK TO BE VERIFIED)

Str. 380

Str. 205

WABUSH FEEDER 33 WA33 46 kV

SMOKEY MOUNTAIN

NEW (N/O)

PROPOSED COMMERCIAL AND INDUSTRIAL DEVELOPMENTS

WABUSH FEEDER 32 WA32 46 kV

WABUSH FEEDER 33 WA33 46 kV

WABUSH TERMINAL STATION

SEPT ISLES

WABUSH TOWNSITE SUBSTATION

SYS PLANNING:	CRW	SHEET 1 OF 1	
SYS OPERATIONS:	--	DATE: NOV 2, 2007	
TERM DESIGN:	--	DRAWN BY: CRW	
PROTECTION:	--	FILE: LABRADOR CITY 25 kV CAPITAL PLAN 2007.SKF	

APPENDIX D

LABRADOR WEST LONG-TERM LOAD FORECAST

Labrador West Load Forecast 2007-2027																				
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Labrador City																				
Gross Peak (kW)1	51,158	52,120	53,280	53,323	53,381	53,528	53,972	54,113	54,238	54,363	54,488	54,613	54,738	54,864	54,989	55,114	55,239	55,364	55,489	55,615
Gross Energy (MWh)1	207,205	211,104	215,801	217,441	216,211	216,808	218,605	219,174	219,681	220,188	220,695	221,202	221,709	222,216	222,723	223,230	223,737	224,244	224,751	225,258
Total Sales (MWh)	199,096	202,842	207,355	208,931	207,749	208,323	210,063	210,610	211,098	211,585	212,073	212,561	213,049	213,536	214,024	214,512	215,000	215,487	215,975	216,463
Company Use (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wabush																				
Gross Peak (kW)1	16,311	16,635	16,992	17,235	17,397	17,560	17,705	17,752	17,793	17,834	17,875	17,916	17,957	17,998	18,039	18,080	18,121	18,162	18,203	18,244
Gross Energy (MWh)1	66,460	67,779	69,231	70,221	70,884	71,547	72,140	72,328	72,495	72,662	72,830	72,997	73,164	73,332	73,499	73,666	73,834	74,001	74,168	74,335
Total Sales (MWh)	62,828	64,082	65,463	66,404	67,034	67,664	68,229	68,407	68,565	68,724	68,882	69,041	69,199	69,357	69,516	69,674	69,833	69,991	70,149	70,308
Company Use (MWh)	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
Labrador West Total																				
Gross Peak (kW)1	67,469	68,755	70,272	70,558	70,778	71,088	71,678	71,864	72,030	72,197	72,363	72,529	72,695	72,862	73,028	73,194	73,360	73,526	73,693	73,859
Gross Energy (MWh)1	273,665	278,883	285,033	287,663	287,095	288,355	290,745	291,502	292,176	292,850	293,525	294,199	294,873	295,547	296,222	296,896	297,570	298,244	298,919	299,593
Total Sales (MWh)	261,924	266,924	272,818	275,335	274,783	275,986	278,292	279,017	279,663	280,309	280,955	281,601	282,248	282,894	283,540	284,186	284,832	285,478	286,125	286,771
Company Use (MWh)	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
1. Gross peak or energy equates to bulk deliveries on interconnected systems.																				
Source: Spring 2008 HROPLF with Summer 2007 Long Term Extension																				
System Planing Department																				
Jun-08																				

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2009 Wood Pole Line Management

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

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1 INTRODUCTION

Hydro maintains approximately 2,400 kilometers of wood pole transmission lines operating at 69, 138 and 230 kV. These lines consist of approximately 26,000 transmission size poles of varying ages, with the maximum age being 43 years. In 2008, approximately 80% of the transmission pole assets are over 20 years old with about 50% of these at or over 30 years old. The remaining assets are less than 20 years old.

Prior to 2003, Hydro's pole inspection and maintenance practices followed the traditional utility approach of sounding inspections only. In 1998, Hydro decided to take core samples on selected poles to test for preservative retention levels and pole decay. The results of these tests raised concerns regarding the general preservative retention levels in wood poles. Poles become susceptible to fungi and/or insect attack as the preservative levels deplete. Figure 1 illustrates typical wood pole inspection techniques. Figure 2 shows typical wood pole inspection results.

Figure 1 - WPLM Inspection Techniques

Figure 2 - Typical Wood Pole Inspection Results

Between 1998 and 2003, Hydro undertook additional coring and preservative testing. This testing confirmed that there were a significant number of poles which had a preservative level below that required to maintain the required design criteria. During this period, certain poles were replaced because the preservative level had lowered to the point that decay had advanced and the pole was no longer structurally sound. These inspections and the analysis of the data confirmed that a more rigorous wood pole line management program was required.

Hydro first initiated the Wood Pole Line Management (WPLM) program as a pilot study in 2003. It was determined that the program should continue as a long-term asset management and life extension program. The program was presented to the Board of Commissioners of Public Utilities (the Board) in October 2004 as part of Hydro's 2005 Capital Budget Application and was titled "Replace Wood Poles – Transmission". The proposal was supported in the application by the Hydro internal report titled "Wood Pole Line Management Using RCM Principles" by Dr. Asim Haldar, Ph.D, P.Eng.

The Board found that “This approach (by Hydro) is a more strategic method of managing wood poles and conductors and associated equipment and is persuaded that the new WPLM Program, based on Reliability Centered Maintenance (RCM) principles, will lead to an extension of the life of the assets, as well as a more reliable method of determining the residual life of each asset. One of the obvious benefits of RCM will be to defer the replacement of these assets thereby resulting in a direct benefit to the ratepayers”.

The Board approved the project submitted in the 2005 Capital Budget, Board Order No. P.U. 53(2004). As part of its annual Capital Budget Application process, Hydro committed to provide the Board with an update of the program work that includes both a progress report of the work completed as well as a forecast of the future program objectives. This report would be provided with the annual Capital Budget Application.

2 PROJECT DESCRIPTION

The WPLM program is a condition-based program, which uses the basic RCM principles and strategies. Under the program, line inspection data in each year is analyzed and appropriate recommendations are made for necessary refurbishment and/or replacement of line components (poles/structures, hardware, conductor, etc.) in the subsequent year. The inspection data and any refurbishment and/or replacement of assets are recorded in a centralized database for easy access and future tracking.

The program is aimed at early detection and treatment of the wood poles before the integrity of the structures is jeopardized. If the deterioration of the structures is not detected early enough, then the reliability of the structures will affect the reliability of the line and the system as a whole. It may also create safety issues and hazards for Hydro personnel and for the general public.

3 EXISTING SYSTEM

As stated previously, Hydro maintains approximately 2,400 km of wood pole transmission lines operating at 69, 138 and 230 kV. These lines consist of approximately 26,000 transmission size poles of varying ages.

The report format has changed to ensure compliance with the October 2007 Capital Budget Guidelines issued by the Board. As this is a recurring inspection of transmission lines, there is no relevant data for:

- Maintenance History;
- Outage Statistics;
- Safety Performance;
- Industry Experience;
- Maintenance or Support Arrangements;
- Vendor Recommendations;
- Availability of Replacement Parts;
- Environmental Performance; or
- Operating Regime.

3.1 Age of Equipment or System

The age of each line can be found in Appendix B.

3.2 Major Work or Upgrades

This section is not applicable since the WPLM Program encompasses the annual inspection, treatment and refurbishment of all of Hydro's wood pole transmission lines.

3.3 Anticipated Useful life

The anticipated useful life of a transmission line constructed with wood is approximately 40 years. Through this maintenance program, Hydro plans to further extend the life of the lines.

4 JUSTIFICATION

A 1998 inspection on the Avalon Peninsula indicated that 48% of the poles sampled did not meet the minimum preservative retention level that would protect the pole against rot or insect damage. A similar program in the Central region verified the results obtained from the Avalon Peninsula. At the time, re-treatment of poles on the Avalon Peninsula was not pursued due to budget constraints. Recent failures near the Hardwoods Terminal Station showed further deterioration of these poles. These conditions justify the strong need for a well-managed wood pole inspection and treatment program. Full scale tests of poles at Memorial University since 1999 indicate a 25% reduction of average pole strength over a 35-year period. The WPLM program detects "danger poles" early to avoid safety hazards and to identify poles that are at early stages of decay to ensure that corrective measures can be taken to extend the average life of these poles. Money is saved in the long term by deferring the cost of rebuilding lines and avoiding forced outages.

Again, as this is a recurring inspection of transmission lines, there is no relevant data for the following:

- Net Present Value;
- Levelized Cost of Energy;
- Cost Benefit Analysis;
- Forecast Customer Growth;
- Energy Efficient Benefits; or
- Losses during Construction.

4.1 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements for the project.

4.2 Historical Information

The four-year historical information for the WPLM program is supplied in Table 1 below. No units or cost per units is available, since the work is not easily defined into individual units such as a line or structure number. The actual work completed is variable and is dependent on actual condition of the asset. For example, in most cases the work completed on any one structure is not related to the work on the next structure (i.e. one structure may require a pole replacement and the next structure may need a crossarm or an insulator replaced). The same is true for a breakdown by individual transmission line, where the cost will be affected by the configuration and voltage of the line, its age and geographical location.

Table 1
Historical WPLM Program Expenditures

Year	Budget ($000)	Actuals ($000)
2008F	2,188.3	
2007	2,147.8	2,214.1
2006	2,302.6	2,362.5
2005	2,587.6	2,612.5

4.3 Update of 2007 Work

The first objective of the 2007 program was to inspect, test and treat at least 3,100 poles and associated line components. The program is built on the strategy of focusing on the older lines first and working towards the newer lines. Table 2 summarizes the inspection accomplishments for 2007.

Table 2
2007 Inspections

Regions	Line Name	Year In Service	Voltage Level	Target Number of Poles Inspected	Actual Poles Inspected	% Complete
Eastern	TL-212	1966	138 kV	57	69	121%
	TL-218	1983	230 kV	125	134	107%
	TL-219	1990	138 kV	200	213	107%
Central	TL-232	1981	230 kV	189	151	80%
	TL-251	1981	69 kV	290	315	109%
	TL-252	1981	69 kV	326	367	113%
	TL-253	1982	69 kV	47	0	0%
Western	TL-250	1987	138 kV	321	354	110%
Northern	TL-229	1976	69 kV	108	108	100%
	TL-239	1982	138 kV	225	225	100%
	TL-241	1983	138 kV	249	250	100%
	TL-244	1983	138 kV	100	100	100%
	TL-257	1970	69 kV	118	120	100%
Labrador	TL-240	1976	138 kV	792	131	17%
Total				3,147	2,537	81%

Overall, the total number of poles inspected was within 20% of the target value. Although individual lines may display larger differences, the overall total for each region was within this margin. The only two lines that showed a large difference in the actual number of poles inspected were TL-240 in the Labrador region and TL-253 in the central region.

The inspection program in Labrador was hampered by difficulties in acquiring lineworkers and equipment failures. Steps were taken during the fall of 2007 to secure resources from Churchill Falls (Labrador) Corporation to complete the inspections. The number of poles targeted in 2008 will also be reduced to 400. This reduced quota still fits into the overall WPLM Program parameters and schedule.

Due to the poor condition of the poles found on TL-251 and TL-252 in Central, it was decided to defer the inspection of TL-253 and focus on the other two lines. Poles on TL-253 have been scheduled for inspection in 2008.

Another objective of the 2007 program was the replacement of defective components identified in the 2006 inspections. Hydro crews replaced 97 poles; 31 crossarms; 19 cross-braces; and many other smaller components as identified in the spring of 2007.

4.4 2008 Work Plans

The proposed inspection and treatment work for 2008 is shown summarized in Table 3.

Table 3
2008 Work Plan

Regions	Line Name	Year In Service	Voltage Level	Target Number of Poles Inspected
Eastern	TL-218	1983	230 kV	19
	TL-219	1990	138 kV	400
Central	TL-232	1981	230 kV	417
	TL-251	1981	69 kV	112
	TL-252	1981	69 kV	141
	TL-253	1982	69 kV	188
Western	TL-215	1969	69 kV	250
	TL-225	1970	69 kV	49
	TL-250	1987	138 kV	157
Northern	TL-229	1976	69 kV	200
	TL--239	1982	138 kV	249
	TL-244	1983	138 kV	100
	TL-257	1970	69 kV	267
Labrador	TL-240	1976	138 kV	400
Total				2,949

In addition to the poles listed in Table 3, a further 168 poles that were rated three in 2003 and 2004 will be re-inspected for further deterioration.

As a result of the 2007 inspection program, a refurbishment program will begin during the summer months of 2008 and continue into the fall. This will include the replacement of approximately 80 poles; 30 crossarms; 25 cross-braces; and many other smaller components. A detailed list of the work to be completed is provided in Appendix A.

4.5 Alternatives

No alternatives have been explored. In 2005, the Board found that this approach was justified and prudent and approved the expenditures as submitted in the 2005 Capital Budget, Board Order No. P.U. 53(2004).

This report satisfies Hydro's commitment to the Board to provide an update of the program work, which includes both a progress report of the work completed as well as a forecast of the future program objectives. This report is provided with the annual Capital Budget Application.

5 CONCLUSION

In conclusion, the major objectives for the 2007 program were achieved, with the exception of those points detailed above. The budget estimate of $2.2 million was realized.

The framework for systematically analyzing a large volume of wood pole transmission line inspection data, developed using the reliability based analysis technique, is still under expansion to include additional components. The method uses a hybrid approach where the uncertainties in load and strength values and the strength deterioration due to aging are taken into account with the condition rating of each pole to develop a condition matrix table.

5.1 Budget Estimate

The WPLM Budget contained in Table 4 includes the complete inspection of the stated line, including the visual inspection supported by field testing each pole using non-destructive testing, and limited full-scale testing to establish correlation full treatment of the pole (internal and external) as required.

It is assumed that a percentage of these poles inspected will also be rejected according to the IOWA curve (shown in Appendix B) depending on their age and group. Poles rejected in the field will be analyzed with respect to reliability issues, and if rejected after structural analysis, a recommendation to refurbish and/or replace will be made.

Using the average age of the poles being inspected along with the IOWA curve, the anticipated pole replacement rate is calculated and this is used to develop the future refurbishment program. A schedule of the pole inspections from 2008 to 2013 is provided in Appendix B. The table also provides the average age and pole rejection rate for each year.

Table 4
WPLM Budget

Project Cost ($x 1,000):	2009	2010	2011	2012	2013	BEYOND '14 to '23	TOTAL
Material Supply	610.4	325.4	453.8	231.0	249.9	3,345.6	5,216.1
Labour	903.1	986.6	1,195.1	758.2	801.7	10,010.1	14,654.8
Consultant	50.0	50.0	50.0	50.0	50.0	500.0	750.0
Contract Work	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Direct Costs	292.8	328.9	398.4	252.7	267.2	3,336.7	4,876.7
O/H, AFUDC & Escln.	214.3	246.1	370.0	269.4	336.9	7,852.9	9,289.6
Contingency	185.6	169.1	209.7	129.2	136.9	1,719.2	2,549.7
TOTAL	**2,256.2**	**2,106.1**	**2,677.0**	**1,690.5**	**1,842.6**	**26,764.5**	**37,336.9**

5.2 Project Schedule

The annual project schedule is highly dependent on the annual work load and availability of outages and is therefore determined during the spring of each year.

APPENDIX A

2008 Refurbishment Work

Refurbishment Work to be Completed in 2008

Region	East	Central	West	North	Lab.	Total
Proposed Inspections						
Total Number of Poles Inspected	**416**	**833**	**354**	**803**	**131**	**2537**
Number of Poles	1	59	4	7	11	82
Number of Crossarms	1	26			1	28
Number of Crossbracing	1	22	1	1		25
Number of Blocking	2	36	6	4	1	49
Number of Kneebraces		27				27
Number of Deadend Clamp	5	5	3	23	15	51
Number of Deadend Assembly		4	1	6	3	14
Number of Foundation	1			1	6	8
Number of Span / Splice	2	6	3	7	7	25
Number of Suspension Clamp					2	2
Number of OHGW		3		7	5	15
Number of Anchor Rod		3		5	1	9
Number of Guy Wire			3			3
Number of Guy Grips						
Number of Dampers	2	1	4			7
Number of Insulators		2	4	1	1	8
Number of Insulator Hardware			58	4	3	65
Number of Insulator Plumbness	1	3	9	2	2	17
Number of Structure Plumbness	1	4	2	3	6	16
TOTAL NUMBER OF ITEMS	**17**	**201**	**98**	**71**	**64**	**451**

APPENDIX B

WPLM Inspection Schedule 2008-2013

(with Average Age of Transmission Lines and Estimated Pole Rejection Rates)

WPLM Inspection Schedule 2008 to 2013

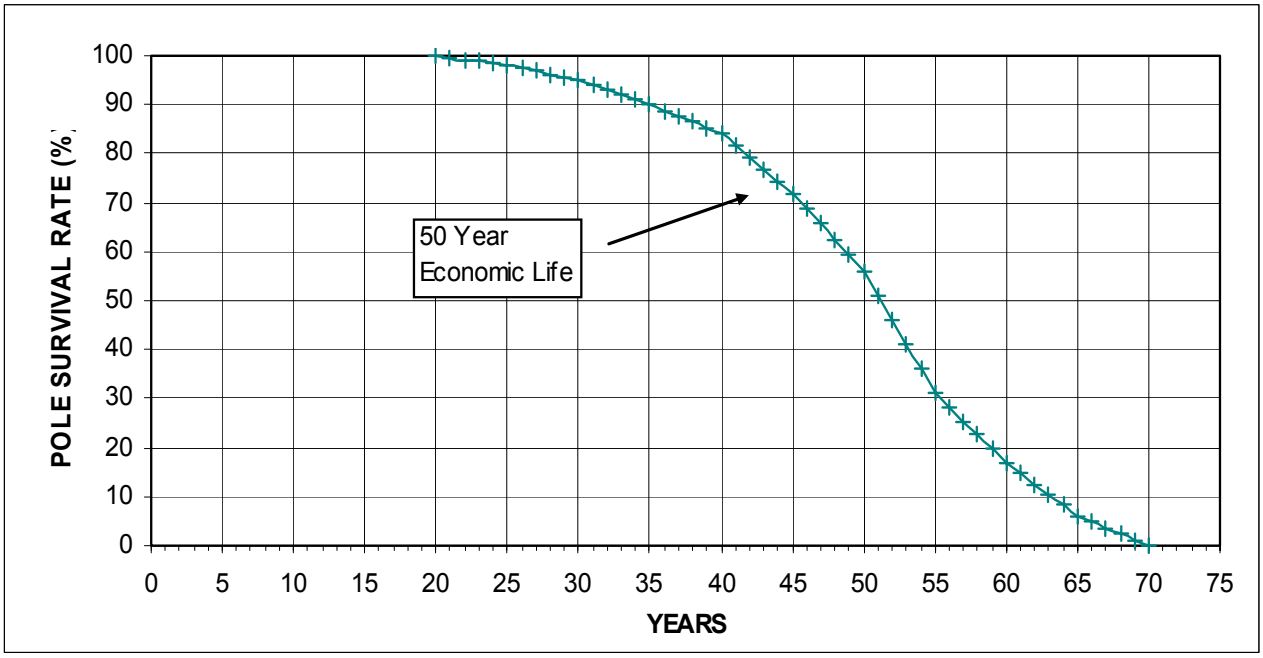
Line	# poles	Year	2008	2009	2010	2011	2012	2013
No. of Poles Inspected			**2949**	**2533**	**2584**	**2296**	**2126**	**2198**
Weighted Average Age			**1981**	**1980**	**1978**	**1983**	**1983**	**1982**
Age at Inspection			**26.81**	**29.34**	**32.00**	**27.68**	**28.55**	**30.88**
Rejection Factor**			**2.6%**	**4.4%**	**7.0%**	**3.2%**	**3.8%**	**5.0%**
TL-201	751	1966					100	151
TL-203	417	1965						
TL-209	185	1971			185			
TL-210	606	1969						
TL-212	312	1966						
TL-215	437	1969	250	187				
TL-218	446	1983	19					
TL-219	1750	1990	400	350	350	363		
TL-220	786	1970				200	350	261
TL-221	594	1970		73				271
TL-222	914	1967						361
TL-223	351	1966						
TL-224	825	1968		150	150	150	224	
TL-225	49	1970	49					
TL-226	893	1970		215	183			
TL-227	972	1970			317			
TL-229	308	1976	200					
TL-232	755	1981	417					
TL-233	640	1973		200	200	240		
TL-233	640	1973		50	79			
TL-234	489	1981		120	120			
TL-239	874	1982	249					
TL-240	2640	1976	400	400	400	400	329	
TL-241	1082	1983		200	200	130		
TL-243	159	1978						
TL-244	274	1983	100					
TL-245	285	1969			46			

WPLM Inspection Schedule 2008 to 2013

Line	# poles	Year	2008	2009	2010	2011	2012	2013
TL-246	274	1981					150	124
TL-250	1283	1987	157					
TL-251	579	1981	112					
TL-252	652	1981	141					
TL-253	188	1982	188					
TL-254	218	1988		118	100			
TL-256	524	1996				425	99	
TL-257	691	1988	267	320	104			
TL-259	863	1990				225	138	500
TL-260	463	1990		150	150	163		
TL-261	511	1996					511	
TL-262	25	2002					25	
TL-263	730	2002					200	530

** Rejection Factor based on a 50 year Iowa Curve

IOWA CURVE (Used to Determine Pole Replacement Rates)



The pole rejection rate is one minus the Pole Survival Rate.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

TL-212 Upgrade

Electrical
Mechanical
Civil
Protection & Control
Transmission & Distribution
Telecontrol
System Planning

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

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1 INTRODUCTION

TL-212 is one of 17 138 kV transmission lines in the Newfoundland and Labrador Hydro (Hydro) Island Interconnected System. It was built in 1966, and is situated between Sunnyside Terminal Station and Linton Lake Terminal Station on the Burin Peninsula (Figure 1). Much of the line traverses rough terrain, which is subject to high winds and icing.

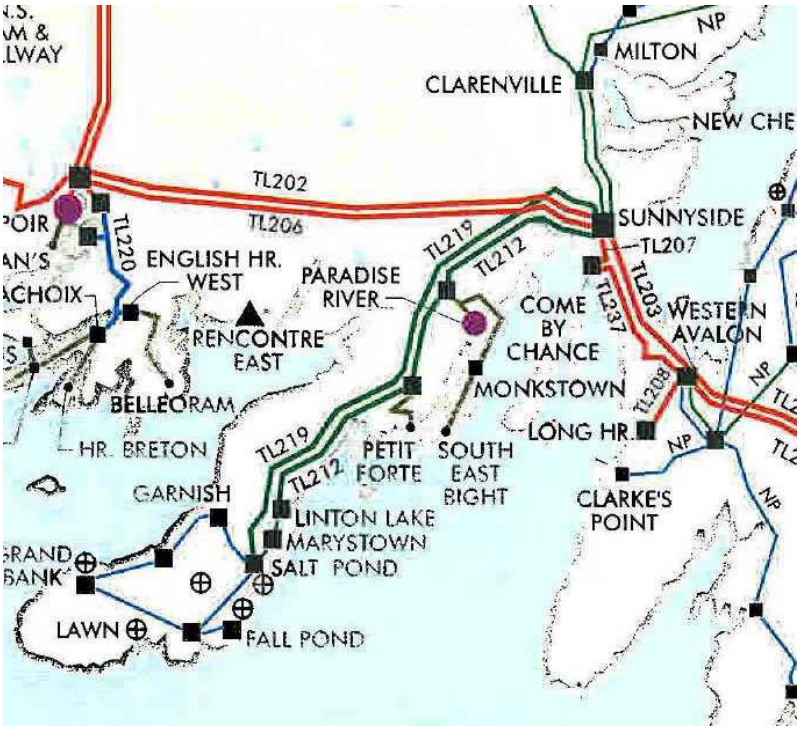


Figure 1 - Location Map for TL-212

The line is parallel to TL-219 and is part of a looped system to the Burin Peninsula. This allows work to be completed with minimal outages to the customer.

The line has a total length of 139 km and it was originally built with aluminum towers that are anchored to the ground with steel guy wires. Figure 2 shows a typical section of TL-212 with the aluminum towers.

Because of problems with availability of the aluminum towers, Hydro no longer uses the original tower design. After several failures in the early seventies, the line was rebuilt with wood pole H-Frame type structures as shown in Figure 2. This trend continues, as all replacements on the line have been with wood poles. Approximately 15 percent of the line now has wood pole structures.

The line is strung with a 266.8 kcmil Partridge conductor, which is a 16 mm diameter aluminum conductor that is reinforced with a steel core. In addition, there is 3/8 inch steel overhead groundwire for seven spans outside each of the terminal stations. The groundwire is installed to provide lightning protection for the terminal station[1].

Figure 2 - Typical Construction Types for TL-212: Aluminum Towers (Left) and Wood Pole (Right)

As this is a typical transmission line project, there is no relevant data or issue for the following items:

- Industry Experience
- Maintenance or Support Arrangements

[1] Hydro's standard in areas of low isochronic levels is to provide overhead groundwires for 1.6km outside of the terminal station.

- Vendor Recommendations
- Availability of Replacement Parts
- Environmental Performance
- Operating Regime

2 PROJECT DESCRIPTION

The aluminum sections of TL-212 have a history of conductor clearance problems, where the conductors sag too close to the ground. The 2008 capital project, "Upgrade Line TL-212 (Sunnyside to Linton Lake)", approved under Board Order No. P.U. 30 (2007), is currently underway to correct the most urgent of these locations. During engineering of the 2008 project, it was determined that there are a number of additional locations where conductor clearance is lower than the Canadian Standard Association Standard, *C22.3 No. 1-01 Overhead Systems*.

This project is to correct these ground clearance issues. In total, there are 25 spans that are located in areas prone to regular ice loads.

As a result of a tower failure in March of 2008, a thorough inspection of the guy wires along the line revealed widespread corrosion on the towers at the southern end of the line. Of the 144 towers inspected, it is recommended that the guy wires be replaced on 47 structures.

The scope of the work is to:

- Replace the guy wires on 47 aluminum towers; and
- Install 25 wood pole H-frame structures at approximately mid-span to improve ground clearance.

3 EXISTING SYSTEM

Hydro designs and maintains its transmission lines to meet the requirements of the Canadian Standard Association (CSA) standards and guidelines and where necessary Hydro has developed its own standards beyond the minimum expected by CSA to account for local conditions.

TL-212 was originally designed to operate under the following conditions:

- Extreme Ice Load: 25.4mm (1 inch) of ice accumulation on the conductor;
- Extreme Wind Load: 177 kilometers per hour (110 miles per hour);
- Combined Ice and Wind Load: 12.7 mm (0.5 inches) of ice accumulation combined with 117.4 kilometers per hour (73 mph) of wind; and
- 6.4 meters (21 feet) of ground clearance for thermal loading of 50 degrees Celsius (120 Degrees Fahrenheit). Thermal loading is the conductor temperature during periods of high power flow.

With the exception of the ground clearance, all of these conditions meet the CSA C22.3 standard for overhead systems. CSA requires that ground clearance be maintained for the condition of greatest conductor sag. Conductor sag is the distance from the horizontal straight line that a conductor sinks or bends between two structure locations. The amount of sag will change with conductor temperature, ice and wind loading and time. As the conductor heats up, or is loaded with ice, the sag will typically increase. For TL-212 the condition of greatest sag is calculated to occur when the conductor is loaded under the extreme ice load and not the thermal load as it was originally designed.

3.1 Age of Equipment or System

TL-212 was originally built in 1966 and the aluminum tower sections are 42 years old.

On the Burin Peninsula, TL-212 has been subjected to adverse weather and environmental conditions such as high winds, ice and snow loads, frequent freeze/thaw cycles and salt contamination in coastal areas. After 40 to 50 years of exposure to the elements, it is common for line components to become deteriorated to the point that they are weakened and at risk of failure.

3.2 Major Work or Upgrades

After major failures in the early 1970s, 11 sections of the line were re-built with wood pole H-Frame type construction. These sections were subsequently upgraded in the mid-1990s. Table 1 details the sections that were rebuilt with wood structures.

Table 1
TL-212 Breakdown of Construction Types

From Structure #	To Structure #	# of Structures	Distance (km)	Type
(Sunnyside)	25	25	7.564	Aluminum
25-1	48-2	50	7.435	Wood
49	129	81	25.640	Aluminum
129-1	142-1	29	4.248	Wood
143	161	19	6.621	Aluminum
161-1	181-1	42	6.295	Wood
182	187	6	1.976	Aluminum
187-1	197-1	24	3.656	Wood
198	318	120	37.857	Aluminum
319	320	2	0.442	Wood
321	436 (Linton Lake)	116	37.041	Aluminum
Sunnyside	Linton Lake	514	138.775	
Total		**367**	116.699	**Aluminum**
		147	22.076	**Wood**

There have been no major upgrades on the aluminum tower sections of the line.

3.3 Anticipated Life

The anticipated life of a transmission line constructed with metal towers is considered to be 50 years, but through proper maintenance and upgrading the useful life line can be extended.

3.4 Maintenance History

The sections of TL-212 having aluminum structures have a ten-year inspection cycle, where ten percent of the line is inspected annually. After the March 2008 failure of Structure 380 (Section 3.5), a visual inspection of the guy wires between Structure 292 and the Linton Lake Terminal Station was completed. The inspection determined that the guy wires on 47 of the 144 towers were corroded and required replacement. Please see Appendix E for details of the inspection. This work is included in the capital proposal. The anchors for the towers and guy grips were not inspected at this time due to the depth of snow.

The wood pole sections of TL-212 are inspected through Hydro's Wood Pole Line Management (WPLM) Program, in which the wood structures undergo a complete inspection every ten years.

3.5 Outage Statistics

In addition to the major failures of the early seventies, a number of documented failures have occurred in the line and are listed below. The two most recent events have resulted in towers collapsing under ice and wind events.

- December 1994 – Extreme ice load caused the conductor to fail on the right phase near Structure 136-2.

- January 1995 – Extreme ice load caused the conductor to fail at Structure 172-1.

- February 1995 – Extreme ice load caused the conductor to fail near the Monkstown Substation.

- March 2005 – Extreme ice load caused the conductor to fail on centre phase and left phase between Structures 110 & 111.

- January 2007 – High winds caused contact between two conductors at Structure 364. This resulted in a line outage of one day.

- December 2007 – Extreme ice and wind caused Structure 34 to fail, causing a line outage of 12 days. This failure, along with a typical sample of ice that was collected during the same icing event, is illustrated in the Figure 3.

Figure 3 - Failure of Structure # 34 – December 2007

- March 2008 – Extreme ice and wind caused Structure 380 to fail, causing a line outage of four days. The failure of a guy wire and anchor led to the collapse of the structure. This failure is illustrated in Figure 4, along with a typical sample of ice that was collected during the same icing event.

Figure 4 - Failure of Structure # 380 – March 2008

The two most recent failures are leading indicators that TL-212 is beginning to deteriorate due to age.

3.6 Safety Performance

The energized conductors of transmission lines must not cause the possibility of injury to people. Overhead conductors, however, elongate with time, temperature and tension, thereby causing a change in their position since installation. Despite the effects of weather and thermal loading on the line, the conductors must be maintained at a safe distance from buildings, objects and people or vehicles passing beneath the line at all times.

Inadequate ground clearance of the conductor, especially under the extreme ice load is the main safety issue with TL-212. This low clearance increases the risk of somebody coming into contact with an energized conductor.

The latest CSA Standard *C22.3 No. 1-01 Overhead Systems* recommends a minimum ground clearance of 5.5 metres (Table 2) under the condition of maximum sag of the

wire, whether thermally loaded or physically loaded under wind and/or ice. It is also prudent to add a factor of safety to this value to allow for such things as snow depth or discrepancies due to the margin of error in survey or construction measurements. Hydro's standard is to maintain a vertical clearance of 6.7 metres, which includes a safety factor of 1.2 metres above the minimum CSA value.

The original 1966 design for TL-212, allowed for 6.4 metres (21 feet) of ground clearance when the conductor is thermally loaded at 50^0C (120^0F). There was no allowance given for when a conductor is physically loaded under the extreme ice load. This ice load can increase the conductor sag by up to 4m in some long spans.

A 2008 engineering study checked the ground clearance along TL-212 for two loading conditions:

1. Thermal Load - The conductor at 50 degrees Celsius and 6.4m of required ground clearance. This represents the original design condition for TL-212.
2. Physical Load – The conductor loaded with 25.4 mm (one inch) of ice and 5.5 metres of required ground clearance.[2]

It should be noted that there was no additional Hydro safety factor added to the minimum CSA value, because it was determined to be too restrictive and result in over 80 percent of the line being impacted. The bare CSA value was deemed acceptable, as there have been no incidents in the 40-year history of the line.

The results from the study are discussed below, and the details are attached as Appendix B. The violations under the thermal load were considered a priority and are to be completed in the 2008 Capital Project.

[2] 5.5m is the minimum vertical clearance for 138kV Construction as per CSA Standard 22.3 No1-01 Table 2.

3.6.1 50 Degrees Celsius and 6.4m of Required Ground Clearance

At TL-212's maximum operating temperature (50^0C), the line performed as expected and there were minimal clearance violations. This validates the assumptions made for the original design parameters. Table 2 presents clearance results where violations occurred.

Table 2
Ground Clearance Violations for 50^0C

From Structure #	To Structure #	Clearance Check	Weather Case	Station	Clearance Violation (m)
36-2	37-1	Ground	50^0C	11061.33	0.52
47-2	48-1	Ground	50^0C	14532.01	4.17
155	156	Ground	50^0C	49225.99	2.05
160	161	Ground	50^0C	51039	0.57

For example, the span between Structures 155 and 156 is a large (407 metres) span that violates the required clearance by 2.05 metres at approximately the mid-span point. This means that the ground clearance is 2.05 metres less than the accepted minimum of 6.4 metres. This is illustrated in Figure 5, which shows the original design with the conductor sags of both 50^0C (120^oF) and 25.4 mm (1 inch) of ice load. The new structure illustrated at the mid-point of the span is installed to correct the clearance violation.

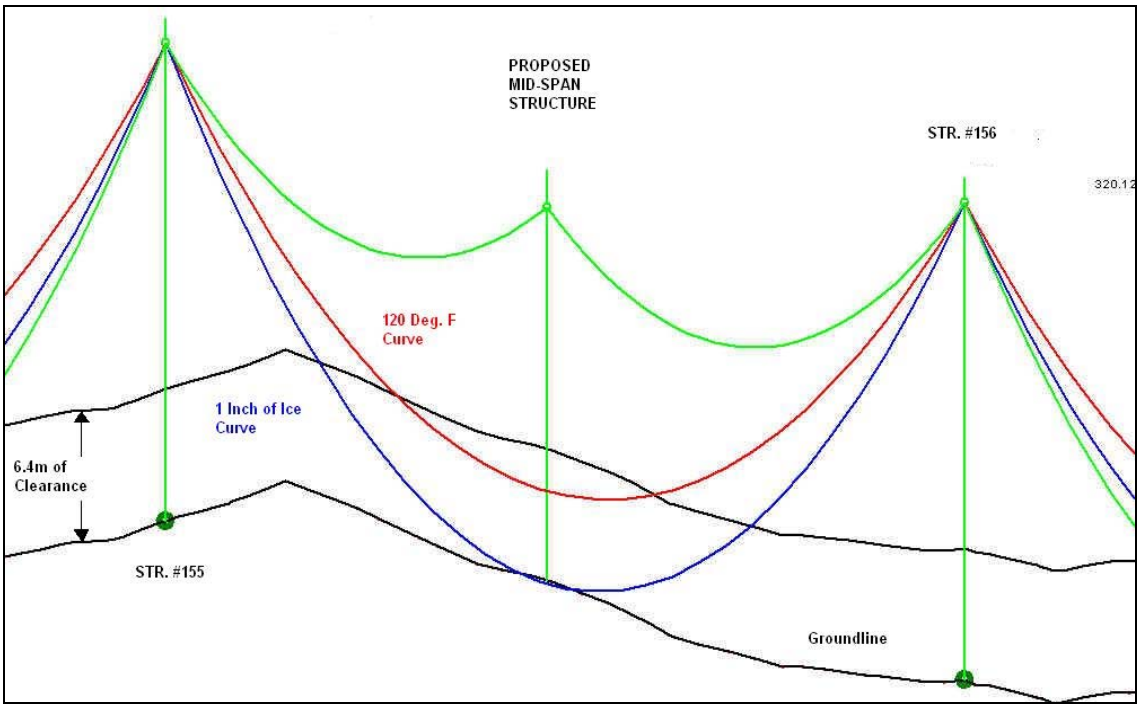


Figure 5 - Span between Structures #155 & 156

3.6.2 One Inch of Ice Load and 5.5m of Required Ground Clearance

Under one inch of ice loading, the number of violations increases to 98 spans. Table 3 presents the number of violations in intervals of 0.5 metres.

Table 3
TL-212 Clearance Violations (One Inch of Ice Loading)

Number of Spans with Clearance Violations Between 0 and 0.5 m	32
Number of Spans with Clearance Violations Between 0.5 and 1.0 m	23
Number of Spans with Clearance Violations Between 1.0 and 1.5 m	16
Number of Spans with Clearance Violations Between 1.5 and 2.0 m	14
Number of Spans with Clearance Violations Greater than 2.0m	13
Total Number of Spans with Clearance Violations at 1 Inch of Ice	98

The 13 spans with clearance violations greater than 2.0 metres will be corrected in 2008, and the remaining spans have been cross-referenced with areas that are prone to receive frequent ice loadings. This project is required to correct a total of 25 spans in

2009 and 2010. The other spans will be reassessed in 2009 and further action determined at that time.

3.7 Discussion of 2008 Engineering Study

Discrepancies between the survey data and the original structure list data have been noted in Appendix C. In the surveyed sections, several spans show a 20 to 25 percent difference between the actual span lengths surveyed and the length in the original line records. This difference has a significant impact on the expected sags because the longer the span length, the greater the sag.

During the review of the original plan and profile drawings for TL-212, discrepancies along the profile such as incorrect height of support at the structure locations or unexplained gaps in the profile were noted. The presence of these discrepancies in the original data lowers the accuracy of the study. Without a complete survey of the line, it is difficult to measure the extent of these differences.

3.7.1 Conductor Selection versus Span Length

The 266.8 Partridge conductor is an industry standard conductor for 138kV construction and performs well for spans below 250 metres. Above this, the sags are typically too large for the typical structure (18.3 metres to 25.9 metres (60 to 85 feet) in height) to accommodate. Since 81 percent of the spans in the aluminum sections of TL-212 are larger than 300 metres, this is likely the cause of the clearance problems experienced, especially during icing events. This is in contrast to the wood pole section, which has experienced no problems and has 90 percent of the spans below 200 metres. Chart 1 details the frequency of span lengths along TL-212.

To illustrate the clearance problem, sags for the maximum ice load were calculated for the 266.8 Partridge conductor based on the range of spans that occur in TL-212. The

results are shown in Table 4. The table also shows the typical structure height that is required to maintain the proper ground clearance over a level span.

The table clearly illustrates that once a span exceeds 250 metres, pole heights are much larger than Hydro typically uses for 138 kV transmission line construction. The maximum height of the steel towers on TL-212 is 24.4 metres (80 feet) above ground, which is equivalent to a wood pole structure of 27.4 metres (90 feet).

Chart 1 - Span Length Frequency (All Spans)

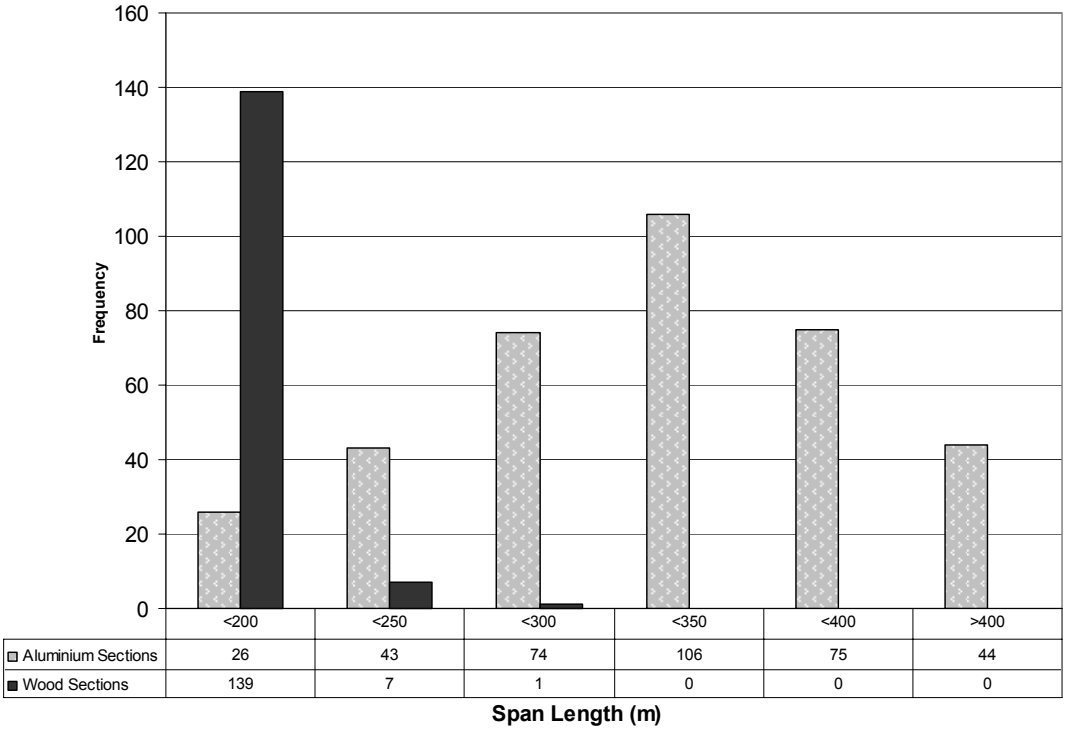


Table 4
Typical Pole Height for Increasing Span Length

Span Length (m)	Sag for 1" of Ice (m)	Typical Pole Height for H-Frame Structure (ft)
150	5.37	50
200	9.12	65
250	14.32	85
300	20.75	115
350	28.44	145
400	37.46	180
450	47.89	225

Approximate limit for the typical towers on TL-212 for a level span

Table 4 assumes a level span and wood pole H-Frame construction. Please note that the assumption of a level span is not usually valid under long span situations, which may occur over valleys or low areas that will have more room for conductor sag. This appears to be the case for TL-212, as only 98 of the 354 spans over 250 metres experience clearance violations under the ice loading.

An alternative to installing a new in-span structure, especially in situations where it is difficult to locate a structure, would be to re-conductor the span with a larger conductor, such as 636 kcmil Grosbeak. For a 400 metres span, the 636 conductor would sag approximately 16.5 metres less than the 266.8 Partridge. This would be sufficient to correct the ground clearance problems experienced on TL-212. This alternative would require the existing structures on either side of the span to be analyzed and possibly modified or replaced. Although probably more costly, it may be an option for select spans along the line if the physical placement of a mid-span structure is not possible. Appendix A provides tables comparing conductor sags for increasing span lengths for the 266.8 Partridge and 636kcmil Grosbeak conductors.

4 JUSTIFICATION

Under certain conditions the energized conductors on TL-212 come too close to the ground and may burn off and/or pose a serious risk to the general public. This is especially true along sections of the line that are used by snowmobiles. To improve the operational performance of the line and reduce the risk to the general public, it is necessary to amend the clearance associated with TL-212.

Following the failure in March of this year, an inspection of the guy wires between Structure 292 and the Linton Lake Terminal Station was completed. The inspection determined that the guy wires on 47 of the 144 towers were corroded and required replacement. A summary of the inspection is provided in Appendix E. Figure 6 shows typical guy wire inspection results.

Figure 6 - Typical Results from Guy Inspections

This guy wire replacement is justified on the requirement to replace failing or deteriorated infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service.

4.1 Net Present Value

A Net Present Value calculation was not performed in this instance as only one viable alternative exists.

4.2 Levelized Cost of Energy

This project will have no effect on the levelized cost of electricity.

4.3 Cost Benefit Analysis

A Cost Benefit Analysis was not performed in this instance as there are no quantifiable financial benefits.

4.4 Forecast Customer Growth

Customer load growth does not affect this project.

4.5 Energy Efficiency Benefits

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

4.6 Legislative or Regulatory Requirements

There are no applicable legislative or regulatory requirements for this project.

4.7 Historical Information

There is no historical information associated with this project. This proposal is a multi-year project for the upgrades to be completed over two years.

4.8 Losses during Construction

There are no anticipated energy losses during construction, as the customer load supplied by TL-212 can be supplied through other lines.

4.9 Status Quo

The status quo is not an acceptable alternative. Energized conductors that are too close to the ground pose a serious risk to the general public, especially along the transmission right-of-ways that are utilized by snowmobiles in the winter.

In addition, the deterioration of guy wires and anchors caused the failure of Structure 380 in 2008. Since the other structures are of the same age, there is a risk of other failures.

4.10 Alternatives

Although it is possible to completely re-conductor the line, the most economical means to complete this project is to:

- Where possible, install a mid-span structure. This is the easiest and most economical solution, $40,000 to $50,000 per structure, and should cover approximately 95 percent of the work.
- If it is not possible to install a mid-span structure, because of terrain or another unforeseen situation, Hydro will change the conductor to improve the clearance. This involves replacing the conductor and at least one or two structures. Depending on the specifics, this option will conservatively cost from $125,000 to $200,000 per span.

Re-conductoring the entire line would cost in excess of $15 million.

5 CONCLUSION

The following recommendations are broken down by category.

Survey

To ensure the conductor clearances are adequate, the shape of the terrain along the transmission line right-of-way, the height and lateral positions of the conductor support points and the position of the conductor under all wind, ice and temperature conditions must be known. The existing records for TL-212 are incomplete and therefore a new survey is required.

2009 / 2010 Refurbishment

Correction of the remainder of the problem spans, listed in Table 3 will be completed under this proposal. The detailed design will be completed, following the survey to be completed in early in 2009. Mid-span structures will be utilized for most spans, while re-conductoring will be considered for some of the long spans where additional structures cannot be physically located.

The new structures will be constructed with the Hydro standard for wood pole structures shown in Appendix D. Table 5 lists the spans that will be corrected in 2009.

Table 5
2009 Project Work on TL-212

	From Structure #	To Structure #	Work to Be Completed
1	19	20	Install Type A Structure approximately mid-span
2	22	23	Install Type A Structure approximately mid-span
3	85	86	Possible re-conductor span
4	203	204	Install Type A Structure approximately mid-span
5	204	205	Install Type A Structure approximately mid-span

6	206	207	Install Type A Structure approximately mid-span
7	217	218	Install Type A Structure approximately mid-span
8	231	232	Install Type A Structure approximately mid-span
9	237	238	Install Type A Structure approximately mid-span
10	241	242	Install Type A Structure approximately mid-span
11	245	246	Install Type A Structure approximately mid-span
12	249	250	Install Type A Structure approximately mid-span
13	252	253	Install Type A Structure approximately mid-span
14	259	260	Install Type A Structure approximately mid-span
15	292	293	Install Type A Structure approximately mid-span
16	298	299	Install Type A Structure approximately mid-span
17	300	301	Install Type A Structure approximately mid-span
18	332	333	Install Type A Structure approximately mid-span
19	311	312	Install Type A Structure approximately mid-span
20	360	361	Install Type A Structure approximately mid-span
21	364	365	Install Type A Structure approximately mid-span
22	373	374	Install Type A Structure approximately mid-span
23	397	398	Install Type A Structure approximately mid-span
24	402	403	Install Type A Structure approximately mid-span
25	433	434	Possible re-conductor span

The guy wires on the 47 towers recommended for replacement in the March 2008 inspection will also be included in the 2009 and 2010 programs.

5.1 Budget Estimate

- Cost to install new structures to correct clearance violations

Table 6

Project Cost ($ x 1,000)	2009	2010	TOTAL
Material Supply	225.0	153.1	378.1
Labour	112.5	58.2	170.7
Consultant	0.0	0.0	0.0
Contract Work	173.6	167.4	341.0
Other Direct Costs	36.4	20.4	56.8
O/H, AFUDC & Escln.	74.8	125.1	199.9
Contingency	0.0	94.7	94.7
TOTAL	**622.3**	**618.9**	**1241.2**

- Cost to replace guys on aluminum towers

Table 7

Project Cost ($ x 1,000)	2009	2010	TOTAL
Material Supply	125.0	85.1	210.1
Labour	62.5	32.4	94.9
Consultant	0.0	0.0	0.0
Contract Work	96.4	93.1	189.5
Other Direct Costs	20.1	11.4	31.5
O/H, AFUDC & Escln.	41.6	70.1	111.7
Contingency	0.0	52.6	52.6
TOTAL	**345.6**	**344.7**	**690.3**

- Total project costs

Table 8

Project Cost ($ x 1,000)	2009	2010	TOTAL
Material Supply	350.0	238.2	588.2
Labour	175.0	90.6	265.6
Consultant	0.0	0.0	0.0
Contract Work	270.0	260.5	530.5
Other Direct Costs	56.5	31.8	88.3
O/H, AFUDC & Escln.	116.4	195.2	311.6
Contingency	0.0	147.3	147.3
TOTAL	**967.9**	**963.6**	**1,931.5**

5.2 Project Schedule

Because of the volume of work to be completed, it is proposed to execute the project over two years, beginning in 2009.

Table 9
Project Schedule 2009

Activity	Milestone
Project Initiation	Jan 2009
Complete Design Transmittal	Feb 2009
Detailed Engineering Design	April 2009
Develop Installation Specification	April 2009
Issue Tender and Award Job	June 2009
Procurement of Materials	June 2009
Contract Execution	Sept 2009
Commissioning	Sept 2009
Close Out and Documentation	Dec 2009

Table 10
Project Schedule 2010

Activity	Milestone
Project Initiation	Jan 2010
Complete Design Transmittal	Feb 2010
Detailed Engineering Design	April 2010
Develop Installation Specification	April 2010
Issue Tender and Award Job	June 2010
Procurement of Materials	June 2010
Contract Execution	Sept 2010
Commissioning	Sept 2010
Close Out and Documentation	Dec 2010

APPENDIX A

Conductor Sag Comparison

Conductor Sags (m) for Increasing Span Length
266.8 kcmil Partridge Conductor
Standard Hydro Tensions

Loading Condition	Span Length (m)					
	150	**200**	**250**	**300**	**350**	**400**
Maximum Ice (25.4mm @ -18oC)	5.37	9.12	14.32	20.75	28.44	37.46
Maximum Temp (50oC)	2.8	6.19	11.44	17.91	24.64	34.68

Conductor Sags (m) for Increasing Span Length
636 kcmil Grosbeak Conductor
Standard Hydro Tensions

Loading Condition	Span Length (m)					
	150	**200**	**250**	**300**	**350**	**400**
Maximum Ice (25.4mm @ -18oC)	3.98	6.16	8.65	11.62	15.85	20.75
Maximum Temp (50oC)	2.66	4.20	5.98	8.32	12.44	17.29

APPENDIX B

Clearance Violations Under 1 Inch of Ice Load

From Structure #	To Structure #	Clearance Check	Weather Case	Station	Ground (m)
9	10	Ground	1 Inch Ice	2539.37	-0.79
13	14	Ground	1 Inch Ice	3792.19	-0.92
14	15	Ground	1 Inch Ice	4187.93	-1.13
15	16	Ground	1 Inch Ice	4550.5	-1.27
17	18	Ground	1 Inch Ice	5071.96	-0.15
19	20	Ground	1 Inch Ice	5709.32	-2.64
22	23	Ground	1 Inch Ice	6674.89	-2.47
29-2	30-1	Ground	1 Inch Ice	8853.79	-0.72
33-1	34	Ground	1 Inch Ice	10034.81	-0.1
34	34-1	Ground	1 Inch Ice	10283.98	-0.34
36-2	37-1	Ground	1 Inch Ice	11061.33	-1.47
44-2	45-1	Ground	1 Inch Ice	13701.93	-0.16
47-2	48-1	Ground	1 Inch Ice	14532.01	-4.7
54	55	Ground	1 Inch Ice	16749.39	-2.04
57	58	Ground	1 Inch Ice	17790.18	-0.33
58	59	Ground	1 Inch Ice	18176.59	-0.01
66	67	Ground	1 Inch Ice	20452.47	-1.04
68	69	Ground	1 Inch Ice	21255.9	-0.01
73	74	Ground	1 Inch Ice	22797.8	-0.34
75	76	Ground	1 Inch Ice	23405.62	-0.65
81	82	Ground	1 Inch Ice	25431.07	-1.26
85	86	Ground	1 Inch Ice	26442.79	-1.64
95	96	Ground	1 Inch Ice	29773.59	-0.5
101	102	Ground	1 Inch Ice	31491.07	-0.14
102	103	Ground	1 Inch Ice	31858	-0.21
106	107	Ground	1 Inch Ice	33120.01	-0.33
107	108	Ground	1 Inch Ice	33415.13	-0.88
110	111	Ground	1 Inch Ice	34237.63	-1.51
111	112	Ground	1 Inch Ice	34621.47	-2.03
112	113	Ground	1 Inch Ice	34916.91	-1.46
116	117	Ground	1 Inch Ice	36316.38	-3.2
119	120	Ground	1 Inch Ice	37315.97	-0.72
125	126	Ground	1 Inch Ice	39357.03	-0.7

From Structure #	To Structure #	Clearance Check	Weather Case	Station	Ground (m)
139-2 1	39-3	Ground	1 Inch Ice	43712.77	-0.03
143	144	Ground	1 Inch Ice	45077.11	-1.23
144	145	Ground	1 Inch Ice	45448.1	-1.06
147	148	Ground	1 Inch Ice	46383.14	-0.74
148	149	Ground	1 Inch Ice	46700.95	-1.59
149	150	Ground	1 Inch Ice	47133.6	-1.78
150	151	Ground	1 Inch Ice	47521.03	-1.6
152	153	Ground	1 Inch Ice	48188.08	-0.55
153	154	Ground	1 Inch Ice	48482.68	-2.38
155	156	Ground	1 Inch Ice	49228.43	-5.65
159	160	Ground	1 Inch Ice	50651.12	-0.77
160	161	Ground	1 Inch Ice	51039.18	-3.12
162-1 1	63-1	Ground	1 Inch Ice	51725.5	-0.09
167 1	67-1	Ground	1 Inch Ice	53293.59	-0.37
182	183	Ground	1 Inch Ice	57916.54	-0.25
185	186	Ground	1 Inch Ice	58817.19	-0.63
203	204	Ground	1 Inch Ice	64900.16	-3.76
204	205	Ground	1 Inch Ice	65271.21	-1.07
206	207	Ground	1 Inch Ice	65909.63	-1.72
210	211	Ground	1 Inch Ice	67277.43	-0.08
215	216	Ground	1 Inch Ice	69142.83	-0.36
217	218	Ground	1 Inch Ice	69818.21	-2.09
219	220	Ground	1 Inch Ice	70549.59	-1.21
221	222	Ground	1 Inch Ice	70997.39	-0.01
223	224	Ground	1 Inch Ice	71582.22	-0.74
228	229	Ground	1 Inch Ice	73213.58	-0.89
229	230	Ground	1 Inch Ice	73651.06	-0.37
230	231	Ground	1 Inch Ice	73923.48	-0.71
231	232	Ground	1 Inch Ice	74318.05	-1.63
233	234	Ground	1 Inch Ice	74913.92	-0.53
237	238	Ground	1 Inch Ice	76404.03	-0.98
239	240	Ground	1 Inch Ice	77154.89	-0.46
240	241	Ground	1 Inch Ice	77474.57	-0.94

From Structure #	To Structure #	Clearance Check	Weather Case	Station	Ground (m)
241	242	Ground	1 Inch Ice	77815.43	-1.79
245	246	Ground	1 Inch Ice	79107.49	-2.65
249	250	Ground	1 Inch Ice	80305.27	-1.75
252	253	Ground	1 Inch Ice	81358.02	-1.76
253	254	Ground	1 Inch Ice	81745.01	-0.28
255	256	Ground	1 Inch Ice	82355.01	-0.38
259	260	Ground	1 Inch Ice	83631.29	-1.53
265	266	Ground	1 Inch Ice	85429.13	-0.55
288	289	Ground	1 Inch Ice	92191.17	-1.43
292	293	Ground	1 Inch Ice	93583.33	-1.18
298	299	Ground	1 Inch Ice	95362.83	-0.91
300	301	Ground	1 Inch Ice	96012.74	-1.82
311	312	Ground	1 Inch Ice	99196.87	-0.48
312	313	Ground	1 Inch Ice	99557.78	-0.3
328	329	Ground	1 Inch Ice	104138.95	-0.13
331	332	Ground	1 Inch Ice	104982.48	-0.38
332	333	Ground	1 Inch Ice	105371.88	-1.87
346	347	Ground	1 Inch Ice	109802.08	-0.61
360	361	Ground	1 Inch Ice	114177.92	-0.89
363	364	Ground	1 Inch Ice	114980.23	-1.3
364	365	Ground	1 Inch Ice	115254.97	-1.05
369	370	Ground	1 Inch Ice	117068.89	-0.32
373	374	Ground	1 Inch Ice	118303.92	-3.28
376	377	Ground	1 Inch Ice	119256.56	-0.2
386	387	Ground	1 Inch Ice	122202.43	-0.14
392	393	Ground	1 Inch Ice	124402.01	-1.44
403	404	Ground	1 Inch Ice	128216.26	-0.67
404	405	Ground	1 Inch Ice	128565.09	-0.41
407	408	Ground	1 Inch Ice	129601.83	-0.08
409	410	Ground	1 Inch Ice	130235.81	-0.07
429	430	Ground	1 Inch Ice	136753.62	-1.01

APPENDIX C

Discrepancies in Survey Results

Str. #	Ahead Span		Difference (m)
	Survey	Str. List	
0	74.17		
1	251.78	259.15	7.37
2	228.38	228.66	0.28
3	245.34	228.66	-16.68
4	319.87	335.37	15.50
5	336.53	335.37	-1.16
6	322.17	320.12	-2.05
7	161.34	167.68	6.34
8	408.99	403.96	-5.03
9	372.69	373.48	0.79
10	346.27	350.61	4.34
11	228.78	243.90	15.12
12	313.61	327.74	14.13
13	389.64	373.48	-16.16
14	358.92	342.99	-15.93
15	372.04	367.38	-4.66
16	198.80	198.17	-0.63
17	282.00	282.01	0.01
18	267.57	282.01	14.44
19	400.21	402.44	2.23
20	275.23	297.26	22.03
21	306.88	342.99	36.11
22	344.57	342.99	-1.58
23	298.52	297.26	-1.26
24	222.20	228.66	6.46
25	237.69	228.66	-9.03
25-1	172.32	152.44	-19.88
26-1	173.18	167.68	-5.50
26-2	143.45	137.20	-6.25
27-1	145.89	152.44	6.55
27-2	132.65	152.44	19.79

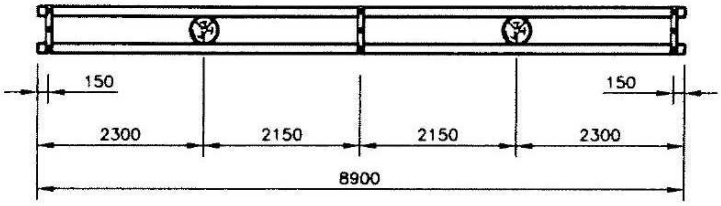
Str. #	Ahead Span		Difference (m)
	Survey	Str. List	
36-1	130.80	131.10	0.30
36-2	125.20	125.00	-0.20
37-1	170.80	167.68	-3.12
37-2	156.49	160.06	3.57
37-3	119.80	121.95	2.15
38-1	106.58	106.71	0.13
38-2	143.90	143.29	-0.61
38-3	134.19	134.15	-0.04
39-1	110.16	121.95	11.79
39-2	133.43	131.10	-2.33
40-1	158.30	152.44	-5.86
40-2	118.98	123.48	4.50
40-3	154.26	157.01	2.75
41-1	154.92	152.44	-2.48
42-1	134.06	157.01	22.95
42-2	188.12	152.44	-35.68
42-3	149.95	152.44	2.49
43-1	112.30	128.05	15.75
43-2	135.46	152.44	16.98
44-1	168.90	161.59	-7.31
44-2	156.13	152.44	-3.69
45-1	151.83	152.44	0.61
45-2	157.13	152.44	-4.69
46-1	143.06	144.82	1.76
46-2	102.99	117.38	14.39
47-1	81.01	96.04	15.03
47-2	168.68	152.44	-16.24
48-1	165.15	137.20	-27.95
81	320.97	322.56	1.59
82	253.14	243.90	-9.24
83	239.45	243.90	4.45

Str. #	Ahead Span		Difference (m)
	Survey	Str. List	
28-1	163.22	167.68	4.46
28-2	136.26	137.20	0.94
29-1	156.84	152.44	-4.40
29-2	150.51	152.44	1.93
30-1	110.51	121.95	11.44
30-2	133.21	137.20	3.99
30	155.53	160.06	4.53
31-1	155.01	131.10	-23.91
31-2	141.04	152.44	11.40
32-1	173.91	167.68	-6.23
32-2	132.60	137.20	4.60
33-1	235.76	243.90	8.14
34	200.16	201.22	1.06
34-1	114.09	114.33	0.24
35-1	175.01	175.30	0.29
35-2	194.24	195.12	0.88

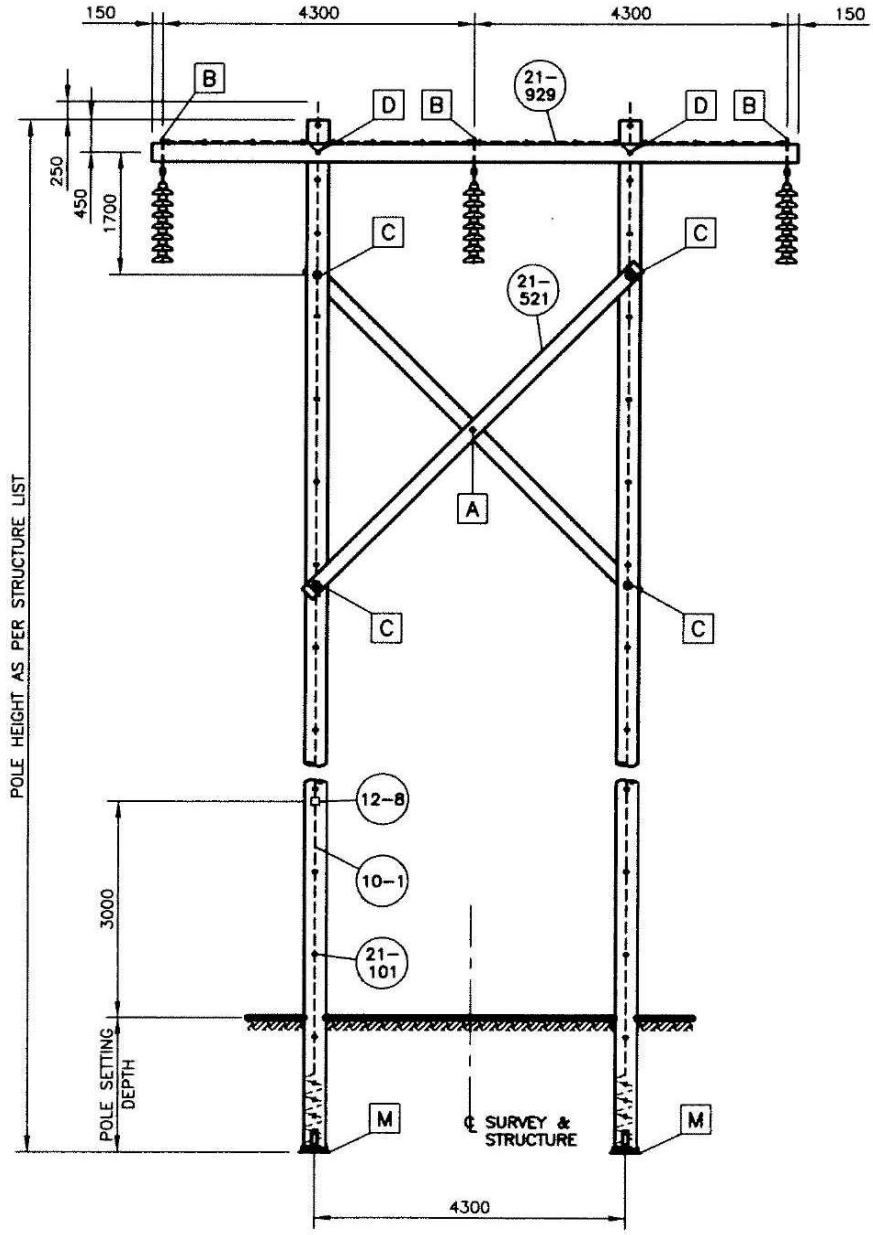
Str. #	Ahead Span		Difference (m)
	Survey	Str. List	
84	209.90	213.41	3.51
85	501.38	503.23	1.85
86	345.08	346.16	1.08
87	329.75	335.37	5.62
88	358.05	370.43	12.38
89	278.13	277.44	-0.69
90	333.47	335.37	1.90
91	342.22	344.51	2.29
92	292.58	288.11	-4.47
93	243.16	246.95	3.79
94	266.57	268.29	1.72
95	386.43	390.24	3.81
96	309.41	310.98	1.57
97	237.91	234.76	-3.15
98	334.66	335.37	0.71

APPENDIX D

Proposed Mid-Span Structure


150
150
2300
2150
2150
2300
8900

PLAN VIEW


150
4300
4300
150
B
D
B
21–929
D
B
250
450
1700
C
C
21–521
A
C
C
POLE HEIGHT AS PER STRUCTURE LIST
12–8
10–1
21–101
3000
POLE SETTING DEPTH
M
℄ SURVEY & STRUCTURE
M
4300

APPENDIX E

Guy Wire Inspection Results – March 2008

Inspection Results – March 2008

Str. #	Comments
292	Guys all good, no rust
293	Guys all good, no rust
294	Guys all good, no rust
295	Guys all good, no rust
296	ALL GUYS RUSTY, SHOULD BE CHANGED (8)
297	Guys all good, no rust
298	Guys all good, no rust
299	Guys all good, no rust
300	ALL GUYS RUSTY (NOT SERIOUS), BUT PROBABLY SHOULD BE CHANGED (8)
301	Guys all good, no rust
302	Guys all good, no rust
303	Guys all good, no rust
304	ALL GUYS RUSTY (NOT SERIOUS), BUT PROBABLY SHOULD BE CHANGED (8)
305	Guys all good, no rust
306	Guys all good, no rust
307	Guys all good, no rust
308	Guys all good, no rust
309	Guys all good, no rust
310	Guys all good, no rust
311	Guys all good, no rust
312	Guys all good, no rust
313	Guys all good, no rust
314	Guys all good, no rust
315	Guys all good, no rust
316	Guys all good, no rust
317	Guys all good, no rust
318	Guys all good, no rust
319	Guys all good, no rust
320	
321	
322	
323	Guys all good, no rust - FOOTING NEEDS TO BE DONE
324	Guys all good, no rust
325	
326	
327	Guys all good, no rust - BRUSH NEEDS TO BE CUT
328	Guys all good, no rust - BRUSH NEEDS TO BE CUT
329	Guys all good, no rust - BRUSH NEEDS TO BE CUT
330	Guys all good, no rust - BRUSH NEEDS TO BE CUT

Str. #	Comments
331	Guys all good, no rust - BRUSH NEEDS TO BE CUT
332	Guys all good, no rust - BRUSH NEEDS TO BE CUT
333	Guys all good, no rust - BRUSH NEEDS TO BE CUT
334	
335	Guys all good, no rust
336	Guys all good, no rust
337	Guys all good, no rust
338	Guys all good, no rust
339	Guys all good, no rust
340	
341	Guys all good, no rust
342	Guys all good, no rust
343	Guys all good, no rust
344	Guys all good, no rust
345	C-Tower
346	Guys all good, no rust
347	Guys all good, no rust
348	Guys all good, no rust
349	Guys all good, no rust
350	Guys all good, no rust - NEEDS 2 BIG NUMBER SIGNS
351	
352	ALL GUYS RUSTY, SHOULD BE CHANGED (8) - FOOTING NEEDS TO BE CHANGED
353	
354	
355	
356	
357	Guys all good, no rust
358	ALL GUYS RUSTY, SHOULD BE CHANGED (8)
359	C-Tower - 2 LOOSE BOLTS ON LOWER TWO LEGS. NEED TO BE REPLACED
360	ALL GUYS VERY RUSTY, SHOULD BE CHANGED ASAP (8), NO GUY GUARDS
361	ALL GUYS VERY RUSTY, SHOULD BE CHANGED ASAP (8), NO GUY GUARDS
362	ALL GUYS VERY RUSTY, SHOULD BE CHANGED ASAP (8)
363	ALL GUYS VERY RUSTY, SHOULD BE CHANGED ASAP (8)
364	
365	ALL GUYS VERY RUSTY, SHOULD BE CHANGED ASAP (8)
366	ALL GUYS RUSTY (NOT SERIOUS) IN SPOTS, PROBABLY SHOULD BE CHANGED (8)
367	ALL GUYS RUSTY (NOT SERIOUS) IN SPOTS, PROBABLY SHOULD BE CHANGED (8)
368	ALL GUYS RUSTY (NOT SERIOUS) IN SPOTS, PROBABLY SHOULD BE CHANGED (8)
369	ALL GUYS RUSTY (NOT SERIOUS) IN SPOTS, PROBABLY SHOULD BE CHANGED (8)
370	ALL GUYS VERY RUSTY, SHOULD BE CHANGED ASAP (8)
371	ALL GUYS VERY RUSTY, SHOULD BE CHANGED ASAP (8)
372	ALL GUYS RUSTY (NOT SERIOUS) IN SPOTS, PROBABLY SHOULD BE CHANGED (8)

Str. #	Comments
373	ALL GUYS RUSTY (NOT SERIOUS) IN SPOTS, PROBABLY SHOULD BE CHANGED (8)
374	ALL GUYS VERY RUSTY, SHOULD BE CHANGED ASAP (8)
375	GUYS GETTING RUSTY, PROBABLY SHOULD BE CHANGED (8)
376	
377	ALL GUYS VERY RUSTY, SHOULD BE CHANGED ASAP (8)
378	ALL GUYS VERY RUSTY, SHOULD BE CHANGED ASAP (8)
379	ALL GUYS VERY RUSTY, SHOULD BE CHANGED ASAP (8)
380	
381	
382	ALL GUYS VERY RUSTY, SHOULD BE CHANGED ASAP (8)
383	Two guys rusty, not serious
384	Guys all good, no rust - BRUSH NEEDS TO BE CUT
385	Guys all good, no rust - BRUSH NEEDS TO BE CUT
386	Guys all good, no rust - BRUSH NEEDS TO BE CUT
387	Guys all good, no rust - BRUSH NEEDS TO BE CUT
388	Guys all good, no rust - BRUSH NEEDS TO BE CUT
389	Guys all good, no rust - BRUSH NEEDS TO BE CUT
390	Guys all good, no rust - BRUSH NEEDS TO BE CUT
391	Guys all good, no rust - BRUSH NEEDS TO BE CUT
392	
393	Guys all good, no rust - BRUSH NEEDS TO BE CUT
394	Guys are lightly pitted - not serious
395	
396	ALL GUYS HAVE VERY BAD PITTING AND RUST, SHOULD BE CHANGED ASAP (8)
397	Guys all good, no rust - FOOTING NEEDS TO BE DONE
398	ALL GUYS HAVE VERY BAD PITTING AND RUST, SHOULD BE CHANGED ASAP (8)
399	ALL GUYS HAVE VERY BAD PITTING AND RUST, SHOULD BE CHANGED ASAP (8)
400	ONE GUY HAS VERY BAD PITTING AND RUST, SHOULD BE CHANGED ASAP (1), & FOOTING
401	ALL GUYS HAVE VERY BAD PITTING AND RUST, SHOULD BE CHANGED ASAP (8)
402	Guys all good, no rust
403	
404	ALL GUYS HAVE VERY BAD PITTING AND RUST, SHOULD BE CHANGED ASAP (8)
405	ALL GUYS HAVE VERY BAD PITTING AND RUST, SHOULD BE CHANGED ASAP (8)
406	ALL GUYS HAVE VERY BAD PITTING AND RUST, SHOULD BE CHANGED ASAP (8)
407	ALL GUYS HAVE VERY BAD PITTING AND RUST, SHOULD BE CHANGED ASAP (8)
408	HALF OF GUYS HAVE VERY BAD PITTING AND RUST, SHOULD BE CHANGED ASAP (8)
409	ALL GUYS HAVE VERY BAD PITTING AND RUST, SHOULD BE CHANGED ASAP (8)
410	GUYS RUSTY, NOT PITTED
411	GUYS RUSTY, NOT PITTED
412	All 8 guys a little pitted, 6-8" spots - not serious
413	All main guys pitted, full length
414	All main guys pitted, full length

Str. #	Comments
415	Guys all good, no rust
416	All main guys pitted, full length
417	All main guys pitted, full length
418	All main guys pitted, full length
419	All 8 guys a little pitted - not serious
420	All main guys pitted, full length
421	All 8 guys a little pitted - not serious
422	All 8 guys a little pitted - not serious
423	All main guys pitted, full length
424	
425	ONE GUY HAS VERY BAD PITTING AND RUST, SHOULD BE CHANGED ASAP (1), & FOOTING
426	ALL GUYS HAVE VERY BAD PITTING AND RUST, SHOULD BE CHANGED ASAP (8)
427	ALL GUYS HAVE VERY BAD PITTING AND RUST, SHOULD BE CHANGED ASAP (8)
428	6 guys pitted, full length
429	All main guys pitted
430	
431	Guys all good, no rust
432	Guys all good, no rust
433	Guys all good, no rust
434	Guys all good, no rust
435	Guys all good, but a little slack

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Replace Diesel Units
Norman Bay, Postville and Paradise River

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

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1 INTRODUCTION

Norman Bay is a small community located on an island in southern Labrador serving 14 residential customers, four general service customers, three street lights and a Newfoundland and Labrador Hydro (Hydro) owned accommodation for a gross annual energy production of 200 to 210 MWh. Electricity in the community is supplied by a Hydro owned and operated diesel generating plant with three diesel generating sets (gensets). Each genset at Norman Bay has a rated capacity of 30 kW for a total installed capacity of 90 kW and firm capacity of 60 kW.

Postville is a small Inuit community located on the northern Labrador coast. The community is only accessible by air or coastal ferry. Electricity in the community is supplied by a Hydro owned and operated diesel generating plant. The diesel plant contains three gensets rated at 275, 252 and 150 kW respectively, giving a plant installed capacity of 677 kW and firm capacity of 402 kW. It generates approximately 1,600 MWh of electricity annually, supplying electricity to 120 customers in the community. Figure 1 shows the diesel generating plant in Postville.

Figure 1: Postville Diesel Plant

Paradise River is a small community on the Labrador coast. Once only accessible by air or coastal ferry, the community has recently become accessible via the Trans Labrador Highway. Electricity in the community is supplied by a Hydro owned and operated diesel generating plant. The diesel plant has three gensets rated at 50, 50 and 90 kW respectively, giving an installed capacity of 190 kW and firm capacity of 100 kW. It generates approximately 90 MWh of electricity annually, supplying electricity to 30 customers in the community.

2 PROJECT DESCRIPTION

This project will replace a total of four gensets in three diesel plants as per Table 1.

Table 1
Unit Replacement

Plant	Unit Being Replaced	Existing Unit Size (kW)	Replacement Unit Size (kW)
Norman Bay	562	30	30 - 50
	563	30	30
Postville	557	150	350
Paradise River	2020	90	27 - 35

Norman Bay

This project will replace two 30 kW diesel gensets, switchgear and automatic controls. Genset replacements will include new exhaust stacks.

The Norman Bay diesel plant is operated part-time by a resident of the community. The lack of a full-time operator makes it necessary to employ automatic controls which start and stop gensets as required to meet power demand. The existing controls were custom built specifically for the installed gensets and cannot be adapted to new equipment. As a result, replacement of existing gensets must be accompanied by replacement of switchgear and controls. New controls will comply with Hydro's current practice for automatic controls and will be compatible with future genset replacements with minimal modification.

Postville

This project will replace Unit 557, a 150 kW Perkins diesel unit manufactured in 1987, with a new 365 kW unit. The unit replacement will require the installation of a new radiator, switchgear, fuel cooling and delivery system, and exhaust system. The unit is

being replaced with a larger unit at this time as the Postville system is currently growing and the forecast peak load is expected to exceed the firm capacity of the plant in 2012.

Paradise River

This project will replace Unit 2020, a 90 kW Caterpillar 3304, with a smaller unit rated at 27 to 35 kW. The project will also include replacement of the unit auxiliary equipment such as the cooling system, exhaust system and unit control panel.

3 EXISTING SYSTEM

Norman Bay

The Norman Bay diesel plant contains three 21-year old gensets (Units 561, 562, and 563) with a rated capacity of 30 kW each for a total installed capacity of 90 kW, and firm capacity of 60 kW.

The diesel plant is operated part-time on contract by a local resident. The forecast peak thermal demand is approximately 60 kW, whereas the instantaneous demand has been noted by the operator to be as high as 67 kW. To manage demand in the community on peak load days, the plant operator calls customers to schedule the use of electric stoves to prevent the load from exceeding the capacity of any two gensets.

Unit 561 is being replaced with a new unit in 2009 as a two-year project. The replacement of Unit 561 will include bringing the system up to current electrical standards and install infrastructure to support plant automation.

Postville

The Postville diesel plant contains three diesel generating units with a plant installed capacity of 677 kW. The individual unit sizes are 252, 275, and 150 kW, respectively. The plant generates approximately 1,600 MWh of electricity annually, supplying electricity to 120 customers in the community. The Postville system peak is forecast to be 361 kW in 2008.

Unit 557, a 150 kW unit, is undersized for the Postville system and therefore is underutilized. Parts are becoming obsolete and the parts that can still be obtained have a long delivery period.

The unit currently has glycol and water contamination in its lube oil as a result of an oil cooler leak. The oil cooler was repaired during the last overhaul but has developed another leak. As a result of the contamination, oil changes on this unit are now being done every 100 hours, compared to a normal oil change interval of 500 hours for a typical unit.

This unit has had governor issues for years and currently has a make shift governor speed adjustment, as a replacement part is no longer available.

Paradise River

The Paradise River diesel plant has three gensets: two rated at 50 kW; and the other at 90 kW, for an installed generating capacity of 190 kW. It generates approximately 90 MWh of electricity annually, supplying electricity to 30 customers in the community.

Unit 2020 is a Caterpillar 3304 rated at 90 kW. This unit is oversized for the Paradise River system which is currently experiencing extremely low loads. With a system peak of 35 kW forecast for 2008, this unit operates well below its best efficiency point.

The average fuel efficiency of the Paradise River diesel plant was 1.46 kWh per litre in 2007, while the fuel efficiency of the other plants in the Labrador region ranged from 3.20 to 3.67 kWh per litre.

3.1 Age of Equipment or System

The diesel gensets and associated equipment at Norman Bay and Postville were purchased and installed in 1987.

Unit 2020 was purchased in 1982 and installed in Mud Lake. In 2000, it was removed from Mud Lake and installed in the Paradise River diesel plant.

3.2 Major Work or Upgrades

There has been no major work or upgrades of the equipment being replaced.

3.3 Anticipated Useful life

Diesel gensets have an economic life of 20 years and an expected average service life of 25 years.

3.4 Maintenance History

Maintenance of gensets generally includes preventive maintenance, corrective maintenance and periodic overhauls. Corrective maintenance (CM) is performed to repair equipment after a failure has occurred, such as a fuel pump failure. Preventive maintenance (PM) consists of oil and filter changes and operational checks of wear components on a periodic basis. The purpose of an overhaul is to replace worn parts, which is meant to restore performance to near new conditions. Hydro's current practice is to overhaul gensets after approximately 20,000 hours of operation.

Norman Bay

The most recent scheduled overhauls of Units 562 and 563 are listed in Table 2. While overhauls are presently scheduled approximately every 20,000 operating hours, they have traditionally been performed every 15,000 hours until recent years. Overhauls cannot solve the chronic fuel pump problems being experienced with these units.

Table 2
Units Nos. 562 and 563 overhauls

Year	Unit Overhauled	Comments
2006	Unit 563	10,000* operating hours since rebuild
2002	Unit 562	16,670 operating hours since rebuild

* The hour meter on 563 stopped at 10,000 hours and has not yet been replaced

There were 24 CM work orders issued for Unit 562 between 2003 and 2007 and six CM work orders have been issued in the first four months of 2008. There were 22 CM work orders issued for Unit 563 between 2003 and 2007 and six CM work orders have been issued in the first four months of 2008. Maintenance costs for these units over the past five years are provided in Table 3 and Table 4.

Table 3
Five-Year Maintenance History – Norman Bay Unit 562

Year	Preventive Maintenance ($)	Corrective Maintenance ($)	Total ($)
2007	290	6,136	6,426
2006	69	3,150	3,219
2005	162	562	724
2004	182	8,026	8,208
2003	198	3,794	3,992

Table 4
Five-Year Maintenance History – Norman Bay Unit 563

Year	Preventive Maintenance ($)	Corrective Maintenance ($)	Total ($)
2007	204	4,316	4,520
2006	86	7,476	7,562
2005	0	11,985	11,985
2004	359	708	1,067
2003	396	2,075	2,471

In addition, changes in fuel properties as a result of reductions in the sulphur content of diesel fuel since the engines were manufactured are believed to be the cause of chronic fuel pump failures. The process of removing sulphur from fuel also reduces desirable qualities which protect parts against wear.[1]

Regulations classify diesel fuel according to end use and set sulphur limits for each class. Regulations for off-road, marine, and rail use are less stringent but on-road fuel is the only class available to Hydro. When the gensets were manufactured, the regulated sulphur content of on-road diesel fuel was 5000 parts per million (ppm). In 1997, sulphur content was regulated to 500 ppm, and 15 ppm in 2006. Under normal circumstances, fuel pumps are expected to last until overhaul. The type of fuel pump on these engines (known as a rotary distributor pump), however, is susceptible to wear when used with low sulphur fuel because it is not sufficiently lubricated by the fuel. Worn components result in reduced fuel delivery to the engines and with less fuel the engines are not able to meet their rated capacity. Consequently, outages occur when the gensets are unable to generate enough power and additional maintenance is required to replace these fuel pumps between overhauls. The fuel pumps on these engines are integral to their operation and there are no possible substitutes.

[1] This is true for diesel units as the fuel oil serves as a lubricant. In larger generating stations, such as the Holyrood Thermal Generating Station, separate lubrication oil is used and lower sulphur fuel does not cause the same wear.

Table 5 summarizes fuel pump replacements recorded in work orders between January 1, 2003 and December 31, 2007. It should be noted that these costs do not include travel and, in some cases, do not include the cost of the fuel pump due to use of a separately purchased spare.

Table 5
Summary of Fuel Pump Replacements – Norman Bay

Year	Unit 562 Pump Replacements		Unit 563 Pump Replacements	
	Count	Cost ($)	Count	Cost ($)
2007	2	2,638	2	2,562
2006	0	0	1	118
2005	0	0	4	5,650
2004	1	1,595	1	273
2003	1	496	0	0

Postville

The five-year maintenance history for Unit 557 is shown in Table 6 below. No overhauls were completed during this time period.

Table 6
Five Year Maintenance History – Postville Unit 557

Year	Preventive Maintenance ($)	Corrective Maintenance ($)	Total Maintenance ($)
2007	2,900	4,200	7,100
2006	1,400	2,100	3,500
2005	0	9,900	9,900
2004	2,100	12,300	14,400
2003	5,400	6,300	11,700

Since installation, Unit 557 has operated approximately 50,800 hours and has been overhauled three times. Since its last overhaul in November 2001, Unit 557 has operated approximately 10,500 hours. In 2007, it operated only 688 hours, as compared to the other units in the plant which operated 6,970 hours and 6,834 hours, respectively.

Paradise River

The five-year maintenance history for Unit 2020 in Paradise River is shown in Table 7 below.

Table 7
Five-Year Maintenance History – Paradise River Unit 2020

Year	Preventive Maintenance ($)	Corrective Maintenance ($)	Total Maintenance ($)
2007	2,600	0	2,600
2006	730	0	730
2005	0	8,300	8,300
2004	450	840	1,290
2003	170	270	440

Since installation, Unit 2020 has operated 44,443 hours and has had two overhauls. Since its last overhaul in November 1997, it has operated 14,919 hours. It operated 2,161 hours in 2007.

3.5 Outage Statistics

Hydro does not currently maintain a diesel generating unit reliability database. Only outages which have a customer impact are recorded. The customer impact is recorded in the general category of loss of supply and includes outages in addition to those caused by the units to be replaced.

The CEA defines Loss of Supply as:

> *Customer interruptions due to problems in the bulk electricity supply system such as under frequency load shedding, transmission system transients, or system frequency excursions.*

Hydro uses this category to capture interruptions originating in the diesel plants. Table 8 below lists the 2003 to 2007 average System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) for Loss of Supply caused outages for Paradise River, Postville, and Norman Bay compared to the total Hydro isolated and complete systems.

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 8
Five-year Average Interruption Indices (2003 – 2007)

SYSTEM	All Causes		Loss of Supply	
	SAIFI	SAIDI	SAIFI	SAIDI
Paradise River System	7.39	3.92	8.43	0.46
Postville System	12.44	10.49	9.57	5.47
Norman Bay System	13.00	5.74	10.44	2.81
Total Hydro Isolated System	9.93	10.70	6.38	2.30
Total Hydro System	6.24	7.73	2.89	2.63
CEA (2002-2006)	2.64	7.61	0.46	0.98

3.6 Industry Experience

Industry experience has been researched with respect to the fuel pump problems being experienced in Norman Bay. The process of removing sulphur from fuel also decreases fuel lubricity, which normally protects fuel system parts from wear. Increased fuel system wear on some older equipment due to the use of low lubricity fuel is common knowledge in industry. The same problem is also being experienced with a relatively new genset (Unit 2057 installed in 2000) located in William's Harbour which uses the same type of fuel pump.

3.7 Maintenance or Support Arrangements

Maintenance on the gensets in Paradise River and Postville are performed by internal operations personnel from Happy Valley Goose Bay. Maintenance on Units 562 and 563 at the Norman Bay diesel plant is performed by Hydro personnel stationed in St. Anthony. Maintenance consists of scheduled preventive maintenance such as oil and filter changes, required corrective maintenance to repair failed components or correct operational problems and scheduled overhauls.

3.8 Vendor Recommendations

Advice has been sought related to the fuel pump problems being experienced on the gensets in Norman Bay and other gensets in the Isolated Rural System. Diesel Injection Sales, which performs fuel pump rebuilds, recommended using a diesel fuel additive to extend fuel pump service life. The additive was used on a trial basis at a cost of $300 to treat 10,000 litres of fuel. With an annual fuel consumption of approximately 159,000 litres, the cost of additive was approximately $4,800 per year. It was stated by Operations that there were no noticeable improvements in fuel pump life or reliability so the additive was not adopted for continued use.

3.9 Availability of Replacement Parts

With the exception of Unit 2020 at Paradise River, spare parts are readily available for these gensets. Replacement parts are not readily available for this unit. The unit has a recurring problem with lube oil contamination with water and glycol which is the result of a lube oil cooler leak. We can no longer obtain a replacement oil cooler for this unit. Increasingly, when spare parts are sought, we find that the parts are not available. Additional parts which we have not been able to source include fuel lines, safety guards, and some common overhaul parts.

Common replacement parts for the 21-year old gensets in Norman Bay can be obtained within days from the local distributor. Uncommon parts are available only from England but can usually be obtained within one week by air freight.

3.10 Safety Performance

There are no safety performance issues related to these genset replacements.

3.11 Environmental Performance

Engine emission improvements may be expected when replacing older units, such as those being replaced in this project, with more modern generating units, but any such improvement cannot be accurately quantified.

3.12 Operating Regime

The Norman Bay, Postville and Paradise River diesel plants are the only source of power generation for their respective communities, and they operate on a continuous basis. In keeping with Hydro's generation planning criteria, two of the three installed

units in each plant must be available at all times to ensure that the electrical needs of the community are satisfied. The individual units are operated in the most efficient manner to meet the load in the community at any given time.

The operation of the gensets in each plant is cycled to distribute operating hours among all three units throughout the year.

4 JUSTIFICATION

This project is justified on the requirement to replace failing or deteriorated infrastructure for Hydro to provide reliable electrical service.

From experience, it is expected that after the gensets are replaced, maintenance will be reduced primarily to scheduled preventive maintenance. No data is readily available for average corrective maintenance costs on new gensets or the rate of corrective maintenance incidents over time.

4.1 Net Present Value

As there are no viable alternatives, a net present value calculation has not been performed.

4.2 Levelized Cost of Energy

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

4.3 Cost Benefit Analysis

As there are no quantifiable benefits, a cost benefit analysis has not been performed.

4.4 Legislative or Regulatory Requirements

The justification of this project is not based on regulatory requirements.

4.5 Historical Information

Table 9 below provides historical information on similar projects completed over the last three years.

Table 9
Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)
2006	1,512.5	1,515.1	4	378.8
2005	304.0	236.6	1	236.6
2004	258.1	247.2	1	247.2

4.6 Forecast Customer Growth

The justification for this project is not based on customer growth, however, customer growth has been considered in sizing replacement engines for those being replaced. Table10 below presents the current peak load forecast for Norman Bay, Postville and Paradise River from 2008 to 2013.

Table 10
Peak Load Forecast - Norman Bay, Postville and Paradise River

Year	Norman Bay		Postville		Paradise River	
	Gross Peak (kW)	% of Firm Criterion	Gross Peak (kW)	% of Firm Criterion	Gross Peak (kW)	% of Firm Criterion
2008	58	96.7	374	93.0	35	35.0
2009	59	98.3	386	96.0	36	36.0
2010	60	100.0	390	97.0	37	37.0
2011	60	100.0	398	99.0	37	37.0
2012	60	100.0	403	100.2	38	38.0
2013	60	100.0	407	101.2	38	38.0

Demand growth at Norman Bay is forecast to increase by 2 kW (approximately 3.5 percent) to a gross peak of 60 kW by 2010 (as shown in Table 10).

The Postville system is experiencing growth due to the economic activity associated with mineral exploration in the area. Firm generation, which represents the power capability following the loss of the largest unit, is expected to be surpassed by 2012, which will require the installation of additional generation in the plant.

The forecast growth in the Paradise River system is low, with the peak increasing from 35 kW in 2008 to 38 kW in 2013.

4.7 Energy Efficiency Benefits

Fuel efficiency improvements may be expected when replacing older units such as Unit 557 with more modern, appropriately-sized equipment, but any such improvement cannot be accurately quantified.

The replacement of Unit 2020 in Paradise River with a smaller unit will allow the plant to operate more efficiently to meet the electricity requirements in the community. An improvement in overall plant efficiency is expected, bringing the Paradise River diesel plant more in line with the other diesel plants in the Labrador region and across the Hydro isolated system.

4.8 Losses during Construction

No losses during construction are anticipated, since gensets will be replaced individually while existing units continue to generate power.

4.9 Status Quo

Maintaining the status quo is unacceptable. If this project is not completed, Norman Bay customers will continue to experience outages due to reliability issues of aging equipment and call-outs for corrective maintenance will continue.

Maintaining the status quo will mean continuing to operate the Paradise River system less efficiently than it should be.

In Postville, maintaining the status quo will allow the reliability of the system to continue to be affected by the unreliability of Unit 557.

4.10 Alternatives

There are no viable alternatives to replacing these gensets.

5 CONCLUSION

This project is necessary to provide reliable power to the customers of Norman Bay, Postville and Paradise River. If the work is not performed, outages will continue in Norman Bay. The unreliability and limited utilization of Unit 557 in Postville will continue to affect the provision of reliable power to the Postville system. Continued use of Unit 2020 in Paradise River will limit plant efficiency to well below that of the other plants in the rural isolated system.

5.1 Budget Estimate

The estimated cost of the diesel unit replacements is $1,869,600. The costs are spread over two years with genset tender and award in 2009 and installations in 2010. The yearly and overall costs are presented in Table 11 below.

Table 11
Budget Estimate

Project Cost:($ x1,000)	**2009**	**2010**	**TOTAL**
Materials Supply	58.0	720.8	778.8
Labour	88.5	407.0	495.5
Consultant		10.0	10.0
Contract Work		65.4	65.4
Other Direct Costs	2.0	87.8	89.8
O/H, AFUDC & Escln	21.2	264.9	286.1
Contingency		144.0	144.0
TOTAL	**169.7**	**1,699.9**	**1,869.6**

Table 12 below presents the project costs by location.

Table 12
Project Costs by Location

Project Cost:($ x1,000)	**Norman Bay**	**Postville**	**Paradise River**
Materials Supply	341.5	271.6	165.7
Labour	276.2	115.1	104.2
Consultant	10.0	0.0	0.0
Contract Work	65.4	0.0	0.0
Other Direct Costs	8.7	45.8	3.5
O/H, AFUDC & Escln	142.0	84.0	60.1
Contingency	70.2	43.3	30.5
TOTAL	914.0	559.8	395.8

5.2 Project Schedule

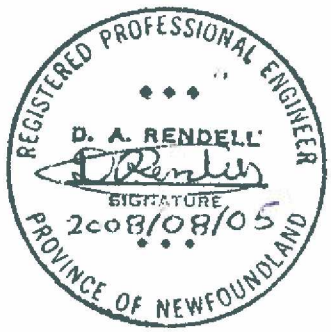
Table 13 shows the planned project schedule.

Table 13
Project Schedule

Activity	**Milestone**
Project Initiation	February 2009
Project Design	June 2009
Equipment Tender	July 2009
Equipment Tender Award	September 2009
Installation – Norman Bay	November 2010
Installation – Postville	October 2010
Installation – Paradise River	September 2010
Project Closeout	December 2010

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Cat Arm Hydro Generating Station Replacement of Accommodations



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Appendices

A - Two Mould Investigation Reports

1 INTRODUCTION

The Cat Arm Development is located on a plateau of the Long Range Mountains on Newfoundland's Great Northern Peninsula, 120 kilometers north of Deer Lake. When completed in 1985, the Cat Arm Hydro Generating Station (Cat Arm) added 127 MW of capacity to the Island Interconnected System of Newfoundland and Labrador Hydro (Hydro). Cat Arm produces approximately 700 GWh of electrical energy annually. Figure 1 below shows the generating station and the existing accommodations at the site.

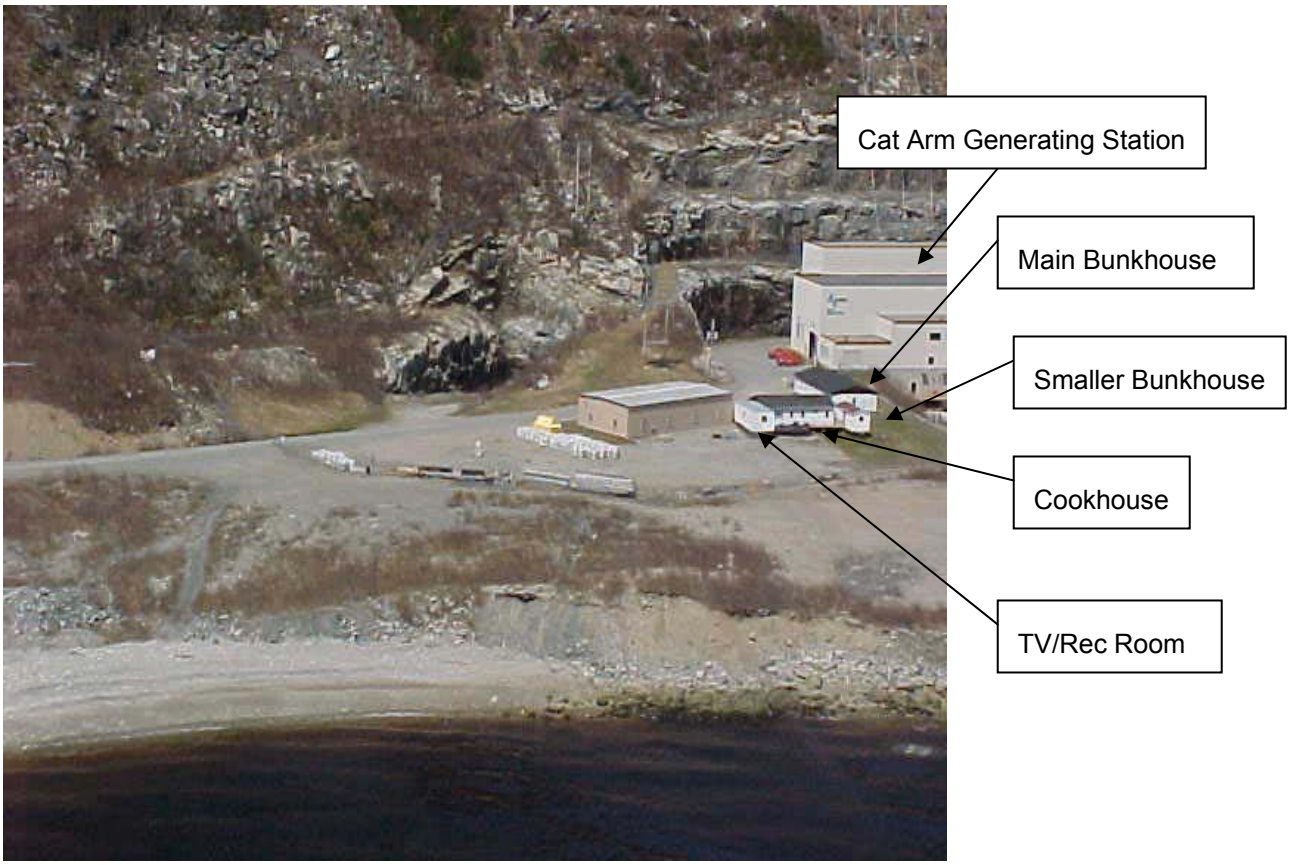

Figure 1 – Cat Arm Generating Station

The current accommodations facility at the Cat Arm consists of four mobile trailers. The two larger trailers have been modified and converted into a bunkhouse and a cookhouse, providing a total of 17 bedrooms, a kitchen, a dining room and a community washroom. One of the smaller units is also used as a bunkhouse and the other is used as a recreational area.

In 2007, Hydro commissioned Pinchin LeBlanc Environmental Limited (Pinchin) to perform a mould investigation within the Cat Arm accommodations after complaints were received from employees concerning air quality and detection of a musty odor while occupying the buildings. Two studies were completed by Pinchin in June 2007 and air quality deficiencies were identified for corrective action. The findings of these reports form the basis for this budget proposal. The studies included as Appendix A are:

- Mould Investigation Report Newfoundland and Labrador Hydro Cat Arm Generating Station, NL Bunkhouse; and
- Mould Investigation Report Newfoundland and Labrador Hydro Cat Arm Generating Station, NL Cookhouse.

Due to the confirmed mould and air quality issues, the accommodations facility at the Cat Arm has not been utilized during the 2007 maintenance season. On page one of both reports, Pinchin states that Health Canada considers mould growth on the interior surfaces of buildings to be a risk factor for health problems. Hydro maintenance and operating staff consider the presence of mould to be a risk to their health and do not use the Cat Arm accommodations. Instead, the staff uses a combination of Accommodations at Pollard's Point and Deer Lake depending on the number of workers required at the Cat Arm Facility. Besides mould problems, the aged accommodations facility at Cat Arm is no longer considered to be suitable because it does not allow for separate accommodations for females and males. The facility also has a questionable septic system and telecommunications facilities are inadequate for staff to perform their duties effectively.

2 PROJECT DESCRIPTION

The scope of work for this project includes the following four components:

1. Six 18.3 metres x 4.4 metres modular units. Four modular units will contain four bedrooms each with a washroom, and two modular units will contain a kitchen, dining room, laundry room, television room and recreational room.
2. A new sanitary sewer system.
3. An upgrade to the telecommunication system for Cat Arm. This will be performed at the same time as the other components to take advantage of the economies of scale provided by the installation of similar equipment in the new accommodations. By taking advantage of this opportunity, the cost of providing communications to Cat Arm will be lower than if the work were done separately.
4. Parking lot and general site improvements such as exterior lighting.

Table 1 below shows details of the work and associated direct costs.

Table 1
Detailed Work

Description of Work		Costs ($000)
1. Civil Labor	Engineering Design, Drafting, Inspection	84.0
2. Telecontrol Labor	Project Management, Design, Installation	72.0
3. Civil Materials	Furniture	30.0
4. Telecontrol Materials	TV Transmitter/Receiver, PBX Express	48.0
5. Travel	Airfare, Hotel, Per diems, Car Rental	36.0
6. Equipment Rentals	Boom Truck, Fleet Vehicle	3.5
7. Contract	Modular Accommodation Units	431.0
	Installation	94.0
	Septic System	15.0
	Concrete Foundation	70.0
	Demolition	15.0
	Air Exchanger	28.0
	Radio Link Upgrade	20.0
	Site Work and Paving	60.0
TOTAL		**1,006.5**

3 EXISTING SYSTEM

The existing facility includes four separate mobile trailer units creating a make-shift, temporary accommodations facility for Hydro's operations and maintenance staff. The four units consist of a bunkhouse, a cookhouse, a television/recreational area and an additional small bunkhouse attached to the cookhouse. The bunkhouse is comprised of 13 bedrooms, a laundry room, and a community washroom. The cookhouse consists of four bedrooms, a kitchen, a dining room, and two bathrooms.

The existing septic system for the Cat Arm accommodations facility was installed in 1983-84, and consists of a septic tank and in-ground disposal field.

Up to and including 2006, most of Hydro's work crews stayed on site at Cat Arm. The accommodations could hold 17 employees, and additional employees travelled to Pollard's Point. The total number on site varied but could reach up to 30 at times. Most of the overflow was accommodated at the River Sea Motel and Carousel Inn at Pollard's Point, which is currently under the same management. These combined facilities can accommodate up to 19 depending on availability. There have been times however, that staff has had to travel to Deer Lake, due to limited accommodations available at Cat Arm and Pollard's Point. Travel to Deer Lake requires that the crews spend more time on the road, which in itself puts them more at risk with respect to highway travel and the possibility of moose accidents. A longer workday due to increased travel will impact maintenance schedules and increase overall project costs. Pollard's Point accommodations are not viewed as a long-term option.

In recent years the majority of the work at Cat Arm is planned and scheduled during August-October, at a time when the reservoir level has lowered. The site is accessible by vehicle and adverse weather conditions will not impact the work schedule or access to the site. During the winter months, the on-line availability of the Cat Arm generators becomes more critical. The operations personnel travel to and from site daily by snowmobile. Crews are sometimes unable to travel the 26 kilometre road due to

snowstorms and adverse weather conditions, and at times, have had to leave site early to avoid getting caught in a snowstorm. There have also been instances over the years, where small maintenance crews have had to go to site during the winter months to address specific problems. These crews have stayed on-site, when travel to Pollard's Point was not an option due to adverse weather conditions. Hydro's experience has shown that problems very often occur under the most severe weather conditions, at which time travel to and from site is not an option. Unfortunately, we are not able to quantify the specific instances when this has occurred. However, the availability of on-site accommodations does play an important role in the operation and maintenance of the Cat Arm facility.

3.1 Age of Equipment or System

The previously used accommodations buildings were placed at the Cat Arm site in 1982.

The existing septic system for the Cat Arm accommodations facility is 24 years old.

3.2 Major Work or Upgrades

Table 2 shows the upgrades that have occurred since installation.

Table 2

Year	Major Work or Upgrades	Comments
2006	Replaced patio outside the bunkhouse	Preventative maintenance
2005	Replaced windows in both the cookhouse and the bunkhouse	Corrective maintenance
1999	Added three bedrooms to cookhouse	Corrective maintenance
1995	Modified washrooms in cookhouse	Corrective maintenance

3.3 Anticipated Useful Life

The service life of an accommodations camp is 20 years. The current facility was put into use in 1982. In addition, the units have been previously used, resulting in the age of the existing system being at least 27 years old.

3.4 Maintenance History

Table 3 summarizes both preventive and corrective maintenance costs incurred for the bunkhouse and the cookhouse from 2003 to 2007. Appendix B provides the detailed maintenance costs.

Table 3

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
Bunkhouse Maintenance			
2007	4.0	2.1	6.1
2006	1.9	0.1	2.0
2005	2.0	10.6	12.6
2004	2.2	0.2	2.4
2003	0.8	1.7	2.5
Cookhouse Maintenance			
2007	0.7	0.3	1.0
2006	0.6	1.4	2.0
2005	1.5	3.8	5.3
2004	1.1	0.2	1.3
2003	0.7	1.3	2.0

3.5 Outage Statistics

There are no Cat Arm generation outages attributable to the accommodations facilities.

3.6 Industry Experience

There is no established standard in this utility industry for on-site accommodation facilities. Modern facilities provide a reasonable level of comfort, privacy, and safety. Adequate levels of comfort and privacy are obtained by allocating single room occupancy, with individual washroom facilities versus a community washroom, the availability of separate male and female accommodations, and modern communication systems, including internet access.

3.7 Maintenance or Support Arrangements

General maintenance for the Cat Arm accommodations facility has been performed by Hydro personnel.

3.8 Vendor Recommendations

There are no relevant vendor recommendations.

3.9 Availability of Replacement Parts

The availability of replacement parts is not a concern.

3.10 Safety Performance

The study carried out by Pinchin in 2007 has confirmed the existence of active mould growth within the interior surfaces of the current accommodations facilities at Cat Arm. Refer to Appendices A and B for the reports. As stated in those reports, Health Canada considers mould growth on the interior surfaces of buildings to be a risk factor for health problems.

Because of the confirmed mould and air quality issues, the accommodations facility at Cat Arm was not utilized during the 2007 season. Hydro's maintenance and operating staff used other facilities such as Pollard's Point and Deer Lake. However, the quality of the accommodations at Pollard's Point has resulted in some employees refusing to stay there, opting to drive 120 kilometers to Deer Lake for the next available accommodations. For maintenance work carried out in 2008 management and the union have informally agreed to use a hotel in Pollards Point which is located approximately forty five minutes from site. Also a temporary cookhouse will be set up at Cat Arm to feed the workforce. This hotel is not a long term option because it has issues such as the availability of hot water, staff to clean the rooms and it may be closing down in the near future.

Additional safety concerns have now been raised due to the extended hours on the job. Employees who stay offsite at Deer Lake, the nearest adequate hotel, have an estimated two hour drive to and from Cat Arm, resulting in four hours of travel per day. The number of staff that travel each day varies depending on the required work to be performed at Cat Arm. Because of fatigue caused by longer working hours, alertness is impaired resulting in an increased risk of accidents such as a moose-vehicle collision.

3.11 Environmental Performance

The septic system for the existing accommodations facility was completed in 1984. During an internal audit in 1998, it was recommended that approvals be sought from the provincial Government Services Center for all sewage disposal systems. The Cat Arm septic system does not have registered provincial approval. The new installation will be in compliance with all applicable environmental standards and regulatory agencies.

3.12 Operating Regime

The Cat Arm plant operates on a continuous basis, with scheduled annual outages for preventive and corrective maintenance. The maximum use of the accommodations facility is during plant maintenance outages. Table 4 summarizes the requirements for accommodations at Cat Arm from 2002-2008.

Table 4
Accommodation Requirements

Year	Duration	# of Employees	Maximum # of employees at site
2008	13 weeks	30	16
2008	2 weeks	7	7
2007	5 weeks	30	16
2007	2 weeks	7	7
2007	4 weeks	7	7
2006	9 weeks	35	16
2006	5 weeks	7	7
2005	6 weeks	30	16
2005	2 weeks	7	7
2004	5 weeks	30	16
2004	2 weeks	8	8
2003	5 weeks	30	16
2003	6 weeks	7	7
2002	7 weeks	30	16
2002	2 weeks	7	7

4 JUSTIFICATION

Over the years, there have been renovations, as stated in Section 3.2, carried out on both the bunkhouse and cookhouse buildings. This is in addition to the regular maintenance, which is carried out on an ongoing basis. Renovations have been carried out to address issues such as poor washroom layout, noise concerns with respect to the television/recreation room near the bedrooms, inability to accommodate more employees, and the lack of recreational facilities.

However, the existing facility poses health risks with respect to the presence of mould. Employees must seek alternative offsite accommodations, resulting in increased daily travel time, which would not occur if on site accommodations were available. This increases Hydro's labour, travel and accommodation costs. Also, safety risks are created because of driven fatigue and exposure to potential moose/vehicle collisions.

In order to meet current building standards and provide the required level of safety and comfort, the existing facility should be replaced with a newer, more modernized facility. The need for this facility is magnified due to its remote location and the potential problems that can be experienced while attempting to gain access during the winter months.

By 2011, the existing septic system will be approximately 27 years old and, based on past experience, the system will require replacement. The new system will consist of a 1,000-gallon septic tank with an ocean outfall extended to the tailrace, approximately 25 metres away.

The existing system was installed as originally designed and approved, but no documentation regarding this system is currently available. In 1998, as a result of an internal compliance audit, it was recommended that governmental approvals be sought for all non-approved sewage disposal systems. A new installation will provide Hydro the

opportunity to bring this system up to current government regulatory compliance standards.

4.1 Net Present Value

A net present value calculation was performed considering two alternatives: construct new accommodations or stay offsite. A 20-year period was chosen for the net present value calculation. The results showed a preference of $ 392,354 in favor of constructing new accommodations. The net present value over the 20-year period was $1,142,684 for new accommodations and $1,535,038 for staying offsite. The breakeven or crossover year was twelve years into the future, in the year 2021. Chart 1 compares the net present value for each alternative and Table 5 shows the cost difference between the two alternatives.

Chart 1

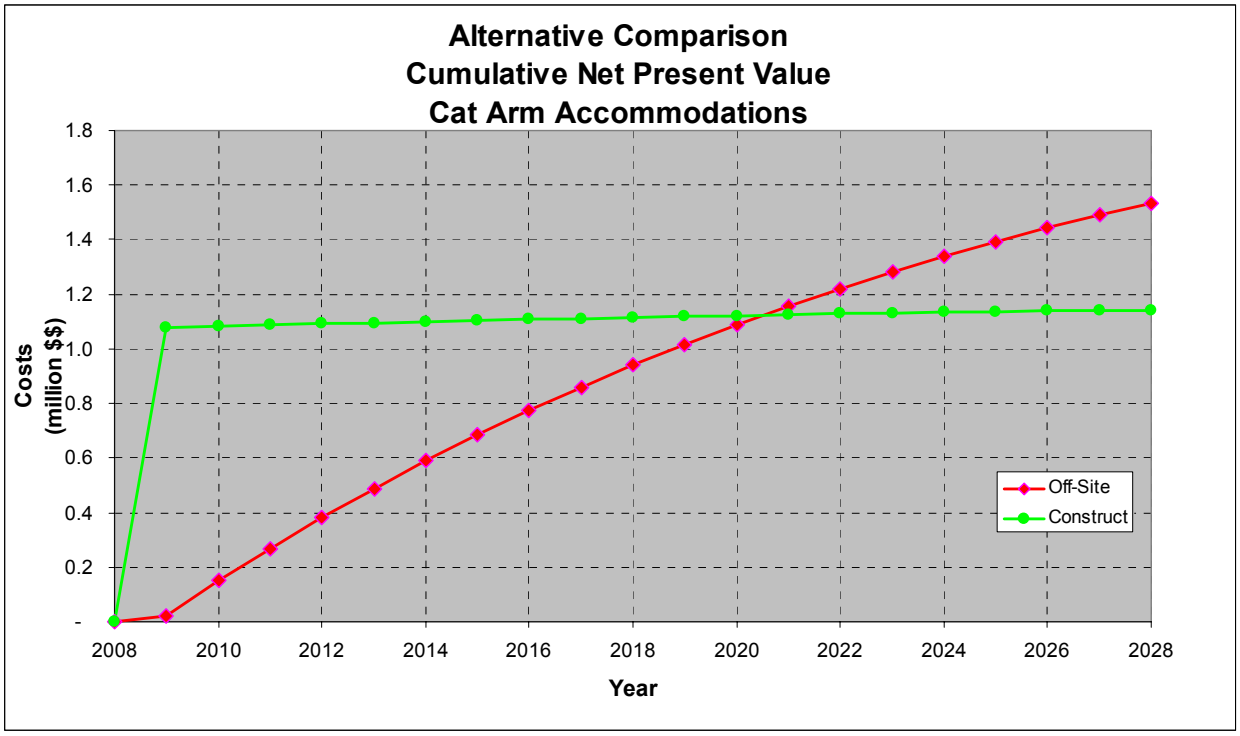

Table 5
Cat Arm Accommodations

Alternative Comparison Cumulative Net Present Worth to the Year 2028		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Construct Accommodations	1,142,684	0
Stay off-site	1,535,038	392,354

For the construct new accommodations alternative, besides the total project capital cost of $1,254,300, an annual operating and maintenance (O&M) cost was considered. This amounted to $6,150 in 2008 dollars escalated at 2.5 percent annually over the 20 year study period. The O&M costs are based on the assumption that two persons will be required to spend 100 hours per year maintaining the camp at a salary and benefits hourly rate of $25 plus $1,000 for materials and $150 for insurance.

For the Stay Offsite alternative an annual cost of $153,600 ($2008) is assumed based on:

- Salary costs due to travel; four hours per day at an hourly rate of $25 for 698 person days per year. This amounts to $69,800 (698 person days is the average of the person days at the Cat Arm facility over the period 2002 to 2008).
- Hotel accommodations; $100 per night for 698 person days. This amounts to $69,800.
- Vehicle usage; four hours per day at an hourly rate of $20 for 175 person days per year (assumes four persons per vehicle, 698 divided by four is approximately 175). This amounts to $14,000.

The annual cost of $153,600 is escalated at the GDP Price Deflator indices of 2.0 percent annually over the 20-year period.

4.2 Levelized Cost of Energy

The scope of this project does not involve analysis of new energy generation sources or enhancements to the existing Cat Arm plant.

4.3 Cost Benefit Analysis

Instead of a cost benefit analysis, a net present value calculation was performed to determine the least-cost alternative, which is to build new accommodations. Deer Lake was used as the assumed accommodations in this analysis.

4.4 Legislative or Regulatory Requirements

Section 11.2 of The Occupational Health and Safety Regulations states that “An employer whose work or process gives off dust or fume or another impurity of a kind and quantity to be injurious or offensive to workers, shall provide, maintain and ensure the proper use of a ventilation system sufficient to protect the workers against inhalation of impurities and to prevent it accumulating in a workplace”.

Canadian Construction (CCA): Mould Guidelines for the Canadian Construction Industry, Guide 82 states that “mould growth is a risk to health and should be removed as quickly as possible”.

4.5 Historical Information

Since this is not a recurring project, historical information is not applicable.

4.6 Forecast Customer Growth

Forecast customer growth has no effect on this project.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits expected as a result of this project.

4.8 Losses during Construction

There are no anticipated energy losses during the construction of the new accommodations facility at the CAT.

4.9 Status Quo

The current facility poses a health hazard to Hydro employees because of the presence of mould, making it inadequate for accommodating workers.

4.10 Alternatives

Two alternatives were considered as discussed in Section 4.1. A net present value analysis shows that it is cost effective to build new accommodations facilities at the Cat Arm site.

5 CONCLUSION

Currently, the existing facility poses significant health risks resulting in employees having to seek alternative accommodations, resulting in extra travel time. As discussed, safety on the road is at risk and Hydro incurs extra costs that do not result in any productivity gains.

The least-cost solution was found to be the replacement of the existing facility with six new modular units, providing accommodations for 16 personnel.

5.1 Budget Estimate

The budget estimate is provided in Table 6.

Table 6
Budget Estimate

Project Cost:($ x1,000)	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	78.0	00	0.0	78.0
Labour	156.0	00	0.0	156.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	733.0	0.0	0.0	733.0
Other Direct Costs	39.5	0.0	0.0	39.5
O/H, AFUDC & Escln	147.1	0.0	0.0	147.1
Contingency	100.7	0.0	0.0	100.7
TOTAL	**1,254.3**	**0.0**	**0.0**	**1,254.3**

5.2 Project Schedule

The project schedule is shown in Table 7.

Table 7
Project Schedule

Activity	**Milestone**
Design	March 2009
Tender	April 2009
Award Tender	May 2009
Contract	October 2009
Project Closed	November 2009

APPENDIX A

Two Mould Investigation Reports
by Pinchin LeBlanc Environmental Limited

MOULD INVESTIGATION REPORT
NEWFOUNDLAND AND LABRADOR HYDRO
CAT ARM GENERATING STATION, NL
BUNKHOUSE

Prepared for:

Newfoundland and Labrador Hydro
Bay D'Espoir Generating Station
P.O. Box 100
Milltown, NL.
A0H 1W0

Attention:

Mr. Robert Bartlett

Pinchin LeBlanc Environmental Ltd. Project 02-7532

June 11, 2007

860 TOPSAIL ROAD, MOUNT PEARL, NEWFOUNDLAND AND LABRADOR, A1N 3J7 TEL: (709) 754-4490 FAX: (709) 754-1359
SAINT JOHN, NB • DARTMOUTH, NS • GOOSE BAY, NL • LABRADOR CITY, NL • CORNER BROOK, NL

Executive Summary

Pinchin LeBlanc Environmental Limited (PLEL) was requested by Newfoundland and Labrador Hydro located in Bay D' Espoir, NL to perform a mould investigation within the Bunkhouse, located at the Cat Arm Generating Station, NL. Jason Lewis, AScT Environmental Engineering Technologist with PLEL performed the investigation on May 22, 2007.

The mould investigation was performed as a result of occupants at the site having concerns with air quality in the bunkhouse due to a musty odour detected while occupying the building.

Visual inspection inside the crawl space identified mould growth on the wooden structural support beams and perimeter plywood sheeting and on the press-wood sheeting located overhead. Wooden structures were also noted to be visibly wet.

One (1) bulk mould sample of mouldy material was collected from the wooden studding located in the crawl space.

Microscopic analysis of the sample collected from the wooden studding located in the Crawl space confirms the presence of active mould growth containing *penicillium* and *phoma* genera like spores, yeast like cells and non-spourlating isolate.

Within the crawlspace the following work should be completed following Level II procedures as outlined in the Canadian Construction Association's, "Mould Guidelines for the Canadian Construction Industry":

- Mould identified on structural building materials (i.e. structural beams and exterior plywood sheeting) located in the crawl space should be cleaned and/or removed.
- Consideration should be given to providing adequate air ventilation into the crawl space. In all situations the underlying cause of the water infiltration or high humidity must be corrected to prevent the continuation or re-occurrence of mould growth.
- A vapour barrier with ballast should be installed to cover the entire earth crawlspace floor. All seams of joining sheets should overlap a minimum of twelve inches (12") and be sealed with pressure sensitive tape or an acoustic sealant. The vapour barrier should lap up onto the foundation walls a minimum of twelve inches (12"), then sealed and caulked tightly to the foundation wall. The vapour barrier around any columns or pipes must be careful fitted and sealed, again with pressure sensitive tape or acoustic sealant.

A contractor with experience in mould abatement should remove the identified mould growth.

The ceiling area of Room # 4 was noted to be sagged. This is may be an indication of water infiltration. Water damaged building materials indicate a source of water and if allowed to continue, a potential source of mould growth. Further intrusive inspection would be warranted in this area to determine the possible presence of any hidden mould growth. Again the source of the water infiltration should also be investigated and corrected.

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1.2 Substrate Moisture……5
2.0 Limitations……5

1. INTRODUCTION

Pinchin LeBlanc Environmental Limited (PLEL) was requested by Newfoundland and Labrador Hydro located in Bay D' Espoir, NL to perform a mould investigation within the Bunkhouse, located at the Cat Arm Generating Station, NL. Jason Lewis, AScT Environmental Engineering Technologist with PLEL performed the investigation on May 22, 2007.

The mould investigation was performed as a result of occupants at the site having concerns with air quality in the bunkhouse due to a musty odour detected while occupying the building.

The bunkhouse camp is a modular unit placed on a wooden foundation. The exterior has metal siding and an asphalt shingle peaked roof. The crawl space located beneath the dwelling consists of an open soil floor, wooden and metal structural supporting beams, wooden studding and a press wood sheeting located overhead. Interior building materials include vinyl sheet flooring and a vinyl covered hard surface material located on the ceilings and walls.

1.1 Indoor Mould Growth

1.1.1. Background

Current evidence suggests that excessive moisture in buildings promotes mould growth and is associated with an increasing risk of symptoms due to irritation, allergy and infection[1]. These may include complaints of headache, cough, respiratory tract irritation, eye irritation, rash, sinus congestion and allergic responses, such as asthma and hay fever-type symptoms. Not all occupants will react to indoor mould exposure. More severe health effects are rare and typically limited to individuals with suppressed immune systems, infants and persons with high occupational exposure such as farmers and possibly remediation workers.

Health Canada considers mould growth on the interior surfaces of buildings to be a risk factor for health problems[2]. It has not published specific guidelines on mould. Rather, it recommends compliance with professional standards for the assessment and control of mould contamination in buildings, including the guidelines set in 2000 by the New York City Department of Health[3]. Canadian guidelines for the management of mould in buildings include those set in 2001 by Manitoba Labour[4] and the 2004 guidelines of the Canadian Construction Association[5]. Some of the common features of these guidelines include,

[1] Fung, F., Hughson, W.G.: Health Effects of Indoor Fungal Bioaerosol Exposure. Applied Occupational and Environmental Hygiene, 18:535-544 (2003).
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[3] NYCDH: Guidelines on Assessment and Remediation of Fungi in Indoor Environments, C. D'Andrea Editor: New York City Department of Health, New York, NY (2000).
[4] Manitoba Labour: Guidelines for the Investigation, Assessment, & Remediation of Mould In Workplaces, Workplace Safety and Health Division, Manitoba Labour, Winnipeg, MB, (March 2001).
[5] CCA: Mould Guidelines for the Canadian Construction Industry, Guide 82, Canadian Construction Association, Ottawa, ON Canada (2004).

- Water-damaged materials should be dried within 48 hours of wetting to prevent mould growth.
- Mould growth in buildings poses a risk of allergic, irritant, infective and possibly toxic responses in some occupants.
- All mould growth should be considered a risk for adverse health effects.
- Mould growth must be abated as soon as possible after discovery.
- Information on the presence of mould growth must be communicated to occupants.
- Building wide evacuation in cases of confirmed mould growth is not indicated unless there is both widespread fungal contamination and confirmed linked illness. However, occupants with persistent health complaints potentially linked to mould exposure should be advised to seek medical attention, and should be given copies of any environmental tests or reports. Persons diagnosed with fungal related disease should not return to the environment until remediation and air testing are completed.
- Occupants with an underlying health condition posing an increased risk of reactivity to mould (e.g., asthma triggered by mould, severe allergies, significantly compromised immune function) should not be present during mould abatement. Such susceptible individuals should be removed from areas adjacent to mould remediation work areas, during the remediation process.
- Mould growth should be removed following work practices designed to contain airborne dust and debris, protect the workers performing the removal, and provide a clean condition at completion. The rigor of these procedures is dependent on the extent of mould growth present.
- Medium and large scale mould abatement work should be performed with the project design and quality assurance assistance of a health and safety professional experienced in mould assessment and remediation.

1.1.2 Bulk Sample Methodology

One (1) bulk mould sample of mouldy material was collected from the wooden studding located in the crawl space.

The bulk sample was collected, by removing a section of the suspect material with a clean sampling tool. The sample was sealed in a zip-lock bag for transportation to the laboratory. The bulk sample was analyzed by microscopic examination to determine the presence or absence of mould growth.

Sample analysis was performed at Mycotaxon Consulting Ltd., Microbiology Laboratory, located in Halifax, Nova Scotia. The laboratory is a Public Works Canada Accredited Mycology

laboratory that participates in the American Industrial Hygiene Association Environmental Microbiology Proficiency Analytical Testing Program.

1.1.3 Observations and Summary of Data

Observations

A visual inspection was performed on the day of the investigation and the following are the observations that were made.

Living Quarters

Visual inspection in the upstairs living space did not identify any visible signs of mould growth at the time of the assessment however a musty odour was detected in the bunkhouse when the building was entered.

The ceiling area of Room # 4 was noted to be sagged. Moisture checks of the ceiling area material using a Tramex Moisture Encounter did not identify any elevated moisture readings in this location at the time of the assessment.

Crawl Space

The crawlspace located beneath the building consists of an uncovered soil floor inside a wooden perimeter plywood foundation. The ceiling space in the crawl space consists of press-wood sheeting and is insulated with fibreglass bat insulation located above the press-wood. Entry into the crawl space on the day of the assessment had to be gained by cutting an access hole beneath the unit in the area of Room # 10 from the exterior of the building. No ventilation holes were observed in the crawl space. It should be noted that access into the crawl space was limited.

Visual inspection of the area identified:

- Visible mould growth on the wooden structural support beams and perimeter plywood sheeting. (Photo 1).
- Visible mould growth on the press-wood sheeting located in the ceiling space. (Photo 2).
- Wooden structures were visibly wet.

Consultation with the site representative indicated that last year the crawl space within this building was reconstructed and the perimeter of the building was covered with soil and ventilation holes were not placed into the crawl space in order to prevent the entry of deer mice into the building.

Summary of Data

One (1) bulk mould sample was collected from the wooden studding located in the crawl space. The analytical results are presented in tabular form below.

Mould Bulk Sampling Bunkhouse Cat Arm Generating Station, NL SAMPLED May 22, 2007		
Sample Location	Sample Description	Sample Result
Crawl Space	Visible mould on wooden studding	active growth yeast-like cells Phoma sp. -like spores Penicillium sp. –like conidiophores + spores non-sporulating isolate

Microscopic analysis of the sample collected from the wooden studding located in the Crawl space confirms the presence of active mould growth containing *penicillium* and *phoma* genera like spores, yeast like cells and non-spourlating isolate. The laboratory certificate is attached as part of this report located in Appendix I.

1.1.4 Conclusions/Recommendations

Within the crawlspace the following work should be completed following Level II procedures as outlined in the Canadian Construction Association's, "Mould Guidelines for the Canadian Construction Industry":

- Mould identified on structural building materials (i.e. structural beams and exterior plywood sheeting) located in the crawl space should be cleaned and/or removed.
- Consideration should be given to providing adequate air ventilation into the crawl space. In all situations the underlying cause of the water infiltration or high humidity must be corrected to prevent the continuation or re-occurrence of mould growth.
- A vapour barrier with ballast should be installed to cover the entire earth crawlspace floor. All seams of joining sheets should overlap a minimum of twelve inches (12") and be sealed with pressure sensitive tape or an acoustic sealant. The vapour barrier should lap up onto the foundation walls a minimum of twelve inches (12"), then sealed and caulked tightly to the foundation wall. The vapour barrier around any columns or pipes must be careful fitted and sealed, again with pressure sensitive tape or acoustic sealant.

A contractor with experience in mould abatement should remove the identified mould growth.

The ceiling area of Room # 4 was noted to be sagged. This is may be an indication of water infiltration. Water damaged building materials indicate a source of water and if allowed to continue, a potential source of mould growth.

Further intrusive inspection would be warranted in this area to determine the possible presence of any hidden mould growth. Again the source of the water infiltration should be investigated and corrected.

1.2 Substrate Moisture

1.2.1 Background

The presence of moisture inside wall cavities and in wall building materials can contribute to the growth of mould. This mould can sometimes be "hidden" inside wall cavities and remain undetected until renovation work uncovers it or occupant complaints arise. Moisture readings can be used to identify potential areas of concern as a result of water infiltration. Moisture readings are also an effective method of determining proper drying of building materials after being exposed to water.

1.2.2 Sample Methodology

During the visual inspection, moisture readings on accessible wall surfaces were taken with a Tramex Moisture Encounter. This unit allows for non-destructive moisture detection in wall surfaces via an analog readout with a chimed alarm at levels exceeding 60% relative moisture. The detection of moisture in building materials can be helpful at identifying hidden sources of mould growth and the extent of water damage. Wood surfaces with a moisture content below 17% will generally not support mould growth[6]. Drywall with a moisture content below 0.7% will generally not support mould growth.

1.2.3 Summary of Data

Moisture readings were collected at random locations on exterior wall and ceiling surfaces throughout the living quarters in the bunkhouse. No elevated moisture readings were detected.

2 STANDARD LIMITATIONS

This report was prepared by PLEL for the sole and exclusive benefit of our client Newfoundland and Labrador Hydro for the project and site location outlined in the report. The report is based on information provided to, or obtained by PLEL, as indicated in this report, and applies solely to site conditions existing at the time of the sampling. This sampling has been undertaken in compliance with currently acceptable practices for indoor air quality, specific client requests, scope of work and schedule.

This sampling was not exhaustive and cannot be construed as a certification of the absence of any contaminants from the site. The work performed by PLEL was conducted in accordance with industry standards and concealed conditions may vary from those encountered or inspected. The degree of mould growth noted in the report may change with time if water or humidity issues continue or develop after the assessment date. Any source of water infiltration or high humidity

[6] American Conference of Governmental Industrial Hygienists: Bioaerosols: Assessment and Control. J, Macher, Ed. ACGIH Cincinnati OH (1999).

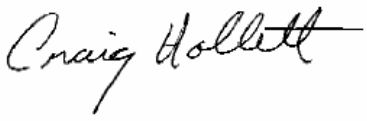
must be corrected to prevent the continuation or occurrence of mould growth. PLEL can only comment on the environmental conditions observed on the date the assessment was performed. PLEL will not provide comment as to the presence or absence of contaminants other than those that were surveyed or sampled for, and at the locations investigated.

No warranty is either expressed or implied, or intended by this agreement or by furnishing oral or written reports or findings. The liability of PLEL or its staff is limited to the lesser of the fees paid or actual damages incurred by the Client. PLEL will not be responsible for any consequential or indirect damages. PLEL will only be liable for damages resulting from negligence of PLEL. All claims by the Client shall be deemed relinquished if not made within one year after last date of services provided.

Information provided by PLEL is intended for Client use only. PLEL will not provide results or information to any party other than the Client, unless the Client, in writing, requests information to be provided to a third party, or unless disclosure by PLEL is required by law. Any use by a third party, of reports or documents authorized by PLEL, or any reliance by a third party on or decisions made based on the findings described in said documents, is the sole responsibility of such third parties. PLEL accepts no responsibility for damages suffered by any third party as a result of decisions made or actions conducted. No other warranties are implied or expressed.

Pinchin LeBlanc Environmental Ltd.

Prepared By:



Craig Hollett, AScT

Indoor Air Quality/Industrial Hygiene

Reviewed By:

David Muise, OHST
Occupational Hygienist

APPENDIX I

LABORATORY CERTIFICATE

MYCOTAXON CONSULTING LTD.
3 Rockwood Ave.
Halifax, Nova Scotia
Canada B3N 1X4

PHONE: 902-475-1456

Fax: 902-475-1982

Mr. C. Hollett
Pinchin LeBlanc Environmental Ltd.
860 Topsail Rd.
Mount Pearl, NL
A1N 3J7

May 29, 2007

Dear Mr. Hollett:

Herewith are the results of the microscopic examination of the bulk sample from your project 02-7532, which were received by this laboratory on May 25, 2007.

SAMPLE	GENERA
1. wooden studding	active growth yeast-like cells Phoma sp. -like spores Penicillium sp. –like conidiophores + spores non-sporulating isolate

I hope this is helpful. If you have any questions concerning this report, please do not hesitate to contact me.

Sincerely yours,
Mycotaxon Consulting Ltd.
AIHA (EMPAT) Participating Laboratory

Per: Thomas G. Rand, Ph.D. Mycology, Public Works Canada Accredited Mycologist

PHOTOS

Photo 1 – Visible black and white mould on wooden studding and perimeter plywood sheeting – Crawl Space.

Photo 2 – Visible mould on over-head press-wood sheeting – Crawl Space

Photo 3 – Sagged ceiling – Room # 4

PINCHIN LEBLANC ENVIRONMENTAL

MOULD INVESTIGATION REPORT
NEWFOUNDLAND AND LABRADOR HYDRO
CAT ARM GENERATING STATION, NL
COOKHOUSE

Prepared for:

Newfoundland and Labrador Hydro
Bay D'Espoir Generating Station
P.O. Box 100
Milltown, NL.
A0H 1W0

Attention:

Mr. Robert Bartlett

Pinchin LeBlanc Environmental Ltd. Project 02-7532

June 11, 2007

860 TOPSAIL ROAD, MOUNT PEARL, NEWFOUNDLAND AND LABRADOR, A1N 3J7 TEL: (709) 754-4490 FAX: (709) 754-1359
SAINT JOHN, NB • DARTMOUTH, NS • GOOSE BAY, NL • LABRADOR CITY, NL • CORNER BROOK, NL

Executive Summary

Pinchin LeBlanc Environmental Limited (PLEL) was requested by Newfoundland and Labrador Hydro located in Bay D' Espoir, NL to perform a mould investigation within the Cookhouse, located at the Cat Arm Generating Station, NL. Jason Lewis, AScT Environmental Engineering Technologist with PLEL performed the investigation on May 22, 2007.

The mould investigation was performed as a result of concerns with suspect mould growth in the cookhouse.

Visual inspection in the upstairs living space did not identify any visible signs of mould growth at the time of the assessment. However the ceiling area of the television room washroom was noted to have water stained ceilings. Moisture checks of the ceiling area using a Tramex Moisture Encounter indicated elevated moisture readings in this location at the time of the assessment.

An intrusive inspection hole was cut into the ceiling area in the television room washroom. The inspection indicated that the ceiling area contained two (2) layers of drywall but no visible mould was present at the time of the assessment.

Visual inspection of the crawlspace identified spotty visible mould growth on the wooden structural support beams and perimeter plywood sheeting. No noticeable water infiltration was noted on the day of the assessment. One (1) bulk mould sample of mouldy material was collected from the perimeter plywood sheeting located in the crawl space. Microscopic analysis of the sample collected from the perimeter plywood sheeting located in the crawl space confirms the presence of active mould growth containing *Trichoderma sp colonies* and non-spourlating isolate.

Within the crawlspace the following work should be completed following Level II procedures as outlined in the Canadian Construction Association's, "Mould Guidelines for the Canadian Construction Industry":

- Mould identified on structural building materials (i.e. structural beams and exterior plywood sheeting) located in the crawl space should be cleaned and/or removed.
- Consideration should be given to providing adequate air ventilation into the crawl space. In all situations the underlying cause of the water infiltration or high humidity must be corrected to prevent the continuation or re-occurrence of mould growth.
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A contractor with experience in mould abatement should remove the identified mould growth.

The source of the water infiltration in the ceiling area within the television room washroom should be investigated and corrected. Water damaged building materials indicate a source of water and if allowed to continue, a potential source of mould growth.

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1.2 Substrate Moisture……5
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Mould Investigation Report
Cat Arm Generating Station
Cookhouse, Cat Arm, NL
Pinchin LeBlanc 02-7532

Privileged and Confidential

1. INTRODUCTION

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The cookhouse camp is a modular unit placed on a wooden foundation. The exterior has metal siding and an asphalt shingle peaked roof. The crawl space located beneath the dwelling consists of an open soil floor, wooden and metal structural supporting beams, wooden studding and a press wood sheeting located overhead. Interior building materials include vinyl sheet flooring and an vinyl covered hard surface material located on the walls and ceilings.

1.1 Indoor Mould Growth

1.1.1. Background

Current evidence suggests that excessive moisture in buildings promotes mould growth and is associated with an increasing risk of symptoms due to irritation, allergy and infection[1]. These may include complaints of headache, cough, respiratory tract irritation, eye irritation, rash, sinus congestion and allergic responses, such as asthma and hay fever-type symptoms. Not all occupants will react to indoor mould exposure. More severe health effects are rare and typically limited to individuals with suppressed immune systems, infants and persons with high occupational exposure such as farmers and possibly remediation workers.

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- Water-damaged materials should be dried within 48 hours of wetting to prevent mould growth.
- Mould growth in buildings poses a risk of allergic, irritant, infective and possibly toxic responses in some occupants.
- All mould growth should be considered a risk for adverse health effects.
- Mould growth must be abated as soon as possible after discovery.
- Information on the presence of mould growth must be communicated to occupants.
- Building wide evacuation in cases of confirmed mould growth is not indicated unless there is both widespread fungal contamination and confirmed linked illness. However, occupants with persistent health complaints potentially linked to mould exposure should be advised to seek medical attention, and should be given copies of any environmental tests or reports. Persons diagnosed with fungal related disease should not return to the environment until remediation and air testing are completed.
- Occupants with an underlying health condition posing an increased risk of reactivity to mould (e.g., asthma triggered by mould, severe allergies, significantly compromised immune function) should not be present during mould abatement. Such susceptible individuals should be removed from areas adjacent to mould remediation work areas, during the remediation process.
- Mould growth should be removed following work practices designed to contain airborne dust and debris, protect the workers performing the removal, and provide a clean condition at completion. The rigor of these procedures is dependent on the extent of mould growth present.
- Medium and large scale mould abatement work should be performed with the project design and quality assurance assistance of a health and safety professional experienced in mould assessment and remediation.

1.1.2 Bulk Sample Methodology

One (1) bulk mould sample of mouldy material was collected from the perimeter plywood sheeting located in the crawl space.

The bulk sample was collected, by removing a section of the suspect material with a clean sampling tool. The sample was sealed in a zip-lock bag for transportation to the laboratory. The bulk sample was analyzed by microscopic examination to determine the presence or absence of mould growth.

Sample analysis was performed at Mycotaxon Consulting Ltd., Microbiology Laboratory, located in Halifax, Nova Scotia. The laboratory is a Public Works Canada Accredited Mycology

laboratory that participates in the American Industrial Hygiene Association Environmental Microbiology Proficiency Analytical Testing Program.

1.1.3 Observations and Summary of Data

Observations

A visual inspection was performed on the day of the investigation and the following are the observations that were made.

Living Quarters

Visual inspection in the upstairs living space did not identify any visible signs of mould growth at the time of the assessment.

The ceiling area of the television room washroom was noted to have water stained ceilings (photo 2). Moisture checks of the ceiling area using a Tramex Moisture Encounter indicated elevated moisture readings in this location at the time of the assessment.

An intrusive inspection hole was cut into the ceiling area in the television room washroom. The inspection indicated that the ceiling area contained two (2) layers of drywall but no visible mould was present at the time of the assessment.

Crawl Space

The crawlspace located beneath the building consists of an uncovered soil floor inside a wooden perimeter plywood foundation. The ceiling space in the crawl space consists of press-wood sheeting and is insulated with fibreglass bat insulation located above the press-wood. The crawl space was accessed from the exterior of the building. No ventilation holes were observed in the crawl space. It should be noted that access into the crawl space was limited.

Visual inspection of the area identified:

- Spotty visible mould growth on the wooden structural support beams and perimeter plywood sheeting. (Photo 1).
- No noticeable water infiltration was noted on the day of the assessment.

Consultation with the site representative indicated that ventilation holes were not placed into the crawl space in order to prevent the entry of deer mice into the building.

Summary of Data

One (1) bulk mould sample was collected from the perimeter plywood sheeting located in the crawl space. The analytical results are presented in tabular form below.

Mould Bulk Sampling Cookhouse Cat Arm Generating Station, NL SAMPLED May 22, 2007		
Sample Location	Sample Description	Sample Result
Crawl Space	Visible mould on plywood sheeting	active growth non-sporulating isolate Trichoderma sp. colonies

Microscopic analysis of the sample collected from the perimeter plywood sheeting located in the crawl space confirms the presence of active mould growth containing *Trichoderma sp colonies* and non-spourlating isolate. The laboratory certificate is attached as part of this report located in Appendix I.

1.1.4 Conclusions/Recommendations

Within the crawlspace the following work should be completed following Level II procedures as outlined in the Canadian Construction Association's, "Mould Guidelines for the Canadian Construction Industry":

- Mould identified on structural building materials (i.e. structural beams and exterior plywood sheeting) located in the crawl space should be cleaned and/or removed.
- Consideration should be given to providing adequate air ventilation into the crawl space. In all situations the underlying cause of the water infiltration or high humidity must be corrected to prevent the continuation or re-occurrence of mould growth.
- A vapour barrier with ballast should be installed to cover the entire earth crawlspace floor. All seams of joining sheets should overlap a minimum of twelve inches (12") and be sealed with pressure sensitive tape or an acoustic sealant. The vapour barrier should lap up onto the foundation walls a minimum of twelve inches (12"), then sealed and caulked tightly to the foundation wall. The vapour barrier around any columns or pipes must be careful fitted and sealed, again with pressure sensitive tape or acoustic sealant.

A contractor with experience in mould abatement should remove the identified mould growth.

The source of the water infiltration in the ceiling area within the television room washroom should be investigated and corrected. Water damaged building materials indicate a source of water and if allowed to continue, a potential source of mould growth.

1.2 Substrate Moisture

1.2.1 Background

The presence of moisture inside wall cavities and in wall building materials can contribute to the growth of mould. This mould can sometimes be "hidden" inside wall cavities and remain undetected until renovation work uncovers it or occupant complaints arise. Moisture readings can be used to identify potential areas of concern as a result of water infiltration. Moisture readings are also an effective method of determining proper drying of building materials after being exposed to water.

1.2.2 Sample Methodology

During the visual inspection, moisture readings on accessible wall surfaces were taken with a Tramex Moisture Encounter. This unit allows for non-destructive moisture detection in wall surfaces via an analog readout with a chimed alarm at levels exceeding 60% relative moisture. The detection of moisture in building materials can be helpful at identifying hidden sources of mould growth and the extent of water damage. Wood surfaces with a moisture content below 17% will generally not support mould growth[6]. Drywall with a moisture content below 0.7% will generally not support mould growth.

1.2.3 Summary of Data

Moisture readings were collected at random locations on exterior wall and ceiling surfaces throughout the living quarters in the cookhouse. Moisture readings, in excess of 15%, were detected in the ceiling area of the television room washroom

As previously mentioned, an intrusive inspection hole was cut into the ceiling in this area but no visible mould was present at the time of the assessment.

2 STANDARD LIMITATIONS

This report was prepared by PLEL for the sole and exclusive benefit of our client Newfoundland and Labrador Hydro for the project and site location outlined in the report. The report is based on information provided to, or obtained by PLEL, as indicated in this report, and applies solely to site conditions existing at the time of the sampling. This sampling has been undertaken in compliance with currently acceptable practices for indoor air quality, specific client requests, scope of work and schedule.

This sampling was not exhaustive and cannot be construed as a certification of the absence of any contaminants from the site. The work performed by PLEL was conducted in accordance with industry standards and concealed conditions may vary from those encountered or inspected. The degree of mould growth noted in the report may change with time if water or humidity issues continue or develop after the assessment date. Any source of water infiltration or high humidity must be corrected to prevent the continuation or occurrence of mould growth. PLEL can only

[6] American Conference of Governmental Industrial Hygienists: Bioaerosols: Assessment and Control. J, Macher, Ed. ACGIH Cincinnati OH (1999).

comment on the environmental conditions observed on the date the assessment was performed. PLEL will not provide comment as to the presence or absence of contaminants other than those that were surveyed or sampled for, and at the locations investigated.

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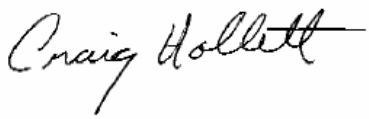
Pinchin LeBlanc Environmental Ltd.

Prepared By:



Craig Hollett, AScT

Indoor Air Quality/Industrial Hygiene

Reviewed By:

David Muise, OHST
Occupational Hygienist

APPENDIX I

LABORATORY CERTIFICATE

MYCOTAXON CONSULTING LTD.
3 Rockwood Ave.
Halifax, Nova Scotia
Canada B3N 1X4

PHONE: 902-475-1456

Fax: 902-475-1982

Mr. C. Hollett
Pinchin LeBlanc Environmental Ltd.
860 Topsail Rd.
Mount Pearl, NL
A1N 3J7

May 29, 2007

Dear Mr. Hollett:

Herewith are the results of the microscopic examination of the bulk samples from your project 02-7532, which were received by this laboratory on May 25, 2007.

SAMPLE	GENERA
1. plywood	active growth non-sporulating isolate Trichoderma sp. colonies

I hope this is helpful. If you have any questions concerning this report, please do not hesitate to contact me.

Sincerely yours,
Mycotaxon Consulting Ltd.
AIHA (EMPAT) Participating Laboratory

Per: Thomas G. Rand, Ph.D. Mycology, Public Works Canada Accredited Mycologist

PHOTOS

Photo 1 – Visible black mould on wooden studding and perimeter plywood sheeting – Crawl Space.

Photo 2 – Water stained ceiling– T V Washroom

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Insulator Replacements

Electrical
Mechanical
Civil
Protection & Control
Transmission & Distribution
Telecontrol
System Planning

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

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1 INTRODUCTION

In the 1960s and 1970s Newfoundland and Labrador Hydro (Hydro) was using Canadian Porcelain (CP) and Canadian Ohio Brass (COB) pin type and suspension type insulators in distribution line construction. Industry experience has shown the porcelain in these insulators is prone to failure caused by cement growth. Cement growth is the expansion of the material which holds in place the pin that supports the connection of the insulator to the pole or to the conductor. Cement growth causes hairline cracks to appear in the porcelain, thereby, weakening the insulator. This leads to electrical and mechanical breakdown. Over the past ten years, Hydro has been replacing CP and COB insulators with Hydro's new standard 34.5 kV Post type clamp top or 35kV Hendrix vise top and the suspension type insulators will be replaced with the new standard Polymer.

The Jackson's Arm Line 1 (L1) and Line 2 (L2) and the Hampden Line 1 (L1) distribution lines were built in 1968. Jackson's Arm L1 services the communities of Jackson's Arm, Wick's Cove, and Godfather's Cove while Jackson's Arm L2 services Schooner Cove, Sop's Arm, Burnt Head Cove, and Pollard's Point. Hampden L1 serves the communities of Hampden, Bay Side, and The Beaches and Rooms located in the vicinity of White Bay in the central area of Newfoundland.

The Little Bay Line 2 (L2) distribution line was built in 1974 and serves the community of Beachside.

2 PROJECT DESCRIPTION

The project will include the replacement of 2,270 insulators on the Jackson's Arm distribution feeders L1 and L2 and on the Hampden distribution feeder L1. It will also include the replacement of 270 insulators on the Little Bay distribution feeder L2.

3 EXISTING SYSTEM

Jackson's Arm L1 is a 12.5 kV three-phase feeder that extends from the Jackson's Arm Terminal Station to the community of Godfather's Cove covering a distance of approximately five kilometers and serving approximately 200 customers. Jackson's Arm L2 is also a 12.5 kV three-phase feeder that extends from the Jackson's Arm Terminal Station to the community of Pollards Point covering a distance of approximately 20 kilometers and serving approximately 300 customers.

Hampden L1 is a 12.5 kV three-phase feeder that extends from the Hampden Terminal Station to the community of The Beaches and Rooms covering a distance of 22 kilometers and serving approximately 300 customers.

Little Bay Line 2 is a 12.5 kV single-phase feeder that is approximately 6.2 kilometers long and extends from the Beachside substation to the community of Beachside. It serves approximately 100 customers.

The existing insulators were installed when the lines were first constructed, have deteriorated over time, and need to be replaced to ensure a reliable source of power to Hydro's customers.

3.1 Age of Equipment or System

Jackson's Arm L1, L2 and Hampden L1 were constructed in 1968 and Little Bay L2 was constructed in 1974.

3.2 Major Work or Upgrades

There have been no major upgrades on Jackson's Arm L1, Jackson's Arm L2 , Hampden L1, or Little Bay L2 since the installation of the lines.

3.3 Anticipated Useful life

The estimated service life of distribution feeders, for depreciation purposes, is 30 years.

3.4 Maintenance History

Table 1 shows the maintenance history for the Jackson's Arm, Hampden and Little Bay systems.

Table 1
Jackson's Arm, Hampden and Little Bay Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($ 000)
Jackson's Arm L1 and L2			
2007	5.3	12.6	17.9
2006	19.9	9.6	29.5
2005	19.5	25.3	44.8
2004	80.5	38.4	118.9
2003	11.9	20.6	32.5
Hampden L1			
2007	10.8	11.2	22.0
2006	7.7	21.6	29.3
2005	0.0	5.6	5.6
2004	0.4	1.2	1.6
2003	19.2	11.4	30.6
Little Bay L2			
2007	0.3	0.2	0.5
2006	0.9	0.7	1.6
2005	3.0	2.9	5.9
2004	10.1	1.8	11.9
2003	2.1	0.5	2.6

3.5 Outage Statistics

Hydro tracks all distribution system outages using industry standard indexes, System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). SAIDI and SAIFI 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 2 below lists the 2003 to 2007 average SAIFI and SAIDI data for the Jackson's Arm, Hampden and Little Bay systems, the 2003 to 2007 corporate values, and the latest CEA five-year average (2002 to 2006) for comparison.

These reliability statistics are not the justification for this project. The insulators on these distributions lines were identified as needing replacement during the last line inspections in 2006.

Table 2
SAIFI and SAIDI Five Year Average Indices (2003-2007)

	All Causes		Defective Equipment	
	SAIFI	**SAIDI**	**SAIFI**	**SAIDI**
Jackson's Arm System	4.69	15.94	0.75	4.42
Line 1	2.82	9.16	0.23	0.27
Line 2	5.93	20.46	1.10	7.19
Hampden System L1	2.89	6.63	0.22	0.94
Little Bay System	1.16	7.67	0.04	0.27
Line 2	0.64	7.06	0.11	0.74
Hydro Corporate	6.24	9.72	0.66	1.14
CEA (2002-2006)	2.35	6.43	0.98	2.14

3.6 Industry Experience

As explained in the introduction of this document, the utility industry has experienced widespread failure of CP and COB insulators.

3.7 Maintenance or Support Arrangements

A complete inspection of the Jackson's Arm L1 and L2, Hampden L1, and Little Bay L2 feeders is performed every nine years to evaluate the condition of the lines. The last inspection was performed in 2006. The inspection is completed by Hydro personnel and any corrective maintenance required is reported, scheduled and performed.

3.8 Vendor Recommendations

There are no specific vendor recommendations for this project. The existing pin type insulators will be replaced with Hydro's new standard 34.5kV post-type clamp top or 35kV Hendrix vise top and the suspension type insulator will be replaced with the new standard Polymer.

3.9 Availability of Replacement Parts

Availability of replacement parts is not a consideration for this project.

3.10 Safety Performance

Mechanical breakdown of the insulators is a safety issue for the line workers of Hydro. The insulators are prone to hairline cracking in the porcelain thus reducing their mechanical strength and increasing the chance of breaking during climbing activities by maintenance crews. This increases the potential for injuries to Hydro personnel.

3.11 Environmental Performance

Environmental performance is not a consideration for this project.

3.12 Operating Regime

The Jackson's Arm, Hampden and Little Bay feeders are in continuous operation providing power to approximately 900 customers.

4 JUSTIFICATION

The insulators used on these lines have been failing throughout the industry, due to cement growth causing radial cracking and weakening of the insulators. Replacement of these insulators is essential to improve system reliability.

4.1 Net Present Value

A Net Present Value calculation was not performed in this instance as only one viable alternative exists.

4.2 Levelized Cost of Energy

This project will have no effect on the levelized cost of electricity.

4.3 Cost Benefit Analysis

As there are no quantifiable benefits, a cost benefit analysis has not been performed.

4.4 Forecast Customer Growth

Customer load growth does not affect this project.

4.5 Energy Efficient Benefits

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

4.6 Legislative or Regulatory Requirements

There are no applicable legislative or regulatory requirements.

4.7 Historical Information

The table below lists insulator replacement projects in the last five years. Cost per unit has increased mainly due to increased contract labour costs.

4.8 Losses during Construction

There are no anticipated energy losses during construction.

Table 3
Five Year History of Insulator Replacement Projects - Cost per Unit

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2007	120.0	123.0	609	0.20	1 project
2006	1019.0	1041.1	4,691	0.22	4 projects
2005	971.7	453.8	4,340	0.10	3 projects
2004	856.5	553.1	4,023	0.14	3 projects
2003	833.5	535.3	3,468	0.15	4 projects

4.9 Status Quo

The status quo is not an acceptable alternative. The existing equipment is in a deteriorated condition. Failure to replace the identified insulators could result in an increase in the number outages of varying durations to the customers in the area. Deteriorated insulators pose a significant risk to regulated operations personnel with the potential of failure during climbing activities by line workers.

4.10 Alternatives

There are no viable alternatives to this upgrade work.

5 CONCLUSION

This project is required to ensure that a reliable energy supply is available for the customers served by the Jackson's Arm L1, L2, Hampden L1 and Little Bay L2 feeders.

5.1 Budget Estimate

The estimate for these projects to be completed in 2009 is $874,200. Jackson's Arm and Hampden insulator replacements will be completed as one project.

Table 4
Budget Estimate Jackson's Arm, Hampden and Little Bay

Project Cost:($ x1,000)	**Jackson's Arm & Hampden 2009**	**Little Bay 2009**	**TOTAL**
Material Supply	176.0	24.5	200.5
Labour	164.0	76.5	240.5
Consultant	0.0	0.0	0.0
Contract Work	185.5	36.0	221.5
Other Direct Costs	34.0	10.5	44.5
O/H, AFUDC & Escln	75.9	20.4	96.3
Contingency	56.1	14.8	70.9
TOTAL	**691.5**	**182.7**	**874.2**

5.2 Project Schedule

Table 5
Project Schedule

Activity	**Milestone**
Initiation	January 2009
Design Complete	March 2009
Equipment Ordered	April 2009
Installation Commences	July 2009
Installation Complete	August 2009
Project Closeout	September 2009

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

L'Anse au Loup Increase Generation

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

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1 INTRODUCTION

The L'Anse au Loup diesel system on the southern coast of Labrador services the entire Labrador Straits region from L'Anse au Clair to Red Bay. On the system, there are approximately 970 customers consuming over 16,000 MWh of electricity annually.

In September 1996, this diesel system was interconnected to a regionally isolated hydroelectric power system of Hydro-Québec, from which Hydro imports secondary energy. Under Hydro's criteria for firm capacity for isolated systems, forecast peak load should be met with the single largest unit out of service. With the interconnection to Hydro Québec's north shore and the resulting line capacity being treated as the largest unit on the system, the firm capacity on the L'Anse au Loup system is the installed capacity of the diesel plant. The diesel plant currently has five diesel units rated at 1,100, 1,000, and 800, and two 600 kW resulting in an installed capacity of 4,100 kW. The L'Anse au Loup diesel plant is shown in Figure 1 below.

Figure 1: L'Anse au Loup Diesel Plant

2 PROJECT DESCRIPTION

This project will replace existing Unit 247, a 600 kW diesel unit, with an 1,100 kW diesel unit; replace auxiliary equipment as necessary, including the unit's cooling system and fuel delivery system; and upgrade the unit's switchgear and the plant's ventilation system.

3 EXISTING SYSTEM

Unit 247 is a 600 kW Caterpillar D398. The total unit operating hours are 85,832 as of May 2008 and it has had six overhauls since it was installed in 1975. The last overhaul was completed in May 1996. As of May 2008, the unit has operated 2,714 hours since its last overhaul. The replacement of Unit 247 with a larger size unit is required to maintain the firm generating capacity of the plant in keeping with Hydro's generation planning criteria.

3.1 Age of Equipment or System

Unit 247, shown in Figure 2 below, was installed in 1975 and is 33 years old.

Figure 2: Unit 247

3.2 Major Work or Upgrades

There have been no major upgrades since the unit's installation.

3.3 Anticipated Useful life

Diesel generating units have an economic life of 20 years and an average service life of 25 years.

3.4 Maintenance History

The five-year maintenance history for Unit 247 is shown in Table1 below. While this unit has had six overhauls, the most recent overhaul was completed in 1996, prior to the history presented.

Table 1
Unit 247 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2007	0.8	0.0	0.8
2006	1.2	4.2	5.4
2005	1.2	0.3	1.5
2004	0.5	24.1	24.6
2003	1.7	1.8	3.5

3.5 Outage Statistics

Hydro does not currently maintain a diesel generating unit reliability database. Only outages which have a customer impact are recorded. The customer impact is recorded in the general category of loss of supply, which includes outages in addition to those caused by the unit to be replaced.

The CEA defines Loss of Supply as:

> *Customer interruptions due to problems in the bulk electricity supply system such as under frequency load shedding, transmission system transients, or system frequency excursions.*

Hydro uses this category to capture interruptions originating in the diesel plants.

Table 2 below lists the 2003 to 2007 average System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) for Loss of Supply caused outages for L'Anse Au Loup compared to the total Hydro isolated and complete systems.

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 2
Five-Year Averages (2003-2007) Interruption Indices

SYSTEM	All Causes		Loss of Supply	
	SAIFI	SAIDI	SAIFI	SAIDI
L'Anse au Loup	13.06	19.16	5.39	1.80
Total Hydro Isolated System	9.93	10.70	6.38	2.30
Total Hydro System	6.24	9.72	2.89	2.63
CEA (2002-2006)	2.64	7.61	0.46	0.98

3.6 Industry Experience

There is no relevant industry experience related to this project.

3.7 Maintenance or Support Arrangements

Maintenance on the diesel units in the L'Anse au Loup diesel plant is performed by Hydro Operations personnel from St. Anthony. Maintenance consists of scheduled preventative maintenance such as oil and filter changes, required corrective maintenance to repair failed components or to correct operational problems, and scheduled overhauls.

3.8 Vendor Recommendations

There are no vendor recommendations.

3.9 Availability of Replacement Parts

Replacement parts are readily available for this unit.

3.10 Safety Performance

There are no safety performance issues related to the unit replacement.

3.11 Environmental Performance

Engine emission improvements may be expected when replacing older units such as Unit 247 with more modern units, but they cannot be accurately quantified.

3.12 Operating Regime

The L'Anse au Loup diesel plant provides primary generation for 970 customers in the region from L'Anse au Clair to Red Bay. While secondary generation is provided by Hydro Québec, the diesel plant must have the capability to supply the electricity needs of these customers when the generation from Hydro Québec is not available.

4 JUSTIFICATION

This project is required to maintain Hydro's firm generation criterion which was established to maintain a reliable supply of power to customers served by isolated diesel plants.

The L'Anse au Loup system has experienced strong growth since its interconnection to the Hydro Québec system and subsequent application of Island Interconnected rates. Based on the most recent (June 2008) load forecast for the system, the peak load served by the L'Anse au Loup diesel plant will exceed plant firm capacity in 2009 and will exceed plant firm capacity by ten percent in 2013. Table 3 contains the Forecast Peak Load out to the year 2013.

Table 3
Forecast Peak Load

Year	2007 (Actual)	2008	2009	2010	2011	2012	2013
Peak Demand (kW gross)	4094	4108	4204	4296	4399	4447	4510
% of Firm Generation	100	100	103	105	107	109	110

The forecast peak load for 2008 exceeds the 4,100 kW capacity of the L'Anse au Loup diesel plant. Under Hydro's criteria for firm capacity for isolated systems, forecast peak load should be met with the single largest unit out of service. In the L'Anse au Loup system, the interconnection with Hydro Québec is deemed to be the largest unit. Therefore, unless the diesel plant is uprated, Hydro's firm generation criteria for this plant will be violated.

4.1 Net Present Value

A Net Present Value calculation has not been performed as only one viable alternative exists and that is to increase generation at L'Anse au Loup.

4.2 Levelized Cost of Energy

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

4.3 Cost Benefit Analysis

As there are no quantifiable benefits, a cost benefit analysis has not been performed.

4.4 Legislative or Regulatory Requirements

The justification of this project is not based on regulatory requirements.

4.5 Historical Information

This is not a recurring project; there is no historical information available.

4.6 Forecast Customer Growth

The L'Anse au Loup system has seen strong growth in electricity sales since its interconnection to Hydro Québec's Lac Robertson Hydro Electric Generating Station in September 1996 and the switch from Isolated Diesel to Island Interconnected rates in October 1996. With the recent upward trend in home heating oil prices and electricity rebates arising from the Provincial Government's Northern Strategic Plan, electric heat has been increasing its market share in domestic accounts resulting in increased sales. The actual and forecast increase in both demand and energy are shown in Tables 4 and 5 on page 9. In addition, preliminary work has begun on a new all-grade school in L'Anse au Loup to replace three existing schools in the Straits area. The planned timing of the new school is for the 2010 – 2011 school year. The forecast peak load is shown

in Table 3 in Section 4 of this document. As previously mentioned, it is expected that the peak load will exceed the L'Anse au Loup diesel plant firm capacity in 2008 and will exceed its firm capacity by ten percent in 2013.

Chart 1
Actual and Forecast Energy 1995 - 2013

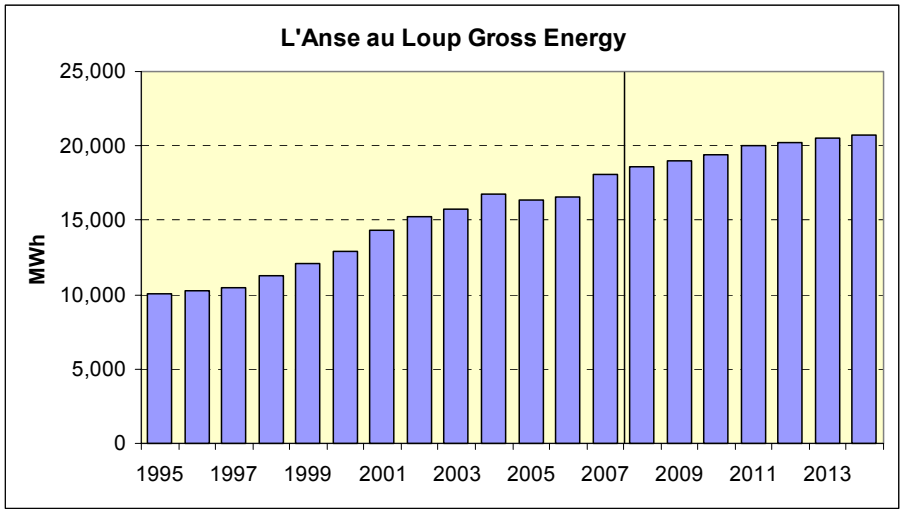
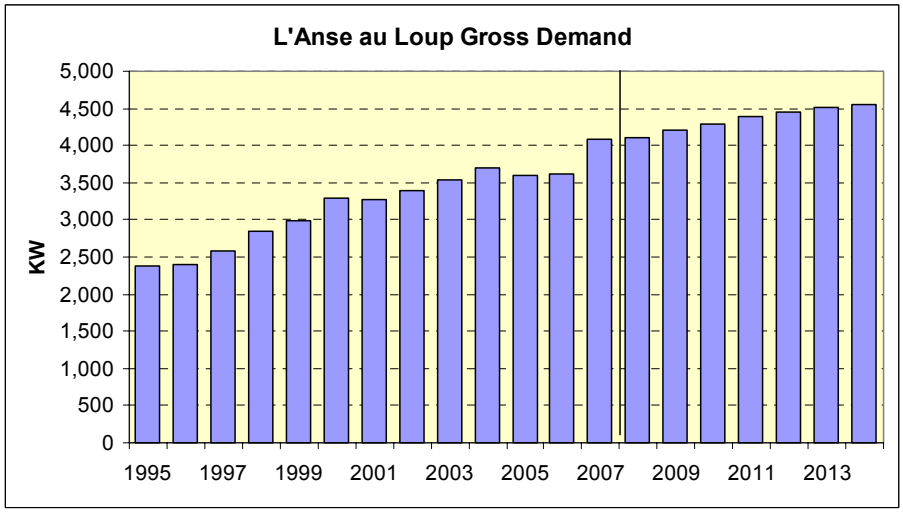


Chart 2
Actual and Forecast Demand 1995 - 2013



4.7 Energy Efficiency Benefits

Fuel efficiency improvements may be expected when replacing older units such as Unit 247 with more modern units but any such improvement cannot be accurately quantified.

4.8 Losses during Construction

Unit 247 will be replaced while the remaining units are available to generate power for the community. No losses during construction are anticipated.

4.9 Status Quo

Maintaining the status quo is not an option. If this unit is not replaced, the firm capacity of the L'Anse au Loup diesel plant will be insufficient to meet customer requirements.

4.10 Alternatives

There are no viable alternatives to replacing this diesel unit. While it is possible that future Conservation and Demand Management (CDM) activities may be able to mitigate load increases, it is not prudent to expect that peak demand could be reduced by 3 percent for the 2009 winter season. CDM results tend to be slower to accumulate than will be useful to delay or reverse the load growth trend being experienced in L'Anse au Loup.

5 CONCLUSION

This project is required to provide reliable electricity supply to the customers of the L'Anse au Loup diesel system. At this time, based on the operating load forecast, it is necessary to replace Unit 247 with a larger unit to ensure the generation needs of the L'Anse au Loup system are met beyond 2008 as demonstrated in Table 3.

5.1 Budget Estimate

As displayed in Table 4, the estimated cost of the replacement of Unit 247 in L'Anse au Loup is $843,700. The costs are spread over two years with diesel unit tender and award in 2009 and installation in 2010.

Table 4
Budget Estimate

Project Cost:($ x1,000)	**2009**	**2010**	**Total**
Materials Supply	0.0	462.3	462.3
Labour	20.0	125.7	145.7
Other Direct Costs	0.0	54.1	54.1
O/H, AFUDC, and Escalation	2.9	112.5	115.4
Contingency	0.0	66.2	66.2
TOTAL	22.9	820.8	843.7

5.2 Project Schedule

Table 5 outlines the planned project schedule.

Table 5
Project Schedule

Activity	Milestone
Project Initiation	February 2009
Equipment tender call	September 2009
Equipment tender award	November 2009
Installation	August 2010
Project Closeout	October 2010

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Replace Off-Road Track Vehicles Whitbourne and Bishop's Falls

NEWFOUNDLAND AND LABRADOR HYDRO

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1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) operates a fleet of heavy duty off-road tracked vehicles comprised of 26 muskeg type units and six mid-size excavators.

The heavy duty off-road fleet is strategically distributed across the transmission and distribution areas throughout the province and is utilized on a regular basis to support line maintenance staff engaged in the maintenance and repair of the transmission and distribution system.

2 PROJECT DESCRIPTION

This project proposes the replacements of two passenger cargo carrying units with dump capability stationed at the Bishop's Falls and Whitbourne line maintenance depots. The existing units are moved throughout the Hydro system by line maintenance crews. They are used to transport the crew and their materials to work sites along the various rights of way. The dump capability facilitates using the units to transport material and backfill when the line work requires installation of tower footings, anchors or poles.

This proposal is to replace the units with similarly configured units, with the addition of a material handling boom. The boom will enhance the efficiency of the unit, by allowing it to also serve as a heavy lifting unit.

As this project relates to the replacement of mobile equipment, there is no relevant data related to:

- Outage Statistics;
- Safety Performance;
- Environmental Performance; or
- Operating Regime.

3 EXISTING SYSTEM

3.1 Age of Equipment or System

Muskeg Unit 7676 is 20 years old. Muskeg Unit 7941 is ten years old and was destroyed by fire in December 2007 while in use to restore a downed tower structure on transmission line TL-212.

3.2 Anticipated Useful Life

The anticipated useful life for muskegs is ten years.

3.3 Maintenance History

Table 1
Five-Year Maintenance History Unit 7676

Year	Preventative Maintenance ($000)	Corrective Maintenance ($000)	Totals ($000)
2007	0.6	3.9	4.5
2006	1.7	20.1	21.8
Q2005	1.2	5.7	6.9
2004	0.8	6.2	7.0
2003	0.8	7.4	8.2

Table 2
Five-Year Maintenance History Unit 7941

Year	Preventative Maintenance ($000)	Corrective Maintenance ($000)	Totals ($000)
2007	0.3	4.2	4.5
2006	1.0	0.1	1.1
2005	1.9	0.8	2.7
2004	1.1	2.5	3.6
2003	1.1	0.0	1.1

4 INDUSTRY EXPERIENCE

Heavy duty off-road equipment is a standard component of any electric utility maintenance fleet which has to maintain transmission or distribution lines in remote areas. The replacement criteria across the Canadian Utility Industry varies depending location, exposure to harsh environmental conditions and the number of the service hours for the equipment. While some variances exist, it is generally the case that this type of equipment is replaced in a 15 to 20-year time frame depending on its functionality and condition. The criterion utilized by Hydro is to consider units which are 15 years old, then evaluate maintenance costs and technological issues. Units which meet the age requirement and warrant replacement are then included in the proposals.

4.1 Maintenance or Support Arrangements

The Hydro fleet of off-road tracked vehicles are primarily maintained by in-house mechanical maintenance personnel. Outside maintenance garages are utilized when the required maintenance is within the expertise of local garages.

4.2 Availability of Replacement Parts

Replacement parts are usually available for these units, however as they age and become more obsolete delays in sourcing replacement parts are common.

5 JUSTIFICATION

Regulated Operations maintains 3,742 kilometers of transmission lines and 3,334 kilometers of distribution lines throughout the electrical system, much of which is located in remote areas inaccessible to wheeled vehicles. Heavy off-road tracked equipment is essential to the line crews in accessing these lines for inspections and to perform planned or emergency maintenance.

Hydro operates in many diverse locations across the province and it is critical to the ability to provide economical and reliable electricity that employees are provided with safe and reliable equipment.

This proposal provides for the normal replacement of two heavy duty off-road vehicles due to their ages and condition and will provide the operators with more efficient and ergonomically designed units. Unit 7676 is very noisy, uncomfortable to ride in and unbearably hot in warmer weather. Current model units are improved significantly from the older units in that they are equipped with hydro static drive, spring suspension seating, safety interlocks on the doors to prevent operating with the doors ajar and air conditioning. Unit 7941 was destroyed by fire.

As this project relates to the replacement of mobile equipment, there is no relevant data related to:

- Levelized Cost of Energy;
- Legislative or Regulatory Requirements;
- Forecast Customer Growth;
- Energy Efficiency Benefits; or
- Losses during Construction.

5.1 Historical Information

Historical information is not applicable in this instance as this is a stand alone proposal to replace a unit which has been in service for 20 years and a ten year old unit which was destroyed by fire.

5.2 Status Quo

Failure to replace these units will lead to increasing downtime and maintenance costs and will result in employees being exposed to undesirable ergonomic conditions. Hydro employees maintain the electrical system and require dependable, comfortable and safe vehicles for their work. Continued operation of these units could negatively affect response times for emergency outages or planned maintenance.

5.3 Alternatives

This type of equipment is essential to line maintenance activity and there are no known alternatives.

5.4 Budget Estimate

The following table shows the budget estimate.

Table 3
Budget Estimate

Project Cost:($ x1,000)	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	660.0	0.0	0.0	660.0
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
O/H, AFUDC & Escln	31.8	0.0	0.0	31.8
Contingency	66.0	0.0	0.0	66.0
TOTAL	**757.8**	**0.0**	**0.0**	**757.8**

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Pole Replacement

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1 INTRODUCTION

Blackjack poles, tar coated for preservation, were commonly used in distribution line construction in the 1960s and 1970s. Many of these poles are still in use throughout Newfoundland and Labrador Hydro's (Hydro) system and they are coming to the end of their useful lives. Blackjack poles are no longer environmentally acceptable because of their coating.

Each year, during line inspections, Hydro identifies poles which are near the end of their useful lives and schedules them for replacement. During the 2006 inspection of the Jackson's Arm and Hampden distribution lines, 76 Blackjack poles were identified for replacement.

The Jackson's Arm Line 1 (L1) and Line 2 (L2) and the Hampden Line 1 (L1) distribution lines were built in 1968. Jackson's Arm L1 services the communities of Jackson's Arm, Wick's Cove, and Godfather's Cove while Jackson's Arm L2 services Schooner Cove, Sop's Arm, Burnt Head Cove, and Pollard's Point. Hampden L1 services the communities of Hampden, Bay Side, The Beaches and Rooms.

As a separate project for 2009, Hydro will be replacing 2,270 insulators on the Jackson's Arm and Hampden distribution lines. The projects were kept separate for several reasons. The completion of the two projects requires different crews of tradespersons and types of equipment. The poles are in various areas along the line and equipment will be moved several times during the project while equipment for the insulator replacements will be gradually moved along the line as the project progresses. The poles must be in place before the insulators are changed and can be installed well ahead of the insulators. Electrical equipment will be moved from the old to new poles during the insulator replacement project and the old poles will be removed at a later date. Pole replacements do not require outages on the distribution feeders.

2 PROJECT DESCRIPTION

This project is required to replace 46 deteriorated poles on the Jackson's Arm distribution feeders L1 and L2 and 30 deteriorated poles on the Hampden distribution feeder L1.

3 EXISTING SYSTEM

Jackson's Arm L1 is a 12.5 kV three-phase feeder that extends from the Jackson's Arm Terminal Station to the community of Godfather's Cove covering a distance of approximately five kilometers and serving approximately 200 customers. Jackson's Arm L2 is also a 12.5 kV three-phase feeder that extends from the Jackson's Arm Terminal Station to the community of Pollards Point covering a distance of approximately 20 kilometers and serving approximately 300 customers.

Hampden L1 is a 12.5 kV three-phase feeder that extends from the Hampden Terminal Station to the community of The Beaches and Rooms covering a distance of 22 kilometers and serving approximately 300 customers. See Figure 1 below.

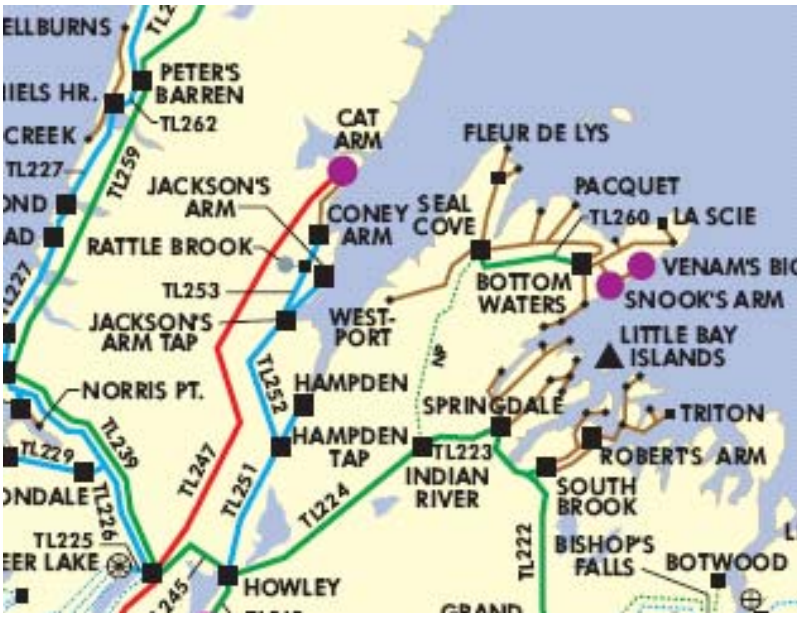

Figure 1: Map of Jackson's Arm Distribution System

The project consists of the replacement of 76 deteriorated poles. Figures 2 and 3 show typical deteriorated Blackjack poles.

Figure 2: Typical Deteriorated Blackjack Pole

Figure 3: Close-up of Blackjack Deterioration

3.1 Age of Equipment or System

The Jackson's Arm and Hampden feeders were constructed in 1968 and the blackjack poles were installed at that time.

3.2 Major Work or Upgrades

There has been no major work since the installation of the line.

3.3 Anticipated Useful life

The estimated service life of a distribution feeder, for depreciation purposes, is 30 years.

3.4 Maintenance History

Table 1 shows the maintenance history for the Jackson's Arm, Hampden and Little Bay for the last five years.

Table 1
Jackson's Arm, Hampden and Little Bay Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($ 000)
Jackson's Arm L1 and L2			
2007	5.3	12.6	17.9
2006	19.9	9.6	29.5
2005	19.5	25.3	44.8
2004	80.5	38.4	118.9
2003	11.9	20.6	32.5
Hampden L1			
2007	10.8	11.2	22.0
2006	7.7	21.6	29.3
2005	0.0	5.6	5.6
2004	0.4	1.2	1.6
2003	19.2	11.4	30.6

3.5 Outage Statistics

Hydro tracks all distribution system outages using industry standard indexes, System Average Interruption Frequency Index (SAIFI), and System Average Interruption Duration Index (SAIDI). SAIDI and SAIFI 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 2 below lists the 2003 to 2007 average SAIFI and SAIDI data for the Jackson's Arm and Hampden systems; the 2003 to 2007 corporate values; and the latest CEA five-year average (2002 to 2006) for comparison.

Table 2
SAIFI and SAIDI Five-Year Average Indices (2003 to 2007)

	All Causes		Defective Equipment	
	SAIFI	**SAIDI**	**SAIFI**	**SAIDI**
Jackson's Arm System	4.69	15.94	0.75	4.42
Line 1	2.82	9.16	0.23	0.27
Line 2	5.93	20.46	1.10	7.19
Hampden System L1	2.89	6.63	0.22	0.94
Hydro Corporate	6.24	9.72	0.66	1.14
CEA (2002-2006)	2.35	6.43	0.98	2.14

These reliability statistics are not the justification for this project. During the last line inspections in 2006, the poles to be replaced in this project were identified as having one to five years of life remaining.

3.6 Industry Experience

Using a standardized grading system (see Section 4), the poles to be replaced have been identified as close to the end of useful life.

3.7 Maintenance or Support Arrangements

A complete inspection of the Jackson's Arm and Hampden feeders is performed every nine years to evaluate the condition of the line. This inspection is completed by regulated operations personnel and any corrective maintenance required is reported, scheduled, and performed.

3.8 Vendor Recommendations

There are no vendor recommendations for this project.

3.9 Availability of Replacement Parts

Availability of replacement parts is not a consideration for this project

3.10 Safety Performance

The deteriorated poles create safety hazards such as spur kick-out and/or pole failure during climbing activities by line workers.

3.11 Environmental Performance

Although there are no specific regulations regarding Blackjack poles, they are coated with tar as a preservative and are considered to be environmentally unacceptable. Blackjack poles have been removed from the market.

3.12 Operating Regime

The Jackson's Arm and Hampden feeders are in continuous operation supplying power to approximately 800 customers.

4 JUSTIFICATION

Hydro performs regular inspections on all distribution poles classifying them using a standardized grading system. The grading system is as follows:

- “A” Condition: excess of five years of life remaining;
- “B” Condition: one to five years of life remaining; and
- “C” Condition: less than one year of life remaining.

During the 2006 inspection, 46 poles on Jackson’s Arm L1 and L2 and 30 poles on Hampden L1 were identified as being in "B" condition and were scheduled for replacement in 2009.

4.1 Net Present Value

A Net Present Value calculation was not performed as there are no viable alternatives.

4.2 Levelized Cost of Energy

This project will have no effect on the levelized cost of electricity.

4.3 Cost Benefit Analysis

A Cost Benefit Analysis was not performed as there are no quantifiable financial benefits.

4.4 Forecast Customer Growth

Customer load growth does not affect this project.

4.5 Energy Efficient Benefits

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

4.6 Legislative or Regulatory Requirements

There are no applicable legislative or regulatory requirements.

4.7 Historical Information

Table 3 shows the history of pole replacement projects in the last five years. The cost per unit has increased mainly due to increased contract labour costs.

Table 3
Five-Year History of Pole Replacement Projects - Cost per Unit

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2007	389.0	451.4	95	4.8	2 projects
2006	152.4	166.5	30	5.6	1 project
2005	167.9	126.6	39	3.2	1 project
2004	864.0	748.6	257	2.9	2 projects
2003	852.0	677.5	180	3.8	4 projects

4.8 Losses during Construction

There are no anticipated energy losses during construction.

4.9 Status Quo

The status quo is not an acceptable alternative. The poles included in this project have exceeded their useful lives, are in deteriorated condition and must be replaced. Failure to replace the identified poles could result in continuing outages of varying durations to the customers it services. Deteriorating pole conditions pose a significant risk to regulated operations personnel because the line is not accessible to regulated operations vehicles and personnel must climb the structures to perform maintenance.

4.10 Alternatives

There are no viable alternatives to this upgrade work.

5 CONCLUSION

This project is required in order to ensure that a reliable energy supply is available for the customers served by the Jackson's Arm and Hampden distribution systems.

5.1 Budget Estimate

The estimate for this project, to be completed in 2009, is $696,800.

Table 4
Budget Estimate Jackson's Arm and Hampden

Project Cost:($ x1,000)	**Jackson's Arm 2009**	**Hampden 2009**	**TOTAL**
Material Supply	57.0	40.0	97.0
Labour	129.0	83.5	212.5
Consultant	0.0	0.0	0.0
Contract Work	133.0	70.5	203.5
Other Direct Costs	31.5	18.5	50.0
O/H, AFUDC & Escln	48.1	29.2	77.3
Contingency	35.1	21.4	56.5
TOTAL	**433.7**	**263.1**	**696.8**

5.2 Project Schedule

Table 5
Project Milestones

Activity	**Milestone**
Initiation	February 2009
Design Complete	March 2008
Equipment Ordered	April 2008
Installation Commences	September 2009
Installation Complete	September 2009
Project Closeout	October 2009

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Upgrade Distribution Feeder
St. Anthony Line 7

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

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1 INTRODUCTION

Each year Newfoundland and Labrador Hydro (Hydro) carries out inspections of its distribution lines. These inspections result in various projects to correct deficiencies in the lines. For some lines, this may mean replacing a few pieces of equipment such as poles, crossarms, or transformers. In other instances, it results in doing a complete upgrade of sections of the line. The project in this report falls into this category.

This project is required to upgrade portions of the St. Anthony Line 7 (L7) distribution line which serves approximately 200 customers in the communities of Cook's Harbour; Boat Harbour; and the Pistolet Bay cabin area on the Great Northern Peninsula.

2 PROJECT DESCRIPTION

The current project will include the replacement of approximately 46 blackjack poles, 660 pin type insulators, 220 suspension insulators, 70 cutouts and 48 spans of three-phase #2 ACSR primary conductor.

3 EXISTING SYSTEM

Typical deteriorated Blackjack poles and insulators are shown in Figures 1 and 2.

Figure 1: Typical Deteriorated Pole, Insulators, and Crossarm

Figure 2: Deteriorated Blackjack Pole

St. Anthony L7 is a 12.5 kV three-phase feeder that extends from the Cook's Harbour substation to the community of Boat Harbour, a distance of approximately 30 kilometers, and serves approximately 200 customers. This line has blackjack poles, old

pin type and suspension type insulators, and #2 ACSR conductor that were installed when the original line was built.

3.1 Age of Equipment or System

The St. Anthony L7 feeder was built in 1968.

3.2 Major Work or Upgrades

Table 1 shows major upgrades that have occurred on St. Anthony in the last five years.

Table 1
St. Anthony Line 7 Major Work/Upgrades

March 2005	Upgrade seven kilometers of line
Sept 2005	Relocate portion of line
Sept 2005	Relocate 14 poles
Dec 2005	Re-route portion of line for causeway
March 2006	Install 13 poles for causeway re-route

3.3 Anticipated Useful life

The service life of a distribution feeder is 30 years.

3.4 Maintenance History

A complete inspection of the line is completed every eight years and corrective and/or preventative maintenance is completed as required.

Table 2 shows the maintenance history for St. Anthony Line 7 in the past five years.

Table 2
Maintenance History for St. Anthony L7

St. Anthony L7	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($ 000)
2007	8.9	10.1	19.0
2006	15.4	11.0	26.4
2005	46.8	12.6	59.4
2004	18.0	18.2	36.2
2003	26.6	13.6	40.2

3.5 Outage Statistics

Hydro tracks all distribution system outages using industry standard indexes: System Average Interruption Frequency Index (SAIFI); and System Average Interruption Duration Index (SAIDI). SAIDI and SAIFI 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 2003 to 2007 SAIFI and SAIDI data for St. Anthony L7; the 2003 to 2007 corporate values; and the latest CEA five-year average (2002 to 2006) for comparison.

Table 3

SAIFI and SAIDI Five-Year Averages (2003 – 2007)

	All Causes		Defective Equipment	
	SAIFI	**SAIDI**	**SAIFI**	**SAIDI**
St. Anthony System	5.80	10.92	1.09	1.85
Line 7	10.42	33.34	1.53	4.54
Hydro Corporate	6.24	9.72	0.66	1.14
CEA (2002-2006)	2.35	6.43	0.98	2.14

The five-year average SAIDI and SAIFI indices for Line 7 are well above the corporate averages and are expected to improve with the upgrade.

3.6 Industry Experience

Using a standardized grading system (see Section 4), the poles to be replaced have been identified as close to the end of useful life. The insulators to be replaced are Canadian Porcelain and Canadian Ohio Brass insulators. The insulators are either pin type or suspension type and both have a history of failure because of cement growth. Cement growth is the expansion of the material which holds in place the pin that supports the connection of the insulator to the pole or to the conductor. Cement growth causes hairline cracks to appear in the porcelain and weakens the insulator. This leads to electrical and mechanical breakdown.

3.7 Maintenance or Support Arrangements

A visual inspection of distribution feeders is performed every eight years to evaluate the condition of the line. This inspection is completed by Hydro personnel and any corrective maintenance required is reported, scheduled and completed.

3.8 Vendor Recommendations

There are no specific vendor recommendations for this project.

3.9 Availability of Replacement Parts

Availability of replacement parts is not a consideration for this project.

3.10 Safety Performance

The deteriorated insulators and poles may break while operations personnel are performing climbing activities and result in falls and/or injuries.

3.11 Environmental Performance

Although there are no specific environmental regulations regarding the use of Blackjack poles, because they are coated in tar they are considered to be environmentally unacceptable and are no longer available from suppliers. The poles are being replaced by Hydro as needed.

3.12 Operating Regime

St. Anthony L7 is in continuous operation providing power to approximately 200 customers in the communities of Cook's Harbour, Boat Harbour and the Pistolet Bay cabin area.

4 JUSTIFICATION

Hydro performs inspections on all distribution poles classifying them using a standardized grading system. The grading system is as follows:

- “A” Condition: excess of 5 years of life remaining;
- “B” Condition: 1 to 5 years of life remaining; and
- “C” Condition: less than 1 year of life remaining.

The deteriorated poles were classified as "B" condition during the last inspection and scheduled to be replaced in 2009.

The insulators have a history of failure due to cement growth breakdown and hairline cracks of the porcelain which results in electrical and mechanical breakdown. During inspections, S & C Electric Company brand name porcelain cutouts were identified as needing to be replaced due to safety hazards, such as breaking when being opened or closed.

The #2 ACSR conductor does not meet Hydro’s minimum standard of 1/0 AASC conductor for distribution feeders.

4.1 Net Present Value

A Net Present Value calculation was not performed in this instance as only one viable alternative exists.

4.2 Levelized Cost of Energy

This project will have no effect on the levelized cost of electricity.

4.3 Cost Benefit Analysis

As there are no quantifiable benefits, a cost benefit analysis has not been performed.

4.4 Forecast Customer Growth

Customer load growth does not affect this project.

4.5 Energy Efficient Benefits

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

4.6 Legislative or Regulatory Requirements

There are no applicable legislative or regulatory requirements.

4.7 Historical Information

A distribution line upgrade consists of the replacement of many different types of equipment such as conductor; poles; insulators; transformers; guy wires; and any other associated hardware. A line could cover several kilometers or only a few. Because of the variety in line lengths and equipment, unit costs for a particular job are not available. Table 4 below lists budgeted and actual costs for line upgrades in the last five years.

Table 4
Distribution Upgrading

Year	Project Description	Budget ($000)	Actuals ($000)
2008F	Upgrade Distribution System - L1 Glenburnie	533.9	
	Upgrade Distribution System - L3 St Anthony	480.1	
	Upgrade Distribution System - Mary's Harbour	263.5	
	Upgrade Distribution System - Port Hope Simpson	205.4	
	Upgrade Distribution System - L4 Bear Cove	149.8	
	Upgrade Distribution Line - L11 Wabush	107.2	
2007	Upgrade Distribution System - L2, L3 Farewell Head	385.3	282.0
	Upgrade Distribution System - L1, L2 St. Anthony	364.3	301.0
	Upgrade Distribution System L1, L2 Rocky Harbour	513.5	393.7
	Upgrade Distribution System - Nain	179.4	185.8
2006	Upgrade Distribution System - Black Tickle	281.8	270.3
	Upgrade Distribution System - L6 St. Anthony	778.3	772.2
	Upgrade Distribution System - L6 Bear Cove	577.7	622.8
	Upgrade Distribution System - L1, L3 Hawkes Bay	379.6	421.1
2005	Upgrade Distribution Line - Northern L'anse au Loup	93.1	50.5
	Upgrade Distribution System - L1, L2 L'anse au Loup [1]	635.6	280.6
	Upgrade Distribution Line - Cooks Harbour	717.5	477.8
2003	Upgrade Distribution System - Little Bay	317.2	293.8
	Upgrade Distribution Line - Pass Island	48.0	65.9

[1] This project was an upgrade to L'Anse au Loup distribution lines 1 and 2. Part of the original project was to replace structures crossing the Forteau River. Due to problems obtaining the necessary permits from the Department of Environment, this portion of the job was not completed. A reduction in costs was also achieved by reassessing the need to replace all automatic splicing sleeves on the lines. Overall reduction in the project cost was $355,000.

4.8 Losses during Construction

There are no anticipated energy losses during construction.

4.9 Status Quo

The status quo is not an acceptable alternative. The existing system has exceeded its useful life and is in a deteriorated condition. Failure to upgrade the existing feeder could increase the number of outages of varying durations to the customers it serves. Deteriorated pole conditions and failing insulators and cutouts pose a significant risk to regulated operations personnel during climbing activities.

4.10 Alternatives

There are no viable alternatives to this upgrade work.

5 CONCLUSION

This project is required to ensure that a reliable energy supply is available for the customers served by the St. Anthony L7 feeder.

5.1 Budget Estimate

The estimate for the project is $689,300. The project is a single-year project to be completed in 2009. Table 5 below summarizes the costs.

Table 5
Budget Estimate

Project Cost:($ x1,000)	**2009**	**2010**	**TOTAL**
Material Supply	147.5	0.0	147.5
Labour	131.0	0.0	131.0
Consultant	0.0	0.0	0.0
Contract Work	248.0	0.0	248.0
Other Direct Costs	31.5	0.0	31.5
O/H, AFUDC & Escln	75.4	0.0	75.4
Contingency	55.9	0.0	55.9
TOTAL	**689.3**	**0.0**	**689.3**

5.2 Project Schedule

Table 6
Project Schedule

Activity	**Milestone**
Initiation	February 2009
Design Complete	March 2009
Equipment Ordered	May 2009
Installation Commences	June 2009
Installation Complete	August 2009
Project Closeout	September 2009

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Upgrade Power Transformers

Electrical
Mechanical
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1 INTRODUCTION

Newfoundland and Labrador Hydro's (Hydro's) Power Transformer Upgrading project is being initiated to either extend the life of existing power transformers or replace units meeting the replacement criteria outlined in Section 2 of this report. Many transformers have been in service for more than 30 years (see Section 3.1). As they age, they are approaching the at-risk phase of their life cycle.

Hydro has 54 terminal stations in the Island Interconnected System and three in the Labrador Interconnected System. The terminal stations contain a total of 114 power transformers. Table 1 provides the number of transformers for each transformer rating.

Table 1
Transformer Rating

Transformer Rating (kV)	# of Transformers
230/138	13
230/69	4
230/66	14
230/46	9
230/16	4
230/13.8	14
230/6.9	1
138/69	2
138/66	5
138/25	7
138/13.8	2
138/12.5	2
69/25	8
69/13.8	1
69/12.5	1
69/4.16	5
66/25	4
66/13.8	2
66/12.5	7
66/7.2	2
66/6.9	3
66/4.16	1
66/0.6	3

Power transformers serve a very critical function to the power system. At the generating stations, transformers are referred to as step up transformers. They step up the voltage for power transmission from the generation source voltage to the line voltage. The voltage is stepped up to reduce the current and thereby reduce the transmission losses. At a terminal or substation, step down power transformers are used to convert the voltage down to distribution voltage levels suitable for delivery to end users. Figure 1 shows a picture of the power transformer T3 at Massey Drive.

The basic components of a power transformer are the steel tank, bushings, core, windings, clamping assembly and insulation system (oil and cellulose paper). The tank houses all the components of the transformer while the bushing acts as an interface between the internal winding conductors and the outside high voltage network. The purpose of the core and windings is to provide the voltage conversion. The transformer oil acts to insulate the windings from ground potential and also provides cooling. The cellulose paper is used to insulate the windings against turn to turn faults and the clamping assembly is required to secure the winding during short circuit magnetic forces.

The aging of the transformer is essentially aging of the insulation system. This aging process reduces both the mechanical and dielectric strength of the transformer. When older transformers are subjected to faults the chance of survival is less relative to newer units. Also, as load is increased on a power transformer the operating temperature is increased which, over time, negatively impacts the cellulose paper strength. The winding insulation can be weakened to the point where it can no longer sustain the mechanical stresses of a fault.

Figure 1: Power Transformer T3 at Massey Drive

2 PROJECT DESCRIPTION

With the power transformer being a critical and a high-cost capital asset, Hydro, like many North American utilities, has been working to maximize the life of its service units. In recent years, there has been a significant effort by Hydro to deal with power transformer problems resulting from their age and/or condition. Such problems include:

- Quality of transformer oil;
- Condition of coolers (radiators);
- Condition of on load tap changers;
- Leaking transformer bushings;
- Failure of protective devices such as gas relays, winding temperature devices and oil level equipment; and
- Leaking transformer gaskets.

The main objective for this project is to take a strategic approach to address all transformer issues collectively as opposed to individual projects. The intention is to utilize known information from the six problem areas stated above to execute a transformer upgrade or a complete replacement.

A transformer replacement will be based on the following criteria:

- Degree of Polymerization (DP) of cellulose insulation paper less than 400[1] (see table in Appendix C). Using a transformer oil sample, specialized laboratories can perform what is known as a Furan Analysis of the oil. As the cellulose paper insulation ages, furanic compounds are released into the oil. Based on the level of furanic compound, a 'DP' number is inferred. New transformers have a DP number of more than 1000. While transformers near the end of their service life show DP numbers of 200 or less.

[1] Hydro has chosen 400 as the target to allow adequate time to plan a replacement before the threshold of 200 is met.

- Significant combustible gas generation in the transformer oil indicates an internal fault is developing. The gas generation rate is regularly recorded by performing a Dissolved Gas Analysis (DGA) from an oil sample.

Currently, there are no units that meet these criteria. However, it can be seen from Appendix C, Transformer T7 at Bay d'Espoir was showing DP levels below 400 in 2005, and this unit is due for replacement in 2012.

It is typically more cost effective and reliable to replace power transformers in a planned mode rather than a reactive mode. Hydro will replace transformers as the DP number becomes less than 400 within a three to five-year window. This will provide the necessary lead time to purchase and schedule the installation during the most appropriate system outage window. Currently, the lead and delivery time for power transformers is 18 to 24 months after receipt of order. Recent industry experience indicates this lead time may continue to increase.

3 EXISTING SYSTEM

This project is required to upgrade or replace aging power transformers currently in service for Hydro.

3.1 Age of Equipment or System

Currently 52 percent of the power transformers on the Hydro system are greater than 30 years old and 11 units are at 42 years of age. Figure 2 below shows the age distribution for Hydro's transformers rated 66 kV and greater.

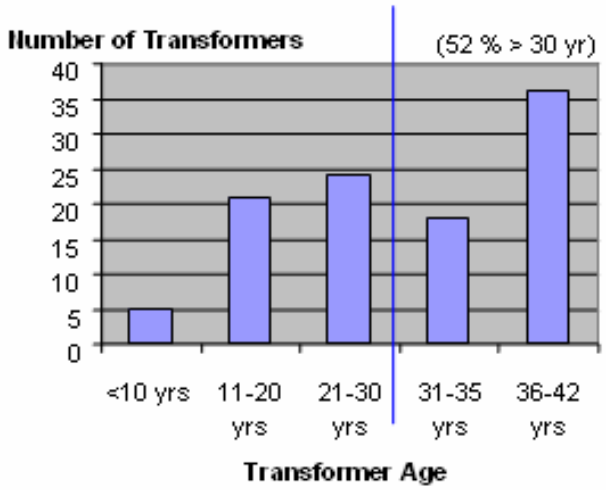

Figure 2: Transformer Age Distribution (66 kV and above)

3.2 Major Work or Upgrades

There have been no major capital upgrades to the power transformer fleet. Work has been confined to regular maintenance and inspections, with minor operational type repairs as discussed below.

3.2.1 Quality of Oil

As a transformer ages sludge begins building up on the windings inside the power transformer tank. This is a result of the chemical reaction between oxygen, oil and a small amount of moisture. As the chemical process takes place, oxygen inhibiter is depleted and acidity of the oil begins to rise. This results in the color of the oil being darker and the electrical insulating properties of the oil being lowered. If this process were left without intervention, the acidity would attack the cellulose insulating paper causing it to be brittle. If the insulating paper becomes weakened, there is a very high probability for failure due to failure of the mechanical strength of the paper. Transformers in this condition will have a low DP number.

After tracking oil quality data for a number of years, the acidity on several units was discovered to be outside the Institute of Electrical and Electronic Engineers (IEEE) Standard 637 oil quality guideline and Hydro decided to reclaim power transformer oil. This reclaiming process is able to bring aged oil back to within oil quality parameters similar to new oil. Figure 3 shows the visual change in oil color as it is reclaimed from start to finish, with the darkest being the start and the clearest being the end of the process. Table 2 outlines the work completed in this area to date. It is also important to note that in 2005 an in-house transformer ranking tool was developed (see Appendix D) to prioritize units for reclamation based upon selectable oil quality values and criticality within the Island Interconnected System.

Figure 3: Reclaimed Oil – Start (left) to Finish (right)

Table 2
List of oil reclamation work completed in recent years

Year	Major Work/Upgrade	Comments
2007	Reclaimed Transformer T2 at Grand Falls and T2 at Cat Arm	Completed work with in-house staff using Hydro's Fluidex Reclamation unit
2006	Reclaimed Transformer T1 at Grand Falls	Completed work with in-house staff using new Fluidex technology oil Reclamation unit
2004	Reclaimed Transformer T1 at Upper Salmon and T2 at Bay d'Espoir	External contractor reclaimed power transformer using fuller earth technique at a cost of $90,000
2003	Reclaimed Transformers T1, T3 and T7 at Bay d'Espoir	ABB reclaimed 3 power transformers, at a cost of $200,000 using a Fluidex technology.

3.2.2 Work Completed on Radiators

Historically radiators were manufactured from painted carbon steel and Newfoundland and Labrador's environmental conditions have resulted in corrosion causing damage beyond repair. In some cases, this damage has lead to oil leaks. Figure 4 shows radiators being replaced at Bottom Waters. Table 3 shows a list of work completed with transformer radiators in recent years.

Figure 4: Radiators Being Replaced at Bottom Waters

Table 3
List of Work Completed With Transformer Radiators In Recent Years

Year	Major Work/Upgrade	Comments
2008	Order placed to replace radiators on T1 at Farewell Head	Work is planned to be completed in September 2008
2007	Remove four radiators from Transformer T1 at Stephenville.	Radiators were leaking and after reviewing the load profile it was decided to remove four of 16 radiators.
2007	Replaced radiators on T1 transformer at Bottom Waters	Radiators were leaking and had to be replaced on an unbudgeted job.
2007	Completed a condition assessment for all power transformers in the TRO Central Region	See table in Appendix A showing ranking and proposed schedule for replacement.
2007	Purchased five radiators for T2 at Holyrood.	Due to a delivery problem the radiators are planned to be installed in 2008.
2006	Replaced radiators on transformer UST2 at Holyrood.	Radiators were leaking.
2005	Purchased new radiators for 230 kV Spare Unit Transformer for Holyrood.	Placed in storage to prevent corrosion.

3.2.3 Work Completed With On Load Tap Changers

In 2006, Hydro implemented a new maintenance philosophy for on load tap changers. On load tap changers are required to change the position of the winding inside the transformer to maintain acceptable customer voltages. To do this, moving components, which wear over time, are required. To measure this wear, an oil sample is taken to analyze the oil quality and particle count. This is a non-intrusive method to determine the condition of the internal parts of the tap changer. Sampling in 2006 revealed the poorest on load tap changer was on Transformer T3 at Massey Drive in Corner Brook. The manufacturer representative was brought to the site in 2007 and the tap changer was removed and overhauled. Figures 5 and 6 show the condition of the on load tap changer prior to and after refurbishment. The next steps are to follow the recommendations as outlined in the table in Appendix B.

Figure 5: Before Overhaul

Figure 6: After Overhaul

3.2.4 Bushing Replacements

In recent years, bushings have been replaced mainly due to leaks and poor Doble (high voltage insulation test) readings. In future, besides replacing leaking units, Hydro will also have to replace units to ensure all bushings containing PCBs are removed from service by 2025. Table 4 contains a listing of transformer bushing replacement in recent years.

Table 4
List of Transformer Bushing Replacements In Recent Years

Year	Major Work/Upgrade	Comments
2007	Replaced three Low Voltage (15 kV) high current bushings on T1 at Bay d'Espoir	Replaced units due to bushing leaks. Cost per unit was $15,000.
2007	Replaced one Low Voltage (15 kV) high current bushing on T1 at Upper Salmon	Replaced unit due to bushing leaks. Cost was $25,000. The cost was elevated due to problems going back online. (Gas relay operation)
2006	Replaced three 15 kV bushings for T1 at Paradise River.	Replaced units due to leaks. Cost was $11,000.
2006	Replaced three 69 kV bushings for T2 at Western Avalon.	Replaced units due to leaks. Cost was $5,300.
2006	Replaced one 230 kV and one 15 kV bushing for T1 at Massie Drive	Replaced units due to leaks. Cost was $24,000.
2005	Replaced one 15 kV bushing for T4 at Hardwoods	Replaced unit due to bushing leaks. Cost was $7,000.
2004	Replaced one 230 kV and one 15 kV bushing for T3 at Hardwoods	Replaced units due to bushing leaks. Cost was $15,000.
2004	Replaced one 230 kV bushing for T1 at Buchans	Replaced unit due to bushing leaks. Cost was $31,000. ($16,000 was required to provide portable generation to facilitate this work).
2002	Replaced a total of six Low Voltage (15 kV) high current bushings on T2 and T6 at Bay d'Espoir	Replaced units due to bushing leaks. Cost was $60,000.

Note: The cost for bushings outlined above is from units taken from inventory. Units purchased at today's prices will be significantly higher.

3.2.5 Protective Device Replacements

As a result of maintenance checks and alarms, there has been a requirement to replace transformer protection devices such as gas relays, winding temperature relays, oil temperature relays and oil level devices. Table 5 lists replacements of protective devices completed in recent years.

Table 5
List of Replacements of Protective Devices Completed In Recent Years

Year	Major Work/Upgrade	Comments
2007	There were nine gas relays, five winding/oil temperature relays.	Total cost was $49,000.
2006	There were four gas relays, four winding/oil temperature relays, and one oil level gauge replaced.	Total cost was $28,000.
2005	There were four gas relays, three winding/oil temperature relays, and one oil level gauge replaced.	Total cost was $25,500.
2004 or earlier	There were four gas relays, nine winding/oil temperature relays, and one oil level gauge replaced.	Each gas relay cost $3,500, winding/oil temperature relays cost $3,500 and each oil level device cost $1,000. Total cost was $46,500

3.2.6 Transformer Leaks

Oil leaks have been experienced on many transformers and are a result of several failure modes such as:

- Leaking bushings and bushing gaskets;
- Leaking valves;
- Leaking winding and oil temperature relays;
- Leaking gas relays;
- Leaking explosion relief devices;
- Leaking manhole and access covers;
- Leaking radiator gaskets and O-rings; and
- Leaking main tank top cover gaskets.

The majority of leaks are the result of failed gaskets which seal attached components to the transformer main tank. Experience indicates the gasket material is failing randomly throughout the transformer fleet and in some cases there are multiple occurrences on the same units. Repairs can be made to a transformer and the next inspection may reveal a leak on the same transformer in another location. The failure rate is accelerated by the age of the transformer and the thermal cycling experienced by the unit.

Depending on the location of the leak, the cost of repairs and required outage time can be quite extensive. Extended outages to these power transformers jeopardize the integrity of the power system and compromise the quality of service to customers. In each case, oil must be removed from the main tank to a level below the leak. This involves pumping and storing oil, installing nitrogen gas supply to protect the exposed internal components and then filtering the oil on refill. If oil has to be removed to a level below the core and windings it is required to put a vacuum on the unit for 24 to 48 hours prior to filling. When oil is moved inside a transformer, a minimum dwell time of 24 hours is required to allow the oil to stabilize and release any trapped air prior to energizing. Each time a transformer is exposed to the atmosphere there is an increased risk of moisture contamination which could result in shortened life or premature failure.

A typical gasket upgrading cost will be in the order of $65,000 due to the equipment and labor required to process oil.

Some transformers are also leaking around the top cover gasket. Replacement of the gasket would involve removal of all bushings, piping, current transformers, protective devices and oil. The top cover which is approximately 10 feet x 15 feet x 1/2 inch thick would have to be removed and a new gasket prepared and installed. This is an extensive job that would involve boom trucks, cranes and a five-man crew for at least six weeks.

Currently, other options are being pursued such as welding a channel around the top perimeter of the transformer completely encompassing the gasket cover. Transformer oil would eventually fill the void created by the new channel thus eliminating any further leaks to the environment. This option will require further engineering analysis to help determine if this approach will be acceptable.

3.3 Anticipated Useful life

According to Electric Power Research Institute (EPRI), the average age of in-service power transformers is 37 years. Failures of power transformers are typically random; however, probability of failure increases with age. The "bathtub" curve below in Figure 7 shows a typical percent failure rate versus age curve for power transformers. Based upon this curve, half of Hydro's in-service transformers are on the tip up part of the curve where the probability of failure is increasing with time.

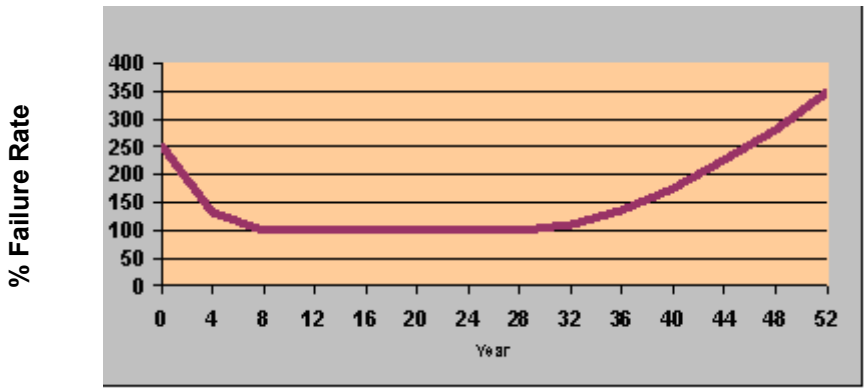

Figure 7: Power Transformers Failure Rate vs. Age

The Hartford Boiler Steam Institute states that the average life of a utility transformer today is 18 years. This is significantly lower than what has been documented by EPRI. Hydro is of the opinion the older designed units have longer life and if proper intervention is completed on the aged units, transformer life will be extended for an additional ten to 15 years.

3.4 Maintenance History

Table 6
Annual Maintenance Cost for Power Transformers In The Last Five Years

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2007	46	242	288
2006	27	133	160
2005	29	254	283
2004	38	323	361
2003	36	244	280

3.5 Outage Statistics

Table 7 lists the five-year average for the performance of power transformer. A comparison is made between Hydro's five-year performance to the latest CEA five-year average (2001-2005).

Table 7
Listing of Power Transformer Performance

	Frequency[1] (per a)	Unavailability[2] (%)
NLH (2003-2007)		
230 kV Transformers	0.02	0.015
138 kV Transformers	0.06	0.003
66 kV Transformers	0.03	0.001
CEA (2001-2005)		
230 kV Transformers	0.07	0.102
138 kV Transformers	0.09	0.147
66 kV Transformers	0.06	0.087

[1] Frequency (per a) is the number of failures per year.
[2] Unavailability is the percent of time per year the unit is unavailable.

There have been 13 forced outages in the past five years but none were due to internal transformer failures.

As stated previously, there have been no specific outages to the power system recorded as a result of power transformer failures. However, with the aging fleet, the risk of failure is high. Risk is evaluated by considering the probability of failure in light of the consequence of the event. With the transformer fleet aging, there is no doubt the probability of failure is increasing thus increasing the risk. The consequences can have very serious impacts to the power system. For example, in January of 2006 Hydro experienced a problem with frazzle ice at Upper Salmon while at the same time there were problems with the generating equipment at Holyrood. This event resulted in public notifications to conserve power during this period as Hydro was approaching its maximum available capacity. For this event, Hydro was able to resolve the issue at Upper Salmon in short order. If the same conditions were to exist at Holyrood and the Upper Salmon transformer were to fail, Hydro's ability to supply the province's demand would be difficult for the duration it would require to procure a new power transformer (12 to 18 months).

Another event occurred on February 14, 2008 in which one unit at Holyrood was already offline due to boiler tube problems when another unit at Holyrood tripped. The trip was a result of water in the cabinet of Unit Service Transformer 3 (UST3). This resulted in the remaining available capacity approaching the system demand. The fact that the temperature was relatively warm for the time of year (- 2 ^{o}C) improved Hydro's ability to supply the lower than normal demand. If the event occurred one day before or two days after (with temperatures approaching -20 ^{o}C) the system demand would have been much higher resulting in load shedding or rolling blackouts within the province.

Both events illustrate the criticality of power transformers in providing reliable service to the people of the province. It is important to note that an outage resulting from a failure of a power transformer would have a severe impact on the power system due to the long lead time for procurement.

3.6 Industry Experience

Many utilities in North America are in a similar position as Hydro in that they have aging infrastructure and are struggling for the most economic and reliable solution to this problem as it requires significant investment. There are many documented papers from various transformer owners touching on the subject of aging transformer infrastructure and various methods to try to deal with this issue. The majority have considered using condition assessment tools, either internally or through an outside vendor, to help with the decision to either upgrade or replace power transformers.

3.7 Maintenance or Support Arrangements

Routine maintenance as well as specialized power transformer work is completed using internal resources. Routine maintenance includes a visual inspection every three months for problems such as leaks, gauges not operating correctly, and other deficiencies. Every year, oil samples are taken and an Oil Quality and Dissolved Gas Analysis is performed to provide an input into the condition assessment tool. This condition assessment tool considers the criticality of the unit and provides an overall Transformer Priority Score (TPS) which is then ranked from highest to lowest. The transformer with the highest score is the unit that will be considered for oil reclamation during the next maintenance season (see Appendix D).

Transformers with on load tap changers have oil samples taken every three years to perform a Tap Changer Activity Signature Analysis (TASA) to help determine the condition of the tap changer. This is a special service offered by an oil analysis laboratory (TJH2b) which enables Hydro to develop a ranking of the condition for each of the on load tap changers. Any future work for tap changers will require a support arrangement from the manufacturer.

In 2005, a Furan Analysis was completed on all power transformers 66 kV and above with re-sampling planned for every four years to help trend the aging process. The next

data set will be available for review in 2009. More frequent sampling will be performed based upon lab results as per Appendix C.

On a six-year cycle, the transformer is taken offline and put through electrical testing with protective devices verified, fan controls checked, windings insulation tested (Doble), and winding resistance verified.

3.8 Vendor Recommendations

There are vendors such as ATI Weidman and ABB who are marketing condition assessment techniques for power transformers to provide customers with a list of 'weak' units that are recommended for refurbishment or replacement. As presented in this report, Hydro has been tracking the problem areas and has developed in-house ranking tools to help determine where the investment should be directed. With in-house expertise there is no need to engage outside help for the condition assessment component of this work.

3.9 Availability of Replacement Parts

The most critical power transformer assets are the generator step up transformers. Currently, there is a spare on order that can replace any of the seven generating units at Bay d'Espoir or the unit at Upper Salmon. However, the spare unit has a maximum rating of 100 MVA which is only two thirds the rating of T7 at Bay d'Espoir. This is particularly important as unit T7 is showing its paper strength to be weak and the probability of failure is high relative to the other units. The ability to acquire the necessary capital to replace this unit also becomes more critical as the associated generator is a 172 MVA unit and happens to be the most efficient unit on the system.

For all transformers on the Hydro system, there is an emergency plan in place to address transformer failures on the system. However, this plan only deals with the first contingency and does not consider the possibility of other system problems occurring at the same time. As a result, if Hydro considered running units to failure without consideration for condition assessment it could be upwards of 18 months to acquire a replacement and the power system will be operating in a restricted mode. This restricted mode would limit flexibility of outages for maintenance of other system equipment and increase Hydro's risk of not being able to supply system demands.

3.10 Safety Performance

This is a reliability based project. If this project is not initiated there is a higher risk of transformer failure and possibly extended power outages within the province which will negatively impact public safety.

3.11 Environmental Performance

Hydro is an ISO 14001 certified company and as a result has several Environmental Management Programs in place. One of these programs is the reporting of spills and leaks.

One of the main sources of leaks is power transformers. Transformers contain Voltesso 35 oil which acts as an electrical insulation medium as well as a coolant. As transformers go through thermal cycling oil leaks are discovered due to component or gasket system failure. Some leaks are significant such as those discovered on the unit transformers at Bay d'Epoir, thus supporting the need for future investment.

Another environmental management program in place at Hydro is the reduction of polychlorinated bipheyls (PCBs) used as an insulating oil in transformers. Recently Environment Canada announced that utilities have until 2025 to remove sealed equipment such as transformer bushings containing PCBs from service.

3.12 Operating Regime

Power transformers are placed in locations in the power system as generator step up units or used in terminal stations to convert to lower voltage levels to enable power to be distributed to customers.

Essentially without the step up power transformers being available, it is identical to having a generator unit offline. In the case of the step down power transformers, the unavailability of the unit, in radial applications, will result in communities without power. In cases where transformers are in parallel, transformer failures can result in load reduction to customers or customer outages.

4 JUSTIFICATION

As stated earlier in this report, 52 percent of Hydro's power transformers are greater than 30 years of age. In recent years, Hydro has been trying to address the six problem areas stated in Section 2 on an individual project basis. With significant investment required to address these concerns it was decided to look at an overall transformer upgrading program and this project was created to permit a planned and orderly upgrade of the power transformer fleet.

In looking at refurbishment, Hydro's condition assessment tool (which evaluates oil quality parameters such as acidity, interfacial tension, dielectric breakdown, dissolved gas parameters and criticality) provides a ranking of the worst to the best units. This is the ranking Hydro uses to determine which transformers will have their oil reclaimed next. For example, the ranking from 2007 to determine the reclamation work for 2008 is shown in Appendix D. It can be seen that the next unit to be completed is T2 at Holyrood. To continue with this work into the future, a $140,000 allocation is required in each of the next five years.

Ranking tools have also been developed to rank the condition of radiators as well as tap changers. In the case of radiators, corrosion has resulted in radiator leaks in recent years. The radiator replacements have been prioritized with Holyrood, Stephenville, Bottom Waters and Farewell Head being the highest priorities. These transformers will be upgraded in the first years of the program. There is $77,000 identified in the budget estimate for this work in each of the next five years.

For tap changers, a review of the maintenance philosophy was completed in 2006 and the best approach was to perform condition based monitoring using tap changer oil samples. This approach is more scientific in that oil samples are sent to a certified lab where they provide a ranking based upon oil quality and particle counts within the oil. As can be seen from the ranking outlined in Appendix B there are several transformers ranked between 3 and 4 which will require work in the near future. The units ranked at

4 will be completed as a priority. It is expected only one tap changer will require upgrading in each year and as a result $58,000 has been budgeted in each year.

Other investments are required to address leaking bushings as well as those that are identified as having PCB levels greater than 50 ppm. Environment Canada has communicated to utilities that all PCB sealed equipment such as transformer bushings must be removed from service by 2025. To accomplish this, Hydro is completing a survey in 2008 to better understand the number involved and the investment required. This project will budget the replacement of six bushings each year at an estimated cost of $140,000 per year.

Besides bushings, there are also critical protective devices and wiring that has been causing problems in recent years. As is shown in Table 5 of Section 3.2.5, annual costs for this work has ranged from $25,500 to $49,000 and it is not expected to decline. As a result, this project has included $48,000 per year to address these issues.

4.1 Net Present Value

A net present value calculation was not performed in this instance as the justification is based upon condition assessment techniques directed towards reliability and upgrades on a priority basis.

4.2 Levelized Cost of Energy

The capital expenditures for this project will not affect the levellized cost of energy for the system.

4.3 Cost Benefit Analysis

A cost benefit analysis is not required for this project proposal, as the project is required for reliability and safety issues.

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements other than those mentioned in Section 3.11 on Environmental Performance.

4.5 Historical Information

See Section 3.2 for a history of problem areas and activities completed in recent years relating to power transformers.

4.6 Forecast Customer Growth

This project is not required due to forecasted customer growth but required to maintain reliability with refurbishment or replacement of the aging transformer fleet.

4.7 Energy Efficiency Benefits

There are no issues related to energy efficiencies associated with this project.

4.8 Losses during Construction

The upgrade of each transformer will be coordinated with the normal outage plans for the transmission system. These outage plans are designed around the system load

requirements. Therefore, there are no production or revenue losses resulting from this project.

4.9 Status Quo

Status quo is not an option. With the current age of the power transformer fleet, failures can be expected if intervention or life extension measures are not considered.

4.10 Alternatives

There are only two solutions to the problems described with power transformers. These are to upgrade the transformers as proposed or replace them. The operation and maintenance costs of either alternative are generally the same. The upgrade option was chosen because it has the least cost and is the simplest solution to the problems.

5 CONCLUSION

The approach being proposed is to continually identify the “weak system units” and replace or refurbish critical assets on the system before they remove themselves from service. With this approach taken over multiple years, investment will be directed to the highest risk units.

As a result of the condition assessments completed to date there is only one transformer targeted to be replaced. Unit T7 at Bay d’Espoir is currently scheduled for engineering work and ordering in 2011 with expected delivery and installation in 2012.

For the remaining units, the upgrade option will be executed with a concentration in various areas annually. Where possible, more than one activity will be completed on a given transformer, however individual work activity priority will always be given to the units with the poorest ranking from the condition assessment of oil quality, radiator condition or tap changer oil condition results.

Table 8 summarizes the work plan for transformer upgrading planned for the next five years.

Table 8
Power Transformer Work Plan Summary 2009 to 2013

	2009 ($000)	2010 ($000)	2011 ($000)	2012 ($000)	2013 ($000)
Oil Reclamation	140	140	140	140	140
Radiator Upgrades	77	77	77	77	77
Tap Changer Upgrades	58	58	58	58	58
Bushing Replacements	140	140	140	140	140
Protective Device Upgrades	48	48	48	48	48
Upgrade Gasket System	65	65	65	65	65
Transformer Replacement	0	0	30	76	95
Contingency and Escalation	126	139	163	195	220
Total	**654**	**667**	**721**	**799**	**843**

It is important to note as well, the activity dollar amount for each year may increase or decrease but the overall budget for the year will be maintained.

5.1 Project Schedule for Each Year

Table 9
Project Schedule for Each Year

Activity	Milestone
Initial Planning and Equipment Ordering Tendering (Radiators, Bushings, and Protective Devices)	February
Equipment Delivery	July
Equipment Installations and Commissioning	November
Project In Service	November
Project Completion and Close Out	December

APPENDIX A

Transformer Radiator Ranking Summary 2008

Table A1: Transformer Radiator Ranking Summary

LOC	DESIG	KV	Rad Condition (1 = Leak 10 = New)	Comments	Target Year to replace
FHD	T1	66	1	Leaking rads identified in 2007	2008
HRD	SST1-2		1.5	1969, 8 rads, sweating with oil stains on the ground	2009
SVL	T1		2.5	1975 14 rads original, severe swelling and blistering. Leaking rads removed	2009
HRD	T6	230	2.5	1966, 3 rads, significant rust, swelling and blistering, 1 of 3 rads rated @6	2009
HRD	T8	230	2.5	1988, 4 rads, all very rusty	2010
BDE	T11	69	2.5	1970, original, significant swelling and blistering on 2, 2 @ 2-3, 7@5	2010
HRD	T7	230	3	1969, 3 rads, significant rust, swelling and blistering, 1 of 3 rads rated @7	2010
HWD	T1	230	3.5	1972, 6 rads, significant-serious rust on 2, original, have been painted	2011
BDE	T10	230	3.5	1976, 4 rads original, all blistering and rusted,	2011
HWD	T2	230	3.5	1978, 12 rads, original, have been painted, scaling and blistering	2011
WAV	T5	230	3.5	1989,4 rads, rusted and swelling, 2 rads drain pipes rusted severely	2012
BDE	T2	230	4	1966, 20 rads, evidence of rust and scaling, rads have been sand blasted and painted	2012
HWD	T3	230	4	1968, 6 rads, have been painted, scaling and blistering	2012
HRD	T2	230	4	1989, 10 rads, 5 new galvanized no paint, 5 original rated @ 3	2013
BDE	T3	230	4.5	1967, 20 rads, some rust on surface, rads appear to have been sand blasted and painted.	2013
BDE	T5	230	4.5	1968, 18 rads, some flaking and blistering,	2013
BUC	T1	230	5	1967, 17 rads, original carbon steel. Painted, some rust and blistering	2014

Table A1: Transformer Radiator Ranking Summary

LOC	DESIG	KV	Rad Condition (1 = Leak 10 = New)	Comments	Target Year to replace
GBK	T1	138	5	1987, 1 rad original painted, surface rust and some blistering	2014
HRD	T10	230	5	1990, 3 rads, original, swelling and flaking,	2014
CRV	T1	69	5	1976, 4 rads original, painted, minor rust between fins, rads welded on	2015
DLS	T1	138	5.5	1989, 5 rads original, significant surface rust, not severe, paint would extend life,	2015
BUC	Spare	230	6	1973, 7 rads, original carbon steel. Painted, some surface rust	>2015
HRD	SST3-4		6	1978, 3 rads, some scaling and swelling, 1 damaged fin (potential leak)	>2015
DLK	T1	138	6	1980, 6 rads, original carbon steel, have been painted, minor to moderate rust	>2015
GFC	T1	230	6	1966, 13 rads, original carbon steel. Painted, some surface rust and minor blistering	>2015
DLK	T2	230	6	1983, 6 rads original carbon steel, minor surface rust	>2015
BBK	T3	230	6	1987, 3 rads original, surface rust	>2015
BDE	T6	230	6	1969, 18 rads, some flaking and blistering	>2015
HRD	UST3		6	1978, 3 rads, 1 rad blistered significantly. Belongs to plant. One (1) Blistered rad replaced in 2007.1@10 2@6	>2015
SVL	T3		6.5	1975, 12 rads have been painted moderate surface rust	>2015
BUC	GT1		7	1966, 3 rads, original carbon steel. Painted, no rust, good shape	>2015
WAV	GT1		7	1966, 3 rads, welded, good shape, have been painted	>2015
BDE	SPARE	25	7	1966, 17 rads original, welded on, some rust, transformer requires painting, very rusty on top of low side junction box (600V)	>2015
BBK	T2	138	7	1967, 8 rads (4 new galvanized, 4 original @ 7)	>2015

Table A1: Transformer Radiator Ranking Summary

LOC	DESIG	KV	Rad Condition (1 = Leak 10 = New)	Comments	Target Year to replace
BUC	T2		7	1983, 6 rads, original carbon steel. Painted, no rust, good shape	>2015
GFC	T2	230	7	1966, 13 rads, original carbon steel. Painted, minor rust, no blistering	>2015
HLK	T2	138	7	1980, 10 rads, original, minor rust a minor swelling	>2015
WAV	T3	230	7	1967, 3 rads, minor rust, have been painted	>2015
WAV	T4	230	7	1966, 3 rads, minor rust and flaking, have been painted	>2015
OPD	GT1	69	7.5	1966, 3 rads welded, painted, in fair-good shape	>2015
SVL	GT1	69	7.5	1975, 3 rads original, minor rust	>2015
BDE	T1	230	7.5	1966, 20 rads, appears to have 8 new rads, all others appear to have been sand blasted and painted	>2015
CBC	T1	230	7.5	1972, 10 rads, original, painted and some minor rust on end 3, PAINTING REQUIRED ON LOW SIDE JUNCTION BOX	>2015
HLK	T1	138	7.5	1980, 10 rads, original, minor rust	>2015
LHR	T1	230	7.5	1968, 4 rads original have been painted, 4 have been removed from other end, minor rust, TRANSFORMER RUSTY AND NEEDS PAINT,	>2015
SOK	T1	138	7.5	Good shape original, painted carbon steel	>2015
BDE	T12	230	7.5	1988, 3 rads original, very little rust, OIL LEAK ON TAP CHANGER	>2015
CBC	T2	230	7.5	1972, 10 rads, original, painted and some minor rust on end 3, PAINTING REQUIRED ON LOW SIDE JUNCTION BOX	>2015
BDE	T4	230	7.5	1968, 11 rads, original	>2015
BDE	T7	230	7.5	1977, 12 rads original, no significant rust	>2015
EHW	T1	69	8	1993, 8 original rads painted galvanized, paint scaling no corrosion	>2015

Table A1: Transformer Radiator Ranking Summary

LOC	DESIG	KV	Rad Condition (1 = Leak 10 = New)	Comments	Target Year to replace
OPD	T1	230	8	1967, 16 rads, one missing (should be 17) no visible rust, primer showing, painting will extend life, original?	>2015
STB	T1	230	8	1977, 5 rads, original carbon steel. Painted, no rust, good shape	>2015
WAV	T1	230	8	1966, 3 rads, good shape, original, minor rust, have been painted	>2015
MDR	T2		8	1970, 6 rads original, carbon steel, painted, good shape	>2015
STB	T2	230	8	1976, 5 rads, original carbon steel. Painted, no rust, good shape	>2015
WAV	T2	230	8	1973, 3 rads, minor rust, original, have been painted	>2015
HRD	T3	230	8	1969, 5 rads (Forced oil coolers) made by Unifin 1992, good condition	>2015
HRD	T5	230	8	1969, rads have been painted, original, good shape, maybe galvanized	>2015
BBK	T1	230	8.5	1967, 3 rads, original rads and have been painted	>2015
SSD	T1	230	8.5	1977, 5 rads have been painted with good shape	>2015
HLY	T2	138	8.5	1981, 4 rads original, very little rust, good shape	>2015
HRD	T9	13.8	8.5	1970, 8 rads, painted, good shape, no visible rust. Belongs to plant	>2015
CBF	T1		9	1966, 16 rads, good shape, minor rust, **TRF TO BE REPLACED IN 2007**	>2015
MDR	T1	230	9	1998, 6 rads original galvanized, good shape, no rust	>2015
BCX	T1		9	1993, Rads original, Painted Galvanize, paint scaling no rust.	>2015
CBF	T2	66	9	rebuilt 2002, 16 rads, original from 1966, indoors, good shape	>2015
OPD	T2	230	9	1986, 3 rads, real good shape, minor touch up paint required at a couple of spots	>2015
MDR	T3	230	9	1981, 9 rads, galvanized, good shape, no rust	>2015

Table A1: Transformer Radiator Ranking Summary

LOC	DESIG	KV	Rad Condition (1 = Leak 10 = New)	Comments	Target Year to replace
SSD	T4	230	9	1976, 5 rads have been painted with good shape	>2015
HWD	T5	66	9	1976, 10 rads, painted galvanized, minor touch up on brackets and rads	>2015
OPD	T3	230	9	1977, 11 rads, Good shape except for 1 which has oil stains on the bottom, unsure why, and some stain on the ground below, all rads appear to have been replaced and looks like they are painted galvanized	>2015
HRD	T1	230	9.5	1976, 20 rads, all new painted galvanized	>2015
HWD	T4		9.5	1992, 12 rads, painted galvanized, good shape, no rust, **CARBON DRAIN PIPES RUSTED AND SHOULD BE REPLACED**	>2015
HRD	UST1		9.5	1969, 10 rads, new galvanized. Belongs to plant.	>2015
HRD	UST2		9.5	1969, 10 rads, new galvanized. Belongs to plant.	>2015
BWT	T1		10	1990, 3 rads, leaking, very rusted and weeping/sweating, all rads replaced 2006-12-06	>2015

APPENDIX B

Transformer On Load Tap Changer Summary Ranking

TASA Rank	Action
1	Resample in 3 years
2	Resample in 3 years
3	Resample in 6 months and consider refurbishment
> 3	Resample immediately to confirm , plan refurbish tap changer if reanalysis gives a TASA Rank of 4 or 4*

Table B1: Tap Changer Ranking Summary 2008

Location	Xfmr	Manufacturer	Operation Counter	TJH2B Ranking	Lab Test Number	Retest Date	Comment(s)
Holyrood	T8	Reinhaussen	18002	4		Refurbish 2008	
Holyrood	T5	ASEA	94355	3.5		Refurbish 2009	
Oxen Pond	T2	ASEA	54961	3		Refurbish 2009	Plan to refurbish at the same time as T5 unit to reduce travel cost for rep.
Hardwoods	T1	GE	173307	3		February 20, 2008	
Sunny Side	T1-A	GE	126316	3		February 20, 2008	
Sunny Side	T1-B	GE	126316	3		February 20, 2008	
Sunny Side	T1-C	GE	126316	3		February 20, 2008	
Stoney Brook	T1-Center	GE	280891	3		March 3, 2008	
Hardwoods	T2	Reinhaussen	162744	3		February 20, 2008	

Table B1: Tap Changer Ranking Summary 2008

Location	Xfmr	Manufacturer	Operation Counter	TJH2B Ranking	Lab Test Number	Retest Date	Comment(s)
Stoney Brook	T2-Center	GE	81216	3		March 3, 2008	
Stoney Brook	T2-Right	GE	81216	3		March 3, 2008	
Bottom Brook	T1 A	GE	183	2		February 28, 2011	
Bottom Brook	T1 B	GE	183	2		February 28, 2011	
Bottom Brook	T1 C	GE	183	2		February 28, 2011	
Holyrood	T10	ABB	40107	2		April 11, 2011	
Bay D'Espoir	T10	ABB (ASEA)	65429	2		April 4, 2011	
Stoney Brook	T1-Left	GE	280891	2		September 4, 2010	
Stoney Brook	T1-Right	GE	280891	2		September 4, 2010	
Stoney Brook	T2-Left	GE	81216	2		September 4, 2010	
Stephenville	T3-Right	Reinhaussen	5745	2		February 28, 2011	
Holyrood	T6 # 1	ABB	13069	2		September 25, 2010	
Holyrood	T6 # 2	ABB	13069	2		September 25, 2010	
Holyrood	T6 # 3	ABB	13069	2		September 25, 2010	
Duck Pond	T1	ABB	2010	1		April 4,	

Table B1: Tap Changer Ranking Summary 2008

Location	Xfmr	Manufacturer	Operation Counter	TJH2B Ranking	Lab Test Number	Retest Date	Comment(s)
						2011	
Deer Lake	T1	Federal Pioneer		1		July 22, 2010	
Doyles	T1	Federal Pioneer	22796	1		April 4, 2011	
West Avalon	T1	GE	73282	1		October 2, 2010	
Buchans	T1	Reinhaussen	72505	1		February 28, 2011	
Massey Drive	T1	Reinhaussen	22629	1		February 28, 2011	
Oxen Pond	T1	Reinhaussen	10281	1		April 11, 2011	
Bay D'Espoir	T12	Federal Pioneer	41991	1		June 6, 2010	
Massey Drive	T2	GE	52667	1		July 22, 2010	
Deer Lake	T2 A	Reinhaussen	35210	1		February 28, 2011	
Deer Lake	T2 B	Reinhaussen	35210	1		February 28, 2011	
Deer Lake	T2 C	Reinhaussen	35210	1		February 28, 2011	
Hardwoods	T3	GE	43845	1		August 23, 2010	
Bottom Brook	T3	Reinhaussen	53988	1		February 28, 2011	
Oxen Pond	T3	Reinhaussen	146785	1		April 11, 2011	

Table B1: Tap Changer Ranking Summary 2008

Location	Xfmr	Manufacturer	Operation Counter	TJH2B Ranking	Lab Test Number	Retest Date	Comment(s)
Stephenville	T3-Centre	Reinhaussen	5745	1		November 8, 2010	
Stephenville	T3-Left	Reinhaussen	5745	1		November 8, 2010	
Hardwoods	T4	Reinhaussen	17408	1		April 11, 2011	
Holyrood	T7 # 1	ABB	9516	1		September 25, 2010	
Holyrood	T7 # 2	ABB	9516	1		September 25, 2010	
Holyrood	T7 # 3	ABB	9516	1		September 25, 2010	
Massie Drive	T3	Reinhaussen	59398	1		September 25, 2010	Tapchanger Refurbished, Nov. 2007

APPENDIX C

Transformer Furan Analysis Results Degree of Polymerization

Color Code	Activity	Criteria
	In Schedule to Replace within 3-5 years	≤ 400 DP
	Annual Furan Analysis	400 > 649 DP
	Continue with 4 yr Furan Analysis	> 650 DP

(Note: Criteria Developed in 2008)

Table C1: Transformer DP Ranking

Location	Serial #	Estimated DP
BAY D'ESPOIR- T7	288926	370-472
Corner Brook-T2	230814-B	426-518 (Prior to 2002 Rewind)
Corner Brook-T1	230815	429-512 (Prior to being replaced in 2007)
Upper Salmon-T1	289479	503-736
PRVTS-T1	T-60753	510-634
HRD-T2	61-00-69225	597-779
BAY D'ESPOIR-T2	293267	647-652
HRD-T1	303236	673-810
WAVTS-T2	288178	699-812
CAT ARM-T1	6311669	721-755
WAVTS-T1	286101	739-872
HLK-T2	1-4228	770-801
HLK-T1	1-4227	788-816
CAT ARM-T2	6311670	793
HUD-T2	284305	825
HVY-T1	289067	840
QZT-T2	92-927	865
VAN-T1	A-3S-6397	867
Hudson Sub-NTL-T2	266877	924
Wabush Sub-T1	292003	927

Table C1: Transformer DP Ranking		
Location	**Serial #**	**Estimated DP**
Wabush Sub-T2	292004	937
HVY-T2	289068	977
Hudson Sub-NTL-T1	2112781	999
CBF-T2	230814	1000
Bartlett Sub-T1	A-3S-6270	>1000
Bartlett Sub-T2	A-3S-6192	>1000
BAY D'ESPOIR- T1	293266	>1000
BAY D'ESPOIR- T3	293456	>1000
BAY D'ESPOIR- T7 after	288926	>1000
BAY D'ESPOIR-T2 after	293267	>1000
BBK-T1	286625	>1000
BBK-T3	61-00-68607	>1000
BRT-spare	1707401001	>1000
BUCHANS-T1	293315	>1000
HRD-T3	287198	>1000
HRDTS- spare	287199	>1000
HRL-T1	291212	>1000
Hudson Sub-T1	A-3S-6352	>1000
HUD-T1	WC5408037	>1000
HVY-T3	A32S0153	>1000
MDR-T1	18757-101-01	>1000
MDR-T2	287527	>1000
MDR-T3	A3S-5316	>1000
MRF-T1	T-60559	>1000
NTP-T1	300499	>1000
NTP-T2	2300500	>1000

Table C1: Transformer DP Ranking		
Location	**Serial #**	**Estimated DP**
NTS-T3	G47521	>1000
NTS-T4	G5372	>1000
OPDTS-T1	N293314	>1000
OPDTS-T2	289703	>1000
OPDTS-T3	A-3S-7857	>1000
QZT-T1	A-3S-6447	>1000
SSDTS-T1	289147	>1000
SSDTS-T4	288838	>1000
STONEY BROOK-T1	288894	>1000
STONEY BROOK-T2	288839	>1000
Upper Salmon-T1 after	289479	>1000
Wabush Sub-T3	T606551	>1000
Wabush Sub-T4	T606552	>1000
Wabush Sub-T5	2306740	>1000
WAVTS-T3	286626	>1000
WAVTS-T4	286167	>1000
WAVTS-T5	61-00-69167	>1000
WTS-T2	292004	>1000

APPENDIX D

Transformer Priority Score and Ranking

		TRANSFORMER PRIORITY SCORE (TPS)									
		GSU (Vital)			Radial (CRITICAL)			All Other (IMPORTANT)			
Condition Factor		10	9	8	7	6	5	4	3	2	1
WORST	10	100	90	80	70	60	50	40	30	20	10
	9	90	81	72	63	54	45	36	27	18	9
	8	80	72	72	56	48	40	32	24	16	8
	7	70	63	56	49	42	35	28	21	14	7
	6	60	54	48	42	36	30	24	18	12	6
	5	50	45	40	35	30	25	20	15	10	5
	4	40	36	32	28	24	20	16	12	8	4
BEST	3	30	27	24	21	18	15	12	9	6	3
	2	20	18	16	14	12	10	8	6	4	2
	1	10	9	8	7	6	5	4	3	2	1

Table D1: Transformer Priority Score Ranking

Transformer	Location	Lab Analysis Score	Criticality Score	TPS Score
T2	HRDTS	7.41	10.00	74.09
T1	CATTS	7.43	8.67	64.43
T1	HLKTS	6.74	8.33	56.16
T1	HRDTS	5.74	9.67	55.47
T5	BDETS1	6.11	8.33	50.95
T4 .	BDETS1	6.07	8.33	50.57
T1	PRVTS	6.99	7.00	48.92
T1	BUCTS	7.44	6.33	47.14
T2	STATS	6.61	7.00	46.30
T6	BDETS1	5.52	8.33	46.02
T1	USLTS	5.27	8.67	45.70
T2	HLKTS	5.43	8.33	45.27
T3	BDETS1	5.35	8.33	44.60
T3	HRDTS	4.67	9.33	43.58
T7	BDETS1	4.56	9.00	41.01
UST3	HRDTS	7.49	5.33	39.91
T3	MDRTS	7.06	5.33	37.61
T2	BDETS1	4.28	8.33	35.70
T1	STBTS	6.83	5.00	34.15
T2	CBFTS	5.35	6.33	33.88
React.R2	Plum Point	6.77	5.00	33.86
React.R1	Plum Point	6.42	5.00	32.10
T1	Bartlett	6.00	5.33	31.98
UST2	HRDTS	5.99	5.33	31.92
T7	HRDTS	7.83	4.00	31.32
SST	STA AirPort	6.20	5.00	31.02
Spare	HRDTS	3.28	9.33	30.64

Table D1: Transformer Priority Score Ranking

Transformer	Location	Lab Analysis Score	Criticality Score	TPS Score
T2	USLTS	4.22	7.00	29.51
T1	STBTS	5.43	5.33	28.95
SST1	CATTS	5.34	5.33	28.47
T3	WAVTS	7.07	4.00	28.27
T1	SSDTS	5.65	5.00	28.24
T1	Wabush	5.53	5.00	27.67
T1	DLKTS	5.53	5.00	27.67
T2 LTC	HVYTS	5.51	5.00	27.56
T3	OPDTS	6.34	4.33	27.48
T1	WAVTS	6.80	4.00	27.18
T1	OPDTS	6.73	4.00	26.91
T5	HRDTS	5.38	5.00	26.88
T10	BDETS1	4.81	5.33	25.62
T2	DLKTS	5.49	4.67	25.61
T2	BBKTS	4.74	5.33	25.26
T1	HVYTS	5.03	5.00	25.17
T10	HRDTS	5.01	5.00	25.06
T4	WAVTS	6.16	4.00	24.64
T3	SVLTS	4.85	5.00	24.26
T1	Parsons Pond	4.49	5.33	23.92
T6	HRDTS	5.98	4.00	23.91
T1	Triton	4.70	5.00	23.52
T2	Hawks Bay	4.34	5.33	23.14
T1	BBKTS	5.68	4.00	22.73
UST1	HRDTS	4.20	5.33	22.41
T12	BDETS1	4.14	5.33	22.05
T1	Muskrat Falls	4.41	5.00	22.05
T1	STATS	4.41	5.00	22.05

Table D1: Transformer Priority Score Ranking

Transformer	Location	Lab Analysis Score	Criticality Score	TPS Score
T1	RWC	4.40	5.00	21.99
T2	STBTS	5.49	4.00	21.95
T1	Wiltondale	4.39	5.00	21.93
T2	Quartzite	4.09	5.33	21.80
T1	BDETS1	2.57	8.33	21.40
T1	SSDTS	4.27	5.00	21.36
T1	GCLTS	2.52	8.33	21.01
T1	Rocky HL	3.88	5.33	20.65
T1	STA AirPort	4.11	5.00	20.57
T5	HWDTS	2.66	7.67	20.40
T1	DPDTS	3.18	6.33	20.14
T4	Wabush	3.98	5.00	19.89
T3	HWDTS	4.88	4.00	19.50
T3	BBKTS	3.64	5.33	19.38
T4	SSDTS	4.84	4.00	19.36
T2	WAVTS	4.83	4.00	19.32
T3	Hawks Bay	3.80	5.00	18.98
T1	Burgeo	3.77	5.00	18.86
T1	Hudson	3.74	5.00	18.69
T1	Wabush	3.74	5.00	18.69
T1	Cow Head	3.50	5.33	18.66
T3	HVYTS	3.49	5.33	18.59
T2	RWC	3.56	5.00	17.78
T1	GBKTS	3.31	5.33	17.63
T2	GFTS	2.64	6.67	17.58
T1	Glenburnie	3.27	5.33	17.44
T2	MDRTS	4.27	4.00	17.09
T5	WAVTS	3.94	4.33	17.09

Table D1: Transformer Priority Score Ranking

Transformer	Location	Lab Analysis Score	Criticality Score	TPS Score
T2	Hudson	3.41	5.00	17.05
T1	MBKTS	3.17	5.33	16.90
T1	Quartzite	3.13	5.33	16.66
T2	Bartlett	3.32	5.00	16.59
T1	FGOTS	3.32	5.00	16.59
T1	CBCTS	2.76	6.00	16.57
T4	HWDTS	4.02	4.00	16.09
T1	MDRTS	3.22	5.00	16.08
T2	Daniels Hr	2.93	5.33	15.63
T1	La Scie	2.97	5.00	14.83
T8	HRDTS	3.70	4.00	14.82
SST-34	HRDTS	2.94	5.00	14.72
T1	JAMTS	2.92	5.00	14.60
T1	Peters Barrens	2.74	5.33	14.60
T1	BWTTS	2.68	5.33	14.29
T1	SVLTS	1.85	7.67	14.20
T2	CBCTS	2.53	5.33	13.51
SS1	USLTS	2.68	5.00	13.41
T2	BUCTS	2.51	5.33	13.39
T1	Hampden	2.57	5.00	12.84

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Replace Light Duty Mobile Equipment Less than $50,000 - Various Locations

NEWFOUNDLAND AND LABRADOR HYDRO

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Appendix

A - Listing of the Mobile Equipment Proposed to be Replaced

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) operates a fleet of light duty mobile equipment comprised of: approximately 120 snowmobiles; 70 All Terrain Vehicles (ATVs); 120 trailers; 10 forklifts; and 25 miscellaneous attachments (lawn mower, backhoe, salt spreader, snow plows, etc).

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 Island electrical system.

The Transportation section 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 of the equipment.

2 PROJECT DESCRIPTION

This project proposes the replacement of 26 snowmobiles, 14 ATVs, six light duty trailers, six heavy duty trailers and one forklift in accordance with Hydro's established replacement criteria, as follows:

- Snowmobiles/ATVs- Line crews - three to five years, condition;
- Snowmobiles /ATVs (other) - five to seven years, condition;
- Trailers: Light Duty - six to eight years, condition;
- Trailers: Heavy Duty - 12 to 15 years, condition;
- Forklifts - 15 to 20 years, condition; and
- Attachments - 10 to 15 years, condition.

As this project relates to the replacement of mobile equipment, there is no relevant data related to:

- Outage Statistics;
- Safety Performance;
- Environmental Performance; or
- Operating Regime.

3 EXISTING SYSTEM

3.1 Age of Equipment or System

Please see Appendix A for a detailed listing of the mobile equipment proposed to be replaced.

3.2 Anticipated Useful life

The anticipated useful life of light ATVs, snowmobiles and forklifts is six years. The anticipated useful life of trailers and attachments is five years.

3.3 Maintenance History

Hydro does not maintain individual maintenance records of this type of equipment.

3.4 Industry Experience

Light mobile equipment replacement scheduling varies dependant on location, exposure to harsh environmental conditions, and the service use of the equipment.

3.5 Maintenance or Support Arrangements

The Hydro fleet of mobile equipment is maintained by external service garages.

3.6 Availability of Replacement Parts

Replacement parts are readily available for all of the equipment proposed to be replaced.

4 JUSTIFICATION

Hydro operates in diverse locations across the province, where it is critical that employees are provided with safe and reliable equipment to provide economical and reliable electricity.

This proposal provides for the normal replacement of mobile equipment in accordance with Hydro's established criteria as stated in Section 2.

As this project relates to the replacement of mobile equipment, there is no relevant data related to:

- Levelized Cost of Energy;
- Legislative or Regulatory Requirements;
- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Losses during Construction.

4.1 Historical Information

Historical information for mobile equipment less than $50,000 is shown in Table 1 below.

Table 1
Mobile Equipment less than $50,000

Year	Units Purchased					Budget ($000)	Actual ($000)
	ATVs	Snowmobiles	Trailers	Forklifts	Attachments		
2008 (F)	20	24	9	1	2	522.2	
2007	15	19	0	0	0	241.0	243.5
2006	15	17	4	0	0	249.2	243.3
2005	11	15	5	0	1	230.8	244.8
2004	10	16	3	0	3	275.0	274.6
2003	5	9	8	0	0	495.6	158.5

4.2 Status Quo

Failure to replace units in accordance with replacement policy will lead to increasing maintenance costs and less reliable vehicles. Hydro employees maintain the electrical system 24 hours a day, seven days a week, and require dependable and safe vehicles. As equipment ages, it experiences increasing downtime which could negatively affect response times for emergency outages or planned maintenance.

4.3 Alternatives

Purchase of this equipment is the only viable option. A Net Present Value calculation was not performed in this instance as only one viable alternative exists.

5 CONCLUSION

This project provides for the normal replacement of light duty, mobile equipment based on projected age and kilometers which is at the end of its life cycle and is no longer dependable.

5.1 Budget Estimate

Table 2
Budget Estimate

Project Cost:($ x1,000)	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	491.8	0.0	0.0	491.8
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
O/H, AFUDC & Escln	20.2	0.0	0.0	20.2
Contingency	49.2	0.0	0.0	49.2
TOTAL	**561.2**	**0.0**	**0.0**	**561.2**

APPENDIX A

Listing of Mobile Equipment Proposed to be Replaced

Unit No.	2009 Light Mobile Type	Area	Age at Retirement	Notes
V7015	ATV	Whitbourne Office	4.1	
V7021	ATV	Whitbourne Office	4.1	Stolen
V7024	ATV	Bishop's Falls Office	4.2	
V7026	ATV	Bay d'Espoir Depot	4.1	
V7620	ATV	Bay d'Espoir Office	5.2	
V7621	ATV	Bay d'Espoir Depot	5.2	
V7622	ATV	Stephenville Office	5.2	
V7623	ATV	Bay d'Espoir Depot	5.2	
V7624	ATV	Whitbourne Office	5.2	
V7625	ATV	Bay d'Espoir Depot	5.2	
V7626	ATV	Whitbourne Office	5.2	
V7627	ATV	Bishop's Falls Office	5.2	
V7628	ATV	Whitbourne Office	5.2	
V7629	ATV	Bishop's Falls Office	5.2	
V9780	Forklift	Bay d'Espoir Office	20.2	
V8800	Heavy Duty Trailer	St. Anthony Office	14.2	
V8794	Heavy Duty Trailer	Postville Office	14.2	
V8796	Heavy Duty Trailer	Postville Office	14.2	
V8804	Heavy Duty Trailer	Bishop's Falls Office	13.2	
V8805	Heavy Duty Trailer	Bishop's Falls Office	13.2	
V8812	Heavy Duty Trailer	Postville Office	13.2	
V8815	Light Duty Trailer	Postville Office	12.2	
V8820	Light Duty Trailer	Stephenville Office	12.2	
V8821	Light Duty Trailer	Bay d'Espoir Depot	12.2	
V8822	Light Duty Trailer	Bay d'Espoir Office	12.2	
V8824	Light Duty Trailer	Bishop's Falls Office	11.2	
V8825	Light Duty Trailer	Postville Office	11.2	
V7002	Snowmobile	Postville Office	4.1	
V7003	Snowmobile	Postville Office	4.1	

Unit No.	2009 Light Mobile Type	Area	Age at Retirement	Notes
V7004	Snowmobile	Postville Office	4.1	
V7507	Snowmobile	Bay d'Espoir Office	7.6	
V7509	Snowmobile	Bay d'Espoir Office	7.6	
V7567	Snowmobile	Bay d'Espoir Office	6.7	
V7568	Snowmobile	Bay d'Espoir Office	6.7	
V7569	Snowmobile	Bay d'Espoir Office	6.7	
V7618	Snowmobile	HVYOFFICE	5.4	
V7619	Snowmobile	HVYOFFICE	5.4	
V7630	Snowmobile	Bay d'Espoir Office	5.1	
V7632	Snowmobile	Stephenville Office	5.1	
V7634	Snowmobile	Stephenville Office	5.1	
V7635	Snowmobile	Bishop's Falls Office	5.1	
V7636	Snowmobile	Bay d'Espoir Depot	5.1	
V7637	Snowmobile	Bay d'Espoir Office	5.1	
V7638	Snowmobile	Bay d'Espoir Office	5.1	
V7640	Snowmobile	Bishop's Falls Office	5.1	
V7641	Snowmobile	Whitbourne Office	5.1	
V7645	Snowmobile	Whitbourne Office	5.1	
V7648	Snowmobile	Whitbourne Office	5.1	
V7650	Snowmobile	Whitbourne Office	5.1	
V7651	Snowmobile	Bay d'Espoir Depot	5.1	
V7652	Snowmobile	Bay d'Espoir Depot	5.1	
V7653	Snowmobile	Bishop's Falls Office	5.1	
V7926	Snowmobile	St. Anthony Office	12.2	

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Terminal Station Grounding Upgrades

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

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A - Oxen Pond Terminal Station Hazardous Touch Potentials
B - Newfoundland and Labrador Hydro Terminals Engineering Standard TS07-004-R2

1 INTRODUCTION

There are 54 Terminal Stations in the Island Interconnected System and three in the Labrador Interconnected System. An important aspect in the design of a terminal station is that proper grounding be installed to protect personnel working in a terminal station from electric shock or even electrocution. Grounding is very important during the occurrence of an electrical disturbance such as a system fault. A system fault occurs when there is a malfunction in an electrical circuit that causes current to flow to ground or between two conductors if they come in contact with each other. Figure 1 shows a portion of a terminal station plan layout. The broken lines illustrate part of the grounding grid system. The small grid in the lower right quadrant of the sketch is called a gradient control mat.

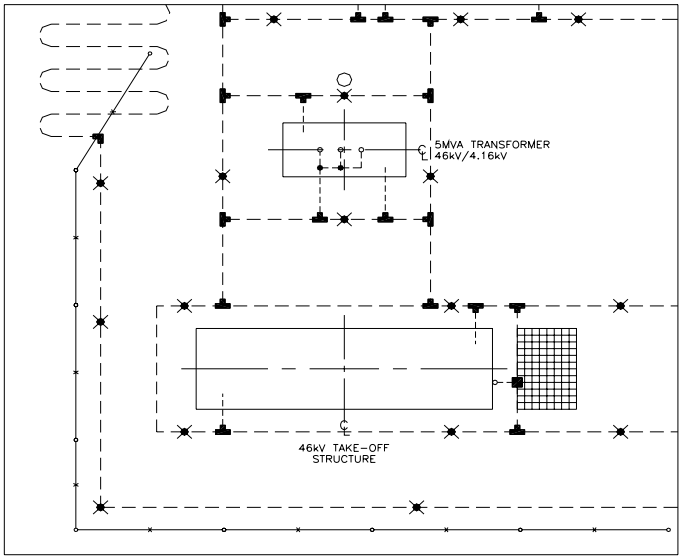


Figure1: Terminal Station Grounding Layout Sketch

This project is to fix unsafe and substandard conditions that exist in Regulated Operations terminal stations because of inadequate grounding. Inadequate grounding consists of two components:

- Grounding grids that allow hazardous step and/or touch potentials.
- Gradient control mats that are missing or improperly installed.

Step/touch potential occurs during a system fault when inadequate station grounding permits the occurrence of different voltage levels in close proximity, that is, within reaching or stepping distance. When differing voltage levels occur in close proximity, there is a risk of electrical shock or electrocution should an individual touch two pieces

of equipment at the same time or step from one location to another. Proper terminal station grounding ensures safe step/touch potential within the station, thus reducing the risk of electrical shock/electrocution.

Gradient control mats are an integral part of the overall terminal station grounding. They are laid at the base of disconnect switches. Their purpose is to provide secondary protection from step/touch potentials.

It should be noted that due to the safety risk to Hydro's employees, as grounding grids that are unsafe are identified, they should be replaced. The scope of this project includes as yet unidentified unsafe conditions, as well as both identified and as yet unidentified substandard conditions.

2 PROJECT DESCRIPTION

This project involves modifying existing grounding grids and installing, or modifying, gradient control mats at terminal stations identified as having hazardous step and/or touch potentials as defined by Institute of Electrical and Electronic Engineers (IEEE) Standard 80-2000. Gradient control mats which are lacking will be installed and those that do not meet Hydro's current Terminals Engineering Standard TS07-004-R2 entitled "Grounding" (attached as Appendix B) will be modified.

To determine the scope of this project, terminal stations with higher risk as identified in Section 3, have had their grounding grids analyzed. Only one terminal station, located at Oxen Pond, has been identified as having hazardous step and/or touch potentials. Based on the analysis to date, it is estimated that eight more terminal stations have hazardous step and/or touch potentials. An inspection of the gradient control mats is being conducted at terminal stations. At the time this report was prepared, 215 mats were inspected of which 101 do not meet Hydro's current grounding standards and at one location, a mat is lacking. Based on the 215 inspected out of approximately 600 gradient control mats it is estimated that 280 gradient control mats are improperly installed and based on one mat lacking out of nine stations, it is estimated that six more are lacking.

This project proposal is for:

- modifying the ground grids at eight terminal stations;
- modifying 280 installed gradient control mats; and
- installing six gradient control mats.

3 EXISTING SYSTEM

The seven stations that have been analyzed are Barachoix, Bottom Brook, Massey Drive, Stony Brook, Sunnyside, Western Avalon and Oxen Pond Terminal Stations. Hazardous step and/or touch potentials have been identified at the Oxen Pond Terminal Station located in St. John's. Figure 2 is a picture of Oxen Pond Terminal Station. Appendix A gives a plan view of the station and a graph indicating areas where the step/touch potential is higher than the minimum threshold level as documented in IEEE Standard 80-2000.

Figure 2: Oxen Pond Terminal Station

3.1 Age of Equipment or System

The age of the equipment associated with this project is not a factor. This project was developed based on non-conformance to IEEE Standard 80-2000 and Hydro's terminal station standards.

3.2 Major Work or Upgrades

There has been no major work or upgrades to any of the terminal station ground grids or gradient control mats since their installation.

3.3 Anticipated Useful life

The anticipated useful life of the terminal station ground grid components is 40 years.

3.4 Maintenance History

Any inspection of the terminal station grounding system is included in an overall inspection of the terminal station facility. As a result, maintenance records specifically relating to the grounding system are not available.

3.5 Outage Statistics

No specific outages have occurred as a result of the grounding system.

3.6 Industry Experience

The North American electric utility industry uses IEEE Standard 80-2000 as the standards to which terminal station grounding systems are to conform.

3.7 Maintenance or Support Arrangements

Maintenance on terminal station grounding is performed by Hydro's internal personnel.

3.8 Vendor Recommendations

Vendor recommendations have not been sought for this project.

3.9 Availability of Replacement Parts

Replacement parts are readily available from local suppliers.

3.10 Safety Performance

Analysis shows that touch potentials at the Oxen Pond Terminal Station exceed the maximum allowable level by 172 percent as defined by IEEE Standard 80-2000. Potentials beyond the maximum allowable level are a very serious safety issue and short-term workarounds are being explored.

3.11 Environmental Performance

Environmental non-compliance is not an issue for this project.

3.12 Operating Regime

All 54 terminal stations are in operation continuously.

4 JUSTIFICATION

This project is justified on the requirement to eliminate unsafe step and touch potentials from Regulated Operations terminal stations and conform to IEEE Standard 80-2000. Also, the station grounding upgrades are needed to meet the current Hydro's current Terminals Engineering Standard TS07-004-R2 so Hydro can provide safe, least-cost, reliable electrical service to its customers.

4.1 Net Present Value

A Net Present Value calculation has not been performed for this project as only one viable alternative exists.

4.2 Levelized Cost of Energy

As no new generation source is considered, this project has no effect on the levelized cost of electricity.

4.3 Cost Benefit Analysis

A Cost Benefit Analysis has not been performed as there are no quantifiable financial benefits for the project.

4.4 Legislative or Regulatory Requirements

The Newfoundland and Labrador Occupational Health and Safety Regulations, section 4 states "An employer shall ensure where it is reasonably practicable, the heath, safety and welfare of his or her workers". The regulations support proceeding with this project.

4.5 Historical Information

As this is the first year of a two-year project, there is no historical information.

4.6 Forecast Customer Growth

Customer load growth does not affect this project.

4.7 Energy Efficiency Benefits

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

4.8 Losses during Construction

No losses will occur with this project because power outages or equipment deenergization is not required.

4.9 Status Quo

The consequence of not completing this project is the continued existence of hazardous step and/or touch potentials in Regulated Operations terminal stations. This is a safety hazard with the potential of being fatal.

4.10 Alternatives

There is only one viable alternative and that is to complete the necessary upgrades.

5 CONCLUSION

The Terminal Stations Grounding Project is necessary to eliminate existing hazardous step and touch potentials from all Hydro's terminal stations and to eliminate nonconformance with Hydro's Terminals Engineering Standard TS07-004-R2. This is done by modifying the grounding grids at the terminal stations where hazardous step and/or touch potentials exist, replacing lacking gradient control mats and fixing incorrectly installed ones. The current plan is to upgrade the grounding at the Oxen Pond terminal Station in 2009 and continue with future grounding upgrades as they are identified.

5.1 Budget Estimate

Table 1
Capital Budget Estimate

Project Cost:($ x1,000)	**2009**	**2010**	**Total**
Material	44.6	44.6	89.2
Labour	120.2	120.2	240.4
Consultant	0.0	0.0	0.0
Equipment Rental	0.0	0.0	0.0
Travel	57.7	57.7	115.4
Contracts	0.0	0.0	0.0
Corp. O/H, Escalation, AFUDC	29.4	46.4	75.8
Contingency	0.0	22.3	22.3
Total	**251.9**	**291.2**	**543.1**

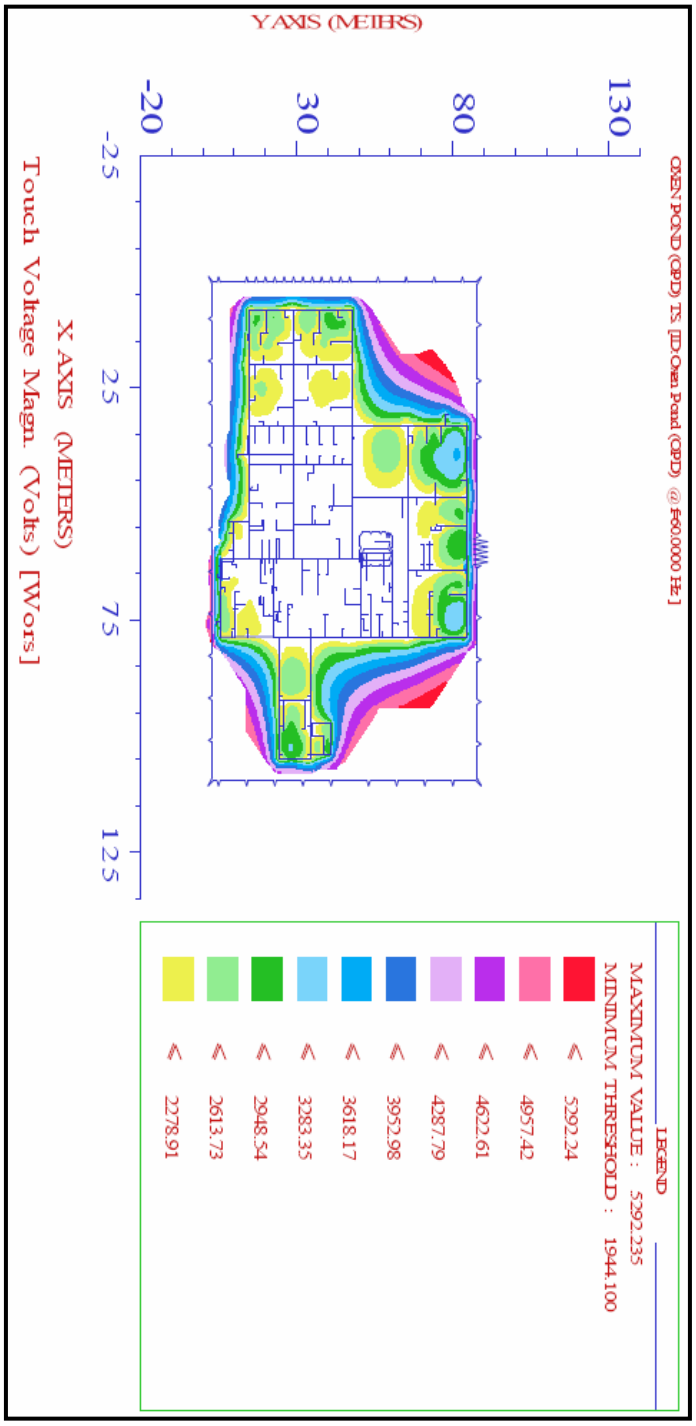
5.2 Project Schedule

Table 2
Project Schedule

Activity	Milestone
Finalized Design – 2009 Work	January 2009
Initial Planning – 2009 Work	February 2009
Material Ordering – 2009 Work	February 2009
Material Delivery – 2009 Work	April 2009
Installation – 2009 Work	August 2009
2009 Work In Service	August 2009
Finalized Design – 2010 Work	January 2010
Initial Planning – 2010 Work	February 2010
Material Ordering – 2010 Work	February 2010
Material Delivery – 2010 Work	April 2010
Installation – 2010 Work	August 2010
2010 Work In Service	August 2010
Project Completion and Close Out	September 2010

APPENDIX A

Oxen Pond Terminal Station Hazardous Touch Potentials


Y AXIS (METERS)
-20
30
80
130
-25
25
75
125
X AXIS (METERS)
Touch Voltage Magn. (Volts) [Wors]
OPEN POND (OPD) TS [ID Open Pond (OPD) @ 660.0000 Hz]
LEGEND
MAXIMUM VALUE : 5292.235
MINIMUM THRESHOLD : 1944.100
< 5292.24
< 4957.42
< 4622.61
< 4287.79
< 3952.98
< 3618.17
< 3283.35
< 2948.54
< 2613.73
< 2278.91

APPENDIX B

Newfoundland and Labrador Hydro Terminals Engineering Standard TS07-004-R2

HYDRO	**TERMINALS ENGINEERING STANDARD**	**No:** TS07-004-R2	
		Page: 1 of 3	
		Issued: 98-01-23	
	GROUNDING	**App'd.**	**D. Collett**
			D. Reeves

1.0 Scope

This standard covers the criteria for fence and station grounding for terminal stations and substations. See standard grounding detail drawings, (TS07-005-RO, Sheets 1 to 12) for installation details.

This standard is to be included with the Drawings when being issued in Construction Contracts.

2.0 Reference Standards

- ANSI/IEEE STD. 80; Guide for Safety in AC Substation Grounding.
- ERICO "Installers and Inspectors Guide," A-7D.

3.0 Grounding Standards

1. Exothermic Connections

   (i) All ground connections shall be of the exothermic type unless otherwise noted on drawings. Cadweld electrical connections manufactured by ERICO Products Inc. shall be the standard of acceptance.

   (ii) All Exothermic connections shall be tested with a solid blow from a 0.9 kg hammer. If any crack or movement is evident in the joint or if 30% of the moulded material is loosened, the connection shall be replaced.

2. Grounding System

   (i) The station ground grid shall be No. 4/0 stranded copper conductor buried at 400 mm below finished grade.

HYDRO	TERMINALS ENGINEERING STANDARD	No:	TS07-004-R2
		Page:	2 of 3
		Issued:	98-01-23

(ii) When possible the station ground conductor shall be placed adjacent to and in the same excavation as the cable trench.

(iii) All risers to station structures or equipment shall be No. 4/0 stranded copper and shall be secured at intervals of 1500 mm (minimum).

(viii) The ground conductor shall be cadwelded to all ground rods, corner posts, gate posts and to every fourth line post (i.e. every 12 m spacing) and to all fence posts along the sections of fence where transmission lines enter the station.

(ix) The fence ground conductor shall be installed under the sweep area of the gate as shown on drawings, to form an equipotential ground mat. The ground conductor shall be buried 400 mm below finished grade and 1m outside the fence.

(x) Barbed wire shall be connected to the fence ground at 12m intervals as shown on the Drawings.

4.0 Justification

Conductor

4/0 stranded copper conductor is used for fence and station grounding because the current carrying capacity of the conductor is sufficient for the maximum fault currents on the Hydro grid. The conductor is also of sufficient physical size to offer good protection from mechanical damage.

Connections

Cadweld connections are used for station grounding rather than mechanical connectors for the following reasons:

- Better electrical connection since conductors are fused together.
- Connections will not deteriorate with age.
- Connections cannot loosen or corrode.
- Connections will withstand repeated faults.
- Low material and labour costs.

HYDRO	TERMINALS ENGINEERING STANDARD	No:	TS07-004-R2
		Page:	3 of 3
		Issued:	98-01-23

Bonding

The fence ground grid is bonded to the station grid because inclusion of the fence within the ground-grid area increases the size of the area and thereby substantially reduces the ground-grid resistance, and hence the maximum ground-grid voltage rises as well. While the fence is now affected by this rise, this is not a concern if internal and perimeter voltage gradients of the grid are kept within acceptable limits.

5.0 Drawings

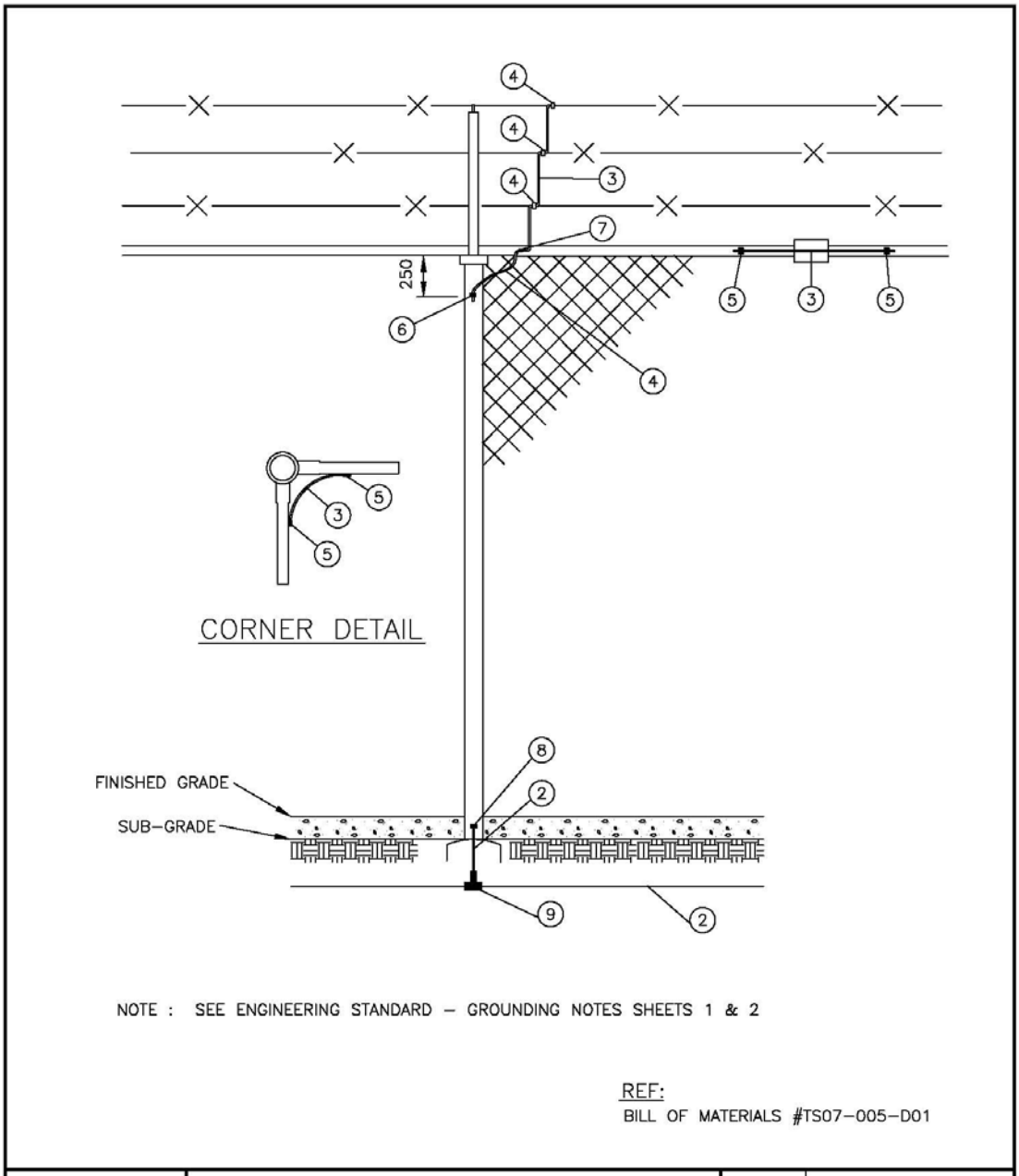
- Drawing # TS07-005-D01, Grounding Bill of Material
- Drawing #s TS07-005-D02 to D12, Grounding Details

ITEM No.	DESCRIPTION
1	GROUND ROD, COPPER COATED 20mm X 3000mm
2	WIRE, NO. 4/0 SD COPPER, BARE CONCENTRIC, LAY STRANDED, 19 STRAND
3	WIRE, NO. 2 SD COPPER, BARE CONCENTRIC, STRANDED
4	COPPER CRIMPIT – #2 SOL – #2 STR. (RUN) TO #8 SOL – #4 STR. (TAP) BURNDY YC2C4
5	CADWELD CONNECTION, TYPE VN, RH & LH, CABLE TO SIDE OF HORIZONTAL STEEL PIPE
6	CADWELD CONNECTION, TYPE VF, CABLE TO VERTICAL STEEL PIPE
7	CADWELD CONNECTION, TYPE HC, THRU HORIZONTAL CABLE TO SIDE OF HORIZONTAL STEEL PIPE
8	CADWELD CONNECTION, TYPE VS, CABLE 45° TO VERTICAL PIPE
9	CADWELD CONNECTION, TYPE TA, CABLE RUN & TAP
10	CADWELD CONNECTION, TYPE VS, CABLE 45° TO FLAT STEEL
11	CADWELD CONNECTION, TYPE GT, CABLE TO GROUND ROD
12	CADWELD CONNECTION, TYPE XA, CABLE TO CABLE 'X' CONNECTION
13	CABLE, WELDING – #4/0
14	SLEEVE [FOR BOTH ENDS OF 4/0 WELDING CABLE], CADWELD, TYPE S-429-F-2S16
15	STUD, THREADED, FOR FASTENING TO STRUCTURAL STEEL, THREAD – 6mmø X 20mm LONG, SHANK – 9mm LONG, HILTI TYPE EW6 H-20-9 P 12
16	CLAMP, 12mm P.V.C. COATED STEEL, 1 HOLE, SPACED AT 1000mm O.C. SCEPTER CS 10-1 OR EQUAL
17	CONNECTOR, GROUND FOR 2 – 4/0 COPPER CONDUCTORS TO FLAT STEEL, BURNDY TYPE GC2929
18	
19	MAT, GRADIENT CONTROL, APPROX. 1800mm X 1200mm GALVANIZED STEEL WITH 150mm SQUARE MESH
20	CONNECTOR, GROUND FOR COPPER CONDUCTOR TO FLAT STEEL, BURNDY GB29, RANGE 2/0-250MCM
21	SERVIT POST FOR COPPER CABLE TO FLAT STEEL, BURNDY KC28, RANGE 1-4/0
22	
23	
24	TERMINAL, NEMA DRILLED 2 HOLE FOR 4/0 BARE STRANDED COPPER, BURNDY NAR. 28
25	
26	
27	
28	
29	
30	WIRE, GALVANIZED STEEL, 7/16"ø, 7 STRAND
31	CONNECTOR, GROUND FOR 3 – 7/16"ø GALVANIZED STEEL WIRE, BURNDY GE2929 OR EQUAL
32	CLAMPS, STRAIGHT LINE, FOR ITEM '30' BURNDY CU4/ORE OR EQUAL
33	
34	
35	
36	

NOTE :
USE WITH DWG. NO.'S TS07-005-D02 TO TS07-005-D12.

HYDRO	TERMINALS ENGINEERING STANDARDS	APP'D.	J. Haynes
			D. Reeves
		ISSUED	2002-05-01
FENCE & STATION GROUNDING BILL OF MATERIALS		DRAWN	C. Harnum
		CHECKED	G. O'Keefe
		DWG. No.	TS07-005-D01-R3

PLOT 1:1

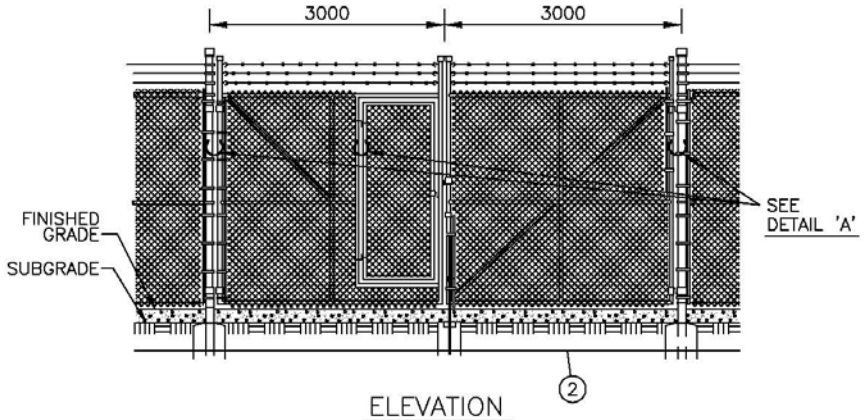


NOTE : SEE ENGINEERING STANDARD – GROUNDING NOTES SHEETS 1 & 2

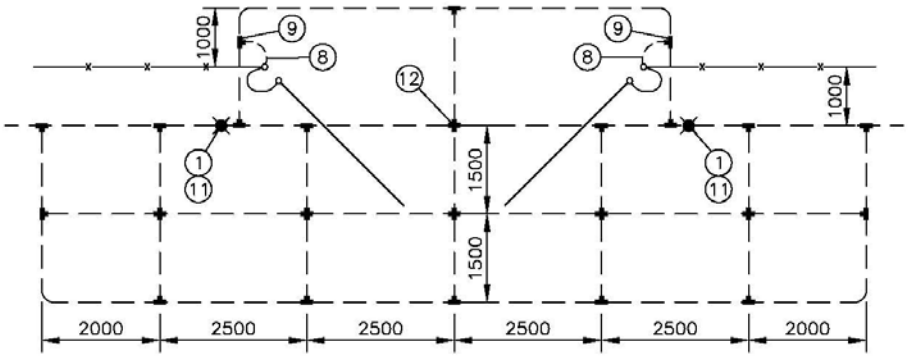
REF:
BILL OF MATERIALS #TS07–005–D01

HYDRO	TERMINALS ENGINEERING STANDARDS	APP'D.	J. Haynes
			D. Reeves
		ISSUED	2002–05–01
FENCE GROUNDING DETAIL		DRAWN	K.B.Ricketts
		CHECKED	G. O'Keefe
		DWG. No.	TS07–005–D02–R1

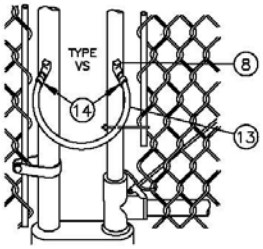
PLOT 1:1



ELEVATION



PLAN



DETAIL 'A'

NOTE

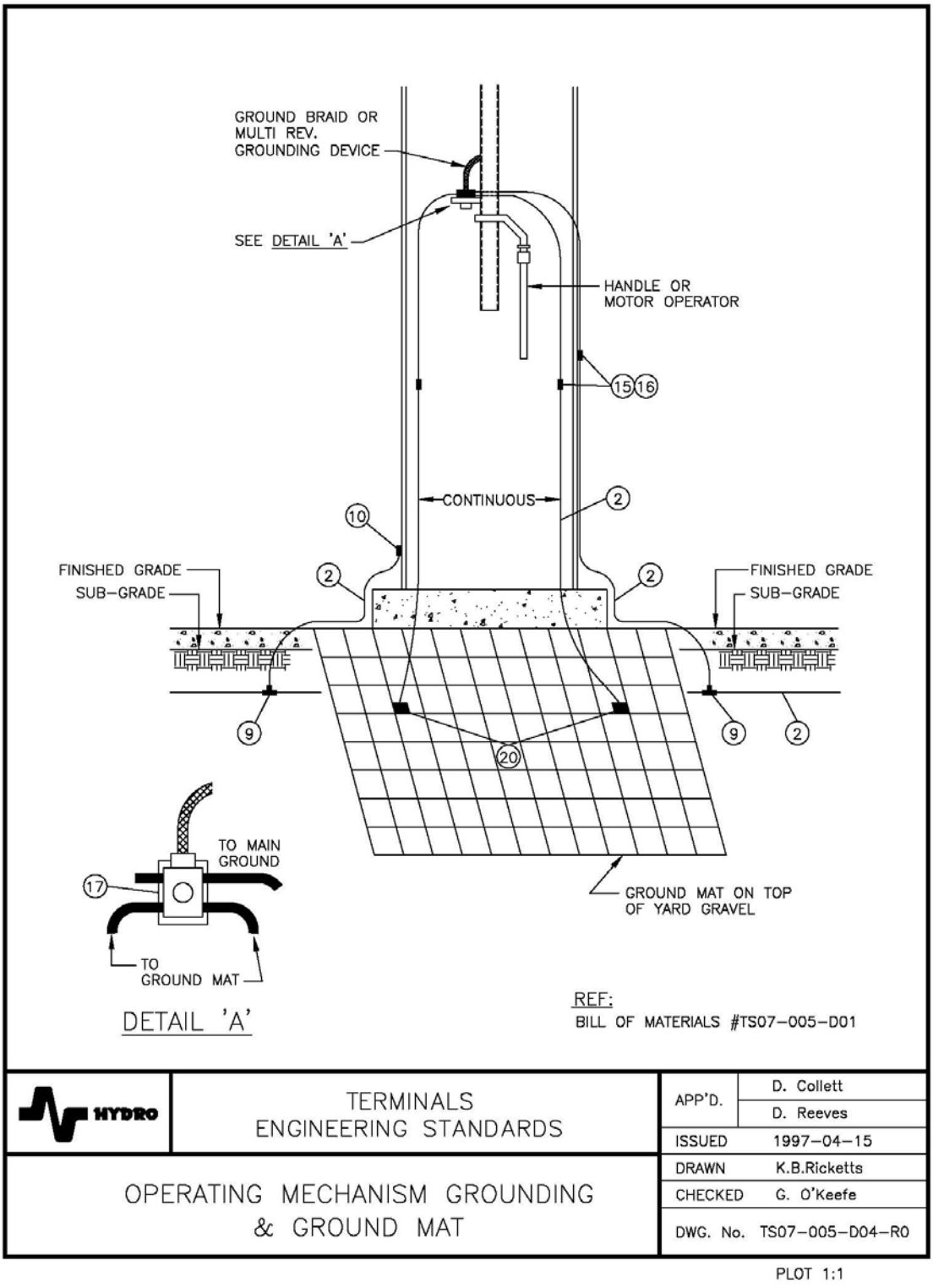
1. REFER ALSO TO CIVIL STANDARDS 'CHAIN LINK FENCING' C49–001 FOR FENCE INSTALLATION DETAILS.

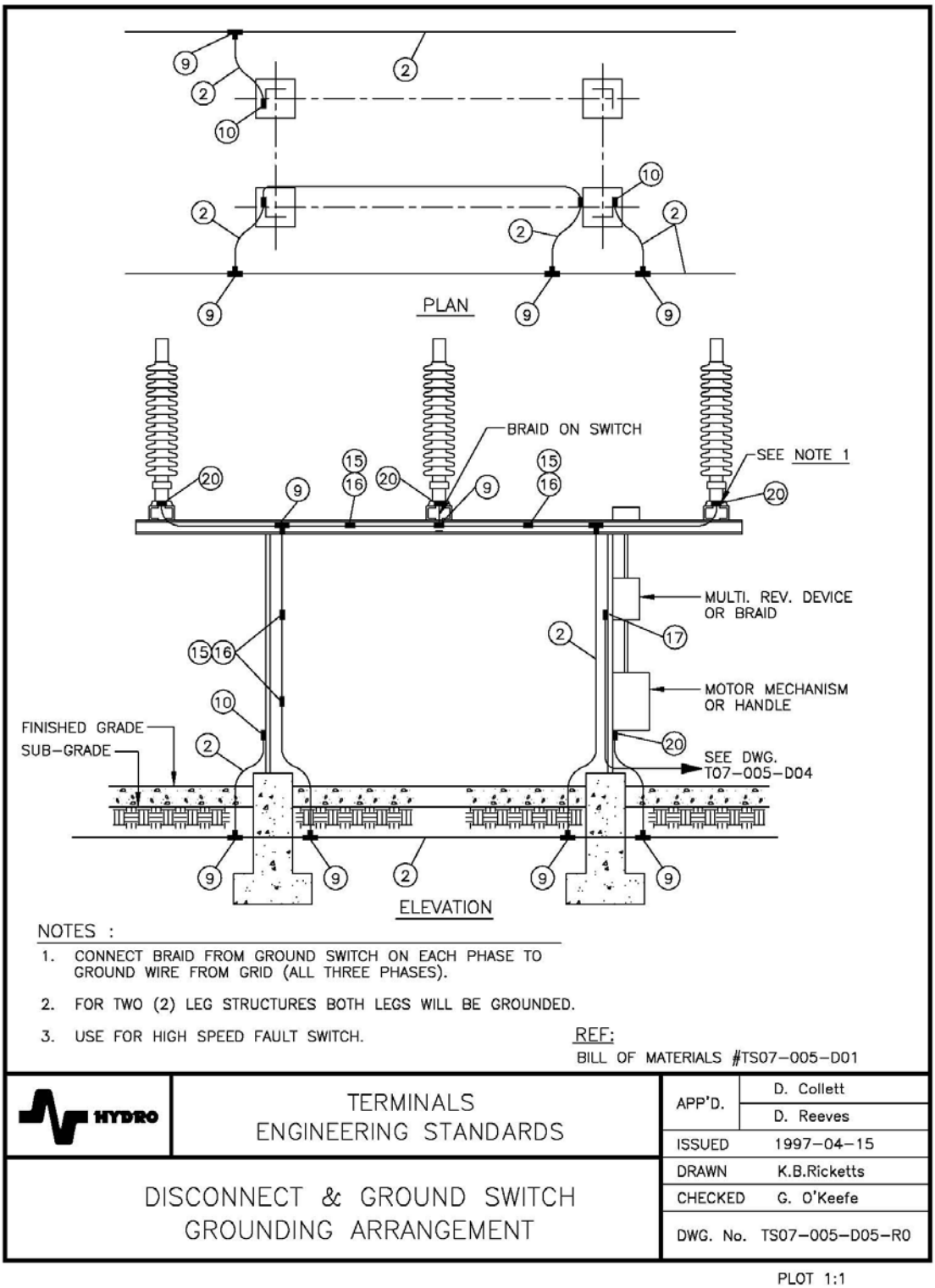
REF.

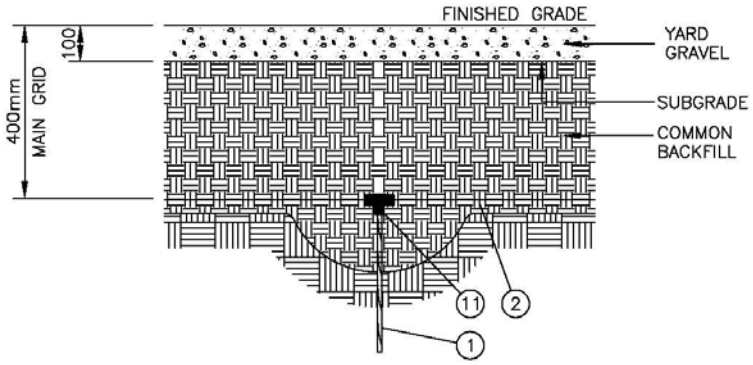
BILL OF MATERIALS #TS07–005–D01

HYDRO	TERMINALS ENGINEERING STANDARDS	APP'D.	J. Haynes
			D. Reeves
		ISSUED	2002–05–01
This Drawing contains intellectual property of Newfoundland and Labrador Hydro (HYDRO) and shall not be copied, used or distributed in whole or in part without prior written consent from HYDRO. Use of the drawing shall be restricted to purposes of prosecution of a contract with HYDRO.	**GATE GROUNDING DETAIL**	DRAWN	K.B. Ricketts
		CHECKED	G. O'Keefe
		DWG. No.	TS07–005–D03–R2

PLOT SCALE 1:1 CAD


GROUND BRAID OR
MULTI REV.
GROUNDING DEVICE
SEE DETAIL 'A'
HANDLE OR
MOTOR OPERATOR
15
16
CONTINUOUS
2
10
FINISHED GRADE
SUB-GRADE
2
2
FINISHED GRADE
SUB-GRADE
9
9
2
20
TO MAIN
GROUND
17
TO
GROUND MAT
GROUND MAT ON TOP
OF YARD GRAVEL
DETAIL 'A'
REF:
BILL OF MATERIALS #TS07-005-D01
HYDRO
TERMINALS
ENGINEERING STANDARDS
APP'D.
D. Collett
D. Reeves
ISSUED
1997-04-15
DRAWN
K.B.Ricketts
CHECKED
G. O'Keefe
OPERATING MECHANISM GROUNDING
& GROUND MAT
DWG. No.
TS07-005-D04-R0
PLOT 1:1


PLAN
BRAID ON SWITCH
SEE NOTE 1
MULTI. REV. DEVICE OR BRAID
MOTOR MECHANISM OR HANDLE
SEE DWG. T07-005-D04
FINISHED GRADE
SUB-GRADE
ELEVATION
NOTES :
1. CONNECT BRAID FROM GROUND SWITCH ON EACH PHASE TO GROUND WIRE FROM GRID (ALL THREE PHASES).
2. FOR TWO (2) LEG STRUCTURES BOTH LEGS WILL BE GROUNDED.
3. USE FOR HIGH SPEED FAULT SWITCH.
REF:
BILL OF MATERIALS #TS07-005-D01
HYDRO
TERMINALS
ENGINEERING STANDARDS
APP'D. D. Collett
D. Reeves
ISSUED 1997-04-15
DRAWN K.B.Ricketts
CHECKED G. O'Keefe
DISCONNECT & GROUND SWITCH
GROUNDING ARRANGEMENT
DWG. No. TS07-005-D05-R0
PLOT 1:1

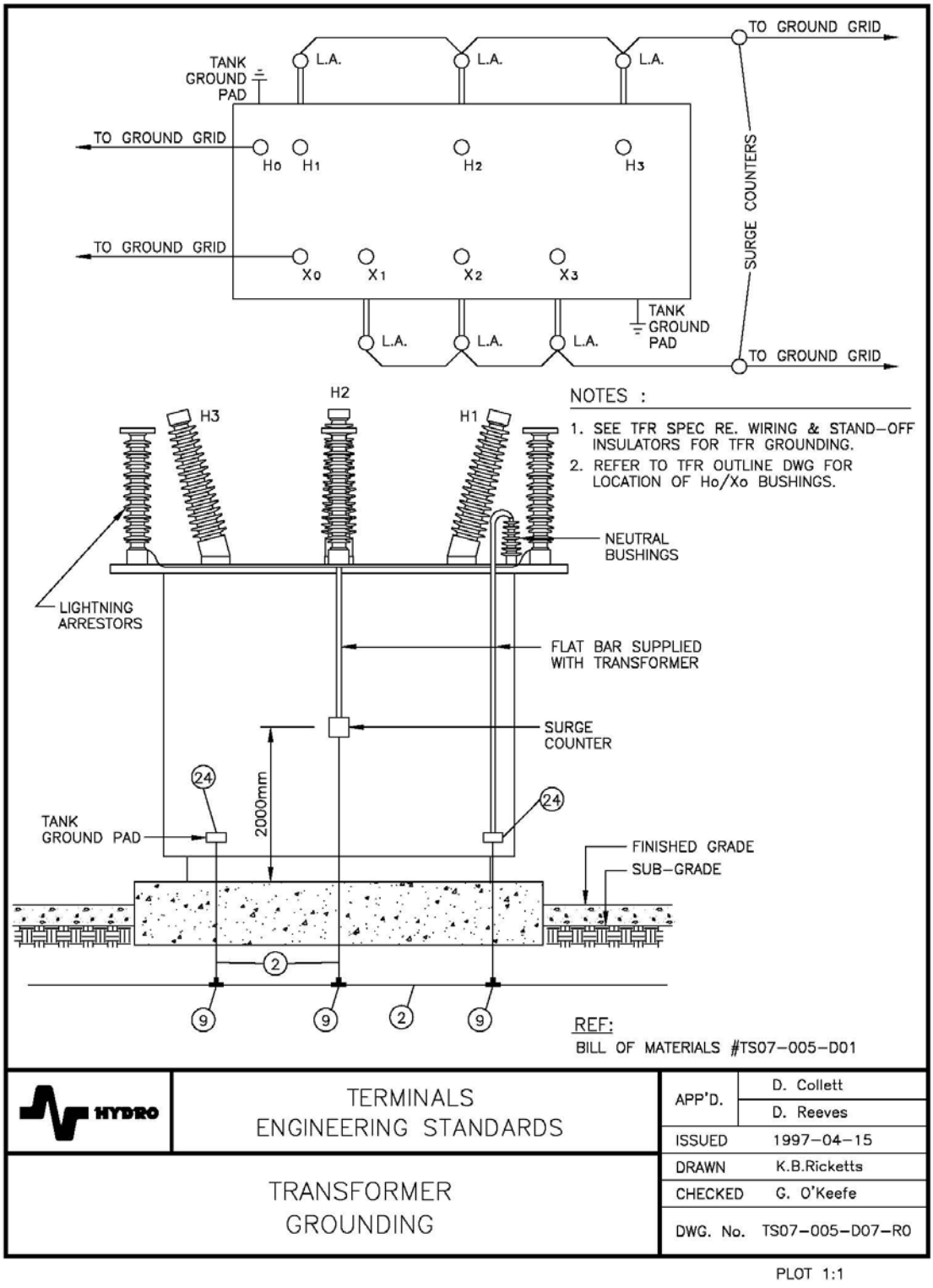


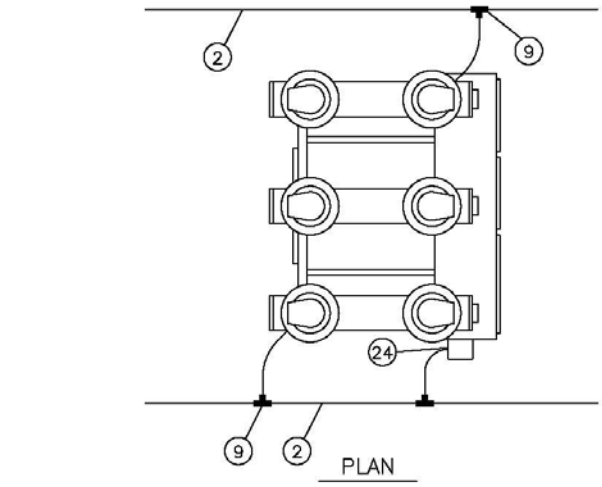
FENCE & STATION GRID

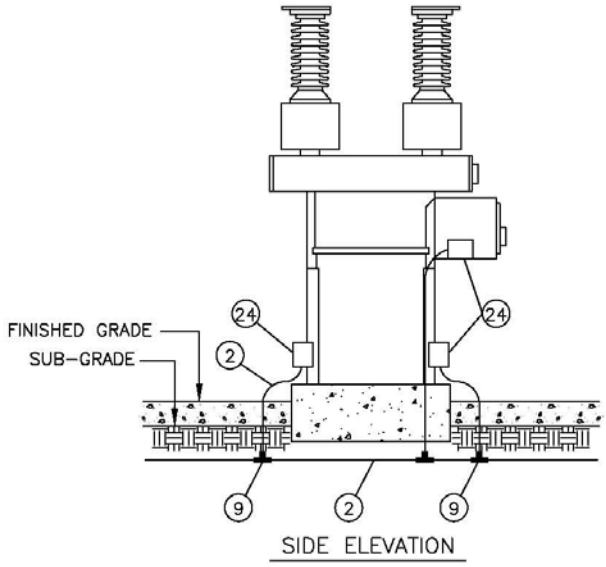
REF:
BILL OF MATERIALS #TS07–005–D01

HYDRO	TERMINALS ENGINEERING STANDARDS	APP'D.	D. Collett D. Reeves
		ISSUED	1997–04–15
TYPICAL GROUND ROD ASSEMBLY		DRAWN	K.B.Ricketts
		CHECKED	G. O'Keefe
		DWG. No.	TS07–005–D06–R0

PLOT 1:1


TO GROUND GRID
TANK GROUND PAD
L.A.
L.A.
L.A.
TO GROUND GRID
H0
H1
H2
H3
SURGE COUNTERS
TO GROUND GRID
X0
X1
X2
X3
TANK GROUND PAD
L.A.
L.A.
L.A.
TO GROUND GRID
H2
H3
H1
NOTES :
1. SEE TFR SPEC RE. WIRING & STAND-OFF INSULATORS FOR TFR GROUNDING.
2. REFER TO TFR OUTLINE DWG FOR LOCATION OF Ho/Xo BUSHINGS.
NEUTRAL BUSHINGS
LIGHTNING ARRESTORS
FLAT BAR SUPPLIED WITH TRANSFORMER
SURGE COUNTER
24
2000mm
24
TANK GROUND PAD
FINISHED GRADE
SUB-GRADE
2
9
9
2
9
REF:
BILL OF MATERIALS #TS07-005-D01
HYDRO
TERMINALS
ENGINEERING STANDARDS
APP'D.
D. Collett
D. Reeves
ISSUED
1997-04-15
DRAWN
K.B.Ricketts
CHECKED
G. O'Keefe
DWG. No.
TS07-005-D07-R0
TRANSFORMER
GROUNDING
PLOT 1:1

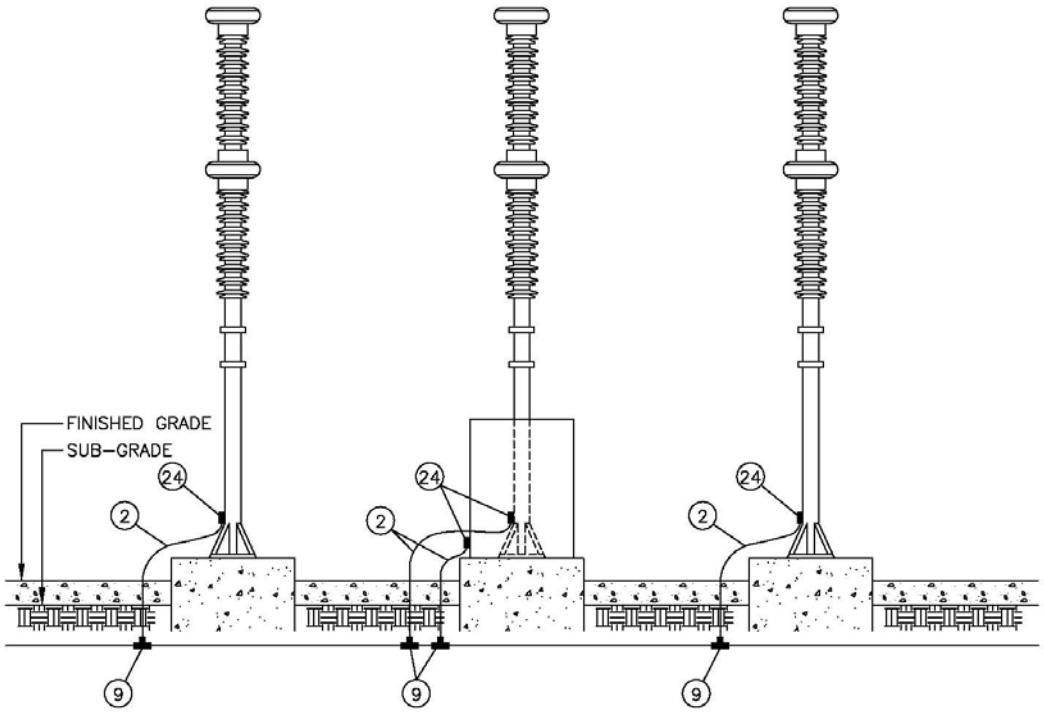




REF:
BILL OF MATERIALS #TS07-005-D01

HYDRO	TERMINALS ENGINEERING STANDARDS	APP'D. D. Collett D. Reeves
GROUNDING DETAILS DEAD TANK CIRCUIT BREAKERS		ISSUED 1997-04-15 DRAWN C. Harnum CHECKED G. O'Keefe DWG. No. TS07-005-D08-R0

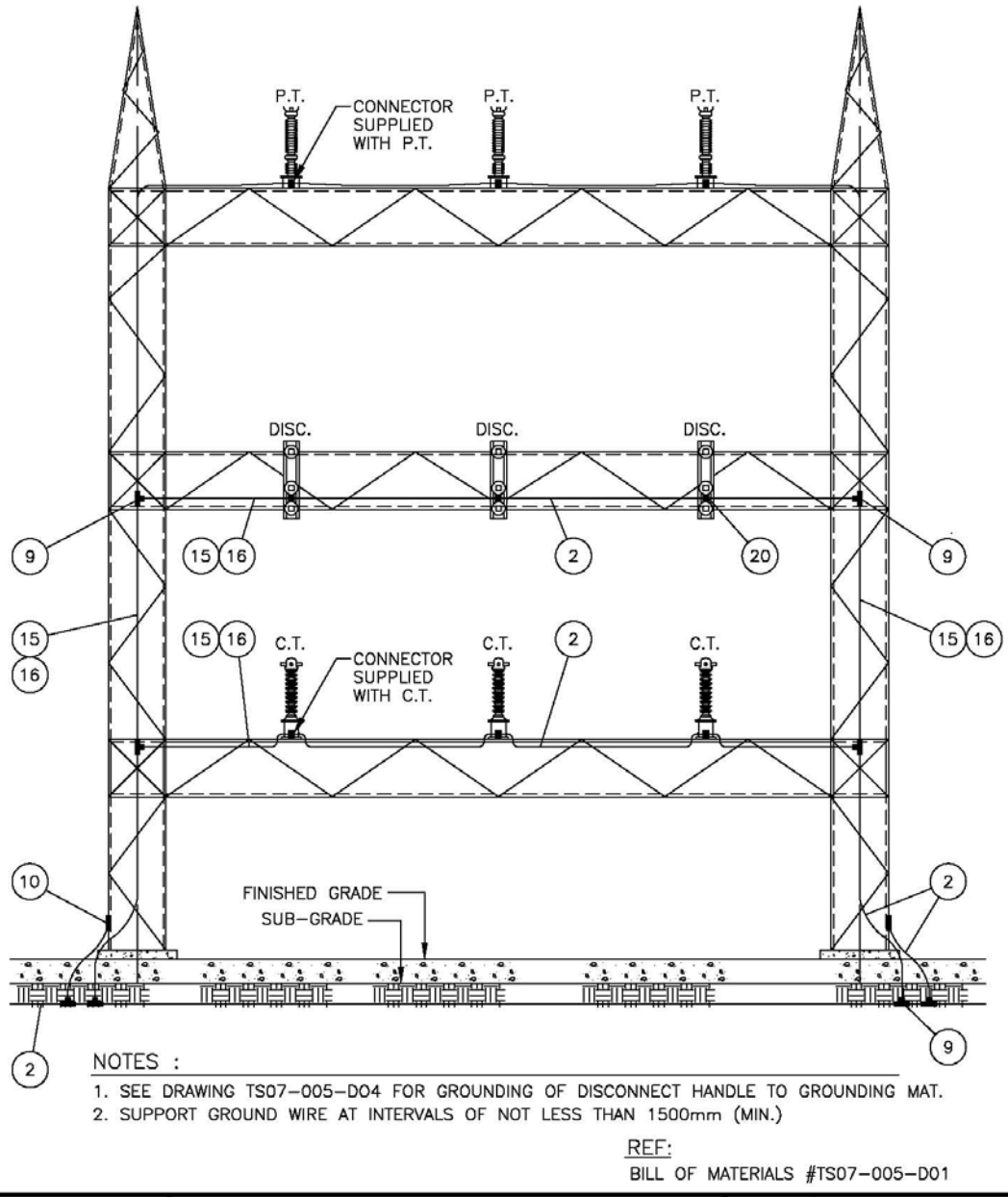
PLOT 1:1



REF:
BILL OF MATERIALS #TS07–005–D01

HYDRO	TERMINALS ENGINEERING STANDARDS	APP'D.	D. Collett D. Reeves
		ISSUED	1997–04–15
GROUNDING DETAILS LIVE TANK CIRCUIT BREAKERS		DRAWN	K.B.Ricketts
		CHECKED	G. O'Keefe
		DWG. No.	TS07–005–D09–R0

PLOT 1:1



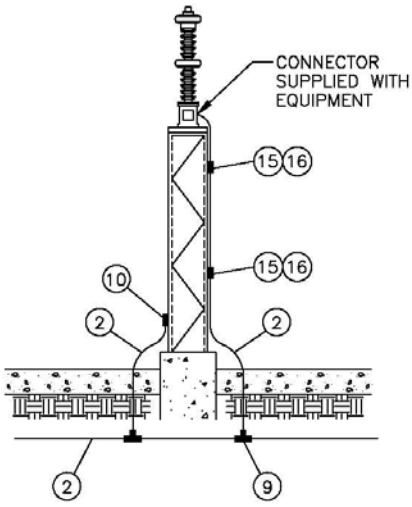
NOTES :

1. SEE DRAWING TS07-005-D04 FOR GROUNDING OF DISCONNECT HANDLE TO GROUNDING MAT.
2. SUPPORT GROUND WIRE AT INTERVALS OF NOT LESS THAN 1500mm (MIN.)

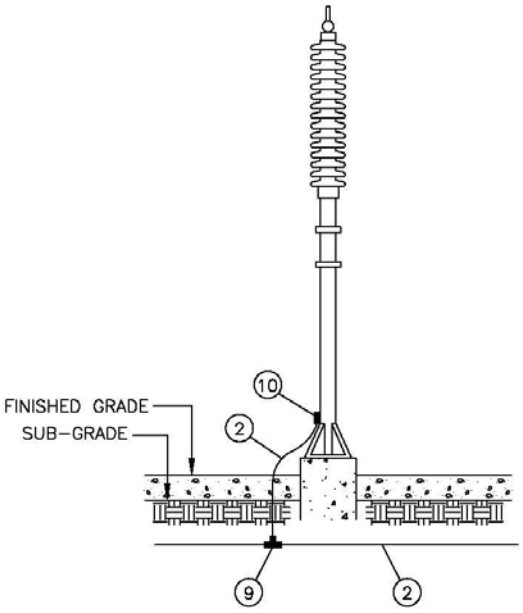
REF:
BILL OF MATERIALS #TS07-005-D01

HYDRO	TERMINALS ENGINEERING STANDARDS	APP'D. D. Collett / D. Reeves
		ISSUED 1997-04-15
GROUNDING DETAILS EQUIPMENT MOUNTED ON STEEL STRUCTURES		DRAWN K.B.Ricketts
		CHECKED G. O'Keefe
		DWG. No. TS07-005-D10-R0

PLOT 1:1



C.T.'S & P.T.'S ON
SEPARATE STRUCTURE

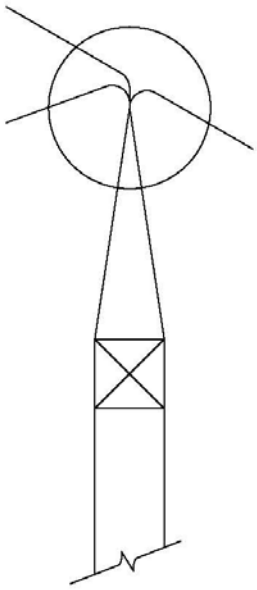


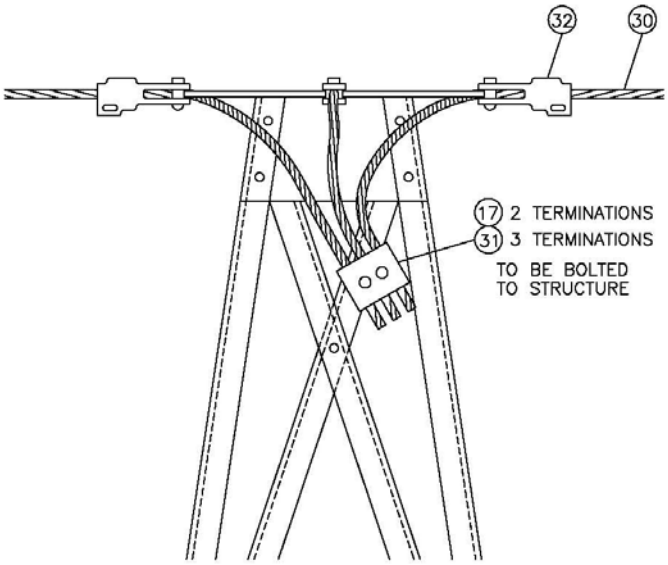
POST INSULATOR

REF:
BILL OF MATERIALS #TS07-005-D01

HYDRO	TERMINALS ENGINEERING STANDARDS	APP'D. D. Collett D. Reeves
GROUNDING DETAILS EQUIPMENT MOUNTED ON STEEL STRUCTURES		ISSUED 1997-04-15 DRAWN C. Harnum CHECKED G. O'Keefe DWG. No. TS07-005-D11-R0

PLOT 1:1





REF:
BILL OF MATERIALS #TS07–005–D01

HYDRO	TERMINALS ENGINEERING STANDARDS	APP'D.	D. Collett D. Reeves
		ISSUED	1997–04–15
GROUNDING DETAILS OVERHEAD GROUND WIRES ON STEEL STR.		DRAWN	C. Harnum
		CHECKED	G. O'Keefe
		DWG. No.	TS07–005–D12–R0

PLOT 1:1

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Replace Vehicles and Aerial Devices

NEWFOUNDLAND AND LABRADOR HYDRO

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A - Listing of Vehicles Proposed to be Replaced

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) operates a fleet of vehicles comprised of approximately 200 light duty vehicles (cars, pickups and vans) and 70 heavy duty trucks (aerial devices, material handlers and boom trucks).

The vehicle 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 Island electrical system.

The Transportation section of Hydro maintains a close liaison with other Canadian utilities through participation on the Canadian Utility Fleet Council and has established vehicle replacement guidelines, which consider the operating regime of the vehicles, as well as average replacement criteria used by other Canadian utilities.

2 PROJECT DESCRIPTION

This project proposes the replacement of 33 light duty vehicles and six heavy duty vehicles in accordance with the established replacement criteria for vehicle age and kilometers, as follows:

- Light duty vehicles - five to seven years or 150,000 kms
- Heavy duty vehicles -seven to ten years or 200,000 kms

As this project relates to the replacement of vehicles, there is no relevant data related to:

- Outage Statistics;
- Safety Performance;
- Environmental Performance; or
- Operating Regime.

3 EXISTING SYSTEM

3.1 Age of Equipment or System

Please see Appendix A for a detailed listing of the vehicles proposed to be replaced.

3.2 Anticipated Useful life

The anticipated useful lives of light duty and heavy duty vehicles are six years and five years, respectively.

3.3 Maintenance History

Please see Appendix A for the historical maintenance costs for vehicles proposed to be replaced.

3.4 Industry Experience

Vehicle replacement criteria across the Canadian utility industry vary dependant on location, exposure to harsh environmental condition, and of the service hours for the vehicle. While some variances exist, it is generally the case that vehicles are replaced in accordance with the replacement criteria utilized by Hydro (Section 2).

The Transportation section of Hydro maintains a database of the vehicle fleet which tracks individual unit history including acquisition date, kilometers and maintenance history. This information is updated on an ongoing basis and is utilized to determine annual vehicle replacements.

From a review of this database, units which meet the replacement criteria of age or kilometers are selected for replacement. The selection is then verified based on the vehicle maintenance history or ongoing maintenance issues.

3.5 Maintenance or Support Arrangements

The Hydro fleet of vehicles is primarily maintained by external service garages. In-house mechanical maintenance personnel are used to maintain the specialized utility equipment such as our aerial devices, booms and heavy off-road tracked equipment.

3.6 Availability of Replacement Parts

Replacement parts are readily available for all of the vehicles being replaced.

4 JUSTIFICATION

Hydro operates in diverse locations across the province, where it is critical that employees are provided with safe and reliable vehicles in order to provide least-cost and reliable electricity to customers.

This proposal provides for the normal replacement of on-road vehicles in accordance with Hydro's criteria as stated in Section 2.

As this project relates to the replacement of vehicles, there is no relevant data related to:

- Levelized Cost of Energy;
- Legislative or Regulatory Requirements;
- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Losses during Construction.

4.1 Historical Information

Table 1 shows the five-year history of the vehicle and aerial device purchases.

Table 1
Vehicle and Aerial Device Purchases 2003 - 2008

Year	Units Purchased		Budget ($000)	Actuals ($000)
	Vehicles	Aerial Devices		
2008 (F)	33	5	$1,826	
2007	23	9	$2,686	$2,218
2006	27	4	$1,732	$1,571
2005	27	1	$868	$768
2004	24	3	$1,531	$1,125
2003	28	15	$2,725	$2,589

4.2 Status Quo

Failure to replace units in accordance with replacement policy will lead to increasing maintenance costs and less reliable vehicles. Employees are expected to maintain the electrical system at any hour of the day, in any weather condition, and require dependable and safe vehicles for their work. As vehicles age, they experience increasing downtime, which could negatively affect response times for emergency outages or planned maintenance.

4.3 Alternatives

The light duty 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 most accurate if done in the year of replacement, as the current year fleet incentives offered by the manufacturers can be factored in. This proposal provides an estimate of the funding required to purchase the required vehicles. Should the subsequent cost/benefit analysis dictate, then costs will be adjusted to reflect the lease option.

5 CONCLUSION

This project provides for the normal replacement of fleet vehicles based on projected age and kilometers which is at the end of its life cycle and is no longer dependable.

5.1 Budget Estimate

Table 2
Budget Estimate

Project Cost:($ x1,000)	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	1,884.2	0.0	0.0	1,884.2
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
O/H, AFUDC & Escln	83.8	0.0	0.0	83.8
Contingency	188.4	0.0	0.0	188.4
TOTAL	**2,156.4**	**0.0**	**0.0**	**2,156.4**

APPENDIX A

Listing of Vehicles Proposed to be Replaced

Unit	Vehicle Type	Age at Retirement (Years)	Projected kms to July of 2009	Replacement Criteria			Life-to-Date Maintenance Costs ($000)
				AGE	KMS	Condition	
V1054	Car	6.1	138,869	X			$8,192
V1058	Car	5.4	170,033	X			$10,008
V1284	Car	4.1	204,974		X		$5,790
V1285	Car	4.1	202,906		X		$5,862
V1287	Car	4.1	208,242		X		$5,522
V1289	Car	4.2	249,281		X		$6,780
V1048	Mini Van	6.1	224,550	X	X		$9,510
V1055	Mini Van	5.9	196,089	X	X		$7,837
V1059	Mini Van	5.0	183,260	X	X		$6,700
V1095	Mini Van	6.8	169,153	X	X		$10,947
V2129	Mini Van	6.8	155,428	X	X		$11,462
V2106	Pick Up	8.1	156,488	X	X		$9,892
V2112	Pick Up	8.1	197,095	X	X		$11,947
V2113	Pick Up	8.1	208,536	X	X		$11,782
V2128	Pick Up	6.7	186,415	X	X		$11,247
V2134	Pick Up	6.8	209,322	X	X		$8,985
V2140	Pick Up	6.9	190,854	X	X		$15,214
V2147	Pick Up	7.1	169,682	X	X		$9,218
V2155	Pick Up	6.0	175,709	X	X		$25,750
V2166	Pick Up	5.0	163,083	X	X		$19,954
V2167	Pick Up	5.1	207,757	X	X		$14,755
V2169	Pick Up	5.0	134,231			X[1]	$16,607
V2170	Pick Up	5.0	202,189		X		$13,297
V2173	Pick Up	5.0	234,300	X	X		$9,792
V2174	Pick Up	5.0	157,707	X	X		$5,493
V2178	Pick Up	5.1	182,304	X	X		$19,851
V2545	Pick Up	9.5	182,677	X	X		$19,124
V2130	Van	6.7	197,370	X	X		$17,440
V2135	Van	6.7	200,116	X	X		$13,883
V2158	Van	6.0	194,065	X	X		$18,092

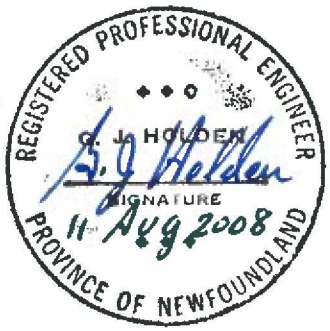
Unit	Vehicle Type	Age at Retirement (Years)	Projected kms to July of 2009	Replacement Criteria			Life-to-Date Maintenance Costs ($000)
				AGE	KMS	Condition	
V2159	Van	6.0	202,670	X	X		$14,959
V4478	Aerial Device	6.9	303,107		X		$52,727
V4481	Aerial Device	6.7	273,494		X		$46,447
V4429	Boom Truck	14.2	75,730	X			$50,415
V4453	Boom Truck	10.6	192,920		X		$101,128
V4465	Boom Truck	8.7	60,682		X	X[2]	$24,676
V4468	Boom Truck	7.5	59,685		X		$20,806

[1] This unit has had recurring drive train problems and is unreliable. The maintenance costs to-date are approximately $20,000.

[2] The chassis has low kilometers but the boom is over 20 years old. It is not economical to replace the boom and install it on an eight year old chassis.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Upgrade System Security

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

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1 INTRODUCTION

In Order No. P.U. 30 (2007) the Board of Commissioners of Public Utilities (the Board) directed Newfoundland and Labrador Hydro (Hydro) to file, with the 2009 Capital Budget Application, a report on the Upgrade System Security Program. This report provides a progress update on that program. The program was started in 2007 and is planned to be completed in 2010. The report describes the work that has been completed to date, and the plans and schedules are in place for the remaining work.

This program was originally proposed in the 2007 capital budget as a three-year program. The scope of the work was generally described as installing security fences/gates, outdoor lighting, closed circuit camera and card access/key systems. At that time, the exact details of the work were not specifically defined. It was planned that in the first year of the program, an engineering review would be conducted on the security requirements of all Hydro facilities. This review would generate a prioritized program for physical system security upgrades. Initially, it was viewed that the program could be completed in three years. Due to the complexity and extent of the work, the program is extended to four years. A summary of the annual costs (actual, approved and proposed) are contained in Table 2 in Section 5.1 of this report.

This program addresses physical security systems only. It does not address issues of security of Hydro's business information systems other than the 2008 pilot project for Smart Cards. This is managed and administered under a separate program. The scope and nature of the physical security upgrades can be classified into three categories: physical security; public protection; and telecommunications.

Physical security upgrades consists of installing physical infrastructure to guard against unauthorized entry, theft and sabotage. Examples of this are the installation of electronic card access systems, surveillance cameras, intruder alarms, and additional fencing. Public protection upgrades consist of higher fencing, area lighting, tower anti-

climb devices and high voltage warning signs. These measures should deter and prevent members of the public from entering dangerous locations and being injured. The telecommunication portion of the project consists of conducting a review of Hydro's telecommunications networks using the North American Electric Reliability Corporation Cyber-Security Standard as a benchmark. The correction and upgrades of any deviation from this standard will be presented in future capital budgets. These physical security upgrades are vital to maintaining reliable service to its customers.

2 PROJECT DESCRIPTION

In 2007, preliminary engineering was done to develop a plan and schedule of work for the program. A listing of physical security deficiencies across the system was developed and then compared with industry standards to isolate those locations and sites where physical security upgrades were required. The upgrades were then grouped into common categories and prioritized by year, based on the nature of the deficiency. This prioritized listing of upgrades forms the basis for the scheduling of work.

Due to a late start on the project in 2007, and the extensive nature of the overall system review, the amount of physical work able to be completed in 2007 was less than originally planned. In 2007 there were three main items of work planned to be undertaken. These were installation of anti-climbing devices on communications towers; installation of high voltage warning signs; and a review of the telecommunications network design.

The installation of anti-climbing devices was completed on 13 communications towers across the system in 2007. In 2008, devices will be installed on a further 11 towers. Once this portion of the work is completed, all communication towers which present possible public hazards will be fitted with anti-climbing devices. The installation of these devices should deter and prevent members of the public from climbing communication towers and possibly injuring themselves.

The second work item launched in 2007 was the installation of “High Voltage” signs at all fenced sites containing energized equipment. This work is being done as operations personnel travel to the various sites for their routine maintenance activities. All sites across the system should be fitted with warning signs by the end of 2008. As with the anti-climbing devices, these warning signs will help to deter members of the public from entering energized areas and possibly causing injury to themselves.

The third work item started in 2007 was an engineering review of Hydro's telecommunications network. The purpose of this review is to evaluate Hydro's design using the North American Electric Reliability Corporation (NERC) Cyber-Security Standard as a benchmark. To complete this work, Hydro intends to engage an external consultant who has experience in NERC compliance assessments. The estimated cost for this portion of the program was in the order of $55,000. However, preliminary discussions with external consultants on the scope of work planned, revealed that the engineering costs would more likely to be in the order of $250,000. Consequently no progress was made in 2007. In 2008, the program will be re-scoped, and a formal Request for Proposal will be issued to engage a consultant. The consultant's deliverable will be a final report with recommendations on the upgrades required to Hydro's systems.

Due to the late start of the project in 2007, work on only two of the three items could be launched in 2007. The actual cost for these two items is $136,600. This leaves $531,300 carried forward to 2008. These funds, combined with the $906,300 approved for 2008, totals $1,437,600 to be utilized in 2008. And, for 2009 and 2010 there is a further $1,469,000 being proposed. Now that the plan and schedule for the program has been developed, greater progress on the upgrades is achievable. The current plan for four years of the program is summarized in Table 1. The 2007 and 2008 proposals were submitted and approved as single-year projects while this proposal is multiyear for 2009 and 2010.

Table 1
Security System Costs

Description	# of Locations	(Actual) 2007	2008	2009	2010
Communication Tower Anti-Climb Devices	24	$85,000	$85,000		
Telecommunication Design Review	N/A		$55,000		
High Voltage Warning Signs	System Wide	$51,600			
Property Access Card Reader Systems	11		$385,000	$68,000	
Two Level Access Card Pilot Project	Hydro Place		$80,000		
Security Camera Systems	45		$495,000	$159,000	$302,000
Intruder Alarm Systems	40		$124,000	$100,200	$95,000
Property Fencing Upgrades	30		$213,600	$275,000	$200,000
Fuel Tank/Structure Anti-Climb Devices	25			$100,000	$55,000
Property Lighting Upgrades	10			$65,000	$49,800
	TOTAL	$136,600	$1,437,600	$767,200	$701,800

2.1 Communication Tower Anti-Climb Devices

The communication towers are lattice steel structures which are very easy for members of the general public to climb. This work item consists of the installation of physical barriers, guards and signs at the base of the towers. This will prevent unauthorized persons from being able to climb the tower and possibly injuring themselves. This part of the work was started in 2007 and will be finished in 2008. Figure 1 below shows such an anti-climb device installed on a communication tower.

Figure 1 – Anti-Climb Device

2.2 Telecommunications Design Review

As described above, the purpose of this review is to evaluate Hydro's design using the North American Electric Reliability Corporation Cyber-Security Standard as a benchmark. Outcomes and recommendations from the consultant's report will be used to support and justify future capital budget proposals.

2.3 High Voltage Warning Signs

This part of the work consists of the installation of high voltage warning signs on all Hydro energized fenced sites. Sign installation was started in 2007 and will be completed in 2008. Figure 2 below shows the design of these high voltage warning signs.

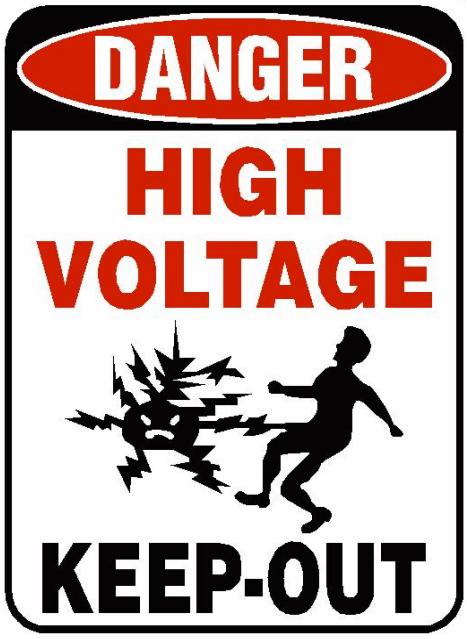

Figure 2 – High Voltage Warning Sign

2.4 Property Card Access Systems

At each of Hydro's Bay d'Espoir Hydroelectric Generating Station and Holyrood Thermal Generating Station there is a manned guardhouse in place to control access to the site. For other locations, the lack of a manned guardhouse makes it necessary to implement alternative methods to restrict access. In some locations across the Hydro system, such as Hydro Place and Bishop Falls Regional Office, there are currently access restrictions in place. A property card access system, where each individual who is granted access to a site is issued a unique access card, is installed. This card can be programmed to grant access to as many sites as required. As well, the system can be set up to limit access to certain individuals during certain hours, or even deny an individuals access instantly if required. This part of the program consists of the installation of additional card access systems for all generating plants, other regional offices and depots throughout the system. All systems will be connected together and coordinated through one central database.

2.5 Two-Level Card Access Pilot Project

The scope of this work consists of testing a “Smart Card” with Hydro’s existing card access system. The concept is to have a two-level authorization for entry to high security areas, such as control rooms, and for accessing Hydro computers. Presently, if an employee card is lost or stolen, it can be used by a third party to gain entry to a high security area. With two-level card access, an employee card must be swiped and a password entered on a keypad to gain entry. A keypad was chosen as the second level of security, as opposed to technologies such as retinal or biometric scanning, as it provides a high secondary level of security for minimal cost. This second level of security will decrease the possibility of unauthorized access.

With regards to accessing Hydro computers, the Government of Newfoundland and Labrador, in January 2008, issued a series of directives for the protection of personal and other confidential information stored on government agency computers. One of these directives indicated that:

“it is not permissible to copy personal and/or confidential government information to portable storage devices (e.g. unencrypted flash drives, memory sticks, CDs)”.

This being the case, any Hydro laptop computer (a type of portable storage device) now requires encryption of its data. The same “Smart Card” described above can be used as an encryption key for a Hydro computer. This means that the data on a computer can only be read with the proper employee card and password. A third party would require both the correct smart card and the correct password to access any of the information contained on a particular computer.

This pilot project will be executed in 2008 with the goal to determine if a two-level card access system is a viable solution to restricting access to sensitive areas and Hydro computers. Should this pilot project be successful, a separate 2009 capital budget proposal will be developed to extend the two-level system.

2.6 Security Camera Systems

At some locations on the Hydro system, there are security cameras already in service. As part of this security system upgrade program, these camera installations will be expanded, and new cameras will be installed at other critical locations such as generating stations and terminal stations throughout the system. Monitoring of these locations is critical to the continued reliability of the system. This portion of the work will be completed over a two-year period. This program will allow access to all cameras within the Hydro system, from any computer, with the proper approval. The program will give Hydro the ability to monitor any plant or terminal station throughout the system at any given time. As well, the recording capabilities of this system will allow for video review at the time of an incident.

2.7 Intruder Alarm Systems

Intruder alarms will be installed at generation plants and terminal stations across the system. Again, this will be implemented over a three-year period. The improved monitoring of the various plants and stations on the Hydro system is critical for the continued safety and security of the system. Intruder alarms will sound an alarm in the Energy Control Center when unauthorized entry to a plant or terminal station is made.

2.8 Fencing Upgrades

The scope of this part of the program is to upgrade facility fencing all across the system. While existing fencing is compliant with current utility standards, these upgrades will focus on critical locations where fencing needs to exceed standards in order to provide that extra level of security. In some locations, terrain, brush or snow depths make unauthorized entry to Hydro sites possible. The fencing upgrades will involve increasing fence height; clearing brush and timber away from fences; installing additional fencing to secure certain critical areas; and clearing patrol routes along perimeter fencing to

enable security personnel to patrol properties. This part of the program will secure the facilities from unauthorized entries and also provide public protection from energized equipment. Figure 3 below shows a fence which requires upgrades due to insufficient height.

Figure 3 - Snow Levels

2.9 Fuel Tank and Structure Anti-Climb Devices

In addition to the telecommunication towers, Hydro has a number of fuel storage tanks and other potentially dangerous structures across the province. Unauthorized access to this equipment could result in theft or sabotage to fuel systems or personal injury. Hydro has prioritized the various sites and over a two-year period anti-climbing devices and signage will be installed to prevent theft, vandalism and/or personal injury. Figure 4 below shows an example of a fuel storage tank which requires an anti-climb device.

Figure 4 – Fuel Storage Tank Requiring Anti-Climb Device

2.10 Lighting Upgrades

In designated locations near generating plants and fuel storage areas, there is insufficient area lighting for effective security monitoring. The locations have been prioritized and over a two-year period, additional area lighting will be installed. This measure will increase the level of security for Hydro employees and also enable security personnel to more effectively monitor activity in and around critical facilities.

3 EXISTING SYSTEM

Hydro owns and operates one thermal generation plant; four gas turbine generation sites; 12 hydroelectric generation plants; 31 diesel generation sites; 66 terminal stations; and ten regional offices. All of these sites contain specialized equipment and/or energized equipment which must be protected for the enhanced reliability and security of the system.

The details of Hydro's existing security system deficiencies are confidential and should not be released into the public record. Hydro is willing to provide to the Board this information "in camera". The descriptions in Section 2 provide a general understanding of the nature of the existing systems and what upgrades are included in this program.

3.1 Age of Equipment or System

As this project mainly involves the addition of new systems and infrastructure to fill deficiencies in Hydro's existing physical security infrastructure, the age of the existing systems has no relevance to this project.

3.2 Major Work or Upgrades

There are no upgrades to report, as this project involves the addition of new systems and infrastructure.

3.3 Anticipated Useful life

Infrastructure upgrades, such as fencing and anti-climb devices, have an anticipated service life of 30 years. Electronic equipment, such as security cameras, card access systems and alarm systems, has an anticipated service life of 15 years.

3.4 Maintenance History

As this project mainly involves the addition of new systems and infrastructure, the maintenance history of the existing systems has no relevance to this project.

3.5 Outage Statistics

To date, a breach of Hydro's physical security system has not resulted in any significant outages. Through the implementation of this project, Hydro will ensure that the production of energy will not be affected by such a breach in the future.

3.6 Industry Experience

Investigations conducted by Hydro's consultants identified deficiencies in Hydro's system-wide physical security. The reports generated by the consultants suggested many possible upgrades to put Hydro on par with the utility industry standard for physical security measures. Hydro has weighed the risks and benefits of these suggested upgrades, and determined that there are a number of upgrades required to bring Hydro up to the industry standard. This condensed list of upgrades will be completed through this capital work.

3.7 Maintenance or Support Arrangements

Once installed, the majority of the maintenance and support of the physical security system will be performed by Hydro personnel. In the case of the card reader systems and other electronic devices, maintenance will be executed through maintenance agreements with external service providers.

3.8 Vendor Recommendations

As this project involves the purchase and installation of new systems and equipment, vendor recommendations will be taken into account when decisions are being made regarding the selection and application of the technology.

3.9 Availability of Replacement Parts

For the new equipment being purchased, parts and servicing will be readily available. As well, for each system installed, spare parts will be purchased and stored for use when needed.

3.10 Safety Performance

A large portion of this project involves upgrades to Hydro's public protection systems. Through the installation of higher fencing, area lighting, tower anti-climb devices and high voltage warning signage, Hydro can deter and prevent members of the public from entering dangerous locations.

3.11 Environmental Performance

There are no specific environmental issues related to this project.

3.12 Operating Regime

The details of the operation of Hydro's various security systems are confidential and will not be released into the public record.

4 JUSTIFICATION

This project is justified on the requirement for Hydro to maintain a secure and reliable system. Initially, Hydro's Risk and Insurance department, working in conjunction with Hydro's insurers, set out to determine the deficiencies which existed in the physical security of Hydro's existing system. The investigations conducted by Hydro's consultants identified deficiencies in Hydro's system-wide physical security. The reports generated by the consultants suggested many possible upgrades to put Hydro on par with the utility industry standard for physical security measures. Hydro has weighed the risks and benefits of these suggested upgrades, and determined that there are a number of upgrades required to bring Hydro up to the industry standard. While these upgrades will not decrease Hydro's insurance premiums, they will help limit Hydro's liabilities, especially with regards to public protection, and stabilize Hydro's future insurance rates.

In addition to industry standards, there are a number of established professional and legal standards which set an industry specific standard of care precedent. In order for Hydro to reduce its liability, it is imperative that Hydro's security program meet or exceed the industry's practices in policy, procedure, physical and technical security countermeasures. Hydro considers these security upgrades, on a corporate wide basis, as being vital to maintaining reliable service to its customers.

Failure to bring Hydro's physical security measures up to par with the industry standard leaves Hydro vulnerable to acts of vandalism, theft, or sabotage. In addition, failure to upgrade Hydro's public protection measures, especially since specific deficiencies have been identified, creates liability issues for Hydro. Hydro must ensure that its public protection systems and procedures effectively limit dangers to the public.

4.1 Net Present Value

A net present value calculation is not applicable to the project.

4.2 Levelized Cost of Energy

As this project does not relate to a generation source, levelized cost of energy is not applicable.

4.3 Cost Benefit Analysis

A cost benefit analysis is not applicable for this project.

4.4 Legislative or Regulatory Requirements

There are no specific legislative or regulatory requirements which affect this project.

4.5 Historical Information

Since this project consists of the installation of new equipment on the system, comment on the history of the equipment is not applicable.

4.6 Forecast Customer Growth

The forecasted customer load on the system has no affect on this project.

4.7 Energy Efficiency Benefits

There are no issues related to energy efficiencies associated with this project.

4.8 Losses during Construction

There will be no losses during construction associated with this project.

4.9 Status Quo

These upgrades are necessary to protect Hydro assets from vandalism, theft and sabotage and to protect the public from injury. For these reasons Hydro cannot maintain the status quo.

4.10 Alternatives

There are no alternative solutions for this project. The only way to address the deficiencies in Hydro's physical security system is to complete the upgrades outlined in this project.

5 CONCLUSION

Upon completion of these upgrades, Hydro facilities will be on par with the industry standard for physical security system requirements. These upgrades will strengthen the security of Hydro facilities, increase public protection, and reduce Hydro's liabilities by increasing Hydro's level of due diligence with regards to public safety.

5.1 Budget Estimate

The costs shown in Table 2 for 2007 are the actual expenditures to the end of 2007. The approved budget for 2007 was $667,000. As described in Section 2, $531,300 of this was carried forward to 2008. The cost shown for 2008 is the approved budget for 2008. Costs shown for 2009 and 2010 are the amounts proposed to be approved in the 2009 capital budget application.

Table 2
Budget Estimate

Project Cost:($ x1,000)	**2007**	**2008**	**2009**	**2010**	**Beyond**	**Total**
Material Supply	119.3	305.0	87.5	147.0	0.0	658.8
Labour	7.9	305.0	139.3	140.5	0.0	592.7
Consultant	1.1	70.0	0.0	0.0	0.0	71.1
Contract Work	0.0	0.0	381.0	254.0	0.0	635.0
Other Direct Costs	0.0	54.0	10.8	9.5	0.0	74.3
O/H, AUDI & Escln	8.3	99.9	86.8	95.8	0.0	290.5
Contingency	0.0	72.4	61.9	55.1	0.0	189.4
TOTAL	**136.6**	**906.3**	**767.2**	**701.8**	**0.0**	**2,511.8**

5.2 Project Schedule

The schedule of major milestones for each year of this proposal is as shown in Table 3 below.

Table 3
Project Schedule

Activity	**Milestone**
Design Complete	March 2009
Tenders Called	April 2009
Award of Tenders	May 2009
Commence Installations	June 2009
Complete Installations	October 2010
Completion of Work	November 2010

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Hydro Place
Energy Efficiency Improvements

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

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B - Project Cost/Benefit Analysis

1 INTRODUCTION

Hydro Place, the Newfoundland and Labrador Hydro (Hydro) main office building, was constructed in the late 1980s utilizing construction practices and design based on cost-effective choices and technology available at the time. It is currently in its nineteenth year of continuous use. Hydro Place is shown in Figure 1 below.

Hydro Place houses the Energy Control Centre (ECC) which operates 24 hours per day. It is home base for approximately 450 employees, on six floors.

Figure 1 - Hydro Place

2 PROJECT DESCRIPTION

An energy audit of Hydro Place was conducted in 2007 by Energy Management Services Limited of St. John's. This project involves the implementation of the recommendations outlined in the energy audit report.

This project consists of five initiatives which, once implemented, will reduce the energy consumption of the building and result in a reduction in annual energy costs. The estimated cost of the retrofit project is $832,600 and will result in an estimated annual operating cost savings of $147,826 including energy savings and reduced operating and maintenance costs. The initiatives required to achieve these savings are:

- New energy management controls;
- Computer and Communications Rooms cooling modifications;
- Lighting redesign and retrofit;
- Variable frequency drives on the chilled water pump and cooling tower fan; and
- Commissioning and rebalancing of the heating, ventilation and air conditioning (HVAC) system.

2.1 New Energy Management Controls

The proposed new control system will replace the pneumatic-electric controls for the baseboard heating with solid state relays. In addition, a revised control strategy will be implemented to more efficiently manage the energy demand of the building during normal operation and transition between unoccupied to occupied mode. The new system will include installation of new software and an energy management platform.

2.2 Computer and Communications Rooms Cooling Modifications

The proposed modification to the Computer and Communications Rooms existing cooling arrangement will utilize the building HVAC system's excess capacity when

available to cool the computer rooms, minimizing the use of the existing dedicated room air conditioning units. The dedicated room air conditioning units will be used only when the building is in unoccupied mode or when the building HVAC system is fully utilized.

2.3 Lighting Retrofit

The proposed lighting retrofit is a redesign of the existing lighting system to reduce lighting levels to current Illuminating Engineers Society (IES) standards and, where cost effective, the replacement of existing lights with energy efficient lighting. In limited use areas such as mechanical and utility rooms, no retrofits are planned, due to the limited operation of the lights in these areas. The replacement tubes, ballasts, and lamps have longer service lives than existing devices which results in reduced operating and maintenance costs.

2.4 Variable Frequency Drives

The proposed retrofit of two existing large motors with variable frequency drives will allow the speed of the motors to be varied in response to system requirements, controlling them from the energy management program. The motors involved are the cooling tower fan motor and the chilled water pump motor which are 30 hp and 60 hp, respectively.

2.5 System Commissioning and Rebalancing

Commissioning and rebalancing the HVAC system after the retrofit will ensure the proper operation of the system within the control limits required for effective building energy management.

For further information related to the planned retrofits, refer to Appendix A - Energy Audit Final Report.

3 EXISTING SYSTEM

The existing HVAC control system is the original system installed in the building and is mid 1980s technology. This control system is outdated and cannot fully perform the functions required to provide comfort and energy management for the building. The proposed project will replace the control system, add an energy management platform, and replace the existing pneumatic-electric controls with solid state relays for improved control of building heating and cooling.

The existing building lighting system is also original to the building and consists primarily of a unique lighting fixture type which is no longer manufactured, but can be retrofit with new components. These fixtures are located in the majority of the office areas in the building. The current lighting levels in the building exceed standards for modern lighting design.

3.1 Age of Equipment or System

The existing building HVAC systems are original to the building and are operated and controlled by 20-year old control technology. The building has been occupied for 19 years.

3.2 Major Work or Upgrades

There have been no major upgrades to the building HVAC and lighting systems since the original construction of the building. The cooling system chiller was replaced in 2005 as a result of the phase out of R-11 refrigerant for environmental reasons. The replacement chiller is a modular type which operates in a staged manner in response to the building cooling requirements. The cost of the chiller replacement was $200,782.

3.3 Anticipated Useful Life

The building has an estimated service life of 50 years. The building mechanical system components vary in their anticipated useful life. Air handling units have an approximate life of 50 years, cooling towers 25 to 30 years, with smaller components such as dampers, cooling and heating coils, and motors having shorter lives, likely being replaced a number of times during the life of the major components. Lighting ballasts have an expected life of 50,000 hours, or approximately 16 years, based on 12 hours per weekday usage.

3.4 Maintenance History

In the last five years, annual preventive and corrective maintenance costs combined have averaged approximately $110,000. This includes all regular maintenance as well as repair or replacement of failed components and troubleshooting and resolution of system problems.

The five-year maintenance history for the building HVAC system is shown in the Table 1 below.

Table 1
Five-yearMaintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2007	92.0	12.6	104.6
2006	95.8	23.1	118.9
2005	83.2	34.6	117.8
2004	73.1	44.8	117.9
2003	72.6	13.0	85.6

3.5 Outage Statistics

There are no outage statistics related to this project.

3.6 Industry Experience

The Building Performance Index (BEPI) standardizes energy consumption data for meaningful comparisons, and uses total annual utility consumption relative to the facility's size and type, while providing weather-normalized measures and regional benchmarks across the country. Industry experience related to the energy efficient operation of office buildings similar to Hydro Place indicates that its BEPI is poor in comparison to buildings of similar use. Office buildings in St. John's typically have a BEPI between 15 and 50, with the lower and upper values being the extremes of good and bad, respectively. It is expected that this project could reduce the BEPI to 21 from 30.5 at Hydro Place (Refer to Appendix A - Energy Audit Final Report, p. 16).

The United States Environmental Protection Agency (USEPA), in conjunction with stakeholders, developed the national energy performance rating as a screening tool which helps to assess performance and identify those buildings which offer the best opportunities for improvement. It is a type of external benchmark that helps energy managers assess how efficiently their buildings use energy relative to similar buildings. The tool used to determine a building's energy performance rating is the Energy Star Portfolio Manager. The system's one to 100 scale allows for a quick understanding of how a building is performing.

An evaluation of the Hydro Place facility utilizing the USEPA Energy Star Portfolio Manager gives Hydro Place an energy performance rating of 22, as compared with an industry average of 50 and an Energy Star rating of 75 or better, which indicates top performance (Refer to Appendix A - Energy Audit Final Report, p. 17).

3.7 Maintenance or Support Arrangements

The preventative maintenance of the HVAC system is currently contracted to an outside company, Johnson Controls. The value of this work is just under $100,000 per year.

Corrective maintenance is also performed by Johnson Controls as necessary, at an additional annual average cost of approximately $25,000 per year.

3.8 Vendor Recommendations

No vendor recommendations were solicited for this project.

3.9 Availability of Replacement Parts

Spare parts are readily available for the equipment being retrofit.

3.10 Safety Performance

There are no safety issues related to this project.

3.11 Environmental Performance

The environmental benefits of this project result from the reduction in annual energy consumption which will be realized once the project is completed. The estimated energy savings of this project are the equivalent of an annual reduction of 912 metric tons of CO_2, or having 185 fewer cars in use.

3.12 Operating Regime

The Hydro Place building is in continuous use. The building is fully occupied approximately 40 hours per week, but is considered occupied for 12 hours per day, five days per week for full operational purposes. The ECC operates on a shift schedule, and is occupied 24 hours per day.

4 JUSTIFICATION

The implementation of the recommended energy efficiency initiatives at Hydro Place will result in a reduction in annual energy consumption of approximately 30 percent. This will translate to an estimated annual energy savings of $109,126. These initiatives, once completed, will also reduce operating and maintenance costs by approximately $38,700.

Modern controls, as will be installed in this project, will allow better control of the building's HVAC system resulting in a reduction in energy consumption as well as an increase in comfort for the building occupants.

4.1 Net Present Value

A net present value analysis is not appropriate for this project, as there are no alternatives to compare.

4.2 Levelized Cost of Energy

As this project does not involve a generation source, levelized cost of energy is not applicable.

4.3 Cost Benefit Analysis

A cost benefit analysis of this project indicates that the project pays for itself within nine years of the proposed efficiency improvements being made. The analysis was made over a 15-year study period, as this is the anticipated life of the largest component of the proposed improvements, the new energy management control system. Hydro's 2008 escalation indices of 3% were used as a conservative estimate for electricity rate increases. A copy of the cost benefit analysis result is given in Appendix B.

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements related to this project.

4.5 Historical Information

As this is not a recurring project, there is no historical information available.

4.6 Forecast Customer Growth

This project is not affected by customer growth.

4.7 Energy Efficiency Benefits

This project is being completed to increase the energy efficiency of the operation of the building. The projected annual reduction in building energy consumption, based on the energy audit performed, is 1,355,918 kWh.

4.8 Losses during Construction

There are no losses during construction, as the building will remain open during the retrofit. Work will be completed at times appropriate for the work being carried out, in order to minimize impact on building operation and comfort level.

4.9 Status Quo

Retaining the status quo will result in higher energy consumption and higher operating costs than is needed to operate the building and less than ideal comfort levels for the building occupants.

4.10 Alternatives

There are no viable alternatives for this project.

5 CONCLUSION

The Hydro Place Energy Efficiency Improvements will reduce the annual energy consumption of the building by approximately 30 percent and result in savings of both energy and maintenance costs. The primary component of the project is replacement of the existing HVAC control system which will result in the majority of the savings realized through the completion of the project, approximately 76 percent.

5.1 Budget Estimate

The estimated cost of the Hydro Place Energy Efficiency Improvements is $832,600. Below is the detailed cost breakdown for the project.

Table 2
Budget Estimate

Project Cost	($000)
Labour	16.3
Contract Work	650.0
O/H, AFUDC, and Escalation	99.7
Contingency	66.6
Total	**832.6**

The contract work portion of the project cost is detailed in Table 3 below.

Table 3
Detailed Project Cost

Improvement	Cost ($000)
New Energy Management Controls	430.0
Computer Rooms Cooling	22.0
Lighting Retrofit	160.0
VFDs	15.0
System Commissioning and Rebalancing	23.0
Total	**650.0**

5.2 Project Schedule

Table 4 provides the planned project schedule.

Table 4
Project Schedule

Activity	**Milestone**
Project Initiation	February 2009
Contract tender call	March 2009
Contract award	April 2009
Installation	June - October 2009
Project Closeout	November 2009

APPENDIX A

HYDRO PLACE ENERGY AUDIT FINAL REPORT

ENERGY AUDIT FINAL REPORT

For:

Newfoundland & Labrador Hydro

Hydro Place, 500 Columbus Drive

St. John's, NL

prepared by:

Energy Management Services Ltd.

Dated: January 2, 2008

Hydro Place Energy Audit

This document contains confidential and proprietary information. It is provided for the sole internal use of Newfoundland & Labrador Hydro and shall not be used or disclosed in any manner or for any purpose not authorized in writing by Energy Management Services Ltd (EMS).

The savings associated with the retrofit measures are based on the services that EMS performs as part of designing, installing and post-retrofit energy management of the measures. We provide turnkey Energy Retrofit/Energy Management solutions taking responsibility of ensuring the savings are obtained and installing the best quality products, that will perform and last, are used, as well as partnering with construction firms that fully understand total facility operation and control, for the retrofit of facilities, is paramount for a successful long-term project investment.

We would like to thank Anthony Jones, Bill Day, Simone Kielley, Mike Whelan and the many Newfoundland & Labrador Hydro employees who helped us many times to understand the facility operations, locating information and input and/or recommendations for this proposal preparation

Hydro Place Energy Audit

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Hydro Place Energy Audit

1. Executive Summary

Energy Management Services has completed an in-depth survey of the facility and has carried out extensive analyses of operational costs, through a review of utility bills over a three-year period. Numerous opportunities for cost reductions through carefully integrated equipment and modernization upgrades have been identified.

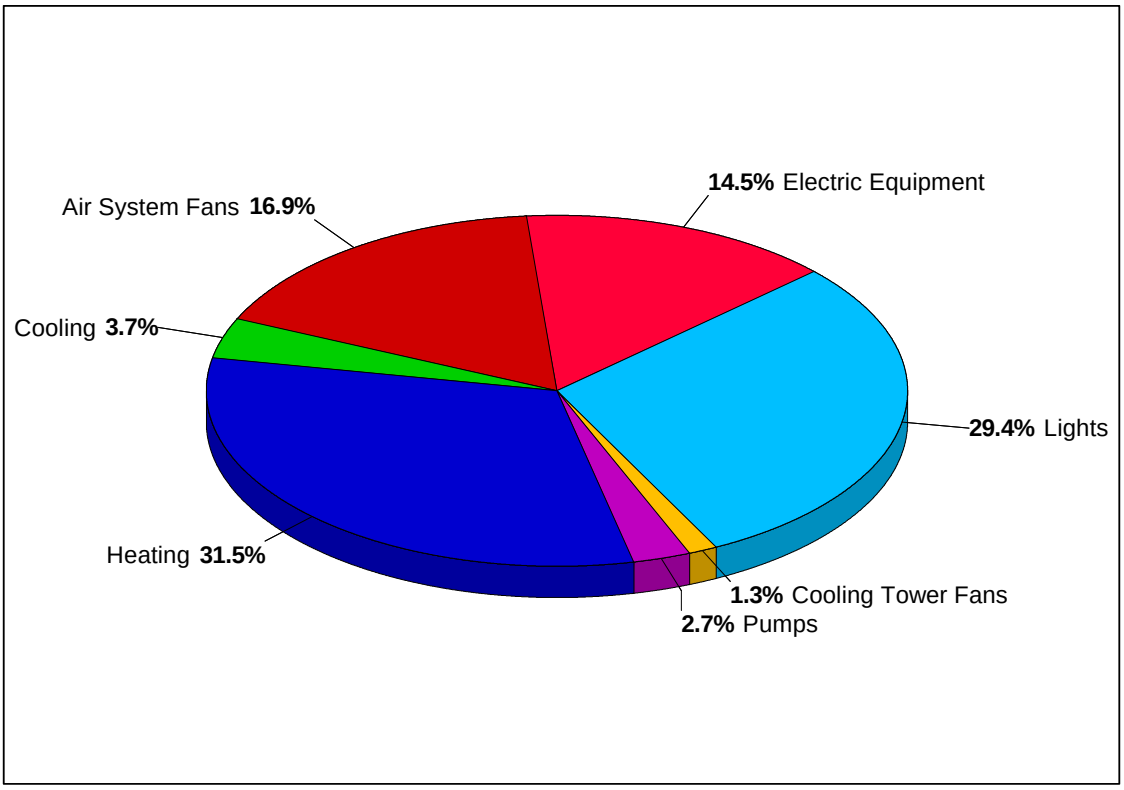
Energy Use:

The building presently uses 4,494,000 kWhr of energy per year (based on twelve months of energy bills for 2006-2007) at a cost of $348,347.00, excluding taxes. This is far too high. The expectation is that these figures could be reduced to 3,138,082 kWh and a cost of $239,221.00

The main reasons for the excess energy use are:

- Over ventilation, too much outside air to be heated or cooled.
- Cooling and heating occurring at the same time due to the obsolete control system.
- Incorrect temperature settings on air handling equipment controls, poor scheduling.
- Motors using too much power; should be replaced with smaller, high efficiency motors.
- Inefficient, outdated lighting.

Figure 1: Reference case profile of Hydro Place's energy use:



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The proposed technical plan will enhance comfort conditions within the facility while reducing sustainable utility costs by $109,126.00 and operating costs by $38,700.00 for a total estimated savings of $147,826.00, annually and reducing greenhouse gas emissions by 912 metric tons. The savings and increased comfort conditions are realized by implementing a comprehensive capital improvement program project estimated to be $650,000.00. The project simple payback is 4.4 years.

We understand that Hydro is moving forward on the development of energy efficiency programming for all electricity consumers. This has lead to an increased emphasis on internal energy efficiency to be in step with their programs, the provincial direction as set in the recent Energy Plan and to realize the very real cost savings and employee comfort benefits that accompany these types of projects.

Coupled with the facility improvements, a major step is an implementation of an employee energy awareness program to instill an energy efficient employee culture and ensure a long-term buy-in on Hydro's efforts to continually improve their energy footprint.

2. Savings Measures:

The following table is a summary of recommended measures that will improve the operational costs and comfort at Hydro Place.

The measures and associated savings are stand-alone items, one measure can be implemented independently of another and they are not prioritized. The implementation priority is more a function of payback, vs. budget vs. timing. For example; item 4 would best be done in the winter, given the requirement of removing cooling pumps from service. Electrical Demand cost savings are included in the Annual Energy Savings figures. Costs include material, labor, engineering and commissioning. Repairs to equipment found to be defective are not included. Lighting savings would include the associated heating penalty / cooling credit since the new lighting arrangement would produce less heat.

Table 1 – Measure Overviews:

Item #	Recommended Measure	Cost: (see Note 1)	Annual Energy Savings	Annual Energy Usage (kWh)	Annual Energy Savings (kWh)	Annual O&M Savings
	Baseline Energy Usage		Energy Cost 06-07: $348,347	4,494,000		
1.	New Energy Management Controls	$430,000	$83,000	3,509,915	984,085	$27,000
2.	Computer Rooms “free cooling”	$22,000	$6,028	3,403,802	106,113	
3.	Lighting Retrofit	$160,000	$17,825	3,178,802	225,000	$11,700
4.	VFD, Chilled Water Pump and Tower Fan	$15,000	$2,272	3,138,802	40,000	
5.	Ventilation Commissioning and Rebalancing	$23,000	See Note 3			
	Total	**$650,000**	**$109,126**	**3,138,082**	**1,355,198**	**$38,700**
	Simple Payback, years (See Note 2)		**4.4**			
	Total GHG Emissions Reductions (See Note 4)	**Metric Tons CO2:**	**912**	**Cars not used:**	**185**	

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Note 1: Total costs and savings do not include HST, do include; materials, labor, consulting and engineering.

Note 2: Simple Payback includes O&M Savings, (costs of maintenance and repairs that will not be required as a result of the retrofit).

Note 3: Savings for Ventilation Commissioning and Rebalancing are difficult to quantify, these steps would be required after a major retrofit to ensure the design parameters are met. This will confirm that airflows are correct, and all equipment operates as designed.

Note 4: Net annual Greenhouse Gas Emission Reduction = 912 metric tons CO2 per year, which is equivalent to 185 Cars and Light Trucks not used.

Hydro Place Energy Audit

Figure 2: Monthly Energy Costs - Hydro Place Existing

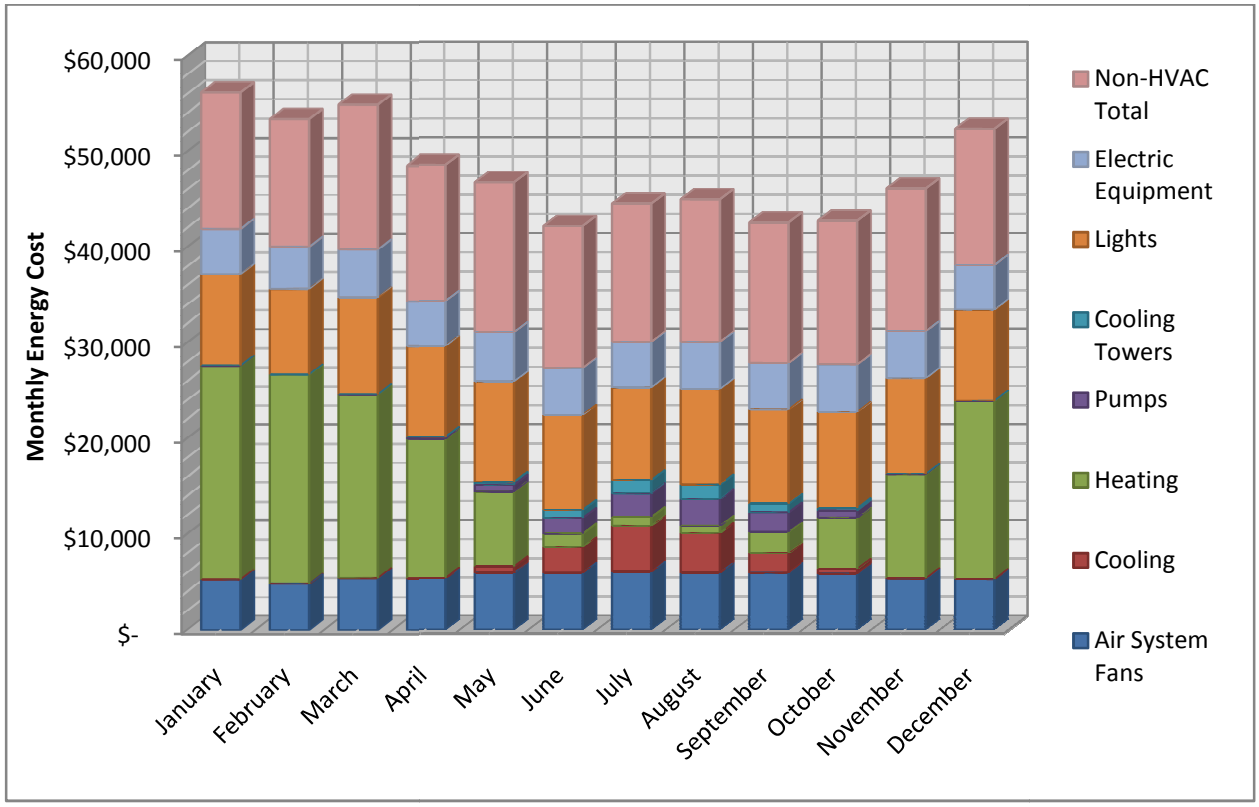

Figure 3: Monthly Energy Costs - Hydro Place Renovated

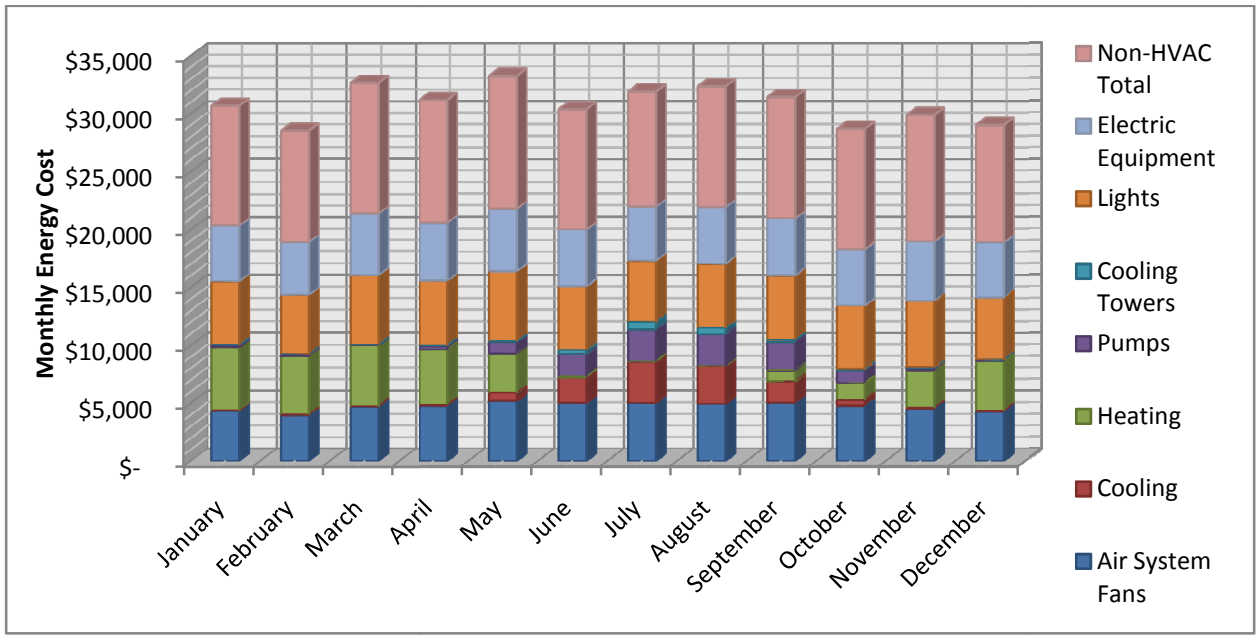

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Table 2: Measures Descriptions:

Item #	Recommended Measure	Description	Estimated Life Expectancy of Measure (years)
1.	New Energy Management Controls	Replace all of the existing controls with modern electric digital controls. The existing control systems are outdated and cannot perform the functions required to properly provide comfort and energy optimization. Install Variable Speed Drives and premium efficiency fan motors. Install new software and energy management platform.	15
2.	Computer Rooms "free cooling"	Modify the existing cooling arrangement such that when cool outdoor air is available; use it to cool the computer rooms, saving operation of the dedicated computer room air conditioners.	indefinite
3.	Lighting Retrofit	Redesign the lighting systems such that energy efficient lights replace existing. and overlighting is eliminated	15
4.	VFD, Chilled Water Pump and Tower Fan	Vary the speed of these large motors according to the load by installing Variable Frequency Drives and controlling them from the energy management platform	15
5.	Ventilation Commissioning and Rebalancing	Recalculate the heating and cooling loads and adjust the settings accordingly. Measure and adjust the airflows according to the design.	10

Hydro Place Energy Audit

Table 3 -Terminology and Abbreviations used in this report

Abbreviation	Name	Description
AHU	Air Handling Unit	An air delivery system consisting of fans, cooling and heating coils, air filters and controls. Air from a floor would be ducted in and out of an AHU.
ASHRAE	American Society of Heating, Refrigeration and Air conditioning Engineers	Regulating body who set the standards for mechanical systems design
BEPI	Building Energy Performance Index	A simple method of benchmarking the energy performance of a building. Buildings with similar occupancies in the same geographic area can be compared by dividing 12 months of energy use by the square footage. Units = kWhr/ft^2/year
BTU/hr	British Thermal Units per hour	Defines heating or cooling capacity, also 1 ton of cooling = 12,000 BTU/hr.
CFM	Cubic Feet per Minute	A measurement of airflow, imperial units
HVAC	Heating, Ventilation and Air Conditioning	
IES	Illuminating Engineers Society	Regulating body who set the standards for lighting design
l/s	Liters per second	A measurement of airflow, metric units
kVA	Kilo Volt Amp	A measure of peak energy use, as applied to Demand (which reflects the total kW draw of the building for its highest 15 minute period per month.)
kW	kilowatt	A thousand watts
kWhr	Kilowatt hour	A thousand watts consumed in one hour, a measure of continuous energy use
OA	Outdoor air	Brought into the building for ventilation and cooling
OAT	Outdoor Air Temperature	Used in the control terminology
RA	Return air	Air going back to an air handling unit
SA	Supply air	Conditioned air sent to the space (a T would denote temperature)
T8, T12	Fluorescent light tube designations	The number indicated the tube diameter in eights of an inch. T8 are generally high efficiency, with T5 also available.
VAV	Variable Air Volume	A control box with a motorized damper that regulates the amount of air that is sent to a space for fresh air, cooling and/or heating.
VFD	Variable Frequency Drive	An electrical device used to vary the speed of a motor
W/SqFt	Watts per square foot	Indicates average lighting or building power usage

3. Facility Overview

The building was constructed in the late 1980's and the building construction was very good, with the design of the mechanical systems based upon cost-effective choices of the technology available at the time.

Progress in electronics has impacted the controls industry such that if the building were being designed today, choices would be made such that modern controls would allow better control and comfort of this building.

The existing control system has limitations such that replacement of the existing control system is warranted. The deficiencies of the existing systems include:

1. No direct feedback from the spaces being heated or cooled from the pneumatic thermostats.
2. Poor space temperature control, simultaneous heat and cooling occurring, many zones have no airflow control, only one thermostat serving multiple zones (does not give good coverage).
3. Higher kilowatt consumption and electrical demand usage than the building should have.

These would be rectified through the recommended retrofits.

The existing control systems use a great number of mechanical devices that require constant adjustment and are prone to failure. As well, motor technology now provides us with high efficiency motors that can use variable speed controllers to adjust fans and pumps to match the exact requirements of the systems.

Modern high-efficiency lighting provides long life, low power usage, less heat input to the space (for lower cooling costs) and better color for improved occupant comfort. Our experience is that lighting retrofits have always dramatically increased occupants satisfaction with their environment.

The building energy use needs to be closely monitored to optimize savings. The best approach is a knowledgeable on-site energy manager who is familiar with the building mechanical and control systems. Alternately, an energy management company can be contracted to perform the monitoring and supervision. Modern energy management systems have monitoring and reporting tools incorporated into their software to accommodate good energy management.

Hydro Place Energy Audit

Building Construction and Envelope

The building, opened in 1989 consists of six floors. We reviewed the architectural drawings to determine the wall and roof construction and calculate the R-values. The wall construction results in a typical R-21.5 and the roofs R-22.2. It was observed that the roof insulation value appeared to be low for the time period in which the building is constructed. ASHRAE has proposed increases to the minimum required roof and wall insulation levels in Standard 90.1 the national model energy code for commercial buildings. If the increases are adopted, the above-deck roof insulation requirements currently at R-15 would go to R-20. Hydro Place currently exceeds standard R-values. A good practice is that anytime roofing work is carried out, opportunities to improve the roof insulation are examined. Attempting to upgrade the roof insulation for its own sake is not cost-effective.

There is a significant amount of glass area that is double glazed with an exterior tint. It appears that the tint is more for aesthetics than energy efficiency. Most of the windows have operable sections, causing many issues with comfort and with heating and cooling control, this is a very difficult situation to reverse. The design of the building is such that there are a greater number of exposed surface for heat transfer than would be seen in a typical "cube" building with equivalent floor area, resulting in greater heating and cooling loads. This is accounted for in the simulation model. An additional challenge is that the building has a significant southern exposure, also requiring that the southern areas need cooling, while the northern areas, being shaded, want heating at the same time.

Leakage and infiltration:

We recorded the temperature trend data from the building automation system. A good indicator of building envelope efficiency is how quickly it "coasts down" when the control system switches from occupied to unoccupied mode. The average building will typically drop 3-5°C. Hydro Place does not. This points then to other probable causes, either that night set back temperatures are not set correctly on the thermostats and/or the unoccupied period is too short, (most likely) the building does not switch to unoccupied until 10:00P.M.

In our examination of the building we found that window and door seals were generally in good repair. We do not believe that building envelope is a major source of energy waste. The receiving area doors between shipping and the mail room, that lead to the office and corridor areas should be changed to automatic operation to close them when not required to be open, to reduce outdoor air infiltration. We observed huge volumes of air blowing from the receiving area to the offices and corridor when the receiving exterior doors are open. This was noticeably worse when the outside wind was high. This infiltrated air must be heated or cooled as it e the facility, causing energy waste and occupant discomfort.

4. Audit Methodology

In performing the energy audit of the building the following tasks were undertaken:

1. Review of the electrical bills
2. Benchmark the energy use relative to other, similar buildings
3. Review of the design drawings and specifications
4. Examination of the current building control system operation and performance
5. Discussions with operations, maintenance and service personnel.
6. Interviews with building occupants
7. Measurement of airflows, temperatures, motor current draw.
8. Examination of window seals, door weather stripping
9. Examination of the installed lighting systems
10. Create a model of the current building heating, cooling and energy use in software
11. Design retrofit measures and estimate costs for the solutions
12. Describe findings and recommendations

A successful energy audit starts with a detailed site investigation to observe and determine when and where your facility uses energy. Each energy consuming system was fully characterized so that potential improvements could be quantified in terms of both energy and cost savings.

We used the following tools to benchmark and quantify energy savings:

- Carrier Hourly Analysis Program, HAP4.3.
- RETScreen (Clean Energy Project Analysis Tools)
- Building Energy Performance Index (BEPI)
- Energy Star Profile Manager

Plant engineering and maintenance personnel were interviewed since they, above all persons, understand the operation of the building, where the problems lie, and usually what the energy efficient solutions are. Field measurements of actual conditions were made to substantiate system operating parameters. Construction drawings were reviewed to understand the building envelope and gather input data for HAP.

Utility bills were collected and the data analyzed. The existing building automation system was examined to understand how the building is controlled and how the control systems are performing.

5. Energy Modeling and Simulation

We modeled Hydro Place's energy use in software, using Carrier's Hourly Analysis Program, HAP4.3. This program calculates all of the building loads for cooling, heating, humidification and dehumidification. It requires inputting of external heat gains and losses from wall, floor, roof and window areas. Inputs for people, ventilation rates, lighting and electrical equipment provide the internal loads.

Our methodology was to reconstruct the building in the HAP as it is today and then apply retrofit measures to subsequent iterations. To accomplish this, the floor, wall, roof, window and door constructions were defined in HAP. Orientations are defined to account for solar loads. The floor areas, number of people per floor, light watts/square foot, electrical equipment watts/square foot were inputted. The ventilation rates and schedules were defined. We then selected what type of mechanical equipment was in use and built a chiller plant in software.

HAP uses the information above and local weather data to calculate cooling and heating loads. These can then be used by an engineer to size cooling, heating, ventilation and humidification equipment. The simulation module of HAP requires the electrical energy data. We used Newfoundland Power Rate Schedule 2.4 for the base building and Schedule 2.3 for post-retrofit models. What we have done is to set up the most accurate case possible, using the base year energy use, including the problems we have seen and work from there to measure improvements.

We were told that the building must be kept in "occupied" mode, (that is; all temperature setpoints at comfort levels, air handling units, humidifiers and cooling equipment is on) until 10:00 p.m. to accommodate late workers. We set up our base model to reflect this.

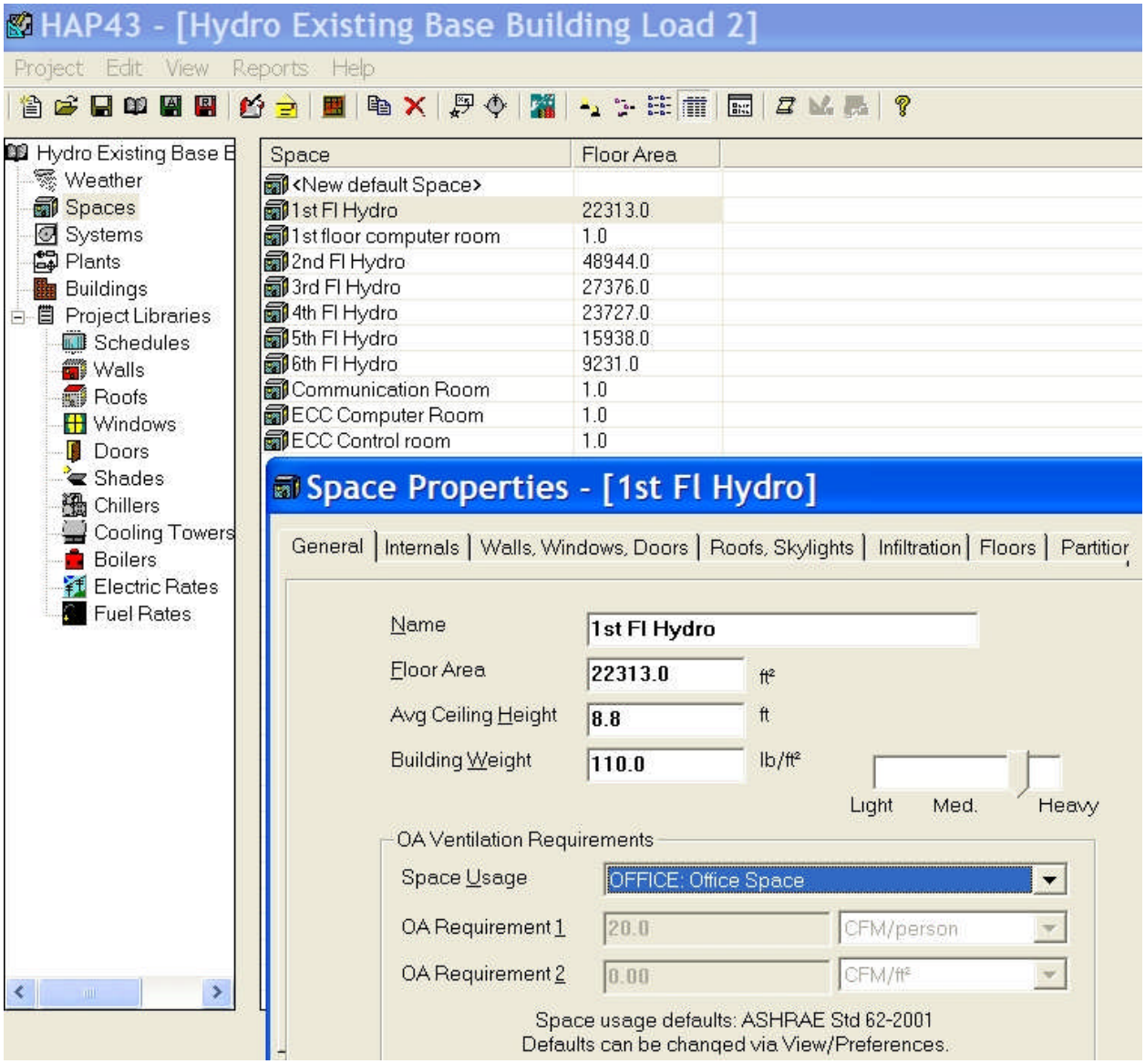
For the retrofit cases, using HAP, we reset the fresh air based upon ASHRAE 62-2001, set the schedules to be correct. For the lighting retrofit we reduced the lighting kW/sq. foot to reflect the changes. For mechanical retrofits, we chose alternate equipment from selection lists, such as VFD on the AHU fans and then ran the simulation again to get the new energy numbers.

We considered each floor to be a zone for the purposes of modeling, if a retrofit project were undertaken, a room-by-room calculation would be done. We input factored cooling loads for the computer rooms, based upon installed air conditioning equipment.

Hydro Place Energy Audit

Figure 4: Hourly Analysis Program Input Screen:

The input screen for HAP4.3, Hydro Place First Floor, space properties, note that the program has a drop-down menu for selection of ventilation rates based upon ASHRAE standards.



6. Baseline Energy Profile

The basic evaluation of a building for energy efficiency is a relatively simple process for experienced analysts. In comparing buildings of similar usage within the same geographic area a calculation can be done by taking the sum of 12 consecutive months of building energy use and dividing it by the square footage. The resultant is kilowatt-hours per square foot per year (kWh/ft^2/year). This is known also as the Building Energy Performance Index or BEPI and is a good starting point to have a high-level look at a facility.

From the architectural drawings, we calculated the building area at 147,529 square feet. We chose July 2006 to June 2007 as our base year for calculations, being the most current twelve consecutive months of data available. The total energy use was 4,494,000 kWhr for a resultant BEPI of 30.5 kWhr/ft^2/year.

Given that Hydro Place has been well constructed with modern (for 1980's) equipment, and controls, this is a very poor BEPI. Office buildings in St. John's typically have a BEPI between 15 and 50, with the end numbers being extremely good and bad. By comparison, an energy study done by one of the audit team, on a similar building some 15 years ago, at 240,000 square feet, had a resultant BEPI of 23. This building had a less advanced control system than Hydro Place, it was expected at the time that with a limited retrofit, the BEPI of that building could easily be reduced to21.

We also input the energy use data and building area into the US government Energy Star Portfolio Manager to establish another benchmark. This program compares buildings in a similar geographic region in a database. Hydro Place scored 22 points out of 100 with an energy intensity of 335 kBTU/ft^2. As a cross-check, HAP calculates 357 kBTU/ft^2.

See:
http://www.energystar.gov/index.cfm?c=evaluate_performance.bus_portfoliomanager

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Figure 5: Energy Star Portfolio Manager Report:

Statement of Energy Performance
FACILITY SUMMARY REPORT
Hydro Place

For 12-month Period Ending: December 31, 2006
Date Generated: December 17, 2007

This document was generated using EPA's Portfolio Manager system. All information shown is based on data provided by the Portfolio Manager account holder. Depending on the use of the SEP Facility Summary, building owners or managers may want to have a professional engineer (PE) verify that the underlying data is accurate. Blank space has been left intentionally on the SEP Facility Summary for a PE stamp.

500 Columbus Drive
St. John's,

Year Built: 1989
Gross Floor Area: (ft²) 147,529

Facility Space Use Summary

Office

Space Name	Gross Floor Area (ft2)	Operating Hours/Week	Workers on Main Shift	Number of PCs	Office Air-Conditioned	Office Heated
Hydro Place	147,529	40	433	300	50% or more	50% or more

Energy Performance Comparison

Results	Current	Baseline	Delta	Target	Industry Average	ENERGY STAR
Energy Performance Rating	22				50	75
Energy Intensity (kBtu/ft2)						
Site	100.44				73.93	54.68
Source	335.46				246.92	182.63
Energy Cost						
$/year	377,813.60				278,093.98	205,683.47
$/ft²/year	2.56				1.88	1.39
CO_2 Emissions (tons/year)	3,060.00				2,252.35	1,665.88

EPA
United States
Environmental Protection
Agency

7. Electrical Billing:

The main components of the energy bill are: (1) kilowatt hour (kWhr) usage, which reflects the energy used by electrical devices; lights, motors, heaters when they are on. (2) Demand, which reflects the highest kW energy use of the building for its highest 15 minute period per month.

The months of July 2006 to June 2007 were the most current full year available at the time of this survey. This was chosen as the base year. The other years demonstrate that energy use has only increased over time. Our experience is that a BEPI of 21 for this building is reasonable and achievable. If the BEPI were reduced to 21, the consumption would be as shown in Column 5

Hydro Place is not that unusual a building in terms of what happens inside. Like any other office building, there are heating and cooling systems, lights and computers.

There are some areas that one might think cause more energy use than other office buildings such as computer rooms and the ECC (that operates 24/7). We do not consider these to be significant contributors to the energy use problem. The computer room cooling load is small relative to the main building heating and motor load. We received data for the heat output from all of the computer equipment in the 1st floor computer room. The total heat output is 143,700 BTU/HR or 12 tons. This would be if all the equipment were giving off all that heat at one time. Practically, the real heat output would be about half of that. We used a similar logic in determining how to account for the computer room load in our simulations. We took the installed cooling capacity of the computer room air conditioner, expected that there was 100% redundancy in the design (for backup in case of an air conditioner failure) and allowed that cooling would be required 50% of the time.

To put the 1st floor computer room heat output in perspective, the total chiller capacity is 250 tons. The ECC cooling system is also small compared to the building load and not worthy of special consideration in terms of the energy analysis.

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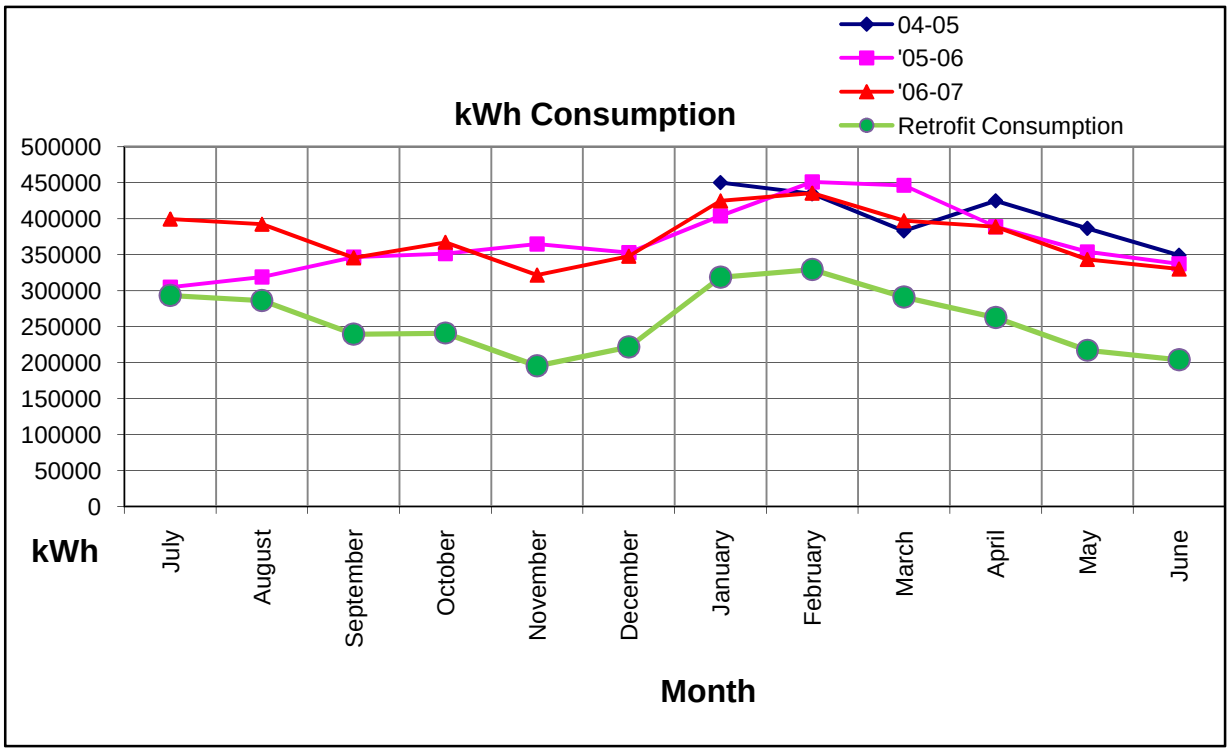
The following table shows the monthly kilowatt hour usage for a portion of 2004-2005, for 12 months of 2005-2006 and 2006-2007. Column 5 shows the projected consumption post-retrofit. The green line on the graph shows where the energy use should be.

Table 3 - Newfoundland & Labrador Hydro Energy Consumption

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
Month	04-05 kWh Consumption	05-06 kWh Consumption	06-07 kWh Consumption	Post-Retrofit Consumption
July		304,800	399,600	293,334
August		319,200	392,400	286,134
September		346,800	345,600	239,334
October		351,600	367,200	240,934
November		364,800	321,600	195,334
December		352,800	348,000	221,734
January	450,000	404,000	424,800	318,534
February	434,400	451,200	435,600	329,334
March	382,800	446,400	397,200	290,934
April	424,800	388,800	388,800	262,534
May	386,400	354,000	343,200	216,934
June	349,200	337200	330,000	203,734
Total	**2,427,600**	**4,421,600**	**4,494,000**	**3,098,802**
BEPI		**30.0**	**30.5**	**21.0**



8. Billing Demand and Demand Control

Demand is the cost paid for using a 15 minutes peak amount of power in each billing period. Peak Demand also determines the high and low kWh consumption costs and the rate class. See Newfoundland Power rate schedule 2.4 and 2.3 in the Appendix. Demand is a costly component that should be aggressively addressed.

The building demand is impacted by things like motors, heaters and humidifiers operating at the same time. Modern control systems monitor building demand and use strategies to limit it.

A graph of building demand month by month, should have two peaks, for winter heating and summer cooling and two valleys for spring and fall when the cooling and heating loads are relatively benign. The demand curve for Hydro Place is relatively flat; this indicates the demand is not being controlled effectively. For example, the demand hit 930 kW on New Year's Day 2007 at 4:30 AM (Information provided by Newfoundland Power). This demonstrates that there is no schedule in place for what should have been set as a holiday, with the demand level not exceeding what is seen during any overnight period, around 300 kW.

We estimate that the demand at Hydro Place could be reduced by an average of 300 kW per month for a savings of over $26,000.00 per year. Taxes not included.

Hydro Place is currently billed at Newfoundland Power's rate schedule 2.4 for usage over 1000 kVA, we expect that the demand at Hydro Place could be controlled below 1000 kVA and the billing rate moved to the more attractive 2.3 schedule.

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The major issues with energy use at Hydro Place center around the building control system.

1. Far too much outdoor air is being introduced and exhausted. The air then has to be heated and humidified or cooled and dehumidified; this imposes unnecessary load on the energy systems and extra run time on systems. We were advised that humidifier maintenance is a costly item at Hydro Place, inadequate control is the likely culprit.
2. The thermostats in the zones do not communicate with the control system. The pneumatic thermostats that control VAV boxes and baseboard heaters operate independently of the main air handling unit controls, the AHU controls have no way of "knowing what the real" zone conditions are.
3. The control strategies for the air handling units are not optimized. The attached screen captures demonstrate that the air handling units are simultaneously cooling and then heating the air.
4. The Demand Control system is not set appropriately. The purpose of demand control is to keep the demand peak to a minimum without affecting comfort. The existing Demand control does not work in this way for two reasons:
5. As the outside air conditions change, the electrical demand required for comfort changes. Hydro place has a set value of 950kW for all times of the year. This can be considerably less, especially in the spring and fall, when the heating is at a minimum and free cooling is available. Without a moving demand target that is adjusted to meet the seasonal needs, proper demand control is not achieved.
6. A proper demand control procedure should be set to not affect comfort. Hydro place has a set demand shed sequence. There is one area that is always the first level of demand shed so in times of high electrical demand that area will be shed too frequently and be chronically uncomfortable. The area whose electrical loads are shed to control demand should be the areas that need the electrical load the least. That area will not notice any comfort change.
7. The control system does not start up the building sequentially. All equipment in the building goes from unoccupied mode to unoccupied mode all at once at 4:00 a.m., resulting in demand peaks. A preferred method would be something like; start warming up the 6^{th} floor @ 4:00 a.m., then the 5^{th} floor @ 4:30 a.m., the 4^{th} @ 5:00 a.m. (Actually this is an oversimplification, zones would warm in defined groups, but it is acceptable for illustration purposes).

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The chart shows the effect of all zones becoming occupied on the same schedule and all equipment starting at the same time.

Table 4 – NF Power Demand usage for Hydro Place:

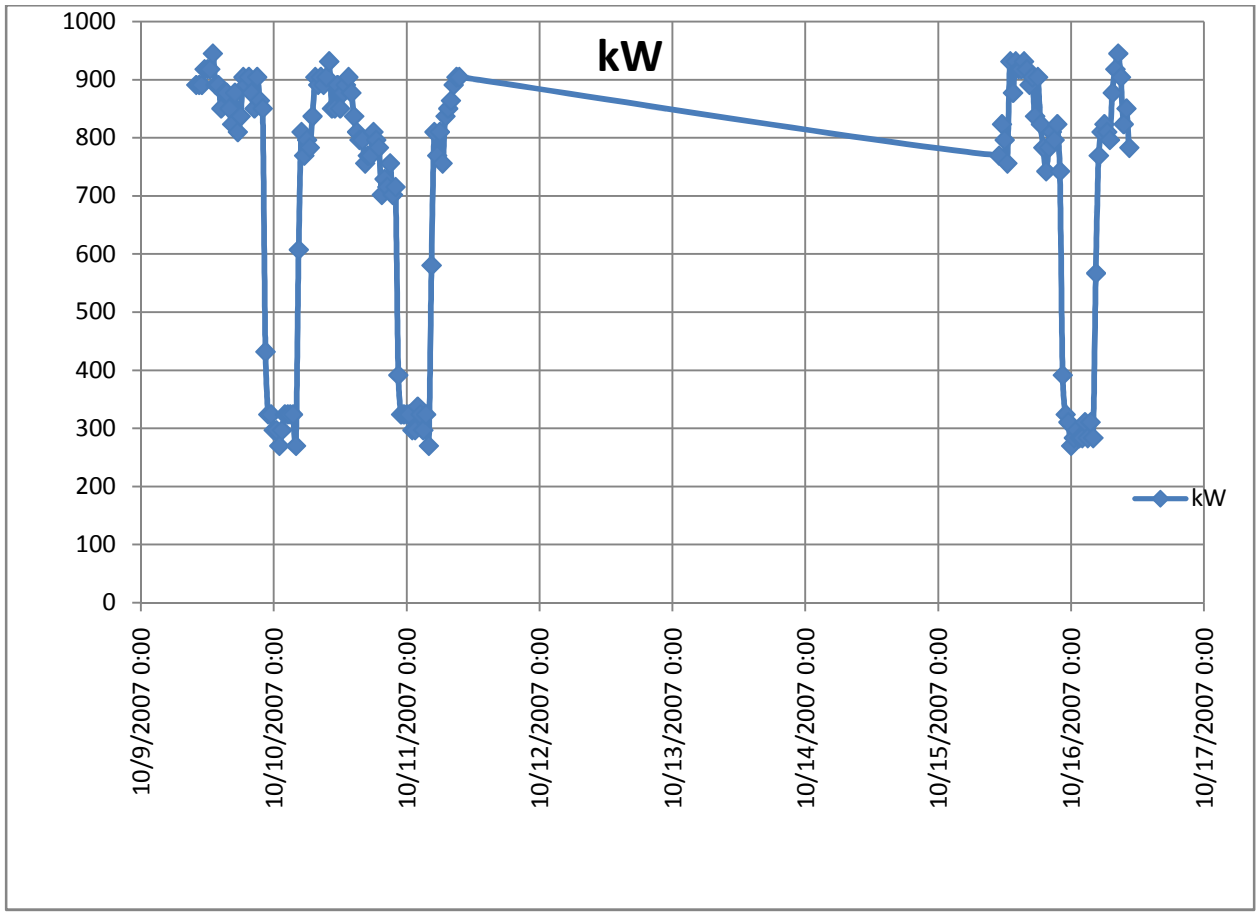

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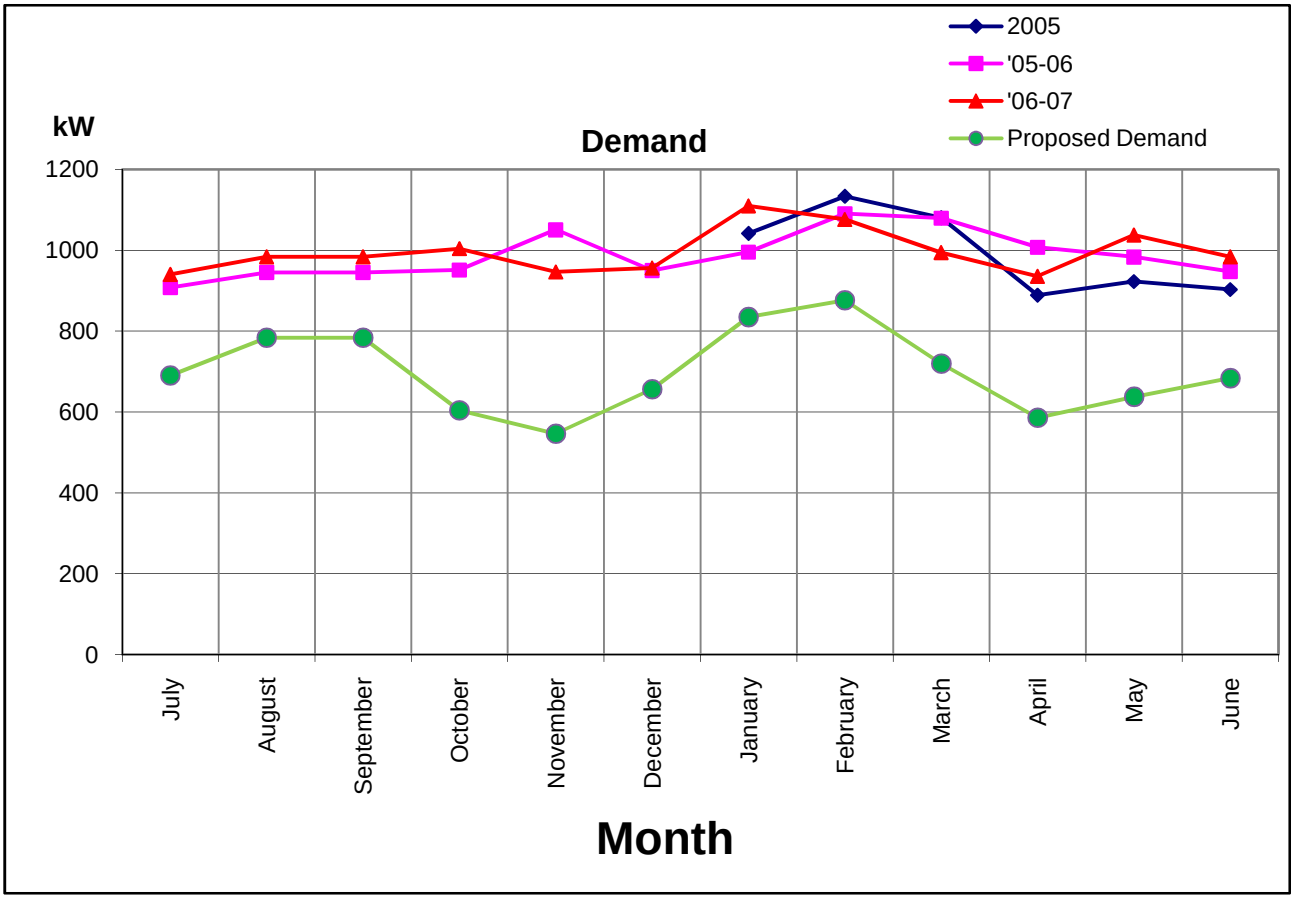
Table 5 - Newfoundland & Labrador Hydro Demand Consumption

Month	04-05 Base Year kW Consumption	05-06 kW Consumption	06-07 kW Consumption	Proposed Consumption	Change
July		908.4	941	691	-250
August		945.6	984	784	-200
September		945.6	984	784	-200
October		951.6	1004	604	-400
November		1051.2	947	547	-400
December		950.4	957	657	-300
January	1042	996.0	1110	835	-275
February	1134	1090.8	1076	876	-200
March	1081	1080.0	995	720	-275
April	889	1008.0	936	586	-350
May	922.8	984.0	1038	638	-400
June	903	948.0	984	684	-300
Total	**5971.8**	**11859.6**	**11955.8**	**8405.8**	**-3550**



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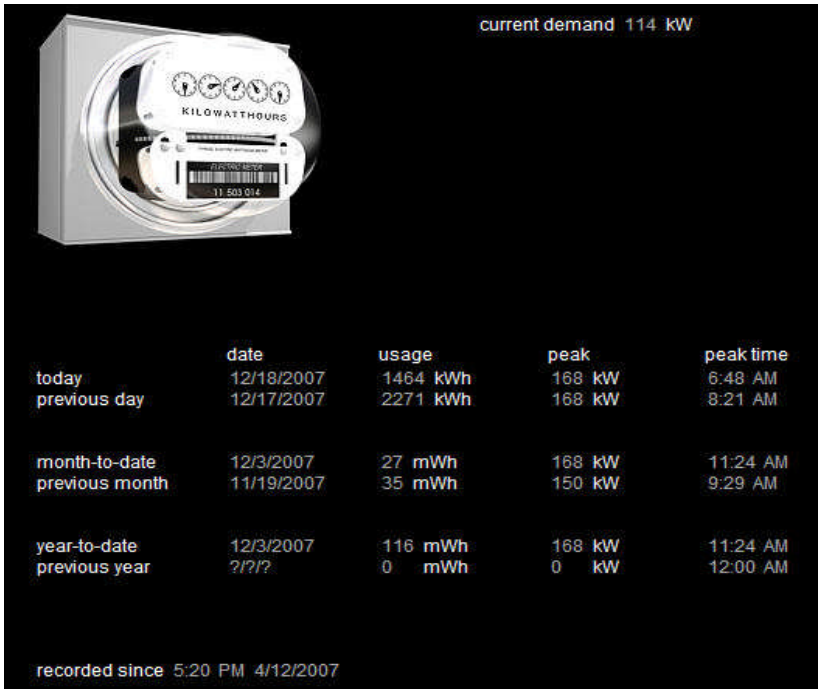
Demand Control:

Demand Control is the process of limiting the maximum building demand during any 15 minute period of peak demand. The objective is to prevent loads from being turned on at the same time during this period. Examples would be; motors starting at the same time, large blocks of heating coming on at the same time or both motors and heaters starting at the same time.

Typically, this is prevented by a demand shed program in the building energy management system. The demand meter outputs the demand level to the building energy management system which takes the data and compares it to a target demand level. If the loads in operation cause the demand level to exceed to target setpoint, the assigned loads are turned off (shed) in sequence.

Figure 6: Screen Capture of a typical Energy Meter Graphic:



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The issue with Hydro Place is that all of the loads are turned on at 4:00 am. They could easily be scheduled such that one area is started at 3:30, another at 4:00, another at 4:30, until the building is fully scheduled ON. The existing control system has this capability.

The building would be warmed using the electric baseboard heaters only. The air handling units would not start. All AHU's are set to bring in a minimum amount of outdoor air. This results in large volumes of air that have to be heated up, this air is then exhausted outdoors, wasting energy and peaking the demand. Minimum fresh air is only required when the building is occupied. If the building is already heated up, then it is in a much better position, demand wise, to deal with the influx of cold fresh air.

The first level of shedding is at 950kVa and the heating zones are arranged such that the loads are shed in the building from a predetermined sequence. The 6th floor heat is shed, then the 5th floor and so on. So in order to aggressively shed demand, the 6^{th} floor would be shed most of the time. In this manner, the current arrangement effectively negates a good demand strategy. From reviewing available trend logs from the existing control system, the 6th floor is shed very often, 5th not so often. Most shedding zones have actually never been shed.

The most effective method of demand control is to have as many electrical loads integrated to the demand control program as possible. Anything that is connected to the energy management system that uses energy can be shed. The loads are then shed or partially shed, based upon a tiered demand level. Stairwells and corridors would be shed first and if the demand continues to rise above the respective setpoint, selective setpoints are slightly altered to shed more loads (heaters, humidifiers). The demand control is seamless to the staff and does not cause temperature discomfort. Demand control occurs for all months of the year.

Three demand targets would be set for each month corresponding to each demand level. Once the energy manager "learns" how the building performs, these levels are fine-tuned for optimum load shed.

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Table 6 - Example Demand Targets

Month	Demand Level 1	Demand Level 2	Demand Level 3
January	800	825	850
February	800	825	850
March	700	750	800
April	700	725	750
May	650	700	750
June	650	700	750
July	750	775	800
August	750	775	800
September	650	700	750
October	650	700	750
November	800	825	850
December	800	825	850

The above targets are the starting points for the demand level control, with the expectation that the levels can be lowered.

Table 7 - Example Zone Setpoints:

Condition	Heating Setpoint °C	Cooling Setpoint °C
Normal Occupied	21.50	23.00
Demand Level 1	20.50	23.50
Demand Level 2	20.00	23.50
Demand Level 3	20.00	24.00
Unoccupied	17.00	28.00

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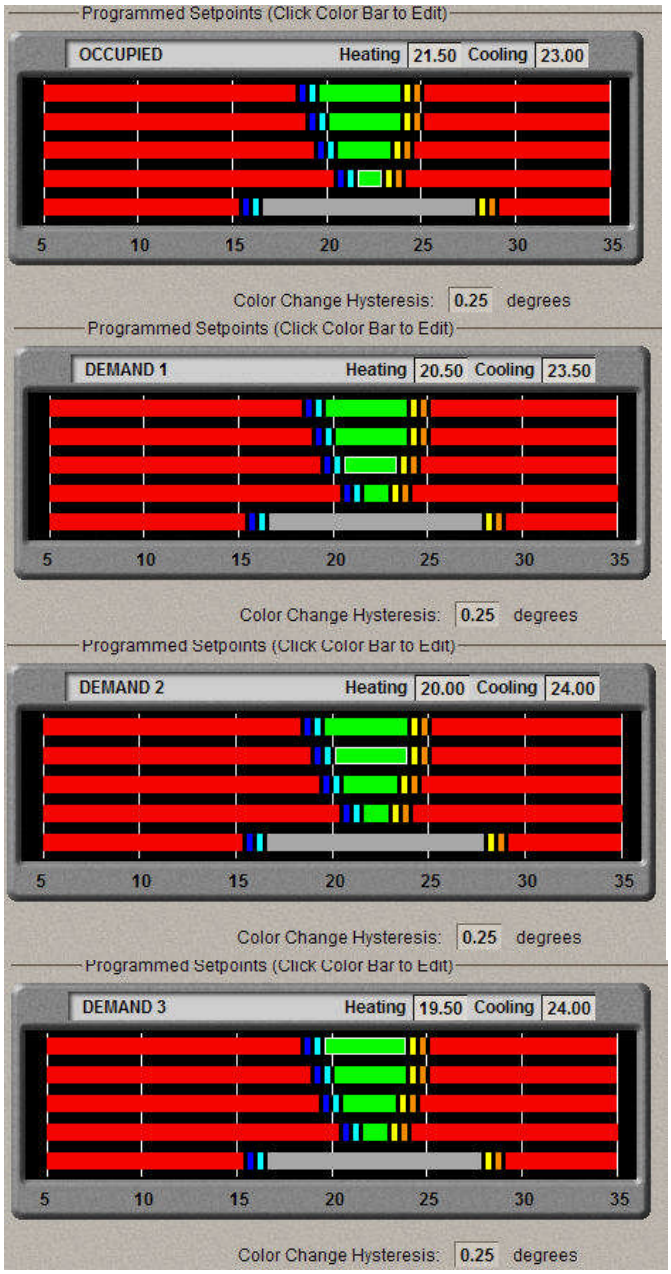
The following screen captures are from an Automated Logic setpoint microblock, the setpoint differences may be as small or large as the occupants need, this strategy has proven very effective in achieving demand savings without causing discomfort. There is no need to define specific shed zones. The determination is based upon each zone's setpoints.

Figure 7: Typical zone setpoint adjustment for demand control:



9. Lighting

Overview

All recommended lighting measures adhere to IES (Illuminating Engineers Society) design standards; this is the accepted standard for lighting design in North America.

Existing Conditions

The building was thoroughly surveyed for existing lighting equipment, light levels and hours of operation.

Fixture Types

There is a combination of lighting fixtures through the facility as described below, it is a typical mix of fixtures that would be found in a building, with the exception of the first fixture:

- 18” x 57” recessed troffer, 2 lamp T8 fluorescent with electronic ballasts fixtures in the majority of office areas. This fixture is very unique, it is not a standard fixture and is no longer manufactured, and however, it can be retrofitted.
- 2’ x 2’ recessed troffer, 2 lamp T12 fluorescent with magnetic ballast in the Executive offices and washrooms off the elevator lobbies.
- 1’ x 4’ recessed, 1 lamp T12 fluorescent fixtures with magnetic ballast in the elevator lobbies.
- 1’ x 4’ wall mount, 2 lamp T12 fluorescent fixtures with magnetic ballast in the stairwells.
- 1’ x 4’ recessed, 1 lamp T8 fluorescent fixtures with electronic ballast in the stairwell walk areas.
- 2 & 3 tube T8 fluorescent with electronic ballasts fixtures and 1-tube T8 on the perimeter parking lot lobby.
- Mechanical rooms are mainly 1’ x 4’, 2-Tube T12 strip fixtures.
- Exterior soffit lighting is grouped in 4- 50 watt High Pressure Sodium on photocell.

The office light levels were measured to be between 40 and 110 foot-candles, with the majority of spaces being around the 75 foot-candle level. The corridors and elevator lobbies were measured between 20 and 45 foot-candle. The recommended standard for general office environment is 40 to 50 foot-candles while corridors are 10 to30 foot-candles. The offices are lit during normal business hours of 7:00 to 22:00, 5 days per week. The cleaners turn off the lights as they finish each floor, with the last lights being turned off at 10:00 PM.

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Common areas such as elevator lobbies, the interior corridors, stairs, and decorative areas are lit in some cases 24 hours per day, but for the majority of the common areas, lighting is on for 12 hours per day.

Scope of Proposed Retrofit

Office Lighting

The existing 18" x 57" 2-Tube T8 fixtures are to be retrofitted with one 4-Tube T8 Super fluorescent ballast for each two fixtures with each fixture having two Super T8 fluorescent tubes. There will be several fixtures removed, with the remaining fixtures repositioned to provide the optimum light levels and light distribution. The light output will be the same with less energy consumption as well the fluorescent tube will have an increased life. The existing ballasts have a rated life of 50,000 hours and will require replacement in the near future (approximately 4 to 5 years) therefore replacement of the ballasts now, with more than a reduction of 50% of the number of installed ballasts is an economical operational cost avoidance. See attached lighting before and after example.

The 2 ft. x 2 ft., two Tube recessed T12 fixtures will be replaced with 2 ft. x 4ft. Two-Super T8 tube fluorescent fixtures. In some cases, such as washrooms, the fixtures will be retrofitted with T8 lamps and electronic ballasts.

A standard T8 lamp consumes 32 watts, compared to the new Super T8 lamp that consumes 25 watts for a net savings per lamp of 7 watts. A T12 lamp consumes 34 watts, however, the magnetic ballast consumes an average of 20% of the connected load therefore, 34 watts now becomes 40.8 watts. A T12 to T8 retrofit saves 8.8 watts and a T12 to Super T8 retrofit saves 15.8 watts. The existing T8 ballasts would be changed to a Super T8 ballast, these must be matched with the Super T8 lamp. The existing T8 lamps could not be used. The current T8 lamp life is 20,000 hours compared to 24,000 for the Super T8 lamp life.

A regular T8 lamp produces mean lumens of 2850 compared to a Super T8 at 2585 lumens, therefore light level would be slightly reduced to be closer to IES (Illuminating Engineers Society) recommendations of 50 foot candles. Super T8 lighting provides additional energy savings as well as substantial operational savings. The existing ballasts are close to the end of their useful life. Spot ballast change-out is a costly operation compared to group ballast and lamp change-out. Also, each current T8 light fixture has its own ballast. We would change the wiring arrangement such that one new ballast would be shared with two fixtures, eliminating 50% of the existing T8 electronic ballasts. Therefore, 50% of the ballasts are removed from future operational repair costs.

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A 2x4 fixture is the most commonly used fixture that can easily fit the existing ceiling T-Bar grid. These newer fixtures provide a far greater light distribution than the older existing 2x2 fixtures. Retrofitting a 2x2 fixture is not a cost effective solution.

The single-tube T-12 end-to-end strip fixture located in the various elevator lobbies and open office decorative valances will be retrofitted with SuperT8 lamps and electronic ballasts.

Exit Lights

There are 34 exit lights containing two 15 watt incandescent tubes operating 24 hours per day. These lamps have an average life of 3000 hours. LED lit exit lamps consume 2.5 watts per fixture and last approximately 25 years. The benefits are; 83% energy reduction, increased fixture illumination and material & labour savings due to the longer LED life, reducing the operating cost of this item.

The exits signs are equipped with 2-15 watt incandescent bulbs. The proposed retrofit will replace all the exit signs with 2.5 watt LED kits (Light Emitting Diodes). LED lights not just consume greater than 80% less energy, they will last approximately 25 years, reducing the operating cost of this item.

Mechanical and Utility Rooms

The mechanical and utility rooms are lit with T12 magnetic ballasts that have not been included as a retrofit measure, as the hours of operation make the payback uneconomical. Please note however that the T12 fluorescent lamp will not be manufactured after 2011 and therefore should be considered for replacement with T8 and electronic ballasts under a maintenance program.

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Heating Penalty / Cooling Benefit

Lighting is 100% heat, therefore if you reduce the lighting load, you reduce heat. The heat has to be replaced by baseboard and/or ventilation heat during the heating season, however it reduces the cooling load during the cooling season. The penalty is usually higher, however approximately 70% of the facility lighting is already T8 with electronic ballasts therefore there is less penalty due to a lesser heat output. Less lighting power input represents less heat and as a consequence, less cooling energy but also more heating energy. The impact of a lighting retrofit on the cooling input required in a building is dependent on two main factors: the percentage of the annual lighting heat that is mechanically cooled and the associated cooling efficiency. In our climate, the length of the cooling season is quite short, so the cooling benefit of the lighting change will be minimal.

The heating impact of a lighting reduction is equally hard to assess. The core areas of buildings seldom require heat, even in the winter time. Lighting heating is generally useful along the perimeter of the building during occupied periods. The heating penalty/cooling credit is accounted for in our simulation by revising the input lighting kW per square foot. The current lighting level is an average of 1.38 watts per square foot, when retrofitted, the usage would be 0.88 watts per square foot (refer to table 8, following page). The cost benefit for this is demonstrated in Figures 2 & 3.

Deemed Savings

The deemed savings in this project are comprised of two distinct elements:

1. Benefits from using one 4-tube electronic ballast for two fluorescent fixtures; eliminates more than 50% of the ballasts that will have to be replaced.
2. Increased benefits for longer life devices being installed in the building.

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Table 8 – Existing and Revised Lighting Energy Use:

Hydro Lighting Watts/Sq/ft						
	Currently Installed kW/floor	**Square Feet/floor**	**Installed Watts/ Sq. ft.**	**Revised KW/floor**	**Revised Watts/ Sq. ft.**	**KW Saved**
Floor1	33.3	22,313	1.49	18.3	0.82	15.0
Floor2	46.3	48,944	0.95	30.5	0.62	15.8
Floor3	46.7	27,376	1.71	31.2	1.14	15.5
Floor4	37.0	23,727	1.56	25.6	1.08	11.4
Floor5	24.0	15,938	1.51	15.7	0.99	8.3
Floor6	21.3	9,231	2.31	10.7	1.15	10.7
	208.6	**147529**	**Average: 1.38**	**133.4**	**Average: 0.88**	**76.6**

Note: Penthouse not included,

10. Mechanical Cooling Systems

The building mechanical systems are well designed with good quality components installed. Air handling units of this type typically have 50 year life spans. Individual components such as dampers, cooling and heating coils and fan motors may be replaced during that time but the overall assembly has a long life. The AHU's are in good condition. The fresh air dampers could be replaced with modern, insulated dampers, we have seen improvements in other systems when this has been done but the savings are difficult to quantify.

The building uses a chilled water system to provide mechanical cooling for the Air Handling Units; direct expansion cooling for AHU's and packaged DX (direct expansion) cooling for the 3 computer rooms. The heat rejection takes place in two systems:

1. Heat removal:

Heat is removed from the building via cooling coils installed in the air handling units. A cold glycol (Chilled Water) solution is pumped through the cooling coils. Building air flows over the cold coil and heat is removed. Cold air is then sent via the duct system to the offices.

Heat is removed from the chilled water via the chiller in the1st floor mechanical room. The chiller uses refrigeration compressors to cool the water.

Heat can also be removed from the chilled water via a plate and frame heat exchanger, this is also known as an economizer. It is called such in that it avoids using the compressors in the chiller to produce cooling and therefore is less costly to operate. The economizer would be used when outdoor air temperatures are low enough to obtain the required heat exchange to provide the design glycol temperature.

2. Heat Rejection:

The heat that is produced by the compressors is then piped in a separate loop to the cooling tower on the roof of the fifth floor. The cooling tower removes the heat via evaporative cooling, by spraying the water over a series of plates where a fan induces counter flow air.

From an energy conservation standpoint, the goal would be to optimize the use of the heat exchanger such that the chiller operation is minimized. We calculated the building cooling requirements to be 190 tons (1 ton of cooling = 12,000 BTU/HR).

The chiller was retrofitted in 2004. The previous chiller was of the centrifugal type that used R-11 as its refrigerant. Due to restrictions of the Montreal Protocol for the reduction of CFC (chlorofluorocarbon) refrigerants, R-11 was phased out and replacement of the chiller would have been necessary.

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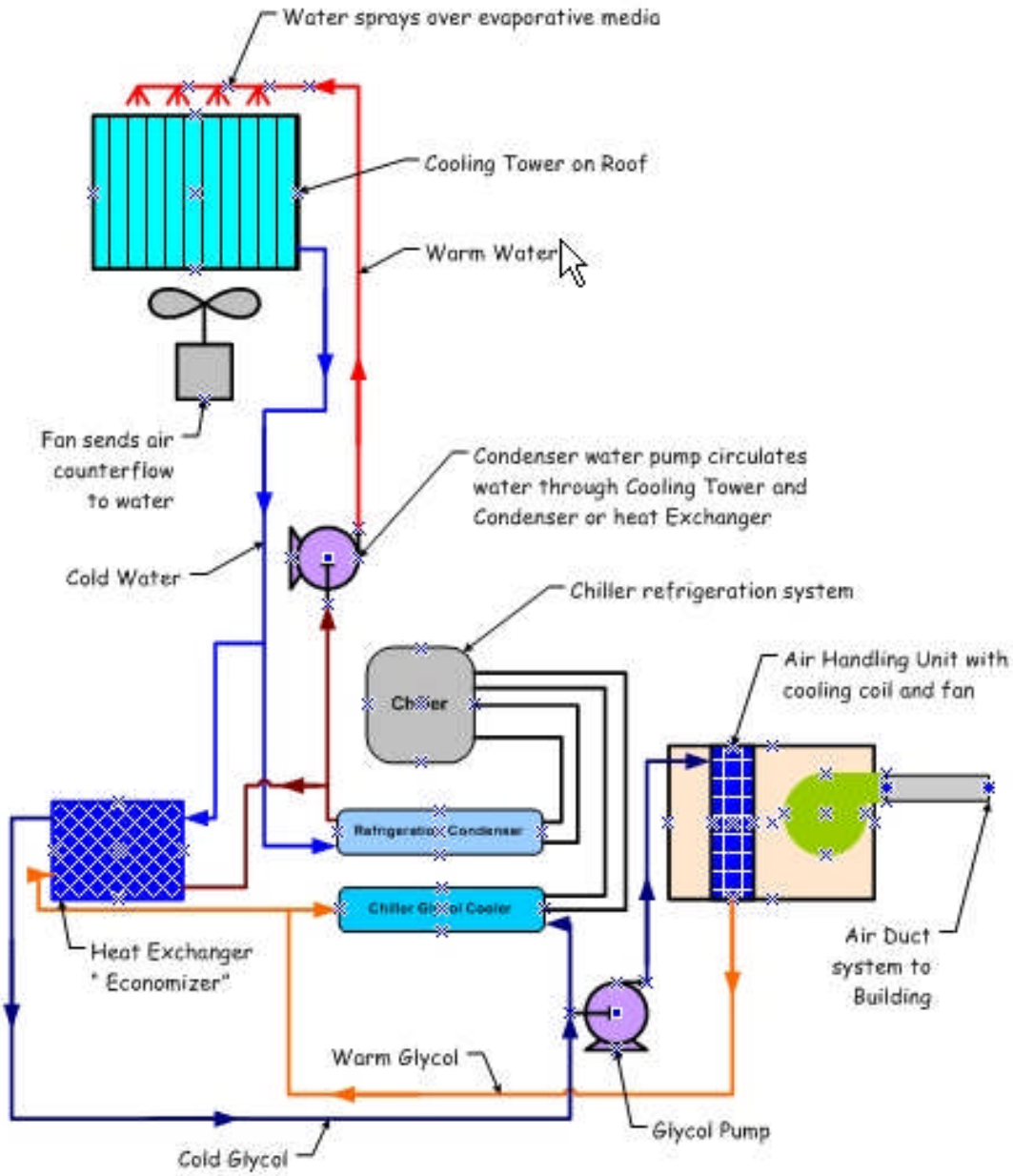
The replacement chiller is a modular type, meaning that instead of one large refrigeration machine, there are 10 individual compressor units of 25 tons each, piped together to produce 250 tons of cooling. This arrangement makes sense in this building as replacement of the R-11 chiller with another large machine would have been physically unfeasible. The modular chiller has the individual stages turned on and off in response to the building cooling requirements.

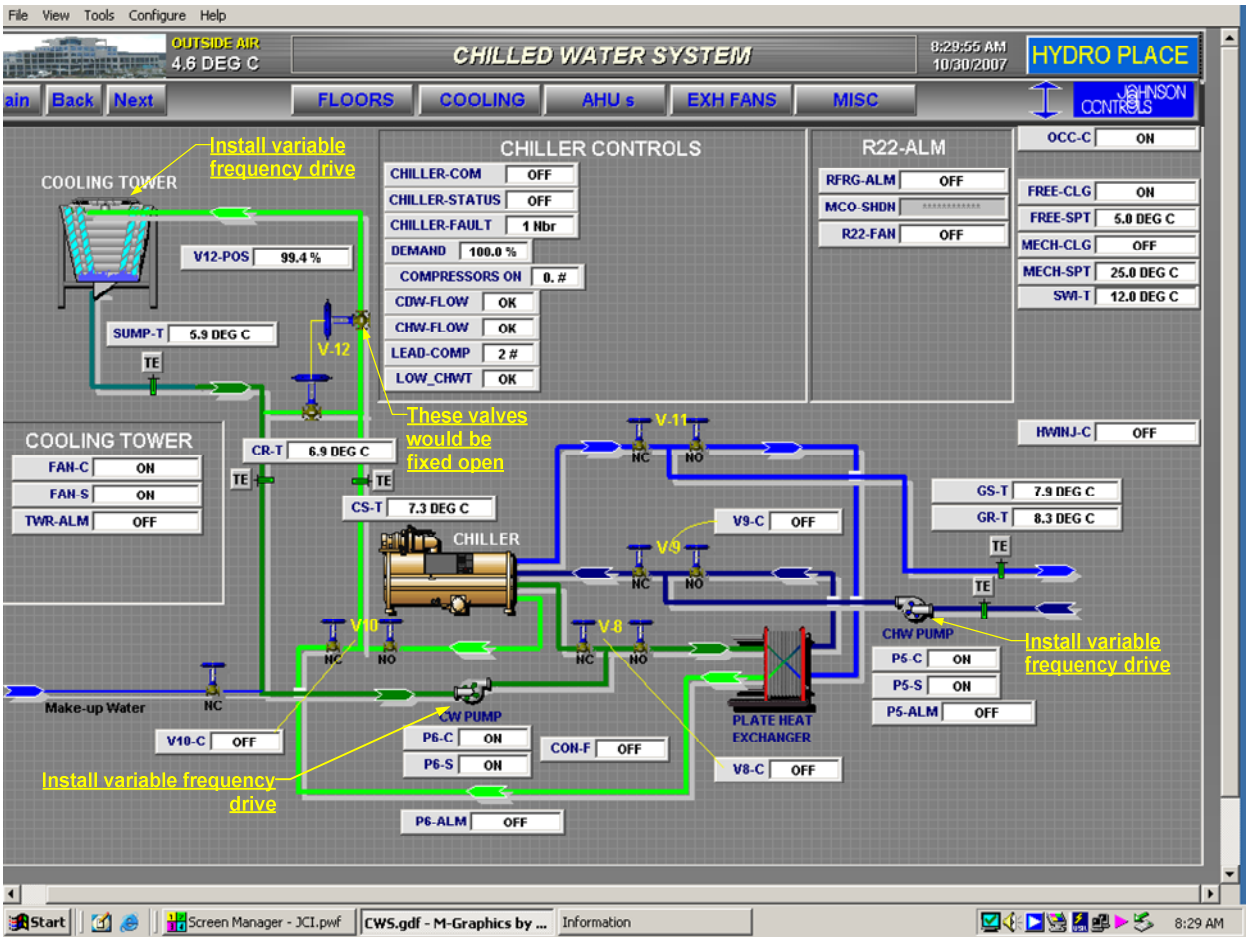
Figure 8: Chilled Water System Flow Diagram:



11. Cooling Tower

Recent research has shown that there are significant savings to be achieved by optimizing the selection of the cooling tower for energy conservation (a tower with greater capacity). This would impact increased use of the economizer for the free cooling cycle and reduced loading of the chiller. The cooling tower is eighteen years old, it is expected that the cooling tower will require replacement sometime in the next ten years due to corrosion. A projection and budget should be developed for replacement and what changes might be done when it is replaced.

Figure 9: Chilled Water System Graphic showing retrofit changes:



The chilled water system capacity is regulated by modulating a series of control valves in the chilled water piping. This system capacity could be more economically regulated instead by varying the speed of the large glycol pump motor and the cooling tower fan using Variable Frequency Drives (VFD). The Cooling Tower Fan is 30 hp, the Chilled water pump is 60 hp. Given the size of these motors, savings would result. (Refer to Table 1, page 6).

12. Zone heating and cooling systems

There are nine Air Handling Units AHU installed in the building.
The function of the air handling unit is to move conditioned air through to the zones. A typical air handler would consist of:

- Supply air Fan
- Return air fan
- Glycol cooling coil
- Electric heating coil
- Steam humidifier
- Outdoor air, mixed air and return air dampers
- Air filters

Table 9 - Hydro Place Air Handling Unit Summary:

AHU #	Serves	Motor HP	Electric Heater kW	Humidifier kW
1	1st floor	25	none	41.6
2	2nd floor	50	none	62.4
3	3rd floor	40	none	62.4
4	4th floor	40	30	41.6
5	5th floor	25	41	27.8
6	6th floor	15	24	17.3
7	Outdoor air to 1st, 2nd, 3rd floors	25	100	None
8	ECC	15	30	20.8
9	Temprite Heat Recovery Unit	not in use		
Total		**235**	**225**	**273.9**

We recalculated the AHU motor sizes, most motors are too large, during the retrofit, the motors would be replaced with correctly sized, premium efficiency motors. We were advised there are no internal components remaining in AHU 9.

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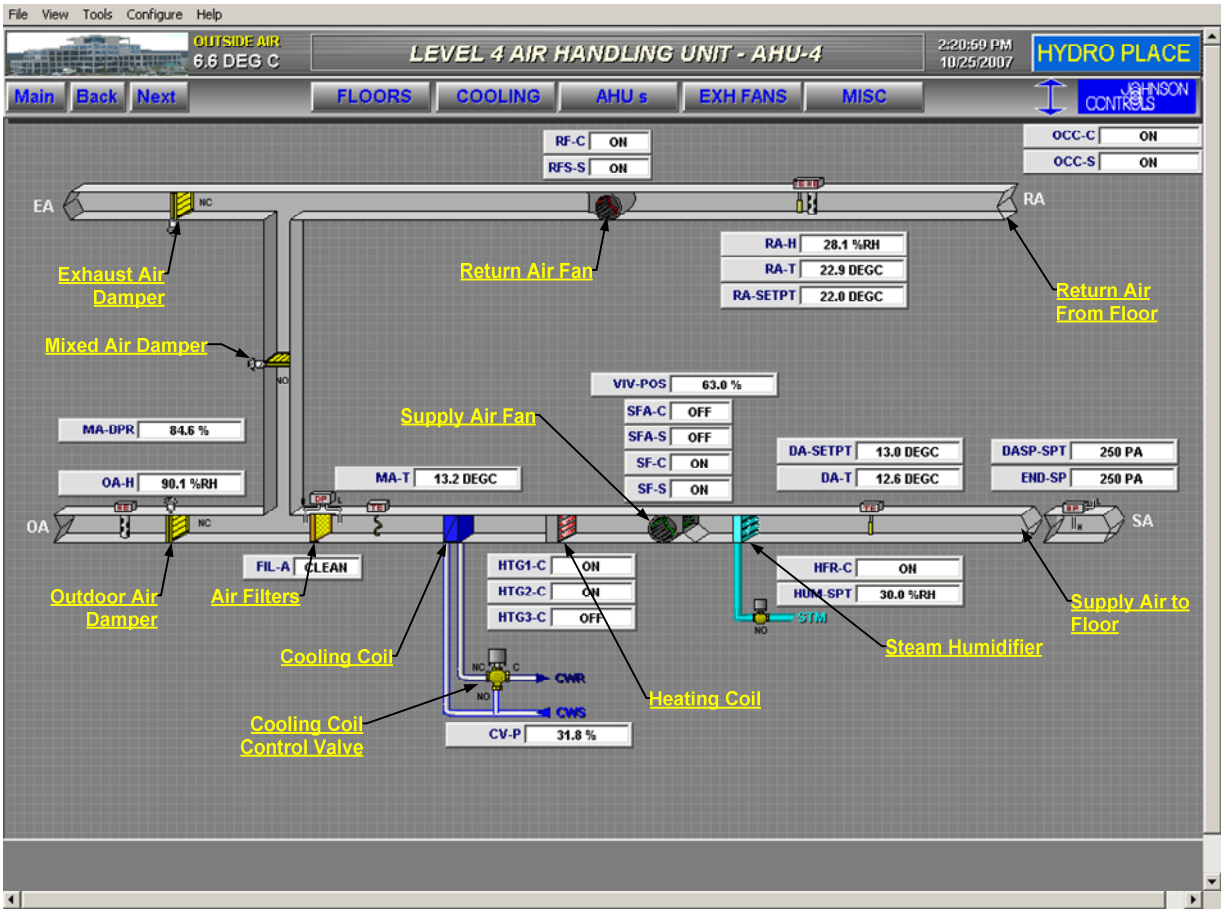
Figure 10: Typical Air Handing Unit Graphic showing Mechanical Devices and Control Components:



13. Air Handling Unit Airflows

The air handling units are supplying and exhausting an excessive amount of outdoor air as was measured.

The current population of the building is 433 people, using the most current standard of 17 CFM per person, the total ventilation rate of the building should be 7361 CFM. We measured actual air flows in the supply and exhaust ducts and found that there is a total of 44,286 CFM of fresh air being supplied (Almost 6 times that required.) This condition does not occur all year round however we expect it does occur for 6-7 months per year (May – July and September to November).

The following table shows the outdoor air requirements as recommended by ASHRAE Standard 62.1-2007, Ventilation for Acceptable Indoor Air Quality.

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Table 10 – ASHRAE Ventilation Standard 62.1-2007:

TABLE 6-1 MINIMUM VENTILATION RATES IN BREATHING ZONE *(continued)*
(This table is not valid in isolation; it must be used in conjunction with the accompanying notes.)

Occupancy Category	People Outdoor Air Rate R_p		Area Outdoor Air Rate R_a		Notes	Default Values			Air Class
						Occupant Density (see Note 4)	Combined Outdoor Air Rate (see Note 5)		
	cfm/person	L/s-person	cfm/ft²	L/s-m²		#/1000 ft² or #/100 m²	cfm/person	L/s-person	
Office Buildings									
Office space	5	2.5	0.06	0.3		5	17	8.5	1
Reception areas	5	2.5	0.06	0.3		30	7	3.5	1
Telephone/data entry	5	2.5	0.06	0.3		60	6	3.0	1
Main entry lobbies	5	2.5	0.06	0.3		10	11	5.5	1
Miscellaneous Spaces									
Bank vaults/safe deposit	5	2.5	0.06	0.3		5	17	8.5	2
Computer (not printing)	5	2.5	0.06	0.3		4	20	10.0	1
Electrical equipment rooms	–	–	0.06	0.3	B	–			1
Elevator machine rooms	–	–	0.12	0.6	B	–			1
Pharmacy (prep. area)	5	2.5	0.18	0.9		10	23	11.5	2
Photo studios	5	2.5	0.12	0.6		10	17	8.5	1
Shipping/receiving	–	–	0.12	0.6	B	–			1
Telephone closets	–	–	0.00	0.0		–			1
Transportation waiting	7.5	3.8	0.06	0.3		100	8	4.1	1
Warehouses	–	–	0.06	0.3	B	–			2
Public Assembly Spaces									
Auditorium seating area	5	2.5	0.06	0.3		150	5	2.7	1
Places of religious worship	5	2.5	0.06	0.3		120	6	2.8	1
Courtrooms	5	2.5	0.06	0.3		70	6	2.9	1
Legislative chambers	5	2.5	0.06	0.3		50	6	3.1	1
Libraries	5	2.5	0.12	0.6		10	17	8.5	1
Lobbies	5	2.5	0.06	0.3		150	5	2.7	1
Museums (children's)	7.5	3.8	0.12	0.6		40	11	5.3	1
Museums/galleries	7.5	3.8	0.06	0.3		40	9	4.6	1
Residential									
Dwelling unit	5	2.5	0.06	0.3	F,G	F			1
Common corridors	–	–	0.06	0.3					1
Retail									
Sales (except as below)	7.5	3.8	0.12	0.6		15	16	7.8	2
Mall common areas	7.5	3.8	0.06	0.3		40	9	4.6	1
Barbershop	7.5	3.8	0.06	0.3		25	10	5.0	2
Beauty and nail salons	20	10	0.12	0.6		25	25	12.4	2
Pet shops (animal areas)	7.5	3.8	0.18	0.9		10	26	12.8	2
Supermarket	7.5	3.8	0.06	0.3		8	15	7.6	1
Coin-operated laundries	7.5	3.8	0.06	0.3		20	11	5.3	2

14 ANSI/ASHRAE Standard 62.1-2007

14. Control System Description

The building has a combination of pneumatic and digital control systems.

Pneumatic controls have been used for building temperature control for over 100 years. A regulated air pressure is sent to all the pneumatic thermostats located throughout the building. As the thermostat senses a change in room temperature, it will vary its air pressure output to a calibrated device such as a switch that would turn on an electric heater or an actuator that would open or close a damper.

In the case of Hydro Place the room thermostats have two temperature settings, one for daytime (occupied) settings and one for night time (unoccupied) settings.

The problem with pneumatic controls is that they are intricate mechanical devices, subject to wear and drift in their settings, they require annual calibration if they are to work properly.

The digital control systems control the:

- Air handling units
- Chilled water system
- Building demand systems
- Night set back systems.
- Scheduling of occupied and unoccupied times

The control system provides an interface to allow the building operator to determine how each system is performing and issue commands. Building information such as demand and temperature trends is available from the DDC system.

In the proposed retrofit solution, the pneumatic-electric (PE) switch that controls the baseboard heaters, would be replaced by a more accurate and reliable solid state relay.

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Control Procedures:

Zone Control

The floor ducting arrangements have Variable Air Volume (VAV) control boxes that open to increase the cooling air flow in most areas. There are other areas that receive a constant airflow from the air handling unit. The temperature in the zones without VAV boxes would be regulated by turning on baseboard heat. The control of the VAV boxes and electric heat is from the pneumatic thermostats.

We observed many cases where there was excessive supply air from the air distribution system and the baseboard heaters were on at the same time. VAV boxes are installed in the open office areas only, as they existed when the building was constructed. All offices are constant volume with local reheat. Since the control of the air handling units is poor, the spaces are left to use local reheat and to suffer discomfort. Given today's energy costs and the advancements in building automation systems, the use of local reheat would be minimized.

One of the issues with the pneumatic thermostats is that the zone occupants often tamper with the settings. We observed temperature settings on thermostats at 30ºC. We expect this may be a cause of the unoccupied temperatures not setting back also.

Drawing 1 below shows the typical current floor ventilation control having the interior zone a VAV and the perimeter constant volume. The ventilation to the perimeter zone cannot decrease when the cooling setpoint is achieved therefore the perimeter heat must come on if the zone overcools. The interior zone does have VAV however, the interior zones require cooling more than the perimeter, hence the coincidental heating/cooling on the exterior zones. The overheating is measured by the AHU as a return air temperature increase and therefore causes the system to react by lowering the cooling supply temperature. This results in a vicious circle of the baseboard heaters trying to overcome the cold air being sent from the air handling unit.

Drawing 2 shows the redesigned ventilation additions to slow down air to the perimeter zones as the temperature is satisfied as determined by new electronic sensors and controls.

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Figure 11: Typical Existing floor (zone) control:

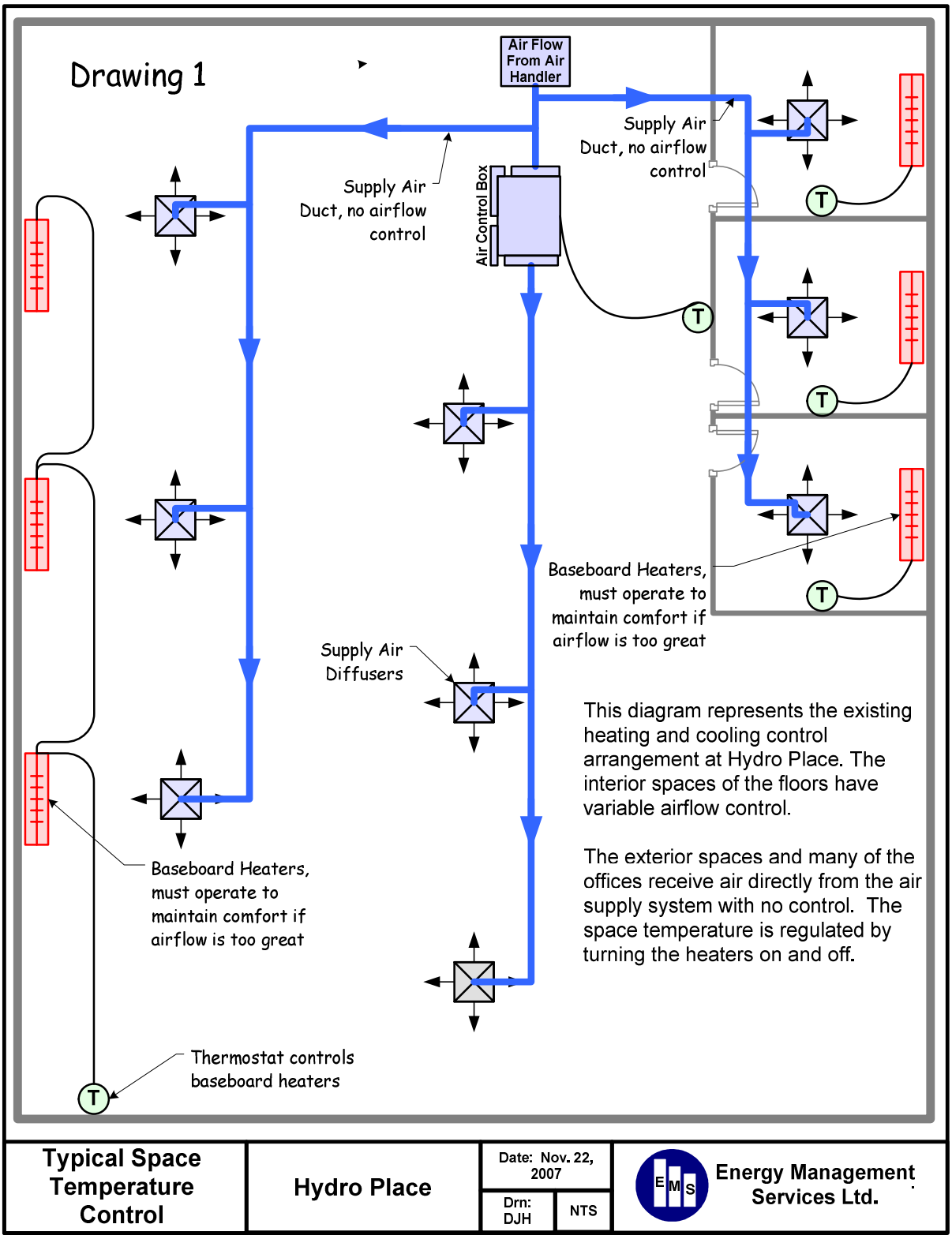

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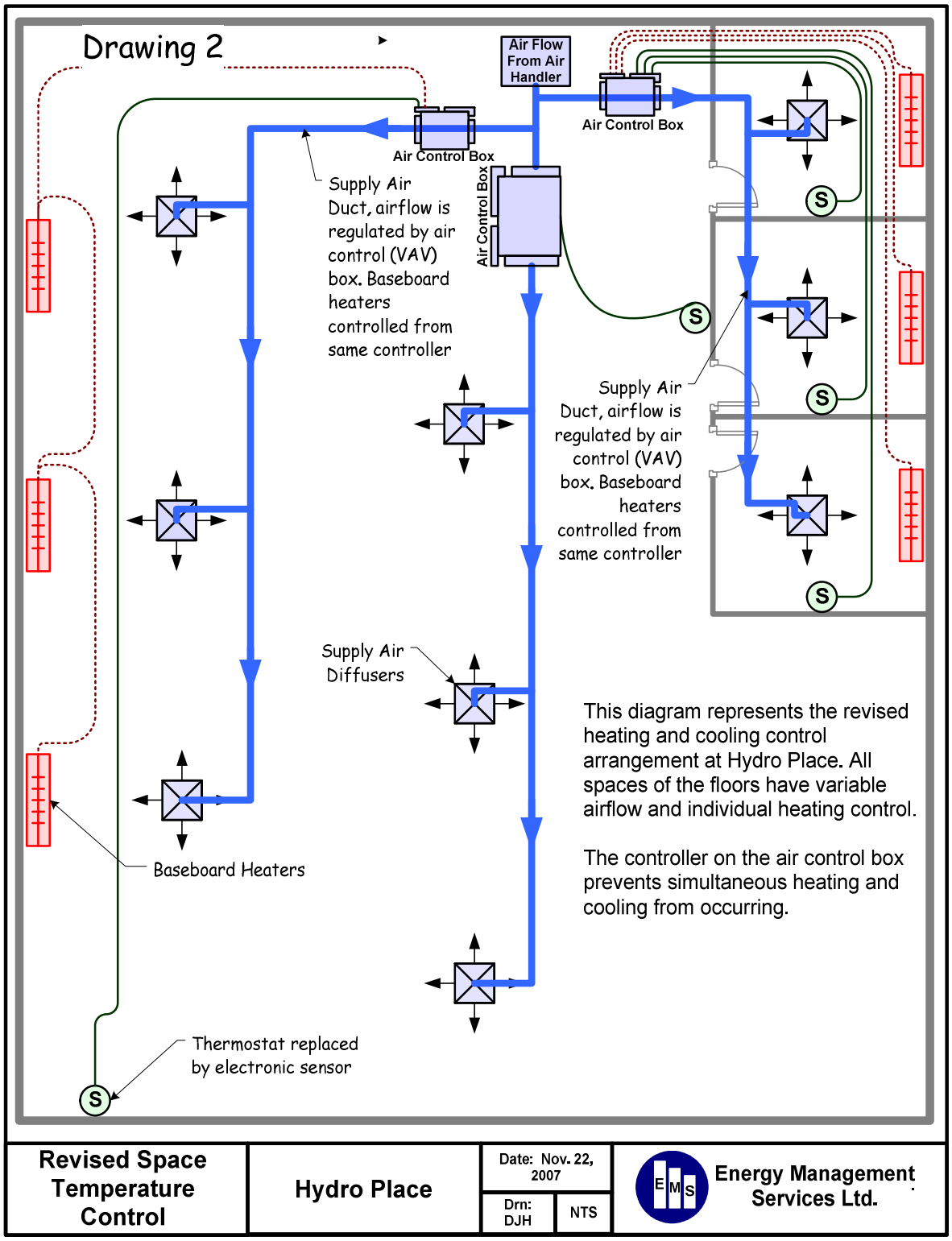
Figure 12: Typical revised floor (zone) control:



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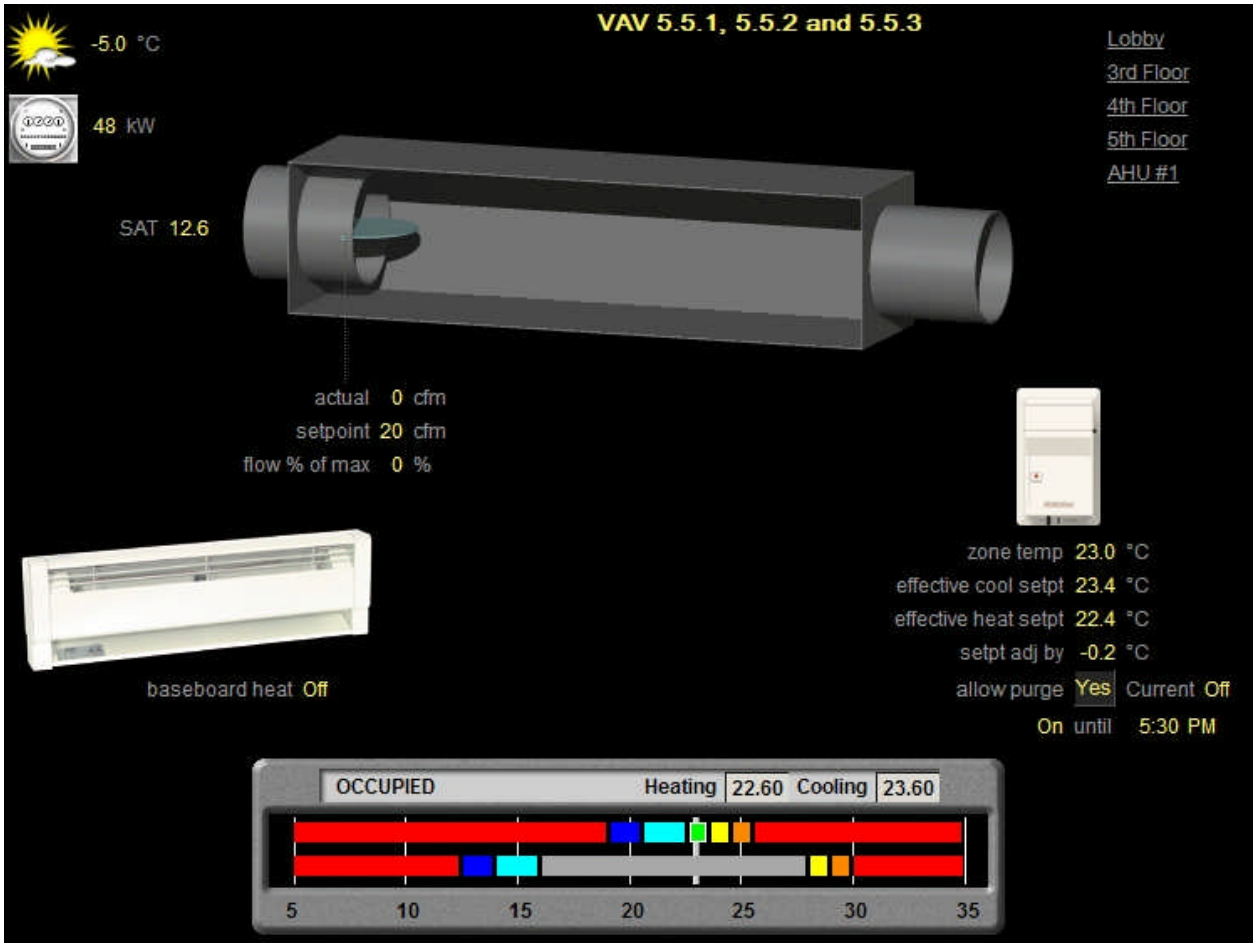
This screen capture shows how the new controller now measures the zone temperature and varies the airflow accordingly. The baseboard heater is also controlled from this device.

Figure 13: Revised zone control graphic:



Control Procedures

Revised Control Strategy for Hydro Place

In the heating season during morning warm-up, start heating the zones earlier depending on the outdoor air temperature (OAT).

All heat in the building is electric resistance. Use the baseboard heat only until building becomes occupied and limits the demand to specified amount. After building is warmed, start the air handling units (Air Handling Unit's) and operate the humidifiers as required, to bring the space to the proper humidification. Operate electric duct heaters to heat make up air only (minimum fresh air).

In the cooling season, free cooling is to be used whenever possible. The free cooling decision is to be made based on Return Air (RA) enthalpy vs. Outdoor Air (OA) enthalpy. This decision is be made per floor.

The building air is to be purged overnight to evacuate summer heat buildup during unoccupied times. This is accomplished by commanding the VAV box dampers to open and then operating the air handling units in economizer mode. This will also prevent a large cooling load in the morning. Cooling loads are to be shed via the same method as the heating loads. The zones that need the cooling the least will be shed first.

Zone Setpoints

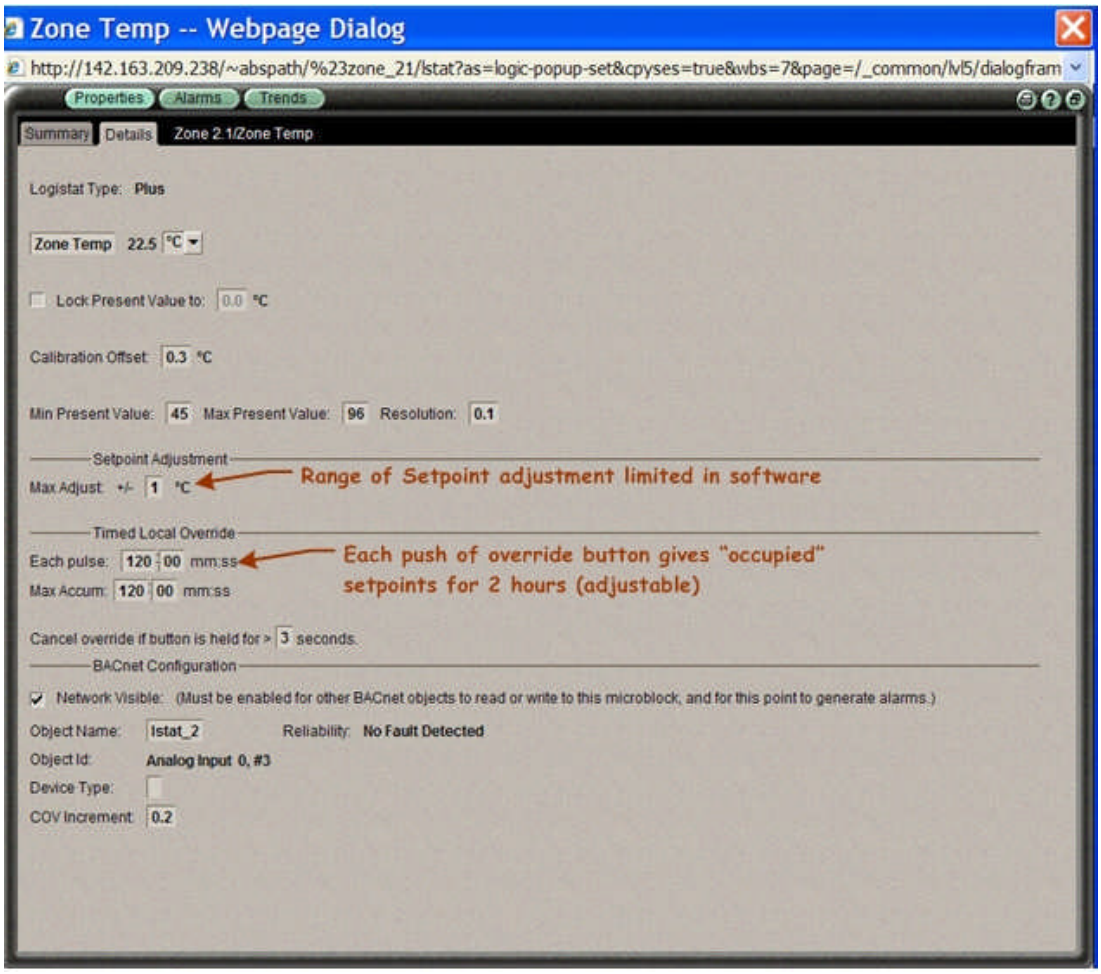
Existing Control:

Zone temperatures are controlled by adjustable thermostats in the spaces with no feedback to the Air Handling Unit's or to other zones. There are zone temperature sensors, however they are not used to control any Air Handling Unit function, and they are for monitoring only.

Recommended Control

Zones will be maintained at occupied setpoint temperatures during occupied times, (typically, 8:00 a.m. to 5:00 p.m. with an occupied temperature of 21°C). Minor adjustments can be made at the sensor location. All zone setpoints shall be limited by software, typically ± 1ºC. This prevents the occupants causing wide swings in temperature.

Figure 14: Revised zone control setup page:



During the heating season temperatures will be allowed to drop after hours, to an unoccupied level (typically 18°C). They will return to their occupied level in the morning, according to the start-up strategy described. The time that they will start to return to their occupied temperature is also determined by the OAT. The colder the OAT, the earlier the zone will begin to return to its occupied temperature.

Air Handling Unit setpoints

Supply Air Temperature= 15 Deg C, Return Air Temperature = 21 Deg C.

On a cool day, around 10degC, every Air Handling Unit was in free cooling, with some as much as 50% outside air. We believe this is from space temperature thermostats that are set at above the RAT setpoint. The Air Handling Unit thinks the space is too warm and then proceeds to begin cooling. We believe all areas to be in cooling due to the fact that zone thermostats are set higher than the Air Handling Unit RAT setpoints. This was supported during a visit to the 3rd floor. Zone thermostat was set at 74 °F, the control system reported the area to be in cooling and the baseboard heat was on. Why not just turn off the heat?

Air Handling Unit Measures

The Air Handling Units have three components that contribute to energy use: a supply air fan, a return air fan and the outdoor air dampers.

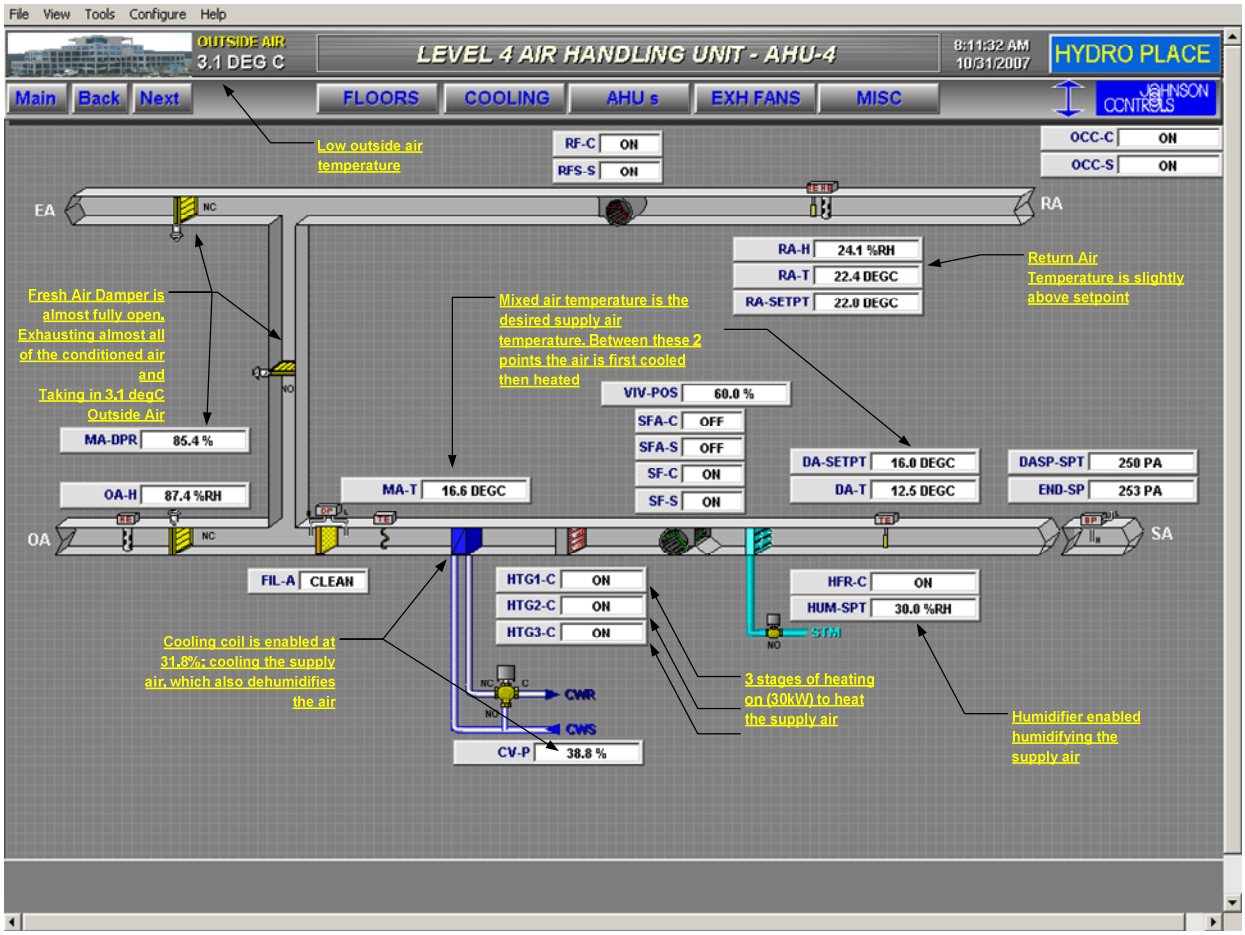
Currently, the air volume that is sent to the spaces is regulated by opening or closing inlet vanes on the supply air fan. This is old technology and not efficient. A better method is to use a Variable Frequency Drive (VFD) that will adjust the motor speed in response to a control signal. With the inlet vane arrangement, the motor runs at its maximum speed. A majority of the time, the motor speed can be reduced, saving motor kW and reducing wear on the motor and drives. Another benefit is that system noise is substantially reduced.

The existing outdoor air dampers are of a non-insulated double blade design. While better than single blade, they are not as efficient as modern insulated double-blade dampers. The efficiencies would come into effect when the building is unoccupied and the damper is closed.

The cost of retrofitting with the dampers with insulated dampers did not warrant this measure.

Hydro Place Energy Audit

Figure 15: Existing Air handling Unit graphic showing problems:

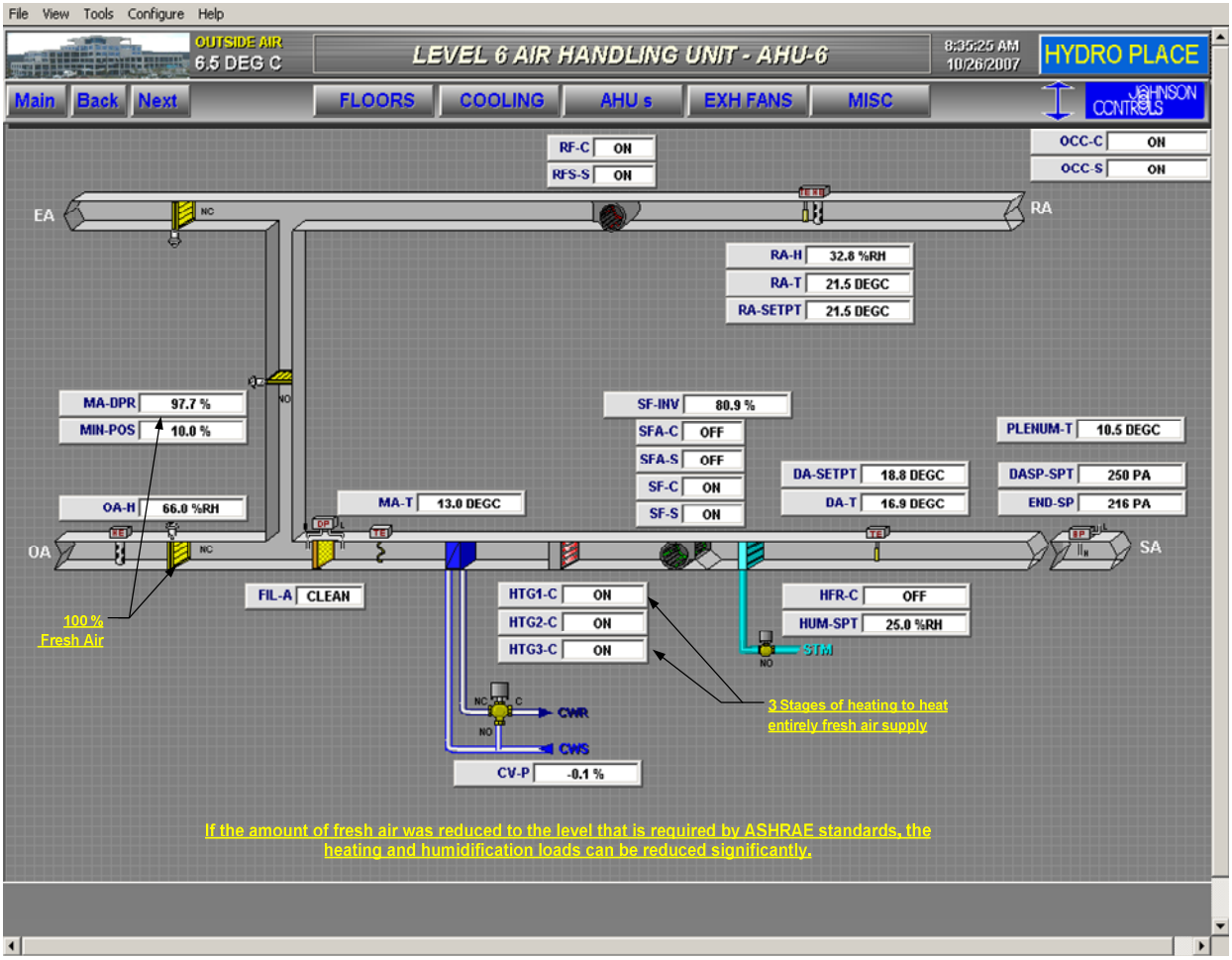


The heating, cooling and humidifying systems are “fighting” each other as well as dealing with too much outdoor air.

Cooling is on, heating is on, humidifier is commanded on, but manually turned off.

Hydro Place Energy Audit

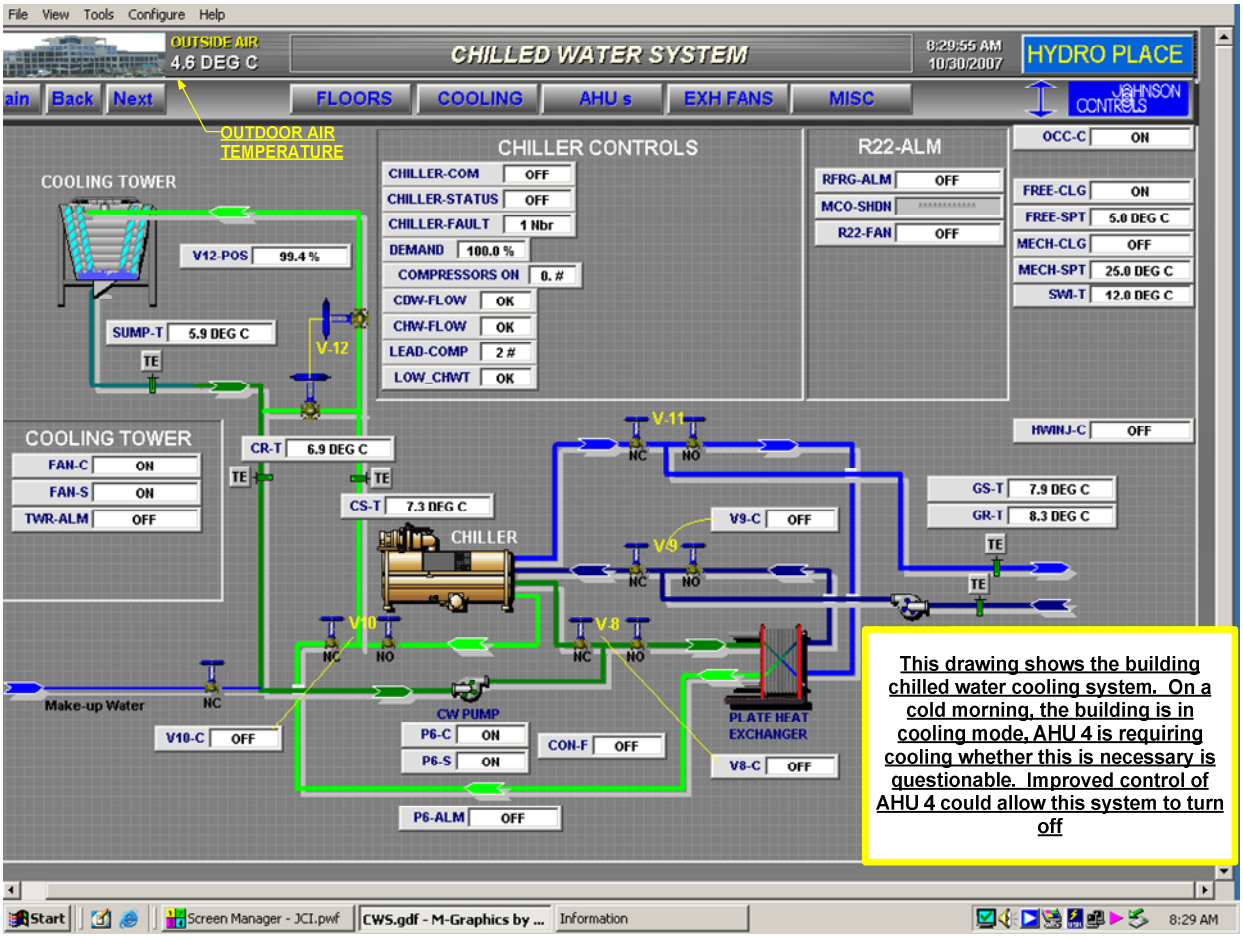
Figure 16: Existing Air handling Unit graphic showing effect of too much outdoor air and poor control:



Excessive heating is required due to too much outdoor air. The above picture shows 100% fresh air entering AHU while all three stages of heat are on.

Hydro Place Energy Audit

Figure 17: Existing Mechanical System graphic showing cooling ON:



Humidification had not been enabled since the summer, the humidifiers had been manually switched off, however the control system was commanding them on.

Air Handling Unit heating was on. There are motorized fresh air dampers on all Air Handling Unit's. Schedules are from 4am to 10pm M-F, 8am to 10pm SS. We believe the building to be unnecessarily bringing in fresh air. Fresh air should only be supplied to occupied zones. Zones should only be occupied during normal working hours or if an override signal is received. Fresh air amount to be determined based on number of zones occupied. This should be controlled through variable speed fans and the VAV system.

15. Humidification

Building humidification is accomplished using packaged steam humidifier units. These have a steam cylinder that is filled with water; electrodes immersed in the water pass a current through the water, causing it to boil. The steam is piped to the air handling unit supply air stream where it is distributed to the zones.

Fresh air not only imposes a wintertime heating load, it also has to be humidified. Humidification load can be reduced by setting the outdoor air dampers to minimum outdoor air position. Strategies can be written such that if the space humidity is low, the outdoor air damper position can be overridden and the dampers closed to get the humidity to desired levels. The humidity setpoint can also be adjusted to shed the humidifiers as part of a demand strategy.

Table 11 – Humidifier kW:

AHU #	Humidifier kW
1	41.6
2	62.4
3	62.4
4	41.6
5	27.8
6	17.3
7	none
8	20.8
Total	**273.9 kW**

This is a significant load.

Humidifiers are also a large maintenance item. The steam cylinders have an average life of about eighteen operating months and cost approximately $400-$500 each to replace. Hydro Place, due to the increased ventilation rates, would cause an increased usage of humidification and therefore require more frequent steam cylinder changes. Correcting the ventilation rates will increase the life of the steam cylinders thereby reducing energy and operating costs.

Changing out the current steam humidification systems, to reduce energy and operating costs was a very long payback therefore not included as a measure.

16. Computer Rooms

Table 12 – Liebert Computer Room Air Conditioners:

AC #	Location	Liebert Model #	Total Capacity kW
7	Communication room	CF066A-COO	17.1
10	1st floor computer room	FH114A	31.6
11	1st floor computer room	FH114A	31.6
12	Communication room	CF43A	11.4
13	ECC computer room 2nd floor	FH199A	53.4
14	ECC computer room 2nd floor	FH199A	53.4
15	ECC control room 2nd floor	FH114A	31.6

The three computer rooms (1st floor and ECC) and the Communications Room are cooled by separate computer room air conditioners. These are manufactured by Liebert and are installed with 100% redundancy. These units have air cooled condensers that reject the heat to the roof. We suggest that the computer rooms could be cooled via the main building air handling system during occupied times when the air handing system is in operation and there is excess capacity available. When the building is unoccupied or if the building system was fully loaded, the Liebert air conditioners would be enabled.

17. Domestic Hot Water

There are two 100 gallon water heaters located in the 1st floor mechanical room serving floors one through five and two 30 gallon water heaters located in 5th floor mechanical room serving the 6th floor. Both sets of tanks have circulating pumps, to be scheduled off based upon the building schedule, after cleaners are finished each day. The pump is to be started after hours, for occupancy, if a schedule is enabled by an operator or a pushbutton override, via any of the override temperature sensors, is depressed. The fitness room will have a new DHW tank installed for its usage, having the DHW disconnected from the main loop. The fitness room pushbutton override will enable the Fitness room DHW tank only.

18. Cafeteria

The cafeteria ventilation and display coolers are an insignificant load and do not contribute to energy inefficiency. The ventilation would be scheduled to match the cafeteria usage. No additional energy retrofit measures for the cafeteria have been included.

19. Commissioning and Rebalancing

When the building was built all of the mechanical and control systems would have been commissioned. The commissioning process has the commissioning team take the design drawings and specifications and verify that the installed equipment is operating as it should. The control sequences of operation are turning things on and off and making adjustments as designed. The re-commissioning process repeats these tests after a building has been in operation for some time.

A re-balancing similarly has the certified balancing company measure the airflows from the duct systems and adjust them according to the design parameters. An additional step that is often beneficial is to have an HVAC engineer re-calculate the design airflows, based upon current building occupancy and room arrangement.

Training:

Building management staff must be trained in the operation of the Energy Management System (EMS). The training must include a through description of the mechanical and control systems and the building manager must understand what is normal and abnormal.

In addition, there must be a trained energy analyst who will regularly review the energy usage and building operation to look for ways of optimizing the seasonal energy use.

20. Interim Measures

The following interim low cost measures could be taken to help with energy reduction and comfort improvements:

1. Scheduling of AHU's – Stagger start times, and shut down AHU's earlier
2. Scheduling of shut down of zones. Have cleaners finish one floor at a time and shut that floor down
3. Reduce amount of fresh air introduced
4. Increase Return air temperature setpoint on control system
5. Close interior doors in vestibules

21. References: (copies available upon request)

15 O&M Best Practices For Energy Efficient Buildings, Portland Energy Conservation, Inc. (PECI) 921 SW Washington, Suite 312, Portland, OR 97205,(503) 248-4636, e-mail: peci@peci.org, Also available on-line at www.peci.org

Advanced Controls for Commercial Buildings: Barriers and Energy Savings Potential
Kurt W. Roth1, Patricia Llana1, Detlef Westphalen1, Louis Quartararo1, and Michael Y. Feng2
1TIAX LLC, 2Charles Stark Draper Laboratory

Methods for automated and continuous commissioning of building systems, Final Report, April 2003, Portland Energy Conservation, Inc..1400 SW 5th Avenue, Suite 700,Portland, Oregon 97201, Battelle Northwest Division, Richland, Washington 99352
Prepared for the Air-Conditioning And Refrigeration Technology Institute
4100 N. Fairfax Drive, Suite 200, Arlington, Virginia 22203

Guidelines For Conducting Energy Audits Of Administrative, Commercial And Office Buildings, November 2001, OECS-NRMU, Phone: (758) 452-1847
E-mail: oecsnr@candw.lc

ENERGYSTAR® Building Upgrade Manual
United States Environmental Protection Agency December, 2004

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An Evaluation of Technologies for Real-Time Measurement of Rates of Outdoor Airflow into HVAC Systems, William J. Fisk, David Faulkner, Douglas P. Sullivan
Indoor Environment Department, Environmental Energy Technologies Division
Lawrence Berkeley National Laboratory, Berkeley, CA 94720, September 27, 2004

Recommissioning –The Optimization of a Building Systems' Operation
Energy Innovators Initiative, Office of Energy Efficiency, Natural Resources Canada, 615 Booth Street, 4th Floor, Ottawa ON K1A 0E9, Tel.: 1 877 360-5500 (toll-free) • Fax: (613) 947-4121 • E-mail: info.services@nrcan.gc.ca • Web site: oee.nrcan.gc.ca/eii

7 Upgrades to Reduce Building Electrical Demand
Kirby P. Nelson, P.E.,(from ASHRAE Journal)

Increasing Energy Efficiency In Data Centers
By Roger Schmidt, Ph.D., P.E., Member ASHRAE; Don Beaty, P.E., Member ASHRAE, and Jay Dietrich, P.E. ,(from ASHRAE Journal)

OA Economizers For Data Centers ASHRAE Journal December 2007

Optimizing Chiller Plant Control Logic, ASHRAE Journal July 2006

ASHRAE Standard 62.1-2007, Ventilation for Acceptable Air Quality

Suggested References:

Energy Star Building Upgrade Manual
Available at:
http://www.energystar.gov/index.cfm?c=business.bus_upgrade_manual

National Resources Canada - A Guide to Implementing an Energy Efficiency Awareness Program see:

(http://oee.nrcan.gc.ca/publications/infosource/pub/ici/eii/pdf/eii-awareness.pdf).

22. Appendix

Effective July 1, 2007

NEWFOUNDLAND POWER INC.
RATE #2.4
GENERAL SERVICE 1000 kVA AND OVER

Availability:

For Service where the maximum demand occurring in the 12 months ending with the current month is 1000 kilovolt-amperes or greater.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: ..... $185.64 per month

Demand Charge:

$7.05 per kVA of billing demand in the months of December, January, February and March and $6.30 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:

First 100,000 kilowatt-hours @ 7.042 0 per kWh

All excess kilowatt-hours @ 5.573 0 per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 15.9 cents per kWh plus the Basic Customer Charge.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00 will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular, Regulation 7(n)], transformation [in particular, Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

Effective July 1, 2007

NEWFOUNDLAND POWER INC.
RATE #2.3
GENERAL SERVICE 110 kVA (100 kW) - 1000 kVA

Availability:

For Service where the maximum demand occurring in the 12 months ending with the current month is 110 kilovolt-amperes (100 kilowatts) or greater but less than 1000 kilovolt-amperes.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: ..... $92.81 per month

Demand Charge:

$7.46 per kVA of billing demand in the months of December, January, February and March and $6.71 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:

First 150 kilowatt-hours per kVA of billing demand,

up to a maximum of 30,000 kilowatt-hours@ 8.431 0 per kWh

All excess kilowatt-hours @ 5.681 0 per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 15.9 cents per kWh plus the Basic Customer Charge.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00 will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular, Regulation 7(n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

APPENDIX B

COST BENEFIT ANALYSIS

PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hydro Place Energy Efficiency
Hydro Place Energy Efficiency
HYP Energy Efficiency

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2008**
Present Worth Year	2008
Number of Years in Study	15
Discount Rate	8.0%
Total In-service Project Cost	$ 832,600
In-service Year	2009
Other Project Cost ***after*** In-service (if applicable)	$ -
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ -
Replacement Year (if applicable)	
Project cost in Ending (**E**) or Beginning (**B**) Year $$	
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	

A	B	C	D	E	F	G	H	I	J	K	L
Year		Annual O&M Cost $	Annual Fuel Price (if applicable)	Annual Fuel Cost $	Other Cost $	Total Costs $	Benefit 1 *Energy Savings* $	Benefit 2 *O&M Savings* $	NET $	P.W. January 2008	Cumulative Present Worth
0	2008	-		-	-	-	-	-	-	-	-
1	2009	-		-	-	832,600	-	-	832,600	770,926	770,926
2	2010	-		-	-	-	(113,534)	(40,263)	(153,797)	(122,089)	648,837
3	2011	-		-	-	-	(115,804)	(41,069)	(156,873)	(115,306)	533,530
4	2012	-		-	-	-	(118,120)	(41,890)	(160,011)	(108,900)	424,630
5	2013	-		-	-	-	(120,483)	(42,728)	(163,211)	(102,850)	321,779
6	2014	-		-	-	-	(122,892)	(43,582)	(166,475)	(97,137)	224,643
7	2015	-		-	-	-	(125,350)	(44,454)	(169,804)	(91,740)	132,903
8	2016	-		-	-	-	(127,857)	(45,343)	(173,201)	(86,643)	46,259
9	2017	-		-	-	-	(130,414)	(46,250)	(176,665)	(81,830)	(35,570)
10	2018	-		-	-	-	(133,023)	(47,175)	(180,198)	(77,284)	(112,854)
11	2019	-		-	-	-	(135,683)	(48,119)	(183,802)	(72,990)	(185,844)
12	2020	-		-	-	-	(138,397)	(49,081)	(187,478)	(68,935)	(254,780)
13	2021	-		-	-	-	(141,165)	(50,063)	(191,227)	(65,105)	(319,885)
14	2022	-		-	-	-	(143,988)	(51,064)	(195,052)	(61,489)	(381,374)
15	2023	-		-	-	-	(146,868)	(52,085)	(198,953)	(58,072)	(439,446)
						-			-	-	-
						-			-	-	-
						-			-	-	-
						-			-	-	-
						-			-	-	-

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Stationary Battery Replacement Program

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

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Appendix
A - Five Year Battery Replacement Schedule

1 INTRODUCTION

Newfoundland and Labrador Hydro's (Hydro's) Stationary Battery Replacement Program (the Program) is an ongoing program to replace stationary battery systems which are required for equipment located in generating and terminal stations and at telecommunications sites throughout Hydro's operating area.

Hydro has 39 generation sites including hydraulic, thermal and diesel, 54 high-voltage (66 kV and above) terminal stations and 14 telecommunications microwave sites. Stationary batteries are located in all of these sites, and are used to provide power to telecommunications, protection and control, and switching equipment during times of AC power loss, enabling Hydro to continue operating the stations, either locally or by remote control from the Energy Control Centre (ECC).

Two types of stationary battery are in use today. The flooded-cell battery shown in Figure 1 is the most common type. It consists of a series of individual cells connected together to supply the required voltage, either 48V or 125V DC, depending on the application. Each cell has rectangular plates of lead-calcium alloy bathed in a sulfuric acid electrolyte. The battery is large, heavy, and unwieldy; however, it has the advantage of high reliability and a typical service life of 18-20 years. If an individual cell fails, the battery continues to operate, although at diminished capacity. This type of battery has three disadvantages. Flooded-cell batteries emit small amounts of hydrogen gas during charging, and therefore require battery room ventilation. The battery also requires regular maintenance to ensure the battery electrolyte does not deplete during operation, and a jar container may fail causing potentially dangerous spills of sulfuric acid.

Figure 1 - Flooded-cell battery (Stephenville)

In an effort to develop a smaller battery with less maintenance and less exposure to dangerous chemicals, manufacturers introduced a new type of battery, known as Valve Regulated Lead Acid (VRLA) or “maintenance-free”, shown in Figure 2. These batteries hold the electrolyte suspended in a gel or paste and utilize a sealed container which reduces the chance of spill and prevents hydrogen escaping to the atmosphere. Unfortunately, once in operation they soon demonstrated several significant disadvantages. In practice, VRLA batteries have only seven to ten years of service life, which is approximately half of the flooded-cell battery service life. The batteries can experience a condition known as “thermal runaway” which is overheating that could lead to an explosion. As well, when a cell fails, it fails with an open circuit, meaning that the failure of one cell can cause the whole bank to fail. For these reasons, many users are moving back to flooded-cell batteries.

Figure 2 - VRLA battery (Hinds Lake)

There are two applications for stationary batteries – telecommunications and station service. The voltage of telecommunications batteries is usually 48V DC. These batteries typically have higher standby capacity (in terms of hours the battery can supply the load) than is required for station service batteries for two reasons. First, they often carry telecommunications for not only the site itself, but other sites as well, so they have a higher standby time requirement. Second, the station service equipment operates intermittently, whereas the telecommunications equipment draws power continuously. Station service batteries operate protection, control and switching equipment in the station, and are typically 125V DC.

Because they operate at a different voltage and on direct rather than alternating current, batteries are equipped with a charging system or charger. The charger converts AC to DC for the battery and attached equipment. Chargers normally last longer than VRLA batteries and, therefore, are not always replaced when the VRLA batteries are replaced. Chargers used for flooded-cell batteries are normally replaced at the same time as the batteries.

2 PROJECT DESCRIPTION

The batteries being replaced under the Program for 2009 are both VRLA and flooded-cell, and are shown in Table 1. The chargers being replaced are shown in Table 2.

Table 1
2009 Battery Replacements

Location	Type	Voltage	Install Date	Manufacturer
Long Harbour (LHR)	Flooded	48V	1988	C&D
St. John's (STJ)	Flooded	48V	1989	C&D
Come By Chance (CBC)	VRLA	48V	2000	Yuasa
Oxen Pond (OPD)	VRLA	48V	2000	Yuasa
Sunnyside (SSD)	VRLA	48V	2000	Exide
Barachoix (BCX)	Automotive	125V	2004	Car Quest
Bottom Waters (BWT)	Flooded	125V	1991	C&D
Long Harbour (LHR)	Flooded	125V	1991	Exide C
Bay d'Espoir Plant (BDP) 1	Flooded	125V	1986	C&D
Bay d'Espoir Plant (BDP) 2	Flooded	125V	1986	C&D
Hind's Lake Plant (HLP)	VRLA	125V	1996	KCR
Hydro Place UPS	VRLA	323V	2003	Sterling

Table 2
2009 Charger Replacements

Location	Battery Voltage	Capacity	Install Date	Manufacturer
Long Harbour (LHR)	48V	50A	1988	Staticon
St. John's (STJ)	48V	75A	1989	Staticon
Barachoix TS	125V	10A	1991	C CanPower Systems
Holyrood TS (HRD)	125V	30A	1985	Saft Nife
Hardwoods (HWD GT CHG 1)	125V	150A	1977	Cigentic
Bay d'Espoir Plant (BDP PH1 CHG1)	125V	40A	1982	Staticon
Bay d'Espoir Plant (BDP PH1 CHG2)	125V	40A	1981	Staticon
Bay d'Espoir Plant (BDP PH1 CHG3)	125V	40A	1987	Staticon
Hinds Lake Plant (HLK CHG 1)	125V	30A	1980	CTS
Hinds Lake Plant (HLK CHG 2)	125V	30A	1980	CTS

The batteries and chargers being replaced under the Program for the years 2009 – 2013 inclusive are shown in Appendix A – Battery Replacement Schedule. This plan is subject to modification if conditions warrant the early replacement of a system, or if a system is showing deterioration different from originally expected.

3 EXISTING SYSTEM

The battery banks throughout Hydro's system are inspected regularly, depending on age and condition, to determine if there is a need for replacement.

Batteries are typically inspected annually and tested as required. More frequent monitoring and testing may be performed if deterioration is noticed.

Flooded-cell batteries and VRLA batteries have an average life of 18 to 20 years and seven to ten years, respectively. Replacement is based on a combination of age and condition. As batteries age, they rapidly deteriorate and will no longer provide sufficient power in the event of an outage.

3.1 Age of Equipment or System

The original installation dates shown in Tables 1 & 2 convey the ages of the various battery banks and chargers being replaced.

3.2 Major Work or Upgrades

There has been no major work or upgrades on any of the batteries or chargers being replaced under this project.

3.3 Anticipated Useful life

Flooded-cell batteries have a typical service life of 18 to 20 years. VRLA batteries have a typical service life of seven to ten years.

For calculating depreciation expense all battery banks and chargers are assumed to have an economic life of 15 years.

3.4 Maintenance History

Battery maintenance varies with the age, location and type of battery. Generally speaking, if batteries are in a location where they are being observed regularly, such as a manned generating station, they may not be tested as regularly as those in locations that are not visited frequently. Visual observation of batteries can offer information regarding their condition.

Regular maintenance included visual inspection, measurement of cell voltage, measurement of electrolyte specific gravity, and replacement of evaporated electrolyte with distilled water.

Conductance testing is a relatively new practice within Hydro and is being implemented to varying degrees across the system. This type of testing is intended to supplement traditional capacity testing, which is the most accurate test of a battery's condition. In a capacity test, the battery is removed from service and connected to a load that is designed to discharge the battery over eight hours. This test of the so-called eight hour rate assesses the actual capacity of the battery. The battery cells are observed during the test for rapid loss of voltage to determine if they have deteriorated. The battery is deemed to have failed the test if it demonstrates less than 80 percent of rated capacity[1].

Because the capacity test takes a significant amount of time and requires a disruption of service, it is difficult to conduct regularly. A suitable proxy for discharge testing is conductance testing, during which the conductance or ability of the battery's individual cells to conduct current is measured. Hydro personnel periodically test batteries using a

[1] Institute of Electrical and Electronics Engineers (IEEE) Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing and Replacement of Vented Lead-Acid Batteries for Stationary Applications, Section 7.

conductance tester. By comparing results over time, deterioration of the battery can be tracked. Ideally, batteries are tested shortly after installation and this baseline used to track changes in the battery's condition. However, many batteries currently being replaced have been in service longer than Hydro has been testing batteries, so baseline test results are not available. As well, some manufacturers publish reference values that are useful for comparing test results; however these results are not available for all batteries. As a result, some judgment must be used.

Chargers are not generally tested. They are replaced as they reach the end of their useful lives.

Each battery being replaced will be discussed individually, where test results are available.

3.4.1 Long Harbor (LHR) 48V Battery

The LHR 48V battery has experienced significant degradation. Tests in 2008 concluded that conductance has decreased by an average of 17 percent for all cells, indicating a need for immediate replacement.

3.4.2 St. John's (STJ) 48V Battery

The STJ 48V battery has experienced significant degradation. Tests in 2007 concluded that conductance has decreased by an average of 17 percent for all cells, indicating a need for immediate replacement.

3.4.3 Come By Chance (CBC) 48V Battery

The CBC battery has experienced significant degradation. Tests in 2008 concluded that conductance has decreased by an average of 19 percent for all cells, indicating a need for immediate replacement.

3.4.4 Oxen Pond (OXP) 48V Battery

The OXP battery has experienced significant degradation. Tests in 2008 concluded that conductance has decreased by an average of 28 percent for all cells, indicating a need for immediate replacement.

3.4.5 St. John's (STJ) 323V Battery

The STJ 323V battery was tested in 2008 by the manufacturer as part of annual maintenance and was recommended to be replaced immediately. The manufacturer's representative indicated that the rate of decrease of conductance indicates a need for immediate replacement.

The remaining batteries do not have available test results. Replacement is based on age and operating experience.

3.5 Outage Statistics

Battery chargers are typically installed in a redundant configuration, in order to minimize outages. Batteries that fail must be replaced immediately. There are no recorded outages for any of the equipment being replaced under this program.

3.6 Industry Experience

Battery life is highly variable and can depend on many factors. High temperature, slightly elevated charging voltage, and the number, duration and depth of discharges can all affect the service life of a battery. Industry users have experienced battery life for VRLA batteries of as little as 24 months[2] and as long as 25 years for flooded cell batteries that are rarely used and maintained under ideal conditions[3]. Hydro has had to replace batteries with as little as five years of use and has kept batteries in service for well over 20 years in some cases. Testing and monitoring of batteries is critical to ensuring that they are available when required.

3.7 Maintenance or Support Arrangements

Most batteries and chargers are maintained by Hydro personnel. Depending on the location, the battery may be inspected and/or tested biannually or annually. The exception is UPS batteries at Hydro Place and Holyrood. Because of the specialized application these batteries are maintained by the manufacturer. Annual inspection and maintenance is performed on these batteries.

[2] "Eliminate VRLA Battery Failures in Telecom Outside Plants and Maximize In-Service Life", B. Williams, *Battcon 2000 Proceedings*, 2000.
[3] "Myths and Misconceptions: Exploring the Myths of Battery Life, a User's Perspective", M.S. Clark, *Battcon 2006 Proceedings*, 2006.

3.8 Vendor Recommendations

Most vendors defer to the standards published by the Institute of Electrical and Electronics Engineers (IEEE) for battery testing and replacement.

3.9 Availability of Replacement Parts

Many, although not all, battery manufacturers have relatively consistent product lines and so replacement of individual cells is available for batteries. When a cell fails prematurely, it is normal to replace it and keep the remainder of the string. However, when the battery reaches the end of its useful life, replacement of individual cells is not recommended. At this point, more frequent inspection, as well as the overhead costs associated with ordering and installing individual cells and the likelihood that multiple cell replacements will be required at different points in time, will offset any cost saving associated with extending the life of the battery for what will likely be only a few years.

3.10 Safety Performance

Aging batteries can on occasion present a safety hazard since cells are more likely to rupture, especially if plate distortion is present. This phenomenon is often observed in aging batteries but rupture is not common. As well, aging cells occasionally develop cracks which may leak. Hydro personnel are equipped with personal protective equipment and spill remediation kits should electrolyte spillage occur.

3.11 Environmental Performance

Because of the presence of sulfuric acid and lead, precautions must be taken in the handling and disposal of batteries. Transportation of Dangerous Goods (TDG) regulations apply to the transport of batteries. Training is provided to Hydro personnel and contractors to ensure that the risk to the environment is minimized.

3.12 Operating Regime

Battery banks and chargers are stand-by equipment and are used to provide power to telecommunications, protection and control, and switching equipment during times of AC power loss, enabling Hydro to still operate terminal stations and microwave sites, either locally or by remote control from the Energy Control Centre. These systems are the last line of defense during power outages, and therefore high reliability and sufficient backup time must be provided. These systems must be available 24 hours per day, every day. Replacement after failure is unacceptable, since a power outage at the station will prolong customer outages.

4 JUSTIFICATION

Flooded-cell batteries have an average service life of 18-20 years; VRLA batteries, seven to ten years. Replacement is based on a combination of age and condition. As batteries age, they rapidly deteriorate and will no longer provide sufficient power in the event of an outage. IEEE Standards 450 and 1188 recommend replacement of a battery at the earliest possible opportunity if the capacity has fallen to 80 percent of its rated capacity.

Based on age alone, the batteries being replaced have either reached or are nearing the end of their useful lives. Testing of the batteries demonstrates the need for timely replacement.

Hydro's Battery Replacement Program ensures that batteries are replaced failure is imminent. Batteries are key components of the infrastructure that is required to support the reliable operation of the power grid. Hydro's battery replacement program ensures that battery life is maximized while at the same time ensuring that reliable operation is maintained.

4.1 Net Present Value

A cost benefit analysis, rather than net present value analysis has been performed. See Section 4.3.

4.2 Levelized Cost of Energy

As the batteries and chargers are not related to generating units, the levelized cost of energy is not applicable.

4.3 Cost Benefit Analysis

A brief cost benefit analysis demonstrates that flooded-cell batteries are the most cost-effective option.

In performing this analysis, the following assumptions were made:

1. The labour cost for engineering, installation and maintenance of a flooded-cell or VRLA battery is the same;
2. A VRLA battery must be replaced after 10 years;
3. A flooded-cell battery must be replaced after 20 years; and
4. Chargers for VRLA and flooded-cell batteries are the same cost, and are replaced at the same time.

Twenty years of data was analyzed to capture the life of one flooded cell and two VRLA batteries.

Table 3
Battery Banks and Chargers Replacement

Alternative Comparison Cumulative Net Present Value to the Year 2028		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Flooded Cell Battery	41,495	0
VRLA Battery	59,346	17,851

PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Battery Banks and Chargers Replacem

Flooded Cell Battery

Flooded

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2008**
Present Worth Year	2008
Number of Years in Study	20
Discount Rate	8.0%
Total In-service Project Cost	$ 48,400
In-service Year	2009
Other Project Cost ***after*** In-service (if applicable)	$ -
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ -
Replacement Year (if applicable)	
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		Annual O&M Cost $	Annual Fuel Price (if applicable)	Annual Fuel Cost $	Other Cost $	Total Costs $	Benefit 1 *(specify)* $	Benefit 2 *(specify)* $	NET $	P.W. January 2008	Cumulative Present Worth
0	2008	-		-	-	-	-	-	-	-	-
1	2009	-		-	-	48,400	-	-	48,400	41,495	41,495
2	2010	-		-	-	-	-	-	-	-	41,495
3	2011	-		-	-	-	-	-	-	-	41,495
4	2012	-		-	-	-	-	-	-	-	41,495
5	2013	-		-	-	-	-	-	-	-	41,495
6	2014	-		-	-	-	-	-	-	-	41,495
7	2015	-		-	-	-	-	-	-	-	41,495
8	2016	-		-	-	-	-	-	-	-	41,495
9	2017	-		-	-	-	-	-	-	-	41,495
10	2018	-		-	-	-	-	-	-	-	41,495
11	2019	-		-	-	-	-	-	-	-	41,495
12	2020	-		-	-	-	-	-	-	-	41,495
13	2021	-		-	-	-	-	-	-	-	41,495
14	2022	-		-	-	-	-	-	-	-	41,495
15	2023	-		-	-	-	-	-	-	-	41,495
16	2024	-		-	-	-	-	-	-	-	41,495
17	2025	-		-	-	-	-	-	-	-	41,495
18	2026	-		-	-	-	-	-	-	-	41,495
19	2027	-		-	-	-	-	-	-	-	41,495
20	2028	-		-	-	-	-	-	-	-	41,495
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Assumptions & Notes:

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Battery Banks and Chargers Replacem

VRLA Battery

VRLA

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2008**
Present Worth Year	2008
Number of Years in Study	20
Discount Rate	8.0%
Total In-service Project Cost	$ 43,000
In-service Year	2009
Other Project Cost ***after*** In-service (if applicable)	$ -
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ -
Replacement Year (if applicable)	
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		Annual O&M Cost $	Annual Fuel Price (if applicable)	Annual Fuel Cost $	Other Cost $	Total Costs $	Benefit 1 *(specify)* $	Benefit 2 *(specify)* $	NET $	P.W. January 2008	Cumulative Present Worth
0	2008	-		-	-	-	-	-	-	-	-
1	2009	-		-	-	43,000	-	-	43,000	36,866	36,866
2	2010	-		-	-	-	-	-	-	-	36,866
3	2011	-		-	-	-	-	-	-	-	36,866
4	2012	-		-	-	-	-	-	-	-	36,866
5	2013	-		-	-	-	-	-	-	-	36,866
6	2014	-		-	-	-	-	-	-	-	36,866
7	2015	-		-	-	-	-	-	-	-	36,866
8	2016	-		-	-	-	-	-	-	-	36,866
9	2017	-		-	-	-	-	-	-	-	36,866
10	2018	-		-	52,417	52,417	-	-	52,417	22,481	59,346
11	2019	-		-	-	-	-	-	-	-	59,346
12	2020	-		-	-	-	-	-	-	-	59,346
13	2021	-		-	-	-	-	-	-	-	59,346
14	2022	-		-	-	-	-	-	-	-	59,346
15	2023	-		-	-	-	-	-	-	-	59,346
16	2024	-		-	-	-	-	-	-	-	59,346
17	2025	-		-	-	-	-	-	-	-	59,346
18	2026	-		-	-	-	-	-	-	-	59,346
19	2027	-		-	-	-	-	-	-	-	59,346
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Assumptions & Notes:

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4.4 Legislative or Regulatory Requirements

IEEE Standards 450 and 1,188 recommend replacement of a battery at the earliest possible opportunity if the capacity has fallen to 80 percent of its rated capacity. Note that these are neither legislative nor regulatory requirements, but are industry accepted standards.

4.5 Historical Information

Table 4
Five-Year Battery Chargers Capital Budget and Expenditures History

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per Unit ($000)	Comments
2007	71.6	69.5	5	13.9	-
2006	89.7	96.8	11	8.8	-
2005	No Budget	No Expenditures	2		Part of battery bank expenditures.
2004	No Budget	No Expenditures	7		Part of battery bank expenditures.
2003	No Budget	No Expenditures	5		Part of battery bank expenditures.

Table 5
Five-Year Battery Banks Capital Budget and Expenditures History

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per Unit ($000)
2007	556.7	346.7	7	49.5
2006	475.2	488.3	14	34.9
2005	529.7	479.9	14	34.3
2004	341.2	389.2	10	38.9
2003	306.6	396.6	9	44.1

4.6 Forecast Customer Growth

Batteries and chargers are not impacted by forecast customer growth.

4.7 Energy Efficiency Benefits

There are no projected energy efficiency benefits related to the replacement of batteries and chargers.

4.8 Losses during Construction

Installation of batteries and chargers will not require customer outages. When a battery is being replaced, a small temporary battery is used to provide backup in case there is an AC power outage. When chargers are being replaced, the battery supplies the load. In either case, customers are not affected.

4.9 Status Quo

Prolonged power outages would result from terminal stations and microwave sites being without backup power when AC power is unavailable from battery banks.

4.10 Alternatives

Acceptable alternatives to stationary batteries do not exist. Stationary batteries are a critical component of, and are integral to, the design of station control and telecommunications equipment.

Because of their short life, when replacing VRLA batteries, flooded cell batteries are substituted whenever possible. Space limitations sometimes dictate that VRLA batteries must be used.

5 CONCLUSION

Stationary batteries are a critical component of the equipment required to control the power grid. In order to ensure that the grid can be controlled during times of disruption, Hydro will replace aging batteries and chargers on a continual basis to ensure that reliability of the overall system is maintained.

5.1 Budget Estimate

The estimate for 2009 is considerably higher than in previous years, owing to the large number of systems that need replacement. It is anticipated that 2009 is an anomaly and that lower amounts will be required in future years. The 2009 estimate is below:

Table 6
Budget Estimate

Project Cost:($ x1,000)	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	285.0	0.0	0.0	285.0
Labour	206.6	0.0	0.0	206.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	46.0	0.0	0.0	46.0
Other Direct Costs	45.9	0.0	0.0	45.9
O/H, AFUDC & Escln	86.9	0.0	0.0	86.9
Contingency	58.3	0.0	0.0	58.3
TOTAL	**728.6**	**0.0**	**0.0**	**728.6**

5.2 Project Schedule

The project schedule is summarized below:

Table 7
Project Schedule

Activity	Milestone
Project Initiation	January 2009
Design Complete	March 2009
Commissioning Complete	October 2009
Project Closed	November 2009

Appendix A

Five Year Battery Replacement Schedule

2009

Battery Replacements

Location	Type	Voltage	Install Date	Manufacturer
Long Harbour (LHR)	Flooded	48V	1988	C&D
St. John's (STJ)	Flooded	48V	1989	C&D
Come By Chance (CBC)	VRLA	48V	2000	Yuasa
Oxen Pond (OPD)	VRLA	48V	2000	Yuasa
Sunnyside (SSD)	VRLA	48V	2000	Exide
Barachoix (BCX)	Automotive	125V	2004	Car Quest
Bottom Waters (BWT)	Flooded	125V	1991	C&D
Long Harbour (LHR)	Flooded	125V	1991	Exide C
Bay d'Espoir Plant (BDP) 1	Flooded	125V	1986	C&D
Bay d'Espoir Plant (BDP) 2	Flooded	125V	1986	C&D
Hind's Lake Plant (HLP)	VRLA	125V	1996	KCR
Hydro Place UPS	VRLA	323V	2003	Sterling

Charger Replacements

Location	Battery Voltage	Capacity	Install Date	Manufacturer
Long Harbour (LHR)	48V	50A	1988	Staticon
St. John's (STJ)	48V	75A	1989	Staticon
Barachoix TS	125V	10A	1991	C CanPower Systems
Holyrood TS (HRD)	125V	30A	1985	Saft Nife
Hardwoods (HWD GT CHG 1)	125V	150A	1977	Cigentic
Bay d'Espoir Plant (BDP PH1 CHG1)	125V	40A	1982	Staticon
Bay d'Espoir Plant (BDP PH1 CHG2)	125V	40A	1981	Staticon
Bay d'Espoir Plant (BDP PH1 CHG3)	125V	40A	1987	Staticon
Hinds Lake Plant (HLK CHG 1)	125V	30A	1980	CTS
Hinds Lake Plant (HLK CHG 2)	125V	30A	1980	CTS

2010

Battery Replacements

Location	Type	Voltage	Install Date	Manufacturer
Berry Hill (BHL)	Flooded	48V	1990	C&D
Deer Lake (DLK)	Flooded	48V	1990	GNB
Hinds Lake (HLK)	Flooded	48V	1990	GNB
Peters Barren (PBN)	Flooded	48V	1990	C&D
Howley (HLY)	VRLA	48V	2000	Yuasa
Happy Valley (HVP)	VRLA	48V	2000	Yuasa

Battery Charger Replacements

Location	Battery Voltage	Capacity	Install Date	Manufacturer
Berry Hill (BHL)	48V	50A	1990	Saft Nife
Peters Barren (PBN)	48V	50A	1990	Saft Nife
Grand Falls (GFC TS CHG 1)	125V	30A	1992	Staticon
Grand Falls (GFC TS CHG 2)	125V	30A	1992	Staticon
Massey Drive (MDR TS CHG 1)	125V	20A	1985	Cigentic
Massey Drive (MDR TS CHG 2)	125V	20A	1985	Cigentic
Stephenville (SVL TS CHG 1)	125V	54A	1974	Powertronic
Paradise River (PDR)	125V	50A	1988	Staticon
Cat Arm (CAT CHG 1)	125V	60A	1985	CTS
Cat Arm (CAT CHG 2)	125V	60A	1985	CTS
Cat Arm (CAT CHG 3)	125V	60A	1985	CTS
Snook's Arm (SNK)	125V	3A	1990	Saft Nife

2011

Battery Replacements

Location	Type	Voltage	Install Date	Manufacturer
Lake Melville (LMR)	VRLA	48V	2001	C&D

Charger Replacements

Location	Battery Voltage	Capacity	Install Date	Manufacturer
Bottom Brook (BBK)	125V	12A	1991	Saft Nife
Buchans (BUC CHG 1)	125V	30A	1990	Saft Nife
Buchans (BUC CHG 2)	125V	30A	1990	Saft Nife
Doyles (DLS)	125V	12A	1991	Saft Nife
Indian River (IRV CHG 1)	125V	40A	1992	Staticon
Indian River (IRV CHG 2)	125V	40A	1992	Staticon

2012

Battery Replacements

Location	Type	Voltage	Install Date	Manufacturer
Bay d'Espoir Plant (BDE PH2)	Flooded	125V	1992	Exide

Charger Replacements

Location	Battery Voltage	Capacity	Install Date	Manufacturer
Bottom Waters (BWT)	125V	10A	1990	Saft Nife
Springdale (SPL TS CHG 1)	125V	30A	1992	Saft Nife
Springdale (SPL TS CHG 2)	125V	30A	1992	Saft Nife

2013

Battery Replacements

None Scheduled

Charger Replacements

None Scheduled

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Hinds Lake to Blue Grass Hill Fibre Optic Cable

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

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1 INTRODUCTION

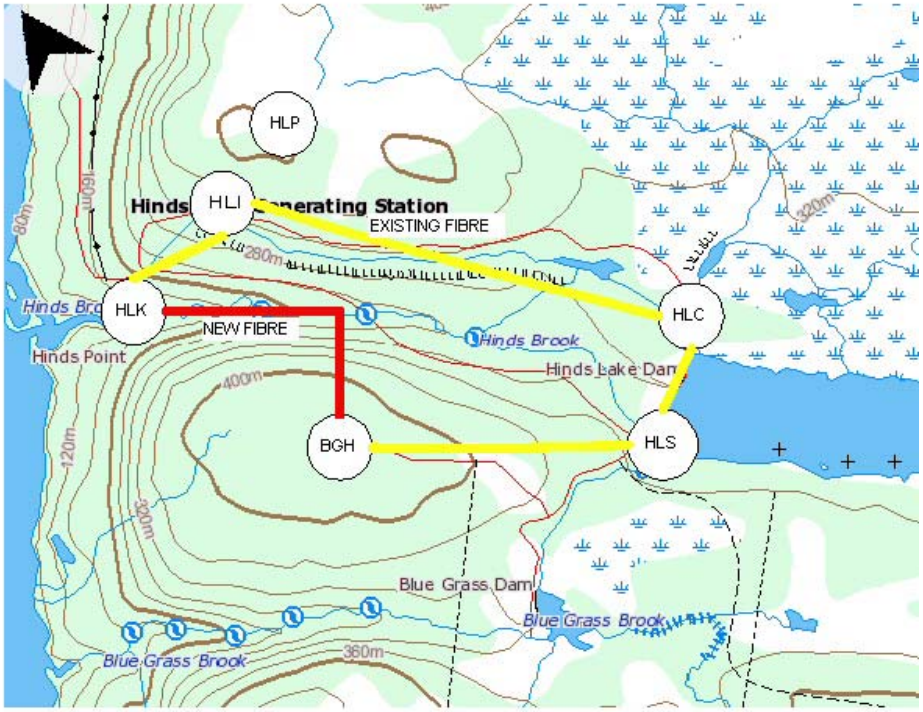
This report describes the justification for the replacement of one link of microwave radio, from Newfoundland and Labrador Hydro's (Hydro's) Blue Grass Hill (Blue Grass Hill) microwave site to Hinds Lake Generating Station (Hinds Lake), with a fibre optic cable. This replacement is being completed because it is the most cost effective option.

Hinds Lake Generating Station is a hydroelectric generating station which consists of one unit rated at 175 MW. The Hinds Lake complex consists of four main facilities: the generating station itself; the Intake building (HLI), where the water from the lake enters a penstock to be delivered to the turbine; the Control Structure building (HLC), where the water from Hinds Lake itself is directed into a canal for delivery to the intake; and the Hinds Lake Spillway (HLS), a spillway structure which allows water to spill into Hinds Brook when required. Figure 1 below is a photo of the Hinds Lake Generating Station.

Figure 1 - Hinds Lake Generating Station

In order to provide remote control of Hinds Lake, microwave radio is used to allow communication with Hydro's Energy Control Centre (ECC) in St. John's and provide teleprotection on several transmission lines. The link to Hinds Lake is routed through the Blue Grass Hill microwave site. Figure 2 illustrates the relative positions of the facilities in the area.

Microwave radio requires a direct line of sight from one location to the next. In the case of Blue Grass Hill to Hinds Lake, a hill that blocked the direct path required Hydro to install a passive repeater, which in this case is a tower with two microwave antennas connected back to back, as can be seen in Figure 3. The passive repeater effectively bends the microwave signal to allow it to pass around a hill. The antenna from Blue Grass Hill points to one antenna on the passive repeater tower, (HLP), which in turn has a second antenna pointing to an antenna at Hinds Lake.



LEGEND	
BGH	Blue Grass Hill
HLC	Hinds Lake Control Structure
HLI	Hinds Lake Intake Building
HLK	Hinds Lake Generating Station
HLS	Hinds Lake Spillway
HLP	Hinds Lake Passive Repeater Tower

Figure 2 - Hinds Lake Structures

Figure 3 - Hinds Lake Passive Repeater (HLP)

In 1999, Hydro installed a fibre optic cable system between these structures, ending at Blue Grass Hill. The system was configured as a ring, with the microwave radio link from Blue Grass Hill to Hinds Lake closing the loop. The advantage of the ring configuration is that failure of one cable would not cause communication failure to any site; the communication would merely continue in the opposite direction.

2 PROJECT DESCRIPTION

The proposed replacement of the microwave link from Blue Grass Hill to Hinds Lake is a fibre optic link that follows a separate route from Blue Grass Hill to Hinds Lake than the existing route. The separate route allows for a ring configuration and greatly increases the reliability of communication.

The project will require the construction of a route to accommodate approximately seven kilometers of fibre optic cable, including poles and guys where required. The cable will follow an existing road from Hinds Lake to Blue Grass Hill as closely as possible, but will also require a path to be cleared across approximately one kilometer of forest to reach Blue Grass Hill. The fibre will be equipped with multiplexers to provide the various communications requirements (voice, teleprotection, Supervisory Control and Data Acquisition (SCADA), etc.) between the two locations. The multiplexers will be configured to take advantage of the two separate fibre optic paths to increase reliability.

The equipment being proposed for replacement under this project consists of the following:

- Alcatel MDR-6000 microwave radio equipment at Blue Grass Hill and Hinds Lake;
- 40 m self-supporting microwave tower at Hinds Lake;
- 130 m guyed microwave radio tower at Hinds Lake Repeater Tower site;
- Cablewave microwave antennas at Hinds Lake, Hinds Lake Repeater Tower site and Blue Grass Hill; and
- Associated cabling, mounting hardware, as well as other miscellaneous equipment.

3 EXISTING SYSTEM

The project is required to replace the existing Alcatel MDR-6000 microwave radio. This radio is now obsolete and is no longer supported by the manufacturer. As well, the towers at Hinds Lake are in need of upgrading in order to bring them to current Canadian Standards Association (CSA) standards.

3.1 Age of Equipment or System

The microwave radio link from Blue Grass Hill to Hinds Lake was constructed in 1980. No significant refurbishing of the towers has been completed. This refurbishing work was scheduled to be completed in 2009, but will no longer be required under this proposal.

The Blue Grass Hill to Hinds Lake microwave radio equipment was purchased in 1998, replacing the original microwave equipment which was purchased in 1980. It is no longer supported by the manufacturer. Hydro will use the removed equipment to prolong the life of remaining similar equipment.

The existing fibre optic cable from Blue Grass Hill, through the three sites as shown in Figure 2, to Hinds Lake was installed in 1999.

3.2 Major Work or Upgrades

There have been no major upgrades of the equipment being replaced since installation.

3.3 Anticipated Useful life

Fibre optic cable and poles are expected to have a useful life of 30 years. Electronic equipment used to provide communication over fibre typically has a useful life of 15 years. Microwave towers are depreciated over 20 years.

3.4 Maintenance History

The five-year maintenance history for the microwave radio and towers being replaced under this proposal is shown in Table 1.

Table 1
Microwave Radio and Towers Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2007	0.6	0.7	1.3
2006	5.0	12.2	17.2
2005	4.3	2.9	7.2
2004	1.9	7.6	9.5
2003	1.7	2.6	4.3

Microwave radio equipment is maintenance intensive and frequent repair or replacement is experienced on the electronic components of the equipment. As well, annual tower inspections are required to ensure that tower integrity is maintained.

3.5 Outage Statistics

There have been no outages on the Hinds Lake to Blue Grass Hill microwave system since its installation in 1999.

However, failure of the communications system could render Hind's Lake inoperable until an operator was able to enter the plant and establish backup voice communication

to the ECC, an event which in extremely poor weather conditions could cause an outage at Hind's Lake of several days duration. Such an event would have a detrimental effect on Hydro's ability to provide reliable power and energy to the Island Interconnected System, particularly if it occurred at a time of high system load or when Hydro was otherwise generation constrained.

3.6 Industry Experience

Other Canadian electric utilities are facing similar issues with the replacement of Alcatel MDR-6000 microwave radio.

3.7 Maintenance or Support Arrangements

The equipment is maintained by internal forces. Towers are inspected annually by outside forces.

3.8 Vendor Recommendations

Alcatel, the vendor of the MDR-6000 microwave radio, has recommended replacement of the radio equipment at the earliest possible opportunity. Alcatel no longer provides full support for the microwave equipment.

3.9 Availability of Replacement Parts

Hydro currently has nine "hops" of Alcatel MDR-6000 microwave radio equipment, including the Blue Grass Hill to Hinds Lake link. A hop consists of two sets of equipment, one for each end of the hop, for a total of 18 sets of this equipment. Repair of the microwave radio components is on an as available basis. Alcatel does not guarantee that parts will be available to repair failing modules. By replacing the Blue

Grass Hill to Hind's Lake link, the equipment that is removed will be used to extend the life of the remaining microwave equipment.

3.10 Safety Performance

Safety performance is not considered in this instance. The project being proposed is being put forward based on the lowest cost to the ratepayer.

3.11 Environmental Performance

The environmental impact of the microwave radio system being replaced here is low. The passive repeater site will be no longer required and can be remediated to a relatively natural state. The equipment being replaced consists of electronics and steel towers, both of which can be recycled.

The environmental impact of the replacement system will consist of the clearing of approximately three hectares of forested land, and the installation of approximately 140 wooden poles. The majority of the poles will be installed along an existing roadway. The poles will be treated in order to prolong their life; however the most appropriate pole treatment which minimizes environmental impacts will be chosen.

3.12 Operating Regime

Because the communications infrastructure is used for protection of transmission lines as well as remote control of a critical generating station, extremely high reliability must be designed into the system. This is the reason for designing a ring topology with a minimum of commonalities between the routes. The equipment is in continuous use and is required 24 hours per day, 365 days per year.

4 JUSTIFICATION

This project is justified on the requirement to replace failing or deteriorated infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service. The chosen alternative is the least cost and will allow Hydro to extend the life of the remainder of its Alcatel MDR-6000 microwave radio.

4.1 Net Present Value

The cumulative net present value of the selected alternative is $610,000. See Section 4.3 for details.

4.2 Levelized Cost of Energy

The Blue Grass Hill to Hinds Lake communications link has no direct effect on the levelized cost of energy, as it does not directly contribute to the production of energy.

4.3 Cost Benefit Analysis

A cost benefit analysis was performed with two alternatives. Alternative 1, replacement of the microwave radio with fibre optic communications, is the lower cost alternative. Alternative 2, replacement of the microwave radio equipment, is the higher cost alternative. The difference is $296,000 in 2008 dollars over an assumed 30-year life of the fibre optic cable. The chart below and Table 2 illustrate the results.

Chart 1

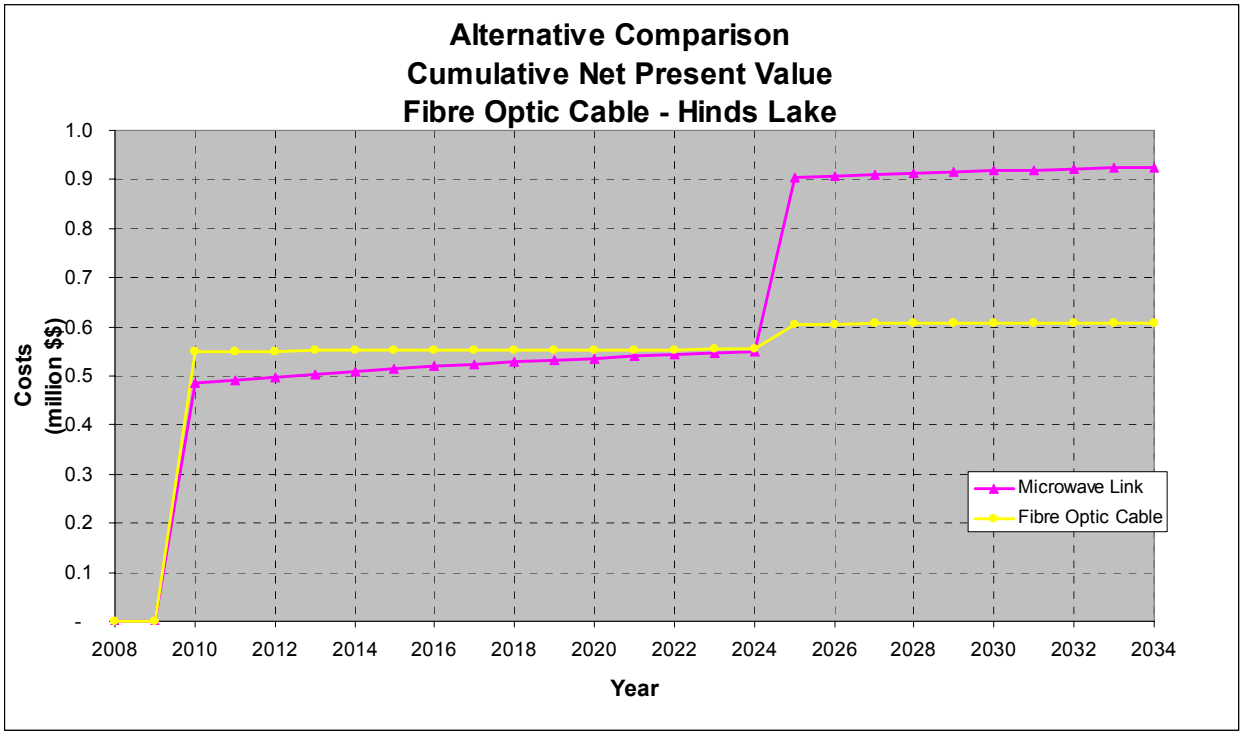


Table 2
Hinds Lake - Install Fibre Optic Cable

Alternative Comparison Cumulative Net Present Worth to the Year 2039		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Install Fibre Optic Cable	609,952	0
Keep Microwave Link	906,423	296,471

4.4 Legislative or Regulatory Requirements

These are no specific legislative or regulatory requirements for this replacement.

4.5 Historical Information

Historical information is not applicable for this project, as it is a one-time installation of new equipment.

4.6 Forecast Customer Growth

There are no anticipated customer growth implications that can be attributed to the installation of a new communications system.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to the installation of a new communications system.

4.8 Losses during Construction

There are no anticipated energy losses during construction of the fibre optic system. As it is a complete replacement of the existing system, it is anticipated that the old system will remain fully functional until the new system is in service.

4.9 Status Quo

The status quo is not an acceptable alternative. The MDR-6000 radio is manufacturer discontinued and must be replaced in the near future. By completing this project now, Hydro can delay the replacement of the remaining MDR-6000 radio and at the same time install a more cost-effective alternative at this location.

4.10 Alternatives

Two alternatives were considered: replacement of the MDR-6000 with a newer generation of microwave, and replacement with fibre optics. As demonstrated in Table 2, the latter is the preferred alternative as it has a lower net present value.

4.10.1 Alternative 1 – Fibre Optic Cable

This alternative consists of the installation of wood poles and fibre optic cable along a route approximately seven kilometers in length, from Blue Grass Hill to Hinds Lake. The route was chosen to allow for a ring configuration, thereby ensuring that availability of the communications network is maximized.

4.10.2 Alternative 2 – Replacement of Microwave Radio Equipment

Under this scenario, the microwave radio equipment is replaced in 2009. As well, the towers at Hinds Lake and the passive repeater tower site are upgraded as recommended by Hydro's consultant. This will extend the life of the towers, but they will still require replacement. It is assumed that the towers are replaced in 2025, when they will be 45 years old. The new towers are assumed to be depreciated over 20 years and the remaining life at the end of 2039 is accrued to the project as a benefit.

5 CONCLUSION

This project is required in order to replace aging microwave radio equipment that is no longer supported by the manufacturer. By replacing the microwave radio with fibre optics, the lowest cost solution for the ratepayer will be implemented.

5.1 Budget Estimate

The budget estimate for this project is provided in Table 3.

Table 3
Budget Estimate

Project Cost:($ x1,000)	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	45.0	37.0	0.0	82.0
Labour	120.5	37.0	0.0	157.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	270.0	0.0	270.0
Other Direct Costs	18.0	8.5	0.0	26.5
O/H, AFUDC & Escln	25.7	76.8	0.0	102.5
Contingency	0.0	53.6	0.0	53.6
TOTAL	**209.2**	**482.9**	**0.0**	**692.1**

5.2 Project Schedule

Table 4 provides the proposed project schedule.

Table 4
Project Schedule

Activity	**Milestone**
Project Initiation	April 2009
Design Complete	June 2009
Commissioning Complete	July 2010
Project Closed	August 2010

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Hardwoods Gas Turbine Plant Life Extension Upgrades

Electrical
Mechanical
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HYDRO
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NEWFOUNDLAND AND LABRADOR HYDRO

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G - Extract (Appendix 6) from "Condition Assessment and Life Cycle Cost Analysis - Hardwoods and Stephenville Gas Turbine Facilities" - Stantec, December 2007

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) owns and operates two 50 MW Gas Turbine plants as part of the Island Interconnected System. They are: Stephenville Gas Turbine Plant, located in Stephenville; and Hardwoods Gas Turbine Plant (Hardwoods), located in the west end of St. John's (see Figure 1).

The Island Interconnected System experiences constant voltage fluctuations that result from changes in supply and demand of electricity. Since voltage fluctuations are undesirable, the system requires constant voltage correction to maintain the proper voltage levels. The system voltage is corrected using a process known as synchronous condensing. This process stabilizes the voltage of the system by acting as a shock absorber if the system experiences a voltage drop. During synchronous condensing, the voltage drop is limited to no more than five percent below the nominal operating levels of 230, 138, or 66 kV. Synchronous condensing is the main function of the Hardwoods and Stephenville Gas Turbine Plants.

Figure 1: Hardwoods Gas Turbine Plant

The Gas Turbine plants are also used to produce power during peak and emergency periods. Both plants are fueled by distillate (diesel) which is more costly than the No. 6 fuel oil used at the Holyrood Thermal Generating Station.

A gas turbine plant consists of major equipment such as gas turbine engines, power turbines and power generators (also called alternators), as well as auxiliary systems such as lube oil systems, fuel systems, electrical systems and control systems. Structures such as buildings, equipment enclosures and exhaust stacks comprise the balance of components that make up the facility.

In 2007, an engineering consulting company, Stantec Inc. (Stantec), was hired to complete a condition assessment and life cycle cost analysis study of the Hardwoods and Stephenville Gas Turbine Plants. Hydro commissioned the study to determine the best course of action to achieve a high degree of operating reliability at least cost for the next 15 years for both sites. Many recommendations were presented in the consultant's final report. The Stantec Report is over 600 pages in length and extracts have been presented herein rather than the entire document. A refurbishment program is required to implement the recommended site improvements to ensure reliable operation of Hardwoods for the next 15 years. This facility, which has been in service since 1976, has experienced equipment failures in recent years. For instance, the inverter failed in 2006 and the Human Machine Interface (HMI) failed in 2007. As well, various components installed at this facility are obsolete.

In 2009, Hydro plans to initiate a four-year program to implement the recommendations for Hardwoods put forth in Stantec's report (see Appendix B). In 2010, Hydro plans to initiate a second four-year program to implement the recommendations for the Stephenville Gas Turbine Plant put forth in Stantec's report.

2 PROJECT DESCRIPTION

This project is to complete work scheduled for the first year of a four-year upgrade program of Hardwoods. The program will include refurbishment of the following equipment and systems:

- Gas Turbine Engines / Power Turbine Equipment;
- Inlet Air Systems End A and End B;
- Exhaust Stacks End A and End B;
- Glycol Cooler for Main Lube Oil;
- Gas Generator / Power Turbine Enclosures End A and End B;
- Alternator and Excitation System;
- Alternator Enclosure;
- Fuel Oil Storage System;
- Electrical Systems;
- Control and Instrumentation Systems; and
- Buildings.

The scope of work for the four-year program is the implementation of all recommended refurbishments described in Stantec's final Condition Assessment and Life Cycle Cost Analysis report for Hardwoods. The detailed scope of work is described in Appendix B. Once all of the recommended work is completed, Hardwoods will be able to operate reliably for the next 15 years.

This project will complete the 2009 scheduled work items listed below. Further details are included in Appendix B and estimated costs are included in Appendix G.

- Inlet Air Systems End A and End B;
- Exhaust Stacks End A and End B;
- Glycol Cooler for Main Lube Oil;
- Fuel Oil Storage System;

- Electrical Systems; and
- Control and Instrumentation Systems.

This work will be completed by a combination of internal forces and contracted labour and will result in increased reliability for the systems upgraded such as the control and instrumentation systems and electrical systems.

Work to be completed in this upgrade program is limited to Hardwoods. It does not include refurbishment of equipment and structures that form part of Hardwoods Terminal Station or the equipment installed for Supervisory Control and Data Acquisition (SCADA) remote control monitoring.

3 EXISTING SYSTEM

Hardwoods consists of two identical gas turbine units. To differentiate one gas turbine unit from the other, the naming convention of End A for the western unit and End B for the eastern unit is used. Each gas turbine unit consists of one Rolls-Royce Olympus C gas turbine engine (Figure 2) and one Curtiss-Wright power turbine. One Brush power generator, or alternator as it is also known, is shared between both gas turbine units. Each gas turbine unit is coupled to the alternator by a clutch. Auxiliary systems, critical to the operation of the facility, include inlet air systems, fuel oil system, electrical system, and control and instrumentation systems. Buildings and structures on site include exhaust stacks, inlet air intakes, control building, fuel unloading building, fuel forwarding building, auxiliary module building, maintenance and parts storage building, high voltage switchgear building, and emergency backup diesel generator building.

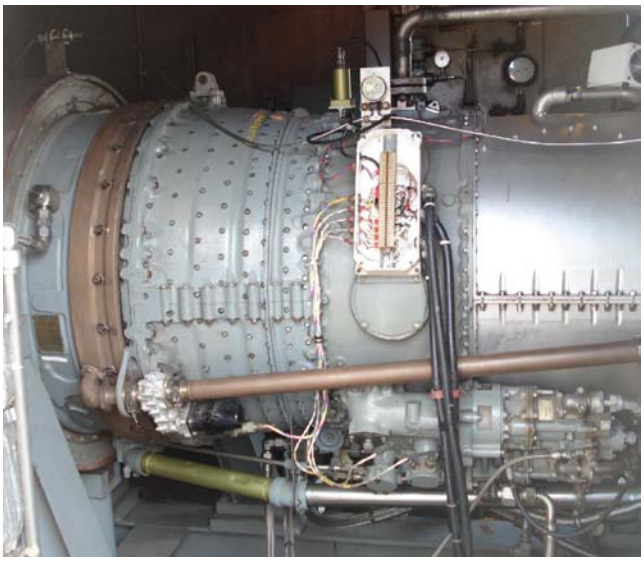

Figure 2: Gas Turbine Engine

The Condition Assessment and Life Cycle Cost Analysis report states that at Hardwoods, the gas turbine engines and power turbines show signs of operational wear and require remedial work (Appendix A: Executive Summary, page E-1). Further testing is required to determine the condition of the alternator. Auxiliary systems and structures were found to be in generally good condition, however, some refurbishment work is required.

Presently, corrosion is visible on the inside of the gas turbine engines and power turbines. The photo below (Figure 3), taken during an internal inspection on May 30,

2007, shows corrosion due to coating loss inside the End B gas turbine engine at Hardwoods.

Figure 3: Corrosion on End B Engine

3.1 Age of Equipment or System

Hardwoods was placed in service in 1976. All major equipment, including the gas turbine engines, alternator, clutches and power turbines, is original.

3.2 Major Work or Upgrades

The End B gas turbine engine was overhauled in 1993 and both power turbines received casing replacements in 1988. Other upgrades at this facility include:

- exhaust stacks (1992);
- new Distributed Control System (DCS) (1997);
- main breaker (1998);
- fire system replacement (2002);
- black start diesel generator (2005);and
- fuel piping from the tank farm (2007).

Appendix C contains a comprehensive listing of major work and upgrades that have taken place at Hardwoods since it was put into service in 1976.

3.3 Anticipated Useful life

A gas turbine has an anticipated service life of 25 years.

3.4 Maintenance History

The five-year maintenance history for the Hardwood Gas Turbine Plant is shown in Table 1 below.

Table 1
Hardwoods Gas Turbine Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2007	$12.4	$393.5	$405.9
2006	$5.6	$441.9	$447.5
2005	$17.1	$239.4	$256.5
2004	$14.9	$258.8	$273.7
2003	$10.5	$225.8	$236.3

Appendix D contains a listing of maintenance work orders, as recorded in Hydro's financial system, from 1999 to 2006, for Hardwoods.

3.5 Outage Statistics

Table 2 below lists the 2003 to 2007 average Capability Factor, Utilization Forced Outage Probability (UFOP) and Failure Rate for Hardwoods compared to all of Hydro's gas turbine units and the latest Canadian Electrical Association (CEA) average (2001 to 2005).

Table 2
Hardwoods Gas Turbine Five Year Average (2003-2007) All Causes

Unit	Capability Factor (%)[1]	UFOP (%)[2]	Failure Rate[3]
Hardwoods	83.91	9.43	260.82
All Hydro Gas Turbine Units	89.69	10.69	61.80
CEA (2001-2005)	89.37	9.72	10.12

[1]Capability Factor is defined as unit available time. It is the ratio of the unit's available time to the total number of unit hours.
[2]UFOP is defined as the Utilization Forced Outage Probability. It is the probability that a generation unit will not be available when required. It is used to measure performance of standby units with low operating time such as gas turbines.
[3]Failure Rate is defined as the rate at which the generating unit encounters a forced outage. It is calculated by dividing the number of transitions from an operating state to a forced outage by the total operating time.

Hardwoods has a failure rate over four times the rate for all of Hydro's gas turbine units and over 25 times the rate posted for the CEA.

3.6 Industry Experience

The Hardwoods plant mainly operates as a synchronous condenser but produces electricity during peak and emergency times. This results in a very high number of starts and stops of the equipment annually. Frequent starts and stops of the equipment reduce its useful life far below the anticipated useful life of a base load plant.

Gas turbine engines, power turbines and clutches degrade over time. The degree of degradation increases as the operating hours increase and as the number of start/stop cycles increases. For gas turbine units that produce electricity during peak times, such as those at Hardwoods, thermal mechanical fatigue caused by start/stop cycles is the dominant limiter of life.

Stantec reports that 90 percent of all unscheduled shutdowns of gas turbine facilities are caused by faulty electrical and control components in auxiliary systems. In addition, since Hardwoods experiences many starts/stops in synchronous condensing and

peak/emergency power generation modes, it is expected that the insulation on the alternator's windings will have a life of only 15 to 20 years as compared to 30 years for a power generation unit. An alternator problem may result in major unplanned outages.

3.7 Maintenance or Support Arrangements

Routine maintenance at Hardwoods on structures, auxiliary systems and some parts of the major equipment systems is performed by Hydro personnel. Any work involving removal of the gas turbine engine casing is performed by external contractors specializing in gas turbine repairs. Internal work on other major equipment is also performed by specialized contractors.

3.8 Vendor Recommendations

There are no vendor recommendations applicable to this project as it involves the refurbishment of Hardwoods.

3.9 Availability of Replacement Parts

The model of gas turbine engine installed at Hardwoods is no longer manufactured. However, the engines will be supported by the manufacturer for the foreseeable future. Sourcing replacement parts for the gas turbine engines has not been an issue to date, however, the availability of spare parts is very limited worldwide. Original manufacturers still support other major components such as the alternator and clutches. It is difficult to acquire spare parts for the power turbine since the manufacturer is no longer in the power turbine business. Therefore, spare parts for the power turbine would either need to be sourced on the second hand market, or reverse engineered and manufactured. Reverse engineering refers to a process of designing a new component by taking apart and analyzing an existing component.

Other pieces of equipment installed at Hardwoods are now obsolete or are no longer being supported by the manufacturer. These include ignition exciters, vibration monitoring system, speed governors/fuel valve assemblies, starter motor (no longer supported), power supply for distributed control system and protection electro-mechanical relays. Spares are readily available for the speed governors, however, the technology is considered obsolete. Spares are limited for the electromechanical relays. Spare parts may be easily sourced for some auxiliary systems. However, replacement parts may not be exactly the same as the original components. Further system modifications may be required when replacing older parts. Control module cards are still available from the manufacturer and will be supported for at least ten years from the date they are discontinued.

3.10 Safety Performance

Stantec reported that kick plates are missing on maintenance walkway guard railings. Rusty stair treads or loose ladder rungs were also reported. Modifications to all defective guard rails, stairs and ladders are within the scope of this project.

3.11 Environmental Performance

There are no identified environmental performance issues related to Hardwoods.

3.12 Operating Regime

Hardwoods operates mainly as a synchronous condenser but also as an electricity generator. Appendix E contains information on the operating hours, number of start/stop cycles, electricity generation hours and synchronous condensing hours for the facility. As a synchronous condenser, it operates approximately 60 percent of the time.

The facility operates in electricity generation mode during peak usage times which is less than one percent of the time. This may occur anytime throughout the year but is most common from mid December to March. As well, this facility is placed in standby mode for emergency electricity generation during unplanned outages. The facility may also be placed in service to generate electricity during planned outages.

4 JUSTIFICATION

The operational reliability of Hardwoods is critical to ensure voltage regulation of the Island Interconnected System. As well, this facility is critical for the generation of peak and emergency power. Unless the reliability of this facility is improved (see Section 3.5), the Island Interconnected System may experience voltage fluctuations and power shortages. The major equipment installed at this facility is over 30 years old and has reached the end of its operating life. Plant refurbishment is now required.

The condition assessment and life cycle cost analysis report for Hardwoods, completed by Stantec in 2007, contains a description of all recommended refurbishments. It is very important that these recommended refurbishments take place over the next four years so that voltage on the Island Interconnected System will continue to be stable and peak and emergency power generation is available whenever it is needed.

4.1 Net Present Value

A net present value calculation of alternatives was completed by Stantec and included in Section 8 of the Condition Assessment and Life Cycle Cost Analysis report. This section of the report is attached as Appendix F.

4.2 Levelized Cost of Energy

This facility generates electricity only during peak/emergency periods. Levelized cost of energy is not a factor in this project.

4.3 Cost Benefit Analysis

A cost benefit analysis has been completed and is attached as Appendix F. Each alternative solution was reviewed. It was determined that option 1B was the least-cost option to achieve a high degree of reliability at Hardwoods for the next 15 years. Please refer to Section 4.10 for a list of alternative solutions.

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements that justify this project.

4.5 Historical Information

This is the first time such a refurbishment program has been proposed and it is not expected to be repeated again.

The condition of the Stephenville Gas Turbine Plant is similar to Hardwoods. An upgrade program of similar scope is planned for the Stephenville Gas Turbine Plant beginning in 2010.

4.6 Forecast Customer Growth

This project is not required to accommodate customer growth.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits within the justification for this project.

4.8 Losses during Construction

There will be no losses during construction as the work will take place during a planned outage.

4.9 Status Quo

If this project is not completed, plant reliability will decrease and the frequency of unplanned outages will increase. This affects the voltage control on the power grid and the plant's ability to generate power during peak and emergency periods.

4.10 Alternatives

Table 3 below contains six alternatives that Stantec presented to Hydro at the completion of the Condition Assessment and Life Cycle Cost Analysis Study. Hydro evaluated each alternative and determined that option 1B was the preferred option.

Table 3
Alternatives

Alternative	Description	Capital Cost Estimate ($000)
1A	Refurbish existing equipment – Hardwoods. Includes optional gas turbine rental allowance.	$7,814
1B	Refurbish existing equipment – Hardwoods.	$4,507
1	New gas turbine engines and power turbines. Refurbish balance of equipment.	$26,420
2	New alternator/exciter. Refurbish balance of equipment.	$7,163
3	New gas turbine facility, including fuel forwarding module, controls and electrical auxiliary equipment. Dismantle existing gas turbines and use as spares.	$36,900
4	Replace Hardwoods with new dynamic Volts-Amperes reactive (VAR) compensator.	$10,000

After evaluating each option, it was determined that option 1B achieves Hydro's objective of increasing reliability at least-cost for the next 15 years at Hardwoods. Stantec's study determined that there is no need to replace the complete facility, auxiliary systems and major components such as the gas turbine engines and turbines. Therefore, options 1, 2, and 3 were eliminated since all involve the replacement of major equipment. Option 4 was eliminated since dynamic VAR compensation only provides synchronous condensing and does not permit the plant to generate electricity. Option 1A was eliminated because Hydro has no requirement for a backup gas turbine engine while an existing gas turbine engine is being overhauled.

5 CONCLUSION

It is very important for Hydro to have a reliable facility for synchronous condensing and peak/emergency power generation on the Avalon Peninsula. Hardwoods Life Extension Project was initiated to implement a list of recommendations contained in a condition assessment and life cycle cost analysis report of the facility that was completed in 2007 by Stantec. The results of the condition assessment and life cycle cost analysis were used to determine the best course of action to achieve the high degree of operating reliability at least cost for the next 15 years for Hardwoods.

5.1 Budget Estimate

The budget estimate for this project includes the work to be completed in the first year of the four-year program as shown in Table 4.

Table 4
Budget Estimate

Project Cost:($ x1,000)	**2009**
Material Supply	0.0
Labour	50.0
Consultant	0.0
Contract Work	350.0
Other Direct Costs	0.0
O/H, AFUDC & Escln	50.3
Contingency	0.0
TOTAL	**450.3**

Further refurbishment projects for the Hardwoods Gas Turbine Plant will be proposed in future capital budget applications.

The budget estimate for the four-year refurbishment program was completed by Stantec and included in the Condition Assessment and Life Cycle Cost Analysis report. Stantec's budget estimate is attached as Appendix G. It is stated in the report that the accuracy of the budget estimate is (+/-) 30 percent.

Table 5 contains the annual budget estimates for the four-year program.

Table 5
Hardwoods Gas Turbine Four-Year Budget

Year	Budget
2009	450.3
2010	2,518.7
2011	1,359.5
2012	2,017.0
Total	**6,345.5**

Since internal labor costs were not included in Stantec's estimate, additional costs were added to cover this item. Some minor work included in Stantec's estimate has already been completed. Costs for these items were removed. The above estimate reflects these changes.

5.2 Project Schedule

This project will be completed in 2009 and the four-year refurbishment program by the end of 2012. Work measures to be completed each year are identified in Table 6 below.

Table 6
Work Schedule

Activity	Year
Site refurbishments. - Inlet air systems; End A & B - Exhaust stacks; End A & B - Glycol cooler for main lube oil - Fuel oil storage system - Electrical systems - Control and instrumentation systems	2009
Refurbish generator. Refurbish exciter.	2010
Refurbish End A gas turbine equipment. Site refurbishments.	2011
Refurbish End B gas turbine equipment. Site refurbishments.	2012

APPENDIX A

Extract (Executive Summary) from Stantec Final Report Condition Assessment and Life Cycle Cost Analysis Hardwoods and Stephenville Gas Turbine Facilities

Stantec

FINAL REPORT
CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS
HARDWOODS AND STEPHENVILLE GAS TURBINE FACILITIES

Executive Summary

Stantec (formerly Neill and Gunter) conducted a Condition Assessment and Life Cycle Cost Analysis Study of the Newfoundland and Labrador Hydro ("HYDRO") Hardwoods and Stephenville Gas Turbine Facilities over the period July through December 2007. The Gas Turbines at each site have been in service since the mid 1970's. The objective of the Study is to provide HYDRO with recommendations on the best course of action to achieve a high degree of operating reliability at each site, at least cost, for a further 15 years of operation.

During the Study period meetings were held with HYDRO officials, visits were made to each site and available HYDRO documentation was reviewed in order to assess the current condition of the equipment and structures at each site and determine the best course of action to allow a further 15 years of reliable service. The Gas Turbines at each site have operated over the years primarily as synchronous condensers providing MVAR support of system voltage. While the Gas Turbines can provide 50 MWs of emergency generation capacity, there has been very little generation provided by the units over the past 30 years. Refer to Report Section 2 for an overview of the Gas Turbine Facilities at each site.

The Gas Turbine Facilities consist of major equipment such as the gas generator engines, power turbines and alternator supported by balance-of-plant auxiliary systems such as the oil fuel supply system; lube oil system; electrical systems (switchgear; motor control centres, dc batteries); control & instrumentation systems (distributed control system; temperature and vibration monitoring equipment). Structures such as buildings, equipment enclosures and exhaust stacks comprise the balance of components that make up the Gas Turbine Facilities at each site.

The condition assessment portion of the Study found that the gas generator engines and power turbines at each site show signs of operational wear and will require remedial work to allow reliable operation over the next 15 years. Since HYDRO was unable to provide any historical electrical testing data or visual inspection information on the alternator at either site, it was not possible to assess the current condition of either alternator and determine the extent of remedial work required to allow reliable operation over the next 15 years. HYDRO will have to conduct, at some point, a thorough electrical testing and visual inspection of the alternator's stator and rotor in order to arrive at a decision as to whether refurbishment or replacement is required. The existing balance-of-plant system equipment, buildings and structures at each site are generally in good condition however there is some degree of minimal refurbishment work required in these systems. Refer to Report Section 5 (Hardwoods) and Section 6 (Stephenville) for details on the condition assessment of each Gas Turbine Facility.

A review of the Operator's Logs provided by HYDRO, particularly over the past 5 years of operation, revealed numerous failed starts and trips of the Gas Turbines at both sites resulting

from sporadic mechanical and electrical issues associated with auxiliary equipment on the gas generators engines and alternator and in the balance-of-plant systems. These sporadic issues are deemed fixable with the proper allocation of time, resources and budget. Refer to Report Section 4 for details on these operational issues.

In response to the findings of the condition assessment portion of the Study, options studied to provide reliable operation over the next 15 years included: (i) the refurbishment of the existing equipment and structures at each site; (ii) the replacement of specific major equipment items (gas generator engines, power turbines and alternator) with new equipment as well as the refurbishment of balance-of-plant systems at one or both sites; (iii) the addition of a new gas turbine to replace one or both existing gas turbines and (iv) for HYDRO's consideration, the addition of a dynamic var compensator (D-VAR) to replace one or both gas turbines for system MVAR support only, the dominant operating mode of the Gas Turbines over the past 30 years. Refer to Report Section 7 for details on the costs and technical aspects of the Options considered.

The 15 year life cycle cost analysis study of each Option included capital costs for engineering, equipment supply and installation, as well as fuel, operational and maintenance costs at each site. The 15 year life cycle cost analysis of each Option was performed using HYDRO's Cost/Benefit Financial Analysis Model which uses the Cumulative Net Present Value (CPW) approach to perform economic analyses comparisons of alternatives. Refer to Report Section 8 for details on the life cycle cost analysis of the various life extension Options considered. The following Table provides a summary of the Options evaluated and the ranking and CPW of each Option.

15 Year Life Extension Options
Cumulative Net Present Value (CPW)

Ranking	Option	CPW (2007 Cdn$)	
		Sub-Case #1	Sub-Case #2
1	Option 4 – DVAR	$8,995,597	$8,995,597
2	Base Case 2B- Stephenville Refurbishment - No GT Rental	$9,548,569	$24,996,028
3	Base Case 1B- Hardwoods Refurbishment - No GT Rental	$11,467,914	$26,930,650
4	Base Case 2A- Stephenville Refurbishment - GT Rental	$13,842,768	$27,711,405
5	Base Case 1A- Hardwoods Refurbishment - GT Rental	$16,010,747	$29,894,660
6	Option 2 – New Alternator/Refurbish Engines & Turbines – GT Rental	$16,248,954	$28,574,070
7	Option 1 – New Engines & Turbines/Refurbish Alternator – GT Rental	$33,088,681	$36,221,835
8	Option 3 – Complete New GT Unit	$38,145,919	$38,145,919

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FINAL REPORT
CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS
HARDWOODS AND STEPHENVILLE GAS TURBINE FACILITIES
EXECUTIVE SUMMARY
December 18, 2007

A decision on the role of the Hardwoods and Stephenville Gas Turbines in the HYDRO system beyond 2023 (the specified 15 years of further service) has not been determined by HYDRO at this time. The financial analysis results in the Table reflect two scenarios beyond 2023. The first scenario (Sub-Case 1) assumes further refurbishment work in 2023, whereas the second scenario (Sub-Case 2) assumes the equipment will generally be totally replaced in 2023 with new equipment. The two scenarios however do not affect the overall ranking of the Options.

While Option 4, the Dynamic VAR Compensator (D-VAR) addition at one site, is ranked 1 in the Options considered, primarily due to significantly reduced operations and maintenance costs going forward, the capital costs used in the life cycle cost analysis of this Option are at best ballpark estimates and can only be confirmed through a detailed study on the application of this technology at one or both sites. In this Option, a D-VAR would replace a gas turbine at one or both sites for MVAR system voltage support only. The question that HYDRO must address regarding this Option is whether backup emergency generating capability is absolutely required at either site going forward. If the answer is yes, this Option can be dismissed from further consideration. If the answer is no, then a more detailed study of this Option should be conducted with the involvement of the equipment supplier to confirm costs and technical details. It is Stantec's opinion that this Option would be competitive with the Base Case existing equipment refurbishment Options 1 and 2 for MVAR system voltage support only, should HYDRO decide to forego generation capability at either site. Refer to Report Section 7 for details on the application of D-VAR technology.

The Base Case Options (1A/1B – Hardwoods) and (2A/2B – Stephenville) rank 2, 3, 4 and 5 of the Options studied. These Options, involving the refurbishment of the existing equipment at each site, assume the alternator will have to be extensively refurbished off-site at a supplier's facilities, over an estimated 4 month period. As noted previously, HYDRO will have to conduct, at some point, a thorough electrical testing and visual inspection of the stator and rotor in order to arrive at a decision as to whether refurbishment or replacement is required. Base Cases 1A and 2A assume that HYDRO will rent a mobile gas turbine to cover the alternator refurbishment period, whereas Base Cases 1B and 2B assume that HYDRO will schedule an estimated 4 month outage at each site when the alternator is being refurbished. The decision on the use of a rental unit is HYDRO's.

Option 2, ranked 6 of the Options studied would only be considered if pending a thorough testing and visual inspection of the alternator, it is determined the alternator cannot be refurbished and replacement is necessary to allow reliable operation over the next 15 years.

Options 1 and 3 ranked 7 and 8 respectively, have high CPWs and are not be considered as Options to pursue.

The Stantec team is of the opinion that the existing equipment, particularly the gas generator engines, power turbines and alternator, as well as the balance-of-plant equipment and

structures can be refurbished sufficiently to allow reliable operation over the next 15 years. It is recommended that Base Case Options 1 and 2 at each site be pursued with a decision required on whether a rental mobile gas turbine will be employed at each site. Since no information was available to assess the condition of the alternator, the decision on the extent of refurbishment work required on this equipment will not be known until a thorough electrical testing and visual inspection of the stator and rotor is conducted. At that time, HYDRO will have to make a decision as to whether refurbishment or replacement is required. If replacement is necessary at one site or the other, then Option 2 should be pursued.

APPENDIX B

Recommended Site Refurbishments to Hardwoods Gas Turbine Plant

Recommended by Stantec, 2007

Recommended Site Refurbishments to Hardwoods Gas Turbine Plant

Recommended by Stantec, 2007

Gas Turbine Engines / Power Turbine Equipment

- Disassemble End A and End B gas turbine engines. Inspect and refurbish as required.
- Inspect End A and End B power turbines upon removal of gas turbine engines. Perform required repairs.
- Completely disassemble and inspect End A and End B clutches.
- Replace ignition igniters.
- Replace speed governors/fuel valve assemblies.

Inlet Air Systems (End A and End B)

- Sandblast interior surfaces and recoat surfaces and silencer.
- Clean exterior of surface corrosion and recoat.
- Clean filter enclosure and recoat.
- Repair seals and recoat plenum access doors.
- Clean and recoat air inlet screens on End B.
- Re-align inlet bellmouth assembly on End B.
- Replace access ladders and modify guardrails.

Exhaust Stacks (End A and End B)

- Replace light gauge cladding with heavy gauge cladding on exterior upper portion of stacks.
- Clean and recoat exterior lower portion of stacks.
- Repair cracks in exhaust stack access door openings, in inner liner and internal rolled edge.
- Replace snow doors.

- Replace access doors with hinged doors.
- Replace access ladders.

Glycol Cooler for Main Lube Oil

- Clean and recoat entire structure.

Gas Generator and Power Turbine Enclosures (End A and End B)

- Clean and recoat exterior surfaces.
- Clean, sandblast, and recoat interior surfaces.

Alternator and Excitation Systems

- Conduct electrical tests on alternator, as per consultant's recommendations.
- Remove rotor for complete inspection of rotor/stator/exciter/bearings.
- Carry out refurbishment work based on inspection results. This may include rewind of stator and rotor, rewind/refurbishment of exciter.
- Perform a trim balance on the rotor to address vibration issues.

Alternator Enclosure

- Clean and recoat exterior surface.
- Fuel Oil System.
- Clean and recoat exterior of fuel oil storage tank.
- Repair and recoat various access stairs and handrails.

Electrical Systems

- Replace alternator 13.8 kV circuit breaker.
- Modify 13.8 kV cabling.
- Repair bus duct leaks.
- Replace 125 Vdc battery charger.
- Replace electromechanical protection relays with digital relays.
- Replace 15 kV power cable supplying the 750 kVA Station Service Transformer.

Control and Instrumentation Systems

- Stock spare input module cards for DCS system.
- Replace DCS power supply.
- Replace obsolete vibration monitoring system.
- Replace obsolete vibration transducers with new accelerometers.
- Replace existing thermocouple terminal blocks with terminal blocks for thermocouple use.
- Install low level cut out switch in oil storage tank.
- Relocate on-engine junction boxes to an off-engine site to reduce affects of vibration and heat.

Buildings

- Control Building: Clean and recoat building and install new roof.
- Fuel Unloading Building: Replace roof, pave area near off-loading containment dyke, replace posts and guardrails.
- Fuel Forwarding Building: Clean and recoat roof, replace posts and guardrails.
- Auxiliary Module Building: Clean and recoat roof.
- Maintenance and Parts Building: Clean and recoat roof.
- High Voltage Switchgear Building: Clean and recoat exterior walls. Replace roof.

APPENDIX C

Hardwoods Gas Turbine Plant - Major Upgrades

Hardwoods Gas Turbine Plant
Major Upgrades

Civil Engineering Projects

1996 – 1997: Tank Farm upgrades.

- One tank was completely removed.
- Remaining tank was cleaned, welds were repaired, and interior floor was painted.
- New dyke liner was installed throughout (Tank was lifted).
- Dykes were re-shaped.
- New dyke section was installed (to reduce size of containment area).
- New piping was installed within tank farm.

2000: Painted exterior of tanks.

Electrical Engineering Projects

Early 1990s: Rotor rewinding and other associated repairs.

1994: Brushless exciter vibration issues.

- In October of 1994 high frequency vibration signatures were observed on the exciter and 'B' end alternator bearing. It is unclear as to the cause of these vibrations, and what, if any, steps were taken to address the situation.

1995 – 1996: Governor repairs.

- During the 1994 outage very low ramp rates existed and problems were experienced with the governor. Repairs were made to the governor in 1995 and 1996. Governors were calibrated and droops were setup.

1998: Switchgear upgrades.

- Purchase and installation of new main breaker. This breaker will be rated at 3000 Amp with an interrupting capacity of 28 kA. The existing breaker will be assessed for use as a system spare to serve both the Stephenville and Hardwoods site.
- Post insulators and insulation coverings on the rigid bus bars will be

replaced/upgraded sufficient to re-rate the switchgear to 15 kV class.

2005: Battery bank replacements.

- The 125V 900 amp-hour VRLA bank for Hardwoods was replaced in 2005. The intention was for the replacement bank to have the same ratings as the previous bank, but we have been unable to confirm this.

Mechanical Engineering Projects

Mid 1980's: Snow door actuation was converted from electric to pneumatic.

1988: Fern Engineering modifications.

- Primarily replaced the casing on each of the 4 Curtiss Wright power turbines (Stephenville and Hardwoods) which were prone to cracking. Other smaller components were replaced as well. Approx. cost $4 million.

Early 1990's: Redesign of inlet air filtration system for gas engine and generator.

1992: Exhaust stack replacement.

- Existing interior silencer panel was reused.

1993: Hardwoods B engine serial # 202223 overhaul.

2002: Gas turbine and generator modules fire systems replacement (Inergen).

2003: Installed new core in Heat Exchanger for MLO system.

2004: Installed new expansion joints in stacks.

2005: Air conditioner, for gas turbine control room, replaced.

2005: New double walled fuel tank for diesel generator.

2005: Black start diesel generator replaced.

- This generator restores Hardwoods to operation without relying on external energy sources.

2005: New flow meter for gas turbine.

2005: Installed motorized valve fuel line by main tank.

2005: Fuel lines for gas turbine installed above ground between unit and the fuel forwarding pumphouse.

2005: Battery bank replaced 2005 and new standby charger.

2006: Repairs to glycol housing.

2007: Both Air compressors have been replaced.

2007: Underground fuel piping replaced.

Protection and Control Engineering Projects

1997: Control system upgrade

- This entailed removing approximately 250 electromechanical relays and timers and replacing the controls with a distributed control system. The DCS included a PC-based operator interface. Commissioning of controls performed by ABB (ETSI).

2003: Thermocouple blocks replaced

Misc.:

- Terminal blocks in junction boxes located around the unit were replaced a few years ago due to the condition of the original set.
- Snubbers (free-wheeling diodes) were replaced at Hardwoods. Some had shorted out a year ago. These were for noise reduction.

2005: Emergency backup diesel generating units installed.

- Diesel Generating Unit #572 including 600V control panel and backup battery charger installed in existing diesel building.
- The diesel unit is designed to start automatically with the loss of AC station service supply to the gas turbine unit and in turn supply power to the backup battery charger which ensures the integrity of the 125 Vdc supply to the gas turbine itself during its starting cycle.
- The diesel unit also provides a backup AC supply for one of the air compressors should the stored air supply run low during attempted start(s) of the gas turbine unit.

2006: AVR Replacement

- The Brush BAVR was removed and a new ABB AVR was installed.

2006: Inverter replacement

- Inverter failed and was replaced.

2007: Human Machine Interface (HMI) replaced after Nov 2007 failure of computer.

APPENDIX D

Hardwoods Gas Turbine Work Order History

Hardwoods Gas Turbine Work Order History

Date	Work Performed
21-Aug-06	Installed combustion cans (under supervision of Rolls Royce Rep Alain Joseph) from SVL END B in HWD END B EGT alarm at 22MW
19-Aug-06	L/P Turbine Inspection completed by Steve Press of Rolls Wood .Everything looked good..
8-Aug-06	Exhaust stack noise reduction panels repaired. Bolts rusted off. Black and Mac performed temporary repairs. Permanment repairs scheduled for fall.
4-Aug-06	Attepted to repair leak on demister
31-Jul-06	HWDGT END A tripped following logic changes due to anti ice valve problem pulling down voltage to P/S. Anti ice valve from SVL END B installed at HWD End A.
17-Jul-06	DC ground fuel valve. Replaced corroded junction box.
7-Jul-06	Repaired drainage sump piping due to heaving from frost.
4-Jul-06	Replaced proximity switch GGA clutch.
14-Jun-06	Changed snubbers (9) in junction box for fuel system GGA & B.
14-Jun-06	Rewired anti ice power supply to increase capacity due to ongoing intermittent P/S loading down problem.
5-Jun-06	HWDGT call out - clutch problem.
1-Jun-06	Fuel leak - Replaced Jordan valve
29-May-06	Repair air dryer - Replaced Hex Air Valve
26-May-06	Repair fuel leak - Replace o-ring on filter GGA
24-May-06	HWDGT, repair leak stand by diesel unit. Replace valve cover gaskets.
23-May-06	Repair lube oil leak on vacuum pump. Replaced line from vacuum pump to demister.
9-May-06	Replace anti ice P/S as a result of a callout on May 7, 2006 due to low voltage on P/S. Calibrated spare P/S and installed.
28-Apr-06	Repaired leaks on MLO System.
24-Apr-06	Replaced bearing and shaft on #1 fan for Glycol cooling system.
19-Apr-06	HWDGT, End B swapped burners 2 & 5 and EGT alarm at 19 MW.
3-Apr-06	Repair demister leak. Replace filter gaskets and housings.
3-Apr-06	Changed solenoid GGA/GGB lube oil system.
30-Mar-06	Installed repaired anti ice valve from OZARK and shipped SVL unit back.
30-Mar-06	Replace 30A, 600V breaker for Gycol system.
24-Mar-06	HWDGT, replace burners GGB (removed burners that were installed March 6, 2006)
22-Mar-06	HWDGT, check P/S to clutch solenoid. Found problem with snubber circuit. Repair clutch on END A OK.
21-Mar-06	GGA, replace Jordan valve.
21-Mar-06	Competed adding 20 drums of TRESSO 32 bearing oil due to sump alarm on March 19. The source of this leak was the expansion joint on rear journal bearing on Turbine A. All expansion joints at HWD and SVL were inspected and tightened as required.
19-Mar-06	Investigate sump alarm at HWDGT.

15-Mar-06	Reinstall anti ice valve from SVL and send anit ice valve back to OZART for repairs.
14-Mar-06	Replaced inverter.
14-Mar-06	Replace cable to fuel filter alarm.
14-Mar-06	Replace safety relief valve on comp "B".
6-Mar-06	Snow doors END B - replaced regulator and solenoid, 3 brackets and clamps.
6-Mar-06	HWDGT, replace burners. Installed refurbished burners in END B and sent old back to SVL.
1-Mar-06	GGA, clutch malfunction. Removed covers and unlocked clutch.
28-Feb-06	HWDGT, high press on fuel forward pump. Replace and relocate thermocouple.
28-Feb-06	Changed final fuel filter on GGA.
23-Feb-06	HWDGT, Glycol S,s #1 fan noisy. Grease bearing housing.
18-Feb-06	Replace Glycol fan belts (2 of 3)
14-Feb-06	Stand by diesel. Replaced AVR, speed pot, replaced actuator cable.
14-Feb-06	Repaired oil leak on demister.
9-Feb-06	Stand by diesel prot trip.
9-Feb-06	HWDGT, repair flow meter error message.
27-Jan-06	Install anti ice from SVL B on HWD End A.
27-Jan-06	Tested manually operation of END A and END B to determine if one end could take 25MW and other 15MW. Failed; Denoted SWDGT to 2 X 15MW = 30MW.
27-Jan-06	Fabricate 2 Jboxes, to prevent water from entering due to snubber circuit failures.
21-Jan-06	**See Jims email for detail.**
20-Jan-06	Snow Doors, repair solenoid.
18-Jan-06	Calibrate fuel meter.
12-Jan-06	Replace Jordan valve.
10-Jan-06	Checked Thermocouples on END B (to ensure exhaust gas temp are "real".
20-Dec-05	GGB replace Jordan valve.
16-Dec-05	Pumped out 240 gallons of fuel. Replaced 3 pressure relief valves in fuel forwarding system.
28-Nov-05	Repaired broken line on snow doors.
18-Nov-05	Installed flow meter. HWDGT GGB Hot End Inspection.
17-Nov-05	HWDGT, GGB invest hot burner.
17-Nov-05	Inspection of HWDGT and SVLGT by Rools Wood/ABB Rep to help with EGT problem.
15-Nov-05	Installed new 125 VDC bank.
14-Nov-05	Replaced standby diesel unit
14-Nov-05	Replaced bottom bearings on both fans.
14-Nov-05	Replace dirty alternator filters.
10-Nov-05	Failed to start. Relay burned up for starting Demister .Replaced relay "OK"
8-Nov-05	Replace burnt vib cards.
27-Oct-05	Replace rusty conduit.
19-Sep-05	HWDGT, fuel module leak/repair.
19-Sep-05	HWDGT, END B temp test.
16-Sep-05	HWDGT, END A replaced proximity switch due to clutch malfunction.
15-Sep-05	HWDGT, invest END A clutch. Checked operation, starting and stopping (intermitent problem)
9-Sep-05	Repaired fuel leak on fuel nozzle no. 7.
23-Aug-05	Repaired broken wire on field GND where it attaches to brush, (Alarm).
21-Aug-05	Snow doors, END A repaired air leak.
12-Aug-05	HWDGT, programed logic for motorized fuel valve.
8-Aug-05	HWGT END A, clutch alarm. Replaced proximity switch on END A and ok.
5-Aug-05	Replace sump drain lines.

4-Aug-05	Hot end inspection performed. W/O 385531
3-Aug-05	Upgrade fuel system for stand fuel to connect to sump drainage system.
27-Jul-05	Contractor install new supply and return lines from fuel forwarding BLDG to END A and END B due to a fuel leak discovered on June 9, 2005 during escavation to tie diesel building drainage system into sump system.
28-Jun-05	Snow doors, replace all flex. Line on snow doors. Replace rusted air cannisters and filters.
22-Jun-05	Pressure tested lines and discovered Sup/Ret lines were pitted and leaking
14-Feb-05	Reparred air leak on snow doors.
27-Jan-05	Reparied fuel leak - FF BLDG - Replaced air trap for main fuel filter.
8-Nov-04	HWGT, repaired fuel leak and pressure tested.
14-Sep-04	Call in - Loss of ready lights. Low temp on MLO, reset unit OK.
9-Sep-04	Call out - computer locked up unit at 40MW ECC had alarms but could not be seen locally. Had to re-boot.
27-May-04	HWGT, replaced AVR voltage adjust motor.
16-Apr-04	HWDGT, repair fuel leak.
10-Apr-04	Replace alternator filters.
7-Apr-04	HWDGT, JB-3 replaced term strip and wiring
1-Apr-04	Repaired float switch for sump
12-Mar-04	Glycol cooling system - installed 2 inspections hatches
12-Dec-03	HWDGT would not start due to vibration alarm. Tightened monitoring bolts on vib detec.
5-Nov-03	HWDGT, intermitent GT fire system alarm. (NF Power system problem and when power would go off, alarm would come in.
20-Aug-03	HWDGT GGA, Replace proximity switch clutch A.
18-Aug-03	GGA, installed overhauled burners that were sent to Rolls Wood in June, 2003.
20-Jun-03	Replaced main lube oil heat exchanger.
12-Mar-03	HWDGT END A Problem with EGT at 22MW.
5-Mar-03	GGA perform hot end inspection by R.R. up
9-Dec-02	GGB repaired Jordan valve.
10-Oct-02	Replaced shaft on main fuel pump #1
27-Sep-02	Change logic for EGT trips/alarms as per Craig Warrens request.
19-Sep-02	Repair oil leak on main supply line to main tank (contractor completed HP welding)
19-Apr-02	Repair demister leak.
18-Apr-02	Repair leak on #1 fuel forwarding pump.
10-Jan-02	Repair leak on Jacky pump GGB
19-Dec-01	Replace and repair Jordan valve GGB.
14-Nov-01	GGA, Repair leak on Jordan valve.
29-Oct-01	GGB tripping on single exhaust thermocouple. All thermocouples are reading high on END B.
22-Oct-01	Repair oil leak on demister
18-Oct-01	Repair leak on jacky pump, GGA
18-Oct-01	Replace limit switch on blow in doors.
28-Sep-01	Elect. Switch for sump replaced.
24-Sep-01	Can not control voltage on unit
4-Jun-01	Fuel leak repair fillter housing GGB
15-Mar-01	Check and repair DC GND
9-Mar-01	Trouble MLO - found belts broken on Glycol cooling fan #1
14-Feb-01	Installed new invertor.
25-Dec-00	Starting problems on Xmas Eve and day. Eventually got END B ON.

18-Dec-00	Inverter and DC GND. GND on the A END governor motor. Flex conduit from motor to JB was replaced.
8-Nov-00	Replaced and tapped broken proximity Switch cover and replaced Prox switch due to clutch A problem.
17-Oct-00	Point fuel storage tank.
6-Oct-00	Replaced safety valves on both receivers.
2-Oct-00	Replaced oil seal on MLO pump #1
28-Aug-00	HWDGT, GGA, oil alarm. Adjusted Glycol regulator.
9-Jun-00	Replace mech seal and o-ring on main fuel forwarding pump.
17-May-00	RR Rep complete hot end inspection on A & B
27-Apr-00	Due to vibration problems GGA was sent to Scotland for repairs.
30-Mar-00	Test thermocouples on EGT A & B 200°C, 400°C, 600°C using oven form HRD plant. All temp within 3% of oven settings. HWGT A & B, recalibrate exhaust thermocouples due to END A tripping EGT.
24-Dec-99	Clutch A-Repair
8-Dec-99	HWDGT, repaired thermostat valve on Glycol system
1-Dec-99	HWDGT, GGA fail to start. C. Warren made logic changes due to BRG/ lube temp trip and alarm being reversed.
30-Nov-99	HWDGT, GGA fail to start. C. Warren made logic changes due to BRG/ lube temp trip and alarm being reversed.
30-Sep-99	Replaced air filters.
10-Sep-99	Install GGA that was removed from SVL.
18-Jun-99	HWDGT, AVR/Exciter trouble AVR 1 & 2 tripped due to 400A fuses in exciter. Four of six fuse, had to be replaced.
15-Jun-99	HWDGT, repair demister leak.
15-Jun-99	Change alternator filters.
June 3-8, 1999	Investigate lube oil trip.Raised High temperature alarm, shut down and trip from 75-100, 80-105, 90-115 on A and B. Change filter on GGA and GGB lube system.
21-Apr-99	Investigate sequence failure/ignitor END A. Adjust sequence fail ignitor form 10-12 sec.
8-Mar-99	Call out - Sync cond trouble, alarm on shut down. Alarm reset okay.
28-Feb-99	Auto Sync Trouble - Callout Reset Okay.
20-Feb-99	Callout - Loss of control of Gas Turbine Aux relay in IRD (KS) faulty.
Mar 12 & 14, 1999	Auto sync trouble alarm on start down fo sync condense on March 12 and twice on March 14, 1999, March 23 & 24. After consulting with eng. 1. Sync trouble 2. Auto Sync trouble 3. Stator temp low were disabled to ECC's alarm page.

APPENDIX E

Operational Data – 2002 to 2007
Hardwoods Gas Turbine Plant

Operational Data – 2002 to 2007

Hardwoods Gas Turbine Plant

	Hours (hrs) Oct 07/02 Running Total	**Hours (hrs) Oct 09/07 Running Total**	**Difference Over 5 Years**
Gen Bkr. Closed Hrs.	12,078	30,152	18,074
Gen Sync Cond Hrs.	11,943	29,670	17,727
Gen Station Total Run Hrs.	12,116	30,254	18,138
GGA Total Run Hrs.	104.6	393.5	288.9
GGA Starts	391	913	522
GGB Starts	283	719	436
GGB Total Run Hrs.	140.2	464.8	324.6

Generation Hrs: for last 5 years

= 347 hours

2007: 30152 - 29670 = 482 hrs

2002: 12078 - 11943 = 135 hrs

For last 5 years: 482 - 135 = 347 hrs.

APPENDIX F

Extract (Section 8.0) from
"Condition Assessment and Life Cycle Cost Analysis - Hardwoods and Stephenville Gas Turbine Facilities"
Stantec, December 2007

Stantec

FINAL REPORT
CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS
HARDWOODS AND STEPHENVILLE GAS TURBINE FACILITIES
December 18, 2007

8.0 LIFE CYCLE COST ANALYSIS OF REFURBISHMENT OPTIONS

8.1 GENERAL

The primary focus of the life cycle cost analysis aspects of the study involves an economic evaluation of the costs associated with the Base Cases and the various Options outlined in Section 7.0 i.e. refurbishing the existing units, the replacement of existing equipment with new, as well as other economic opportunities for improvement. The 15 year life cycle analysis includes capital costs for equipment supply and installation as well as operational and maintenance costs at each site.

The life cycle cost analysis of each Gas Turbine option was performed by using HYDRO's Cost/Benefit Financial Analysis Model. The HYDRO cost/benefit analysis template uses the Cumulative Net Present Value (CPW) approach to perform economic or financial analyses of alternatives as part of the justification of a project. For the purposes of this Study, the CPW approach compares the various options available for Hardwoods and Stephenville Gas Turbines to provide reliable operation for a further 15 years.

8.2 FINANCIAL MODEL INPUT DATA/CRITERIA/COSTS

In discussions with HYDRO, it was agreed that the future operational mode of the Gas Turbines at each site, on an annual basis, will reflect to a large degree its annual operation over the past 5 years in terms of MW and MVAR output, operational and maintenance budgets. In a series of emails throughout October 2007, HYDRO provided the following Financial Model Input information. A copy of the various emails is included in Appendix 11.

8.2.1 MWHRS AND MVAR OUTPUT

The MWhrs loadings forecast for each Gas Turbine for the next 15 years is a very variable number as dictated by changing power system operational conditions. It was recommended in an October 26, 2007 HYDRO email (Email No. 1) to use 1200 MWhrs annually for each of Hardwoods and Stephenville Gas Turbines. It is recognized this number could change significantly over the next 15 years.

A HYDRO email of November 2, 2007 (Email No. 2) provided daily MVAR loadings on each Gas Turbine over the period June 10, 2006 – November 1, 2007. The daily average for both Hardwoods and Stephenville was typically under 10 MVAR with occasional peaks up to 25 MVAR. It will be assumed that this MVAR mode of operation will continue for the next 15 years.

The synchronous condenser operating hours, over the past 5 years at each site, as advised in a HYDRO email of October 26, 2007 (Email No. 1), are as follows:

- Hardwoods – 15,512 hours or an average of 3102 hours annually
- Stephenville – 4,799 hours or an average of 960 hours annually

The average annual hours of synchronous condenser operation will be carried forward as the annual MVAR operating mode for the next 15 years.

8.2.2 Operations and Maintenance Budgets

HYDRO, in an email of October 24, 2007 (Email No. 3) provided the following information on Operations and Maintenance Budgets at Hardwoods and Stephenville over the period 2002 through 2006 with a forecast for 2007. These Budget costs exclude fuel costs.

Table 7
Operational and Maintenance Costs
Hardwoods and Stephenville
(Excludes Fuel Costs)

Year	Hardwoods	Stephenville
2002	$178,000	$83,000
2003	$236,000	$105,000
2004	$114,000	$175,000
2005	$425,000	$114,000
2006	$486,000	$355,000
2007 (Forecast)	$300,000	$160,000
5 Yr Ave (Excluding 2007)	**$287,800**	**$166,400**

The 5 year average will be carried forward, adjusted for inflation, as an annual operations and maintenance cost for the next 15 years.

8.2.3 Gas Turbine #2 Oil Fuel Price Forecast

HYDRO, in an email of October 11, 2007 (Email No. 4), provided a forecast of #2 Oil fuel prices per liter over the period 2008 through 2037. For the purposes of the options life cycle cost analysis exercise, the 15 year forecast costs between 2008 and 2023 will be used.

Table 8
 # 2 Oil Fuel Price Forecast (Cdn$/l)
2008 - 2023

Year		Hardwoods		Stephenville
2008		0.624		0.686
2009		0.552		0.613
2010		0.557		0.619
2011		0.578		0.640
2012		0.606		0.668
2013		0.631		0.694
2014		0.666		0.730
2015		0.686		0.752
2016		0.721		0.788
2017		0.751		0.820
2018		0.786		0.856
2019		0.816		0.888
2020		0.847		0.919
2021		0.867		0.941
2022		0.882		0.957
2023		0.902		0.979

These annual fuel forecasts will be carried forward to compute fuel costs at each site for the next 15 years.

8.2.4 Inflation and Escalation Forecast

HYDRO, in an email of October 26, 2007 (Email No. 5), provided a forecast of inflation and escalation for the period 2000 through 2027. The forecast, included in Appendix 11, provides forecasts for General Inflation, Electric Utility Construction Price Escalation (5 categories) and Operating and Maintenance Cost Escalation.

The figures for the period 2008 through 2023 will be used in the life cycle cost analysis of the various Gas Turbine options.

8.2.5 Fuel Consumption at Each Site

HYDRO, in an email of November 13, 2007 (Email No. 6) provided the following information on fuel consumption at Hardwoods and Stephenville over the period 2004 through 2007. The 2007 figures are for a partial year assumed to cover 9 months. The consumption numbers are as follows:

Table 9
#2 Fuel Oil Consumption (litres)
Hardwoods and Stephenville
(2004 - 2007)

Year	Hardwoods	Stephenville
2004	95,288	50,241
2005	433,380	147,566
2006	738,552	389,686
2007 (partial year)	*262,691*	*204,485*
2007 (full year forecast)	350,255	272,646
3 Yr Ave (Excluding 2004)	**507,395**	**269,966**

The 3 year average will be carried forward as an annual fuel consumption figure for the next 15 years.

8.3 SUMMARY OF GAS TURBINE FACILITY REFURBISHMENT CAPITAL COSTS

The following Table 10 is a summary of the capital costs of the Gas Turbine Facility refurbishments – Base Case and Options - presented in Section 7.0 of this Report, which will be the subject of the life cycle cost analysis exercise. As noted in the various Tables in Section 7.0, there are further costs, associated with a number of the options, primarily modifications to existing enclosures to accommodate new equipment that will require further detailed investigation by the new equipment suppliers.

Table 10
Gas Turbine Facility Refurbishment Capital Costs
(2007 Costs)

Cost Analysis Alternatives		Description		Capital Costs (Cdn$)
Base Case				
1A		Refurbish Existing Equipment - Hardwoods GT Allowance for Temporary Gas Turbine Rental (1)		$4,506,880.00 3,307,500.00
1B		Refurbish Existing Equipment - Hardwoods GT No allowance for Temporary Gas Turbine Rental		$4,506,880.00
2A		Refurbish Existing Equipment - Stephenville GT Allowance for Temporary Gas Turbine Rental (1)		$4,538,883.00 3,307,500.00
2B		Refurbish Existing Equipment - Stephenville GT No allowance for Temporary Gas Turbine Rental		$4,538,883.00
Options				
1		New Engines & Power Turbines – Refurbish Balance of Equipment (2) – one site Allowance for Temporary Gas Turbine Rental (1)		$26,419,761.00 3,307,500.00
2		New Alternator / Exciter – Refurbish Balance of Equipment (2) – one site Allowance for Temporary Gas Turbine Rental (1)		$7,163,381.00 3,307,500.00
3		New Gas Turbine – Dismantle existing Gas Turbine and use as Spare Parts – one site		$36,900,000.00
4		Dynamic Var Compensation – Ballpark estimate at this time as a more detailed study is required to define scope and costs		$10,000,000.00

Note (1): The Gas Turbine rental covers a period of 4 months at the site.

Note (2): There are further costs associated with these options, primarily modifications to existing enclosures to accommodate the new equipment, which will require further detailed investigation by the new equipment suppliers.

8.4 LIFE CYCLE COST ANALYSIS ASSUMPTIONS AND COMMENTARY

A life cycle cost analysis of each option was performed using HYDRO's Cost/Benefit Financial Analysis Model. The following sub-sections provide an overview of the analysis, assumptions

and other criteria. Commentary is provided on the financial analysis of each Gas Turbine Facility Option. A copy of the various Life Cycle Cost Analysis Model runs is included in Appendix 12.

For the purposes of this study, the following assumptions have been used throughout all of the options:

Initial project capital cost is incurred end of year 2008

- Annual costs (fuel and O&M) begin 2009
- Annual costs are escalated through 2023 using the default indices in the NLH
- financial analysis tool
- The average fuel consumption over the past three years has been used as the base
- case for projections of future fuel consumption at both Hardwoods and
- Stephenville sites
- The 2007 project capital costs provided in Section 7.0 have been escalated to 2008
- to determine the “Project In-Service Cost,” using the built-in “Hydro and Thermal
- Plant Indices” escalation factors in the NLH financial analysis tool
- O&M costs have been assumed as 50% materials and 50% labour
- Cumulative net present values are expressed in January 2007 dollars

Each of the options described below were analyzed to determine the comparative cumulative net present value (CPW) over 15 years of operation. Note that two sub-cases were run for each scenario, in order to gauge the possible impact of future HYDRO maintenance requirements:

Sub-Case #1: Additional refurbishment costs are assumed to be required in 15 years, and are accounted for in the financial model as replacement costs occurring in 2023. Future refurbishment costs are adjusted to reflect the degree of work completed in 2008 for each option.

Sub-Case #2: It is assumed that equipment refurbished in 2008 will require replacement in 15 years. These costs are accounted for in the financial model as replacement costs occurring in 2023.

8.4.1 Base Case 1A – Hardwoods Refurbishment with Mobile Gas Turbine Rental Allowance

This scenario considers refurbishment at the Hardwoods site, with an allowance included for 4 months of rental mobile equipment during the refurbishment period.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $11.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is $16.0 million and $29.9 million for Sub-cases #1 and #2, respectively.

8.4.2 Base Case 1B – Hardwoods Refurbishment with No Mobile Gas Turbine Rental Allowance

This option considers refurbishment at the Hardwoods site (i.e. identical to the Hardwoods base case), except that no allowance for rental equipment is included.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $6.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is $11.5 million and $26.9 million for Sub-cases #1 and #2, respectively. The lower costs than Base Case 1A illustrate the financial impact of rental unit expenses during refurbishment.

8.4.3 Base Case 2A – Stephenville Refurbishment with Mobile Gas Turbine Rental Allowance

This scenario is for refurbishment at the Stephenville site, with an allowance included for 4 months of rental mobile equipment during the refurbishment period.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $11.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is $13.8 million and $27.7 million for Sub-cases #1 and #2, respectively. Note that while the Stephenville refurbishment capital costs are similar to Hardwoods, the CPW is considerably lower due to Stephenville's lower utilization and fuel costs.

8.4.4 Base Case 2B – Stephenville Refurbishment with No Mobile Gas Turbine Rental Allowance

This option considers refurbishment at the Stephenville site (i.e. identical to the Stephenville base case), except that no allowance for rental equipment is included.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $6.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is $9.5 million and $25.0 million for Sub-cases #1 and #2, respectively. The lower costs than Base Case 2A illustrate the financial impact of rental unit expenses during refurbishment.

8.4.5 Option No. 1 – Replacement of Engines and Power Turbines

This option is for replacement of the gas engines and power turbines, and refurbishment of the alternator and auxiliaries. The Hardwood site is assumed as the base case. An allowance for 4 months of rental mobile equipment during the refurbishment period is included.

For projecting future annual costs, 90% of historical fuel consumption and 75% of historical O&M costs have been assumed. This is to reflect that fuel consumption is expected to improve following installation of modern engines, and that less maintenance will be required on the new machines.

For Sub-Case #1, it is assumed that partial refurbishment/major maintenance of the unit will again be required in 2023. This is to account for the fact that the original alternator would still be in place at that time, and that the engines will have been operating for 15 years. A cost of $5.9 million in 2023 dollars is assumed, based on 50% of the complete 2008 refurbishment cost estimate. For Sub-Case #2, an allowance is made for complete replacement of the alternator in 2023 as well as other required balance-of-plant refurbishments similar to that work done in 2008. Future costs are escalated using the default value in the NLH model, for a total cost of $15.8 million in 2023 dollars.

The estimated CPW of costs for this option is $33.1 million and $36.2 million for Sub-cases #1 and #2, respectively. This is one of the highest cost options, due to the high costs of the engine replacement which are incurred early in the project's life.

8.4.6 Option No. 2 – Replacement of Alternator and Exciter

This option considers replacement of the alternator, and refurbishment of the gas engines and power turbines. The Hardwood site is assumed as the base case. An allowance for 4 months of rental mobile equipment during the refurbishment period is included.

For projecting future annual costs, 100% of historical fuel consumption and 80% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs will be improved by installation of the new alternator.

For Sub-Case #1, it is assumed that partial refurbishment/major maintenance of the unit will again be required in 2023. This is to account for the fact that the original engines would still be in place at that time, and that the alternator will have been operating for 15 years. A cost of $5.9 million in 2023 dollars is assumed, based on 50% of the complete 2008 refurbishment cost estimate. For Sub-Case #2, an allowance is made for complete replacement of the engines in 2023 as well as other required balance-of-plant refurbishments similar to that work done in 2008. Future costs are escalated using the default value in the NLH model, for a total cost of $44.8 million in 2023 dollars.

The estimated CPW of costs for this option is $16.2 million and $28.6 million for Sub-cases #1 and #2, respectively.

8.4.7 Option No. 3 - New Gas Turbine Facility

This option is for installation of a complete new gas turbine, including engine, alternator and auxiliaries. The Hardwoods site is assumed as the base case. No allowance is included for rental equipment, as it is assumed that the new unit would be installed while the old system was still operational.

For projecting future annual costs, 90% of historical fuel consumption and 70% of historical O&M costs have been assumed. This is to reflect that fuel consumption is expected to improve following installation of modern engines, and that less maintenance will be required on the new unit. A capital maintenance expense of $2.0 million in 2023 is allowed for both Sub-Cases.

The estimated CPW of costs for this option is $38.1 million for both Sub-cases #1 and #2. It is assumed that only routine major maintenance will be required in 2023.

8.4.8 Option No. 4 - Dynamic Var Compensation

Although this option requires additional investigation, a scenario was developed to gauge the potential of dynamic VAR compensation. No allowance is included for rental equipment, as it is assumed that the new equipment would be installed while the old system was still operational. For future annual costs, it is assumed that fuel consumption will be eliminated and O&M costs will be reduced to 10% of historical.

With these assumptions, the DVAR option appears very competitive with the refurbishment options. The CPW of this option is $9.0 million, placing it ahead of all the alternatives. Additional work is required to further develop the technical and financial aspects of this option; however, it is evident that it deserves additional consideration.

8.5 LIFE CYCLE COST ANALYSIS RESULTS AND RANKING OF OPTIONS

The results of the life cycle cost analysis are summarized below in Table 11. In general, the refurbishment options are the least cost alternatives, regardless of the capital expenditure that is assumed to be incurred in 15 years time.

Table 11
CPW of Alternatives

Ranking	Option	CPW (2007 Cdn$)	
		Sub-Case #1	**Sub-Case #2**
1	Option 4 – DVAR	$8,995,597	$8,995,597
2	Base Case 2B – Stephenville Refurbishment, No Rental Allowance	$9,548,569	$24,996,028
3	Base Case 1B – Hardwoods Refurbishment, No Rental Allowance	$11,467,914	$26,930,650
4	Base Case 2A – Stephenville Refurbishment, with Rental Allowance	$13,842,768	$27,711,405
5	Base Case 1A – Hardwoods Refurbishment with Rental Allowance	$16,010,747	$29,894,660
6	Option 2 – New Alternator/Refurbish Engines & Turbines	$16,248,954	$28,574,070
7	Option 1 – New Engines/Refurbish Alternator	$33,088,681	$36,221,835
8	Option 3 – Complete New GT Unit	$38,145,919	$38,145,919

Figures 1 and 2 provide a graphical summary of the options for Sub-Case #1. Note that the annual operating costs of each alternative have a relatively minor impact on life cycle costs compared to the required capital expenditures. This is due primarily to the ongoing projected synchronous condenser mode of operation of the Facilities over the next 15 years. If generation at each site should increase significantly in the next 15 years, O&M costs will increase accordingly. The lower O&M and fuel savings expected for the options where major equipment replacements are completed in 2008 therefore do not outweigh the early capital expenditure.

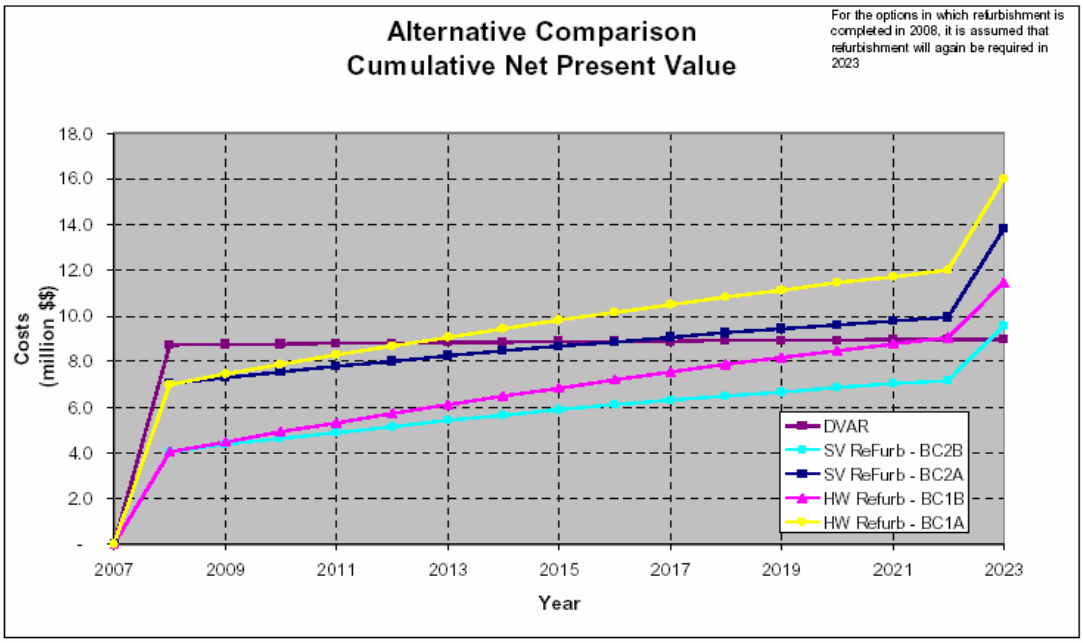

Figure 1
Sub-Case #1 – Base Cases and DVAR Compensation

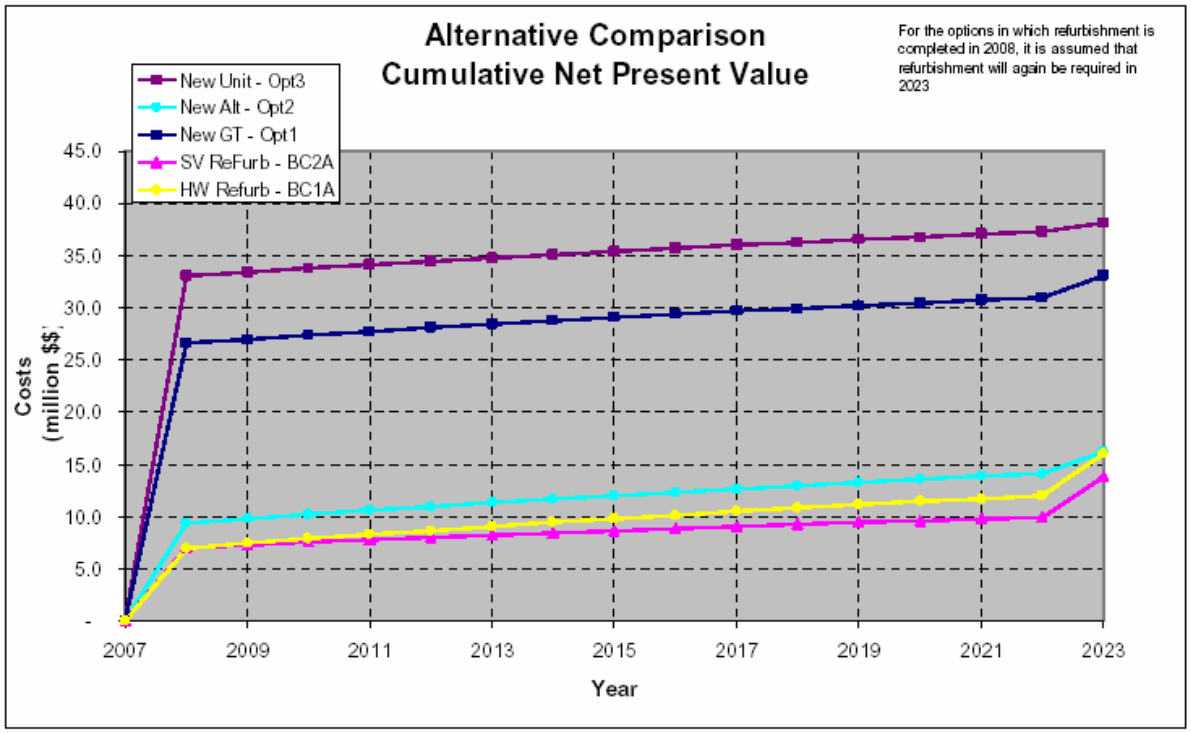

Figure 2
Sub-Case #1 – Base Cases and Equipment Replacement Options

APPENDIX G

Extract (Appendix 6) from
"Condition Assessment and Life Cycle Cost Analysis - Hardwoods and Stephenville Gas Turbine Facilities"
Stantec, December 2007.

COST ESTIMATE SPREADSHEET No. 1

HARDWOODS GAS TURBINE FACILITY

REFURBISHMENT RECOMMENDATIONS

Newfoundland and Labrador Hydro		
Stephenville and Hardwoods Gas Turbine Condition Assessment Study		
NG Job No. 21061		
Rev 1 ------ 2007-12-14		
	COST ESTIMATE SPREADSHEET No. 1	
	HARDWOODS GAS TURBINE REFURBISHMENT RECOMMENDATIONS	
Item	Hardwoods Recommendations	Cost Total
1--	**Gas Generators / Power Turbines Equipment**	
1	Engine A assembly be removed, disassembled to allow for detailed internal inspection with major refurbishments as required (Report para. 5.2.1)	
	o S&S Turbines Cost to refurbish and test engine assembly in BC	$515,000.00
	o Cost to transport engine assembly to BC & back	3,200.00
	o Engine removal & reinstallation by S&S Turbines Technicians	14,000.00
2	Engine B assembly be removed, disassembled to allow for detailed internal inspection with major refurbishments as required (Report para. 5.2.1)	
	o S&S Turbines Cost to refurbish and test engine assembly in BC	$460,000.00
	o Cost to transport engine assembly to BC & back	3,200.00
	o Engine removal & reinstallation by S&S Turbines Technicians	14,000.00
3	Inspect the Power Turbine assemblies A & B in detail upon removal of the Engines as noted in Items 1 & 2 to verify the mechanical integrity of the units. Inspect and refurbish the following: (Report para. 5.2.5)	$120,000.00
	o Main line bearings inspection	
	o Remove turbine blades and perform metallurgical sampling to verify alloy composition and wear to the blade roots	
	o Remove turbine disks and perform metallurgical sampling to verify alloy composition and creep growth.	

		o Apply anti-corrosion/thermal protection coatings to the turbine															
		blades and nozzles.															
4		Completely disassemble and inspect the Power Turbine Clutches A & B.												$13,000.00			
		Determine and resolve the interference problem between the clutches															
		and the proximity switches. (Report para. 5.2.6)															
5		Spare Item															
6		Spare Item															
7		It is recommended that HYDRO replace the following obsolete															
		auxiliary components with components of current design:															
		(Report para. 5.2.2)															
		Quantity		**Device**													
			o	Replace Ignition Exciters										$24,000.00			
			o	Replace Speed Governors/fuel valve assemblies										$56,000.00			
8		**Option:**															
		S&S Turbines provides a rental engine for the period when an engine															
		leaves site for refurbishment in BC until its return to site (estimated at															
		120 days per engine - assumes only one engine off-site at any time)															
		o 120 days per engine x 2 = 240 days (8 months)															
		o Fee for installation and removal = $14,000.00															
		o Monthly on-site rental fee = $2,450.00 x 8 = $19,600.00															
		o Fired hour charge = $42.00 per hour															
		(Assume 60 hours in 8 months = $2,520.00)															
		o Return transport from/to BC = $5,200.00															
												Total:		$41,320.00			$1,263,720.00
2--		**Inlet Air Systems A & B**															
9		Interior of both Inlet Air Plenums A and B be sand blasted and the												$ 18,000			
		surface of the Inlet Air Plenums and the silencers re-coated.															
		(Report para. 5.2.3)															
10		The exterior of both Inlet Air Structures be cleaned of surface corrosion												$ 24,000			

	& flaking and re-coated. (Report para. 5.2.3)				
11	Clean the surface corrosion inside the filter enclosure at the top of each Inlet Air Structure and re-coat. (Report para. 5.2.3)	$	4,000		
12	Replace the inner row of rubber sealing strips in Inlet Air Plenum A (Report para. 5.2.3)	$	1,500		
13	Complete following items regarding the access doors to both Air Plenum structures: (Report para. 5.2.3)				
	o Sand blast and coat all areas corroded under the access doors	$	700		
	o Weld new plates inside the troughts	$	600		
	o Replace the weather stripping on the access doors	$	1,000		
	o Install a new drip cap over both access doors				
14	Replace the ladders providing access to the platforms attached to each Inlet Air Structure and install kick plates on the ends of the platforms. (Report para 5.2.3)	$	5,500		
15	Clean the highly corroded screens on the Unit B Inlet Air Structure and re-coat. (Report para. 5.2.3)	$	2,000		
16	Re-align the inlet bellmouth assembly on Engine B (Report para. 5.2.3)		$5,000	$	62,300
3--	**Exhaust Stacks A & B**				
17	Replace the light gauge exterior cladding on the upper portion of each Exhaust Stack with a new corrogated metal cladding system. (Report para. 5.2.4)	$	22,000		
18	Clean the surface corrosion and coating failures on the heavy gauge cladding on the lower portion of each Exhaust Stack and re-coat. (Report para. 5.2.4)	$	15,000		
19	Repair cracks at two corners of the Exhaust Stack A access door opening in the inner liner, as well as cracks in the welds holding the interior mesh and insulation in place. (Report para. 5.2.4)	$	800		

20	Repair cracks at two corners of the Exhaust Stack B access door opening in the inner liner, as well as cracks in the inner liner below the door opening and the internal rolled edge. (Report para. 5.2.4)	$ 1,200		
21	Replace the snow doors on each Exhaust Stack. (Report para. 5.2.4)	$ 34,000		
22	Replace existing access doors on the Exhaust Stacks with operable hinged doors with proper flashings and weather stripping In addition, modify the hatches below these doors, in the roof of the gas turbine enclosures, to prevent water leaks. (Report para. 5.2.4)	$ 16,500		
23	Replace the ladders providing access to the platforms on each Exhaust Stack. (Report para. 5.2.4)	$ 5,500		$ 95,000
4--	**Glycol Cooler for Main Lube Oil**			
24	The entire Glycol Cooler steel structure and associated cladding be cleaned, prepared and re-coated within next 2 years. (Report para. 5.2.9)	$ 9,500		$ 9,500
5--	**Gas Generator / Power Turbine Enclosures A & B**			
25	The exterior of both Gas Generator / Power Turbine Enclosures be cleaned of corrosion, prepared and re-coated within next 2 years. (Report para. 5.2.10)	$ 10,000		
26	The interior of both Gas Generator / Power Turbine Enclosures be cleaned, areas with corrosion sandblasted and re-coated. (Report para. 5.2.10)	$ 11,000		
27	Modify the existing man doors to both Power Turbine Modules to have inspection windows added. (Report para. 5.2.10)	$ 1,600		$ 22,600
6--	**Alternator & Excitation System**			
28	Conduct Electrical Tests on the Alternator and Exciter while in its	$7,000.00		

		enclosure to determine condition as follows: (Report para. 5.3.3)			
		o Alternator Stator EL-CID Test			
		o Alternator Stator Polarization Index Test			
		o Alternator Stator Partial Discharge Test			
		o Alternator Rotor Megger Test - 500 vdc			
		o Measure Alternator Rotor Winding Resistance			
		o Rotating Exciter Stator and Rotor Megger Tests			
		o Measure Rotating Exciter Stator and Rotor Winding Resistance			
29		Remove & replace the Alternator from its Enclosure and remove the rotor	$50,000.00		
		for a complete visual inspection of the stator / rotor / exciter. Inspections			
		shall include: (Report para. 5.3.3)			
		Stator Inspection to include but not limited to:			
		o Loose or damaged Wedges			
		o Loose or cracked or failed winding connections			
		o Dusting, greasing and other signs of windings movement			
		o Indications of arcing (hot spots) and damaged core laminations			
		o Loose core bolts			
		o Signs of corrosion, contamination and excessive dirt			
		Rotor Inspection to include but not limited to:			
		o Signs of physical damage			
		o Loose or cracked or failed winding connectors			
		o Slot wedge migration and possible contact with retaining rings			
		o Signs of overheating			
		o Loose rotor wedges			
		o Dye penetrant examinations and magnetic particle tests on forgings; retaining rings and fan components to detect fatigue cracks.			
		Bearings Inspection to include but not limited to:			
		o Assess general condition of the bearings			
		o Determine if the bearings require re-babbiting or machining.			
		Carry out refurbishment work as required following			
		completion of electrical tests (Item 27) and visual inspections			

	(Item 28). Estimate includes:			
	o Rewind of stator at supplier's shop	$1,200,000.00		
	o Rewind of rotor c/w new end caps and overspeed testing at supplier's shop	$800,000.00		
	o Rewind /refurbishment of exciter	$25,000.00		
	o Transport costs to/from supplier's shop - assume UK	$30,000.00		
30	Perform a trim balance on the rotor to address the vibration issue observed physically and noted on the vibration monitoring system. There is a residual imbalance between the non-exciter and exciter of the alternator. (Report para. 5.2.7)	$10,000.00		$2,122,000.00
7--	**Alternator Enclosure**			
31	The exterior of the Alternator Enclosure be cleaned to remove surface corrosion and flaking, prepared and re-coated within next 2 years. (Report para. 5.3.7)	$ 9,000		
32	Add inspection windows to the man doors in the alternator module for safety purposes. (Report para. 5.3.7)	$ 1,600		$ 10,600
8--	**Fuel oil System**			
33	Clean, prepare and re-coat the storage tank exterior within the next 5 to 7 years. (Report para. 5.4.1)	$ 40,000		
34	Clean, prepare and re-coat the storage yank stairs and handrail within the next 2 to 3 years. (Report para. 5.4.1)	$ 4,000		
35	Replace two corrode stair treads on the storage tank stairs. (Report para. 5.4.1)	$ 750		
36	Install a kickplate at the handrail on the top of the storage tank. (Report para. 5.4.1)	$ 500		$ 45,250

9--	**Electrical Systems**			
37	Replace the alternator existing 13.8 kV circuit breaker with a new circuit breaker. (Report para. 5.5.1)	$60,000		
38	Modify cabling in the 13.8 kV cable entrance cubicle as follows:			
	o Short term - install dividers to separate the power cables from the control and instrumentation cables.	$3,500.00		
	o Long term - Replace and install power cables in a separate compartment from the control and instrumentation cables.	$9,500		
	(Report para. 5.5.1)			
39	Repair bus duct leaks by either (i) applying rubberized asphalt roofing compound over the duct or (ii) cover the bus duct with cladding. (Report para. 5.5.3)	$6,000		
40	Replace the existing 125 Vdc Battery Charger due to obsolence. (Report para. 5.5.5)	$17,000		
41	Recommendation for HYDRO to prepare a replacement program and budget to replace over time the electro-mechanical generator protection relays with digital relays. (Report para. 5.5.6)	$21,000		
42	Replace the 15 kV power cable supplying the 750 kVA Station Service Transformer. (Report para. 5.5.7)	$6,100		$123,100
10--	**Control & Instrumentation Systems**			
43	Stock spares for input channel modules in the ELSAG Bailey INFI 90 DCS System. (Report para. 5.6.1)	$8,000		
44	Replace the existing DCS System interface computer (PC) with a new PC with the latest PCV and QNX software. (Report para. 5.6.1)	$4,500 $8,000		
45	Replace the existing obsolete DCS power supply system with a new power supply. (Report para. 5.6.1)	$24,000		

46	Due to hot and humid conditions in the Control Building, it is recommended that an air conditioning unit be installed in the area of the DCS equipment. (Report para. 5.6.1)	$1,000		
47	Replace the obsolete vibration monitoring system. (Report para. 5.6.3)	$20,000		
48	Replace the existing obsolete vibration transducers with new accelerometers. (Report para. 5.6.3)			
49	Replace the existing terminal blocks for thermocouple terminations with terminal blocks designed for thermocouple use. (Report para. 5.6.4)	$600		
50	Install a low level cut out switch in the oil storage tank as a backup to the level transmitter. (Report para. 5.6.9)	$2,500		
51	Relocate the on-engine electrical junction boxes off the engines to isolate the terminations from vibration and heat. (Report para. 5.6.12)	$1,500		$70,100
11--	**Buildings**			
52	Control Building Refurbishments: (Report para. 5.7.1)			
	o The exterior of the Building be cleaned of corrosion, prepared and re-coated within next 2 to 5 years.	$ 11,000		
	o Install a new sloped roof over the existing flat roof for water tightness purposes.	$ 7,000		
53	Fuel Unloading Building Refurbishments: (Report para. 5.7.2)			
	o Replace the roof of the Building within next 2 years.	$ 5,000		
	o Pave the area surrounding the concrete off-loading containment dyke to facilitate the clean up of any spills.	$ 1,200		
	o The timber posts and guardrail protecting the concrete off-loading dyke and piping should be replaced.	$ 1,000		
54	Fuel Forwarding Building Refurbishments: (Report para. 5.7.3)			
	o Clean the roof, remove corrosion and repaint within 1 year.	$ 3,000		
	o Clean the roof, remove corrosion and repaint within 1 year.	$ 1,500		

| | | |

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Microwave Antenna Radome Replacement Program

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

HYDRO
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NEWFOUNDLAND AND LABRADOR HYDRO

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Appendix

A – Radome Replacement Schedule

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) has a network of microwave radio, by which corporate communications and System data are transmitted. This report presents the Hydro Radome Replacement Program. 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 manufacturer's recommendation. Historically, this project has been executed by external contractors and supported by internal resources.

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.

The Hydro 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 System (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 m and range in diameter from 2 m to 5 m. 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 delicate components of the antennas responsible for sending and receiving microwave radio signals are covered using a shell 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 these elements. 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.

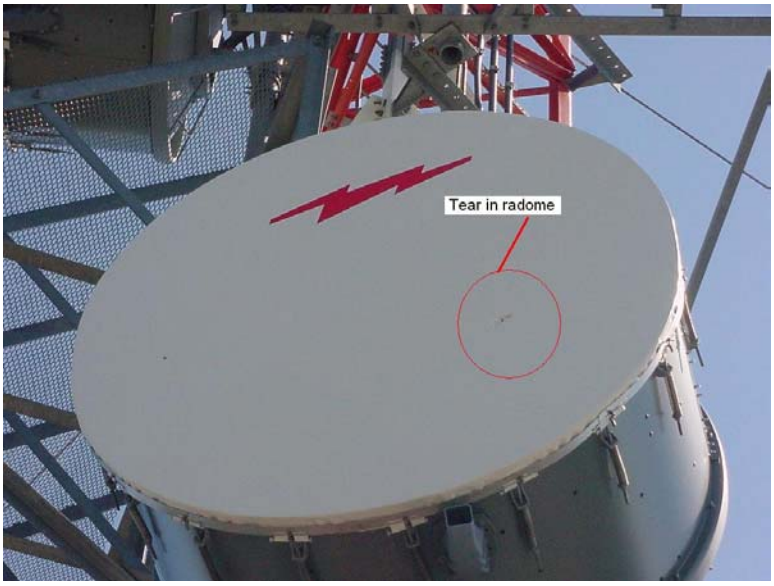


Figure 2: Tear in radome

Figure 3: Heavily damaged radome

Other modes of failure are less common. Ice falling from the tower can damage radome components, such as the stays 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.

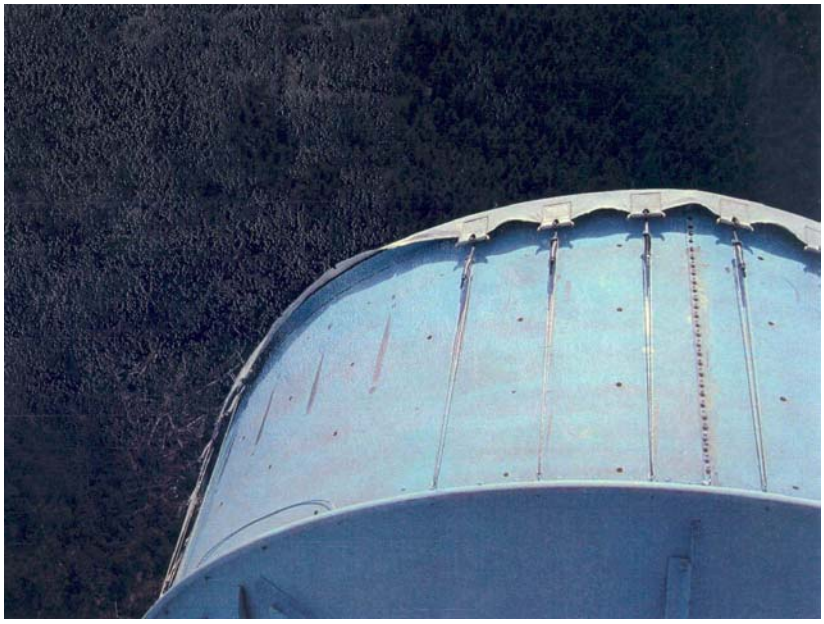


Figure 4: Missing radome mounts

2 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. Radomes are replaced at different sites throughout the network each year, depending on age and condition. The radome replacement schedule for 2009-2013 is provided in Appendix A. 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.

3 EXISTING SYSTEM

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.

3.1 Age of Equipment or System

Refer to the Installed/Last Replaced column of Appendix A for the ages of the radomes being replaced.

3.2 Major Work or Upgrades

There are no upgrades available for a radome. They must be replaced based upon the estimated useful lives of the individual radomes or upon observed damage during inspection.

3.3 Anticipated Useful life

Hydro's microwave antennas are supplied primarily by two manufacturers, Andrew Antenna 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.

For calculating depreciation expense, radomes are assumed to have an economic life of ten years.

3.4 Maintenance History

Radome maintenance consists of inspection when the tower is inspected. Because radomes cannot be repaired, damaged radomes are replaced when identified.

3.5 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 both Sandy Brook Hill Microwave 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 costs in labour and materials.

3.6 Industry Experience

Industry experience information is not available.

3.7 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.

3.8 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 and Cable Wave, the following conclusions were met:

- Cable Wave radomes (made of Hypalon material) should be replaced on a seven-year cycle;
- Andrew radomes (made of Teglar material) should be replaced on an eight-year cycle.

Andrew radomes, with a slightly longer life, cannot be substituted for CableWave radomes on CableWave antennas.

3.9 Availability of Replacement Parts

A radome consists of one piece of material with mounting hardware to connect it to an antenna. Mounting hardware is available should a piece be found missing or damaged. If a radome must be replaced, the mounting hardware is typically not re-used.

3.10 Safety Performance

There are no known safety performance issues associated with the radomes.

3.11 Environmental Performance

There are no environmental performance concerns or environmental code violations associated with the operation of microwave radomes.

3.12 Operating Regime

A microwave antenna, and by extension its radome, is in continuous use and has a 100% duty cycle.

4 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 Cost 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 for these sites would be distributed over a number of years.

The decision to distribute the replacement of radomes presents another obstacle: some radomes will be left in service for period 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 cost of a microwave failure today would be far more significant than 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. In 1996, only SCADA communications data was transmitted. 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.

4.1 Net Present Value

A Net Present Value calculation has not been done as there is only one viable alternative.

4.2 Levelized Cost of Energy

As the radomes are not related to generating units, the levelized cost of energy is not applicable.

4.3 Cost Benefit Analysis

A cost benefit analysis was not performed in this instance as there are no quantifiable financial benefits.

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements associated with radome replacement.

4.5 Historical Information

Table 1
Capital Budget and Expenditures for the Last Five Years

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2007[1]	26.9	9.2	1	9.2	Labour only. Nothing was replaced.
2006	No Budget	No Expenditures			
2005	No Budget	No Expenditures			
2004	No Budget	No Expenditures			
2003	No Budget	No Expenditures			

[1] First year of replacement program.

4.6 Forecast Customer Growth

Radomes are not impacted by forecast customer growth.

4.7 Energy Efficiency Benefits

There are no projected energy efficiency benefits related to the replacement of radomes.

4.8 Losses during Construction

There is no System outage required for this project.

4.9 Status Quo

The status quo is unacceptable. Allowing radomes to stay in service until failure will cause protracted outages on Hydro's communications system and will increase the likelihood of power system outages.

4.10 Alternatives

No viable alternatives exist to radome replacement.

5 CONCLUSION

Hydro's Radome Replacement Program is necessary in order to avoid outages caused by radome damage.

The radome replacement program proposed by Hydro is based on operational experience and manufacturer's recommendation. Historically, this project has been executed by external contractors and supported by internal resources.

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.

5.1 Budget Estimate

Table 2
Budget Estimate

Project Cost:($ x1,000)	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	35.0	0.0	0.0	35.0
Labour	24.0	0.0	0.0	24.0
Consultant	15.0	0.0	0.0	15.0
Contract Work	24.0	0.0	0.0	24.0
Other Direct Costs	6.6	0.0	0.0	6.6
O/H, AFUDC & Escln	14.6	0.0	0.0	14.6
Contingency	10.5	0.0	0.0	10.5
TOTAL	**129.7**	**0.0**	**0.0**	**129.7**

5.2 Project Schedule

The proposed project schedule is shown in Table 3.

Table 3
Project Schedule

Activity	Milestone
Project Initiation	February 2009
Installation & Commissioning Complete	October 2009
Project Closed	November 2009

Appendix A

Radome Replacement Schedule

2009 Radome Replacement

Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
USL	GDH	2000	3.0m(10')	CW	DA10-71hp
GPH	SBH	2000	3.6m(12')	CW	DA12-71hp
GPH	BDH	2000	1.8m(6')	CW	DA6-71hp
BUC	MMH	2001	1.8m(6')	CW	DA6-71hp
BGH	HLP	2000	2.4m(8')	CW	DA8-71hp
BAH	SSD	2001	1.8m(6')	Andrew	HP6-71E
BAH	CBC	2001	1.8m(6')	Andrew	HP6-71E
BAH	CAH	2001	2.4m(8')	Andrew	HP8-71D

2010 Radome Replacement

Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
CAH	FMH-main	2001	3.0m(10')	Andrew	HP10-71D
CAH-div	FMH-div	2001	2.4m(8')	Andrew	HP8-71D
CAH	WAP	2001	2.4m(8')	Andrew	HP8-71D
CAH-main	BAH-main	2001	3.0m(10')	Andrew	HP10-71D
CAH-div	BAH-div	2001	2.4m(8')	Andrew	HP8-71D
WAP	CAH	2001	2.4m(8')	Andrew	HP8-71D
WAP	WAV	2001	2.4m(8')	Andrew	HP8-71D
FMH	HRP	2001	2.4m(8')	Andrew	HP8-71D
PHH-main	FMH-main	2001	3.0m(10')	Andrew	HP10-71D
PHH-div	FMH-div	2001	1.8m(6')	Andrew	HP6-71E

2011 Radome Replacement

Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
STB	SBH	2001	1.8m(6')	CW	DA6-71hp
MMH	BUC	2001	1.8m(6')	CW	DA6-71hp
BAH-main	SHH-main	2004	2.4m(8')	Andrew	HP8-71GE
BAH-div	SHH-div	2004	2.4m(8')	Andrew	HP8-71GE
CBC	BAH	2001	1.8m(6')	Andrew	HP6-71E
SSD	BAH	2001	1.8m(6')	Andrew	HP6-71E
WAV	WAP	2001	1.8m(6')	Andrew	HP6-71E
FMH-main	PHH-main	2001	3.0m(10')	Andrew	HP10-71D
FMH-div	PHH-div	2001	1.8m(6')	Andrew	HP6-71E
FMH-main	CAH-main	2001	3.0m(10')	Andrew	HP10-71D
FMH-div	CAH-div	2001	2.4m(8')	Andrew	HP8-71D

2012 Radome Replacement

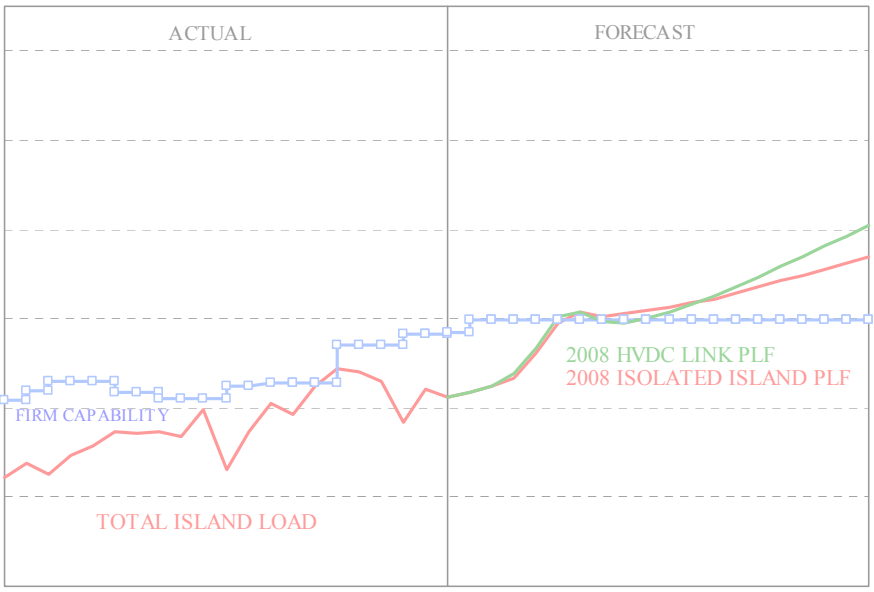
Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
GDH-main	GCH-main	2004	3.0m(10')	Andrew	HP10-71D
GDH-div	GCH-div	2004	2.4m(8')	Andrew	HP8-71D
GCH-main	GDH-main	2004	3.0m(10')	Andrew	HP10-71D
GCH-div	GDH-div	2004	2.4m(8')	Andrew	HP8-71D
DLK	DLP	2001	4.5m(15')	Gabriel	SR15-71B
BFI	SBH	2004	2.4m(8')	Andrew	HP8-71GE
NDH-main	SPH-main	2004	3.6m(12')	Andrew	HP12-71E
NDH-div	SPH-div	2004	3.6m(12')	Andrew	HP12-71E
HRP	FMH	2001	2.4m(8')	Andrew	HP8-71D
PHH	HWD	2001	1.8m(6')	Andrew	HP6-71E
PHH	OPD	2001	1.8m(6')	Andrew	HP6-71E
OPD	PHH	2001	1.8m(6')	Andrew	HP6-71E

2013 Radome Replacement

Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
GDH	USL	2004	3.0m(10')	CW	DA10-71hp
GDH	BDH	2004	3.0m(10')	CW	DA10-71hp
MMH	BGH	2004	2.4m(8')	CW	DA8-71hp
MMH	SBH	2004	3.6m(12')	CW	DA12-71hp
BGH	DLP	2004	3.6m(12')	CW	DA12-71hp
BGH	MMH	2004	2.4m(8')	CW	DA8-71hp
SPH-main	NDH-main	2004	3.6m(12')	Andrew	HP12-71E
SPH-div	NDH-div	2004	3.6m(12')	Andrew	HP12-71E
SPH-main	SHH-main	2004	3.6m(12')	Andrew	HP12-71E
SPH-div	SHH-div	2004	3.6m(12')	Andrew	HP12-71E
ECC	PHH	2001	1.8m(6')	Andrew	HP6-71E
HWD	PHH	2001	2.4m(8')	Andrew	HP8-71E

Generation Planning Issues

2008 Mid Year Update



System Planning

July 2008

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador PROFESSIONAL ENGINEERS AND GEOSCIENTISTS
BRADLEY M. COADY
SIGNATURE
2008-07-22
DATE
NEWFOUNDLAND & LABRADOR

Executive Summary

This report provides an overview of the Island Interconnected System (the 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 addressed to ensure that a decision on the preferred source can be made through an orderly process.

Under the Province's Energy Plan Hydro is to evaluate a High-Voltage Direct Current (HVDC) Link to deal with emissions from its Holyrood Thermal Generating Station (HTGS). This requires Hydro to maintain two planning load forecasts and two preliminary generation expansion plans; one for the HVDC Link and one for the Isolated Island scenario. Based on an examination of the System's existing plus committed capability, in light of the 2008 Planning Load Forecasts (PLF) and the generation planning criteria, the System can expect capacity deficits starting in 2013 under both scenarios and firm energy capability deficits starting in 2013 for the HVDC scenario and 2014 for the Isolated Island scenario.

Due to the economic and environmental benefits associated with displacing heavy fuel-oil at the HTGS, Hydro signed agreements for the development of wind generation projects at St. Lawrence and Fermeuse, both with planned in-service dates in 2008. A decision for a third wind project would be required by at least 2009 in order meet a 2010 in-service date.

Beyond the wind projects, a decision on what alternative to pursue is required by 2009 in order to be in-service by 2012 to meet capacity and firm capability requirements that begin in 2013. In order to meet these requirements, Hydro has identified two generation alternatives: a 50 MW combustion turbine in the event the HVDC Link scenario is ultimately pursued; and the 23 MW Portland Creek hydroelectric plant in the event the traditional Isolated Island scenario is pursued.

It should be noted, 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 Link – Hydro must be prepared to react if the proposed Lower Churchill Project is delayed or fails to receive sanction;
- HTGS End-of-Life – Hydro must determine what is required to ensure the HTGS can be operated reliably under both an Isolated Island and HVDC Link future;
- Emissions control considerations – Hydro must remain vigilant in considering the impact that environmental initiatives could have on production costing and future planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling due to increased environmental scrutiny 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 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 and costs.

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1.0 Introduction

This report provides an overview of the Island Interconnected System (the 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 addressed to ensure that a decision on the preferred source can be made through an orderly process.

This report is normally completed at year end, but given the many uncertainties at the end of 2007, with respect to the load forecast and generation expansion alternatives, it was decided to defer the report until some of the uncertainties were clarified. This report is a mid year review and while some of the uncertainties have been resolved, others still exist. This report should be considered as an interim report until a further update can be completed at the end of 2008.

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 can be made on which option Hydro will pursue 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 process.

2.0 Load Forecast

This review utilizes the 2008 long-term Planning Load Forecast (PLF) as prepared in the spring of 2008. Long-term load forecasts for the Province are derived using Hydro's own electricity 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. For this analysis, Hydro has included the lower Churchill River generation and transmission investments as an alternative to the isolated Island future while recognizing that these developments have yet to be technically committed through project sanction. Some key assumptions respecting incremental economic activity for both generation supply futures are:

- Continued newsprint operations at Corner Brook[1] and Grand Falls;
- Single Island oil refining operation at Come by Chance;
- Start-up of the Vale Inco NL[2] nickel processing facility on the Island in 2012;
- Teck Cominco[3] mining operations continuing through 2014.

In terms of high-level economic indicators, growth rate summaries for the HVDC Link and Isolated Island scenarios are presented in Table 2-1. As indicated in the table, there are modest longer-term economic differences associated with the two generation supply alternatives.

[1] Kruger Inc. announced on October 22, 2007, that it was shutting down Paper Machine No. 1, for an indefinite period of time, as of November 5, 2007.
[2] Voisey's Bay Nickel Company changed its name to Vale Inco Newfoundland and Labrador Limited (Vale Inco NL) on November 29, 2007.
[3] Teck Cominco completed the acquisition of Aur Resources on September 27, 2007

Table 2-1

Provincial Economic Indicators – 2008 PLF				
		2007-2012	**2007-2017**	**2007-2027**
Adjusted Real GDP at Market Prices* (% Per Year)	HVDC Link	1.9%	0.9%	0.9%
	Isolated Island	1.0%	0.8%	0.9%
Real Disposable Income (% Per Year)	HVDC Link	2.3%	1.5%	1.4%
	Isolated Island	1.6%	1.4%	1.3%
Average Housing Starts (Number Per Year)	HVDC Link	2,352	2,229	2,000
	Isolated Island	2,339	2,211	1,988
End of Period Population ('000s)	HVDC Link	504	497	489
	Isolated Island	501	492	487
*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 carries out system planning for the total System and that includes the demand and energy supplied by Hydro's customer-owned-generation resources in addition to Hydro's bulk and retail electricity supply. The projected electricity growth rates for the System under both the HVDC Link and Isolated Island cases are presented in Table 2-2. An important source of load growth for the utility sector on the Island continues to be a high penetration for electric space and water heating systems across residential and commercial new construction. For Hydro's industrial customers, current operations are assumed for the newsprint mills and oil refinery, the Teck Cominco mine is expected to operate through 2014 and the Vale Inco NL nickel processing facility will be commissioned in 2012.

Table 2-2

Electricity Load Growth Summary – 2008 PLF				
		2007-2012	2007-2017	2007-2027
Utility[1]	HVDC Link	1.6%	0.8%	1.2%
	Isolated	1.4%	0.9%	0.9%
Industrial[2]	HVDC Link	0.1%	1.5%	0.9%
	Isolated	0.1%	1.5%	0.9%
Total	HVDC Link	1.2%	1.0%	1.0%
	Isolated	1.0%	1.1%	0.9%

1. Utility load is the summation of Newfoundland Power and Hydro Rural.
2. Industrial load is the summation of Corner Brook Pulp and Paper, AbitibiBowater[4], North Atlantic Refining, Teck Cominco and Vale Inco NL.

Table 2-3 provides a summary of the 2008 PLF projections for electric power and energy for the System for the period 2008 to 2017. Similar long-term projections are also 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.

[4] On January 29, 2007, Abitibi-Consolidated Inc. (ACI) and Bowater Inc. announced their intentions to merge. The merger was formally completed on October 29, 2007 with the creation of AbitibiBowater Inc.

Table 2-3

Electricity Load Summary – 2008 PLF						
HVDC Link	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]
2008	1,302	5,888	283	2,030	1,566	8,112
2009	1,323	5,965	278	2,007	1,582	8,167
2010	1,341	6,039	278	2,016	1,600	8,251
2011	1,355	6,145	318	2,039	1,622	8,380
2012	1,372	6,212	356	2,262	1,652	8,673
2013	1,388	6,237	364	2,576	1,721	9,017
2014	1,393	6,231	357	2,644	1,725	9,079
2015	1,404	6,167	357	2,599	1,730	8,970
2016	1,398	6,143	357	2,599	1,724	8,945
2017	1,397	6,206	357	2,599	1,724	9,009
Isolated Island	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]
2008	1,302	5,888	283	2,030	1,566	8,112
2009	1,324	5,965	278	2,007	1,582	8,167
2010	1,341	6,039	278	2,016	1,600	8,251
2011	1,353	6,097	318	2,039	1,621	8,332
2012	1,368	6,145	356	2,262	1,649	8,606
2013	1,381	6,176	364	2,576	1,714	8,955
2014	1,387	6,222	364	2,644	1,720	9,071
2015	1,400	6,219	357	2,599	1,726	9,022
2016	1,404	6,260	357	2,599	1,730	9,064
2017	1,412	6,293	357	2,599	1,738	9,097

Note: 1. Utility and Industrial demands are non-coincident peak demands.
2. Total System is the total Island Interconnected System and includes losses and demands are coincident peak demands.

3.0 System Capability

Hydro is the prime supplier of system capability to the Island Interconnected System, accounting for 80 percent of its net capacity and 79 percent of its firm energy. Capability is also supplied by customer generation from Newfoundland Power Inc., Corner Brook Pulp and Paper Limited (Kruger Inc.) and AbitibiBowater Inc. Hydro also has contracts with four Non-Utility Generators (NUGs) for the supply of power and energy and has signed two contracts for wind power that will become operational later in 2008.

Hydroelectric generation accounts for 65 percent of the System's existing net capacity and firm energy capability. The remaining net capacity comes from thermal resources and is made up of conventional steam, combustion turbine and diesel generation plants. Of the existing thermal capacity, approximately 70 percent is located at the HTGS and is fired using 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 below.

Table 3-1

Island Interconnected System Capability – As of June 2008			
	Net Capacity [MW]	Energy [GWh]	
		Firm	Average
Newfoundland & Labrador Hydro			
Bay D'Espoir	592.0	2,272	2,646
Upper Salmon	84.0	492	567
Hinds Lake	75.0	191	220
Cat Arm	127.0	678	667
Granite Canal	40.0	290	339
Paradise River	8.0	33	36
Snook's, Venam's & Roddickton Mini Hydros	1.3	5	7
Total Hydraulic	927.3	3,961	4,482
Holyrood	465.5	2,996	2,996
Combustion Turbine	118.0	-	-
Hawke's Bay & St. Anthony Diesel	14.7	-	-
Total Thermal	598.2	2,996	2,996
Total NL Hydro	**1,525.5**	**6,957**	**7,478**
Newfoundland Power Inc.			
Hydraulic	92.1	324	423
Combustion Turbine	36.5	-	-
Diesel	7.0	-	-
Total	135.6	324	423
Corner Brook Pulp and Paper Ltd.			
Hydraulic	121.4	793	864
AbitibiBowater Inc.			
Hydraulic	58.5	430	467
Non-Utility Generators			
Corner Brook Cogen	15.0	100	100
Exploits River Partnership	32.3	117	137
Rattle Brook	4.0	13	16
Star Lake	15.0	87	141
Total	66.3	317	394
Total Island Interconnected System	**1,907.3**	**8,821**	**9,626**

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[5].

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability[6].

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 but it does incorporate the committed additions of the St. Lawrence and Fermeuse wind projects scheduled for in-service late 2008. 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 realistic firm system capability. Previously, firm system

[5] 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.
[6] 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.

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 start in 2013 and energy deficits start in 2013 for the HVDC Link scenario and 2014 for the Isolated Island scenario. Since the closure of the pulp and paper mill in Stephenville, capacity deficits now precede energy deficits indicating that the system is now capacity, rather than energy, constrained.

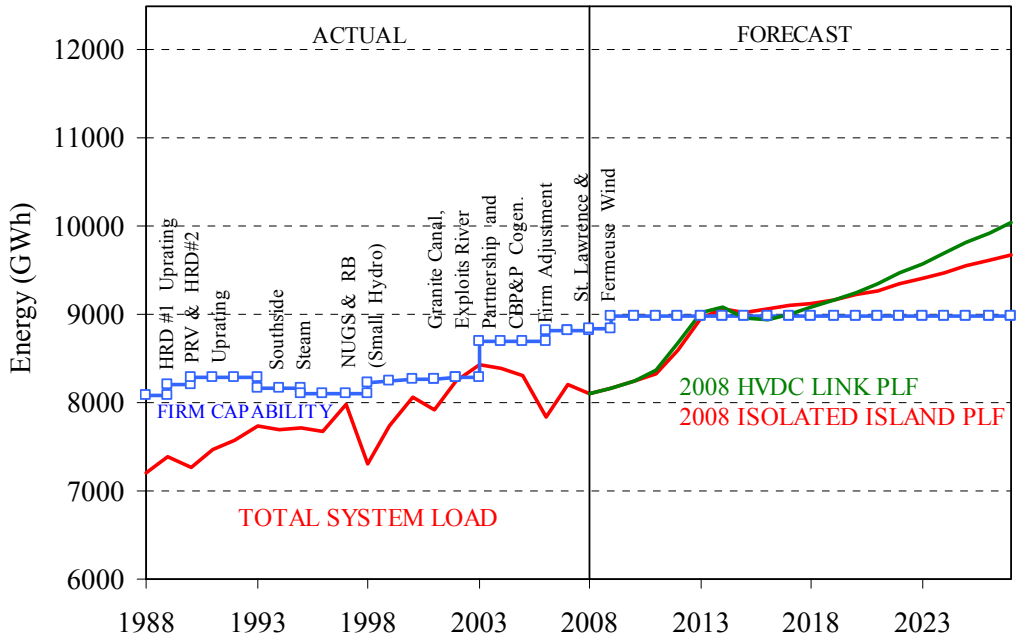
It should be noted that the capacity deficits trigger the need for the next generation source by 2013 under the current planning criteria. Under the expansion scenario ultimately pursued, this need may be met by different sources as explained in the Preliminary Generation Expansion Analysis section (Section 7).

Table 5-1 – Load Forecasts Compared to Planning Criteria

Year	Load Forecasts				Existing System plus 54 MW Wind Power in 2008		LOLH [hr/yr]		Energy Balance [GWh]	
	Maximum Demand [MW]		Firm Energy [GWh]							
	HVDC Link	Isolated Island	HVDC Link	Isolated Island	Installed Net Capacity [MW]	Firm Capability [GWh]	HVDC Link	Isolated Island	HVDC Link	Isolated Island
2008	1,566	1,566	8,112	8,112	1,961	8,849	0.46	0.46	737	737
2009	1,582	1,582	8,167	8,167	1,961	8,988	0.39	0.39	821	821
2010	1,600	1,600	8,251	8,251	1,961	8,988	0.55	0.55	737	737
2011	1,622	1,621	8,380	8,332	1,961	8,988	0.86	0.80	608	656
2012	1,652	1,649	8,673	8,606	1,961	8,988	1.66	1.50	315	382
2013	1,721	1,714	9,017	8,955	1,961	8,988	5.28	4.57	-29	33
2014	1,725	1,720	9,079	9,071	1,961	8,988	5.90	5.54	-91	-83
2015	1,730	1,726	8,970	9,022	1,961	8,988	5.48	5.61	18	-34
2016	1,724	1,730	8,945	9,064	1,961	8,988	4.97	5.92	43	-76
2017	1,724	1,738	9,009	9,097	1,961	8,988	5.38	6.79	-21	-109

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 current status of 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 186 GWh and 201 GWh, respectively.

The development would include the construction of a 3 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

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 requires: a 320 metre long diversion canal; three concrete dams; a 2,900 metre long penstock; a 27-kilometre-long 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

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 20 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

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

Newfoundland and Labrador 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. Pending further review and eventual operating experience, a maximum of 80 MW from wind is considered economically and technically acceptable as alternatives to meet a portion of the generation requirements for 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. These projects have begun construction and are expected to be in-service by December 2008.

Each wind farm could potentially consist of a number of interconnected wind turbines; each ranging is size from 1.8 to 3.0 MW, tied to a single delivery point on the System's transmission network. For example, a 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, respectfully.

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

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. Presently, the System's first two wind projects are expected to be in-service by December 2008.

6.5 Combined Cycle Plant (CCCT)

The combined cycle facility, also known as a combined-cycle combustion turbine (CCCT) facility, consists of a combustion turbine fired on light oil, 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.

In either alternative, the power ratings being considered are either a 125 MW or a 170 MW (net) combined-cycle combustion turbine (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

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.

6.6 HTGS 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

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 by approximately 20 percent to be competitive 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. 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 (CT)

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 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.

Schedule and Cost Estimate

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 and updated in March 2008, by Hydro's Mechanical Engineering Department. Approximately 90 percent of the direct cost is for the gas turbine package and due to the recent 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, 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 *NewEnergy Strategist*® software to 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 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 of Commissioners of Public Utilities (Board). In the Province's 2007 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 will be addressed via the addition of scrubbers and electrostatic precipitators. 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. For this analysis, the two committed 27 MW wind projects that are expected to be in service by December 2008 have been included.

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 2008. Other key economic parameters necessary to quantify the long-term costs of alternate generation expansion plans are summarized in Appendix B.

Based on the study assumptions outlined previously, the least-cost[7] generation expansion plan, under the two scenarios, is shown below in Table 7-1 and graphically in Figures 7-1 and 7-2. Under both scenarios, generation from wind-based sources continues as the next preferred source from amongst Hydro's identified portfolio of resource options.

Wind is preferred under both scenarios due to the benefits of fuel displacement and emissions reductions at the HTGS. Also, the wind project positively affects the LOLH calculation. Without this wind project, Hydro may need additional generation sources, beyond what has been identified in the table below, for capacity and energy requirements under both scenarios. The final decision on whether or not to proceed with a wind project will require some deeper analysis to determine the optimal timing, and size of a potential project.

Under the HVDC scenario, after the third wind project in 2010 the next preferred source would be a 50 MW CT in 2012. This CT is needed to satisfy Hydro's capacity (LOLH) planning criteria and will serve to provide some firm energy, if needed, until the HVDC Link is operational in late 2014. As part of the HVDC Link project, several CTs would be required to protect the System's reliability in the event of a prolonged HVDC Link outage. Once the HVDC Link is operational, this newly built CT would revert to a standby status and serve as a backup to the HVDC Link. In late 2014, the link would be put in-service and this would provide Hydro's system capability requirements well beyond the horizon of this expansion analysis.

Under the Isolated Island scenario, following the third wind project in 2010, the next least-cost supply options, in increasing order of cost, are the indigenous hydroelectric plants of Portland Creek in 2012, Island Pond in 2014 and Round Pond in 2016 followed by a 170 MW CCCT plant in 2022 and a 50 MW CT in 2025. The CCCT plant is indicative of the most economic thermal plant, which the Island would require in the long-term for firm capability as an isolated system.

[7] 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.

For the Isolated Island scenario, further additions of thermal-electric plants can be expected post 2027. 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. These, and other issues, are discussed further in the following section.

Table 7-1

2008 Generation Expansion Plans (Preliminary)		
Year	**HVDC Link Scenario Hydro's Alternatives + Wind (Capacity/Firm Capability)**	**Isolated Island Scenario Hydro's Alternatives + Wind (Capacity/Firm Capability)**
2008	SL Wind (27 MW/92 GWh) & FM Wind (27 MW/74.7 GWh)[8]	
2009		
2010	Wind (25 MW/77.2 GWh)	Wind (25 MW/77.2 GWh)
2011		
2012	CT (50 MW/394.2 GWh)	Portland Creek (23 MW/99 GWh)
2013		
2014	HVDC Link	Island Pond (36MW/186 GWh)
2015		
2016		Round Pond (18 MW/108 GWh)
2017		
2018		
2019	SVL Retired	
2020	HWD Retired	
2021		
2022		CCCT (170 MW/1,340 GWh)
2023		HWD & SVL Retired
2024		
2025		CT (50 MW/394.2 GWh)
2026		
2027		
Note: The HVDC Link expansion plan satisfies Hydro's generation planning criteria well beyond the 2027 planning horizon. However, the Isolated Island expansion plan will require further additions as HTGS units are retired beginning in 2031 (estimated).		

[8] These projects have been committed to by execution of power purchasing agreements in 2007. Therefore, they are common to both expansion plans.

Figure 7-1
Preliminary HVDC Link Expansion Plan vs. Load Forecast

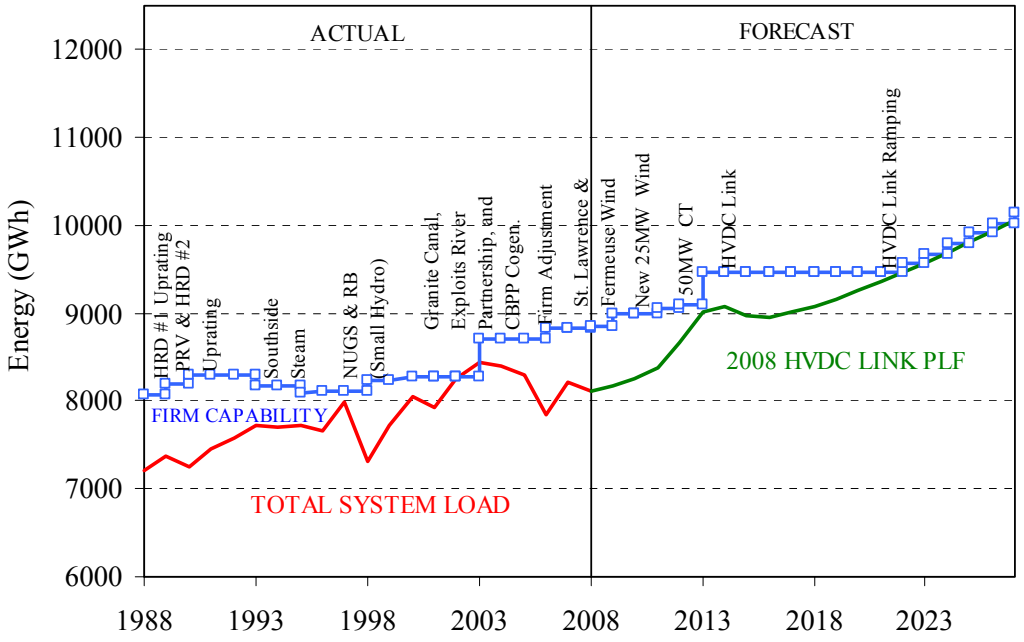
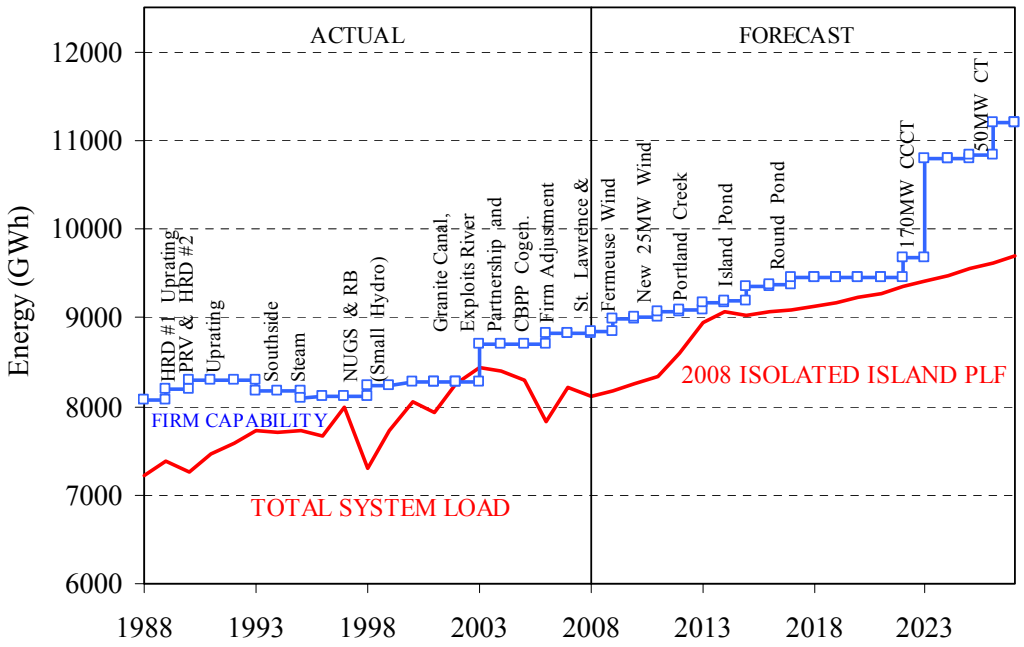


Figure 7-2
Preliminary Isolated Island Expansion Plan vs. Load Forecast



8.0 Timing of Next Decision

8.1 The Board of Commissioners of Public Utilities

Prior to 1996, Hydro was not required to seek approval from the Board for its capital program. With the 1996 amendments to the Hydro Corporation Act, and in the absence of a Government exemption, Hydro must seek Board approval before committing to a new generation project.

8.2 Decision Timing

Based on this most recent generation expansion analysis for both the 2008 HVDC Link and Isolated Island forecasts, 54 MW of wind generation has been committed and will be coming online in late 2008. The next requirement for additional generation is in 2012 to avoid exceeding the LOLH criterion in 2013.

Assuming an additional 25 MW wind project is added by 2010; Hydro would have to initiate the project in late 2008 or early 2009 to meet the in-service date. As indicated in the preliminary expansion plan (Table 7-1), the next generation source after the wind project, under both scenarios, would be required in-service in 2012.

Hydro would have to initiate the generation expansion project in 2009 in order to meet the required in-service date for either a 50 MW combustion turbine under the HVDC scenario or the 23 MW Portland Creek hydroelectric plant under the Isolated Island scenario. The 2009 decision will require clarity regarding the future path, whether the HVDC Link will be a reality or the Island will continue as an isolated system. The current plan for the HVDC Link anticipates a project sanction in 2009; however, this schedule is currently under review and delays in the sanction date will have implications for the 2009 generation expansion decision. It is hoped some of this uncertainty will be resolved by the end of 2008 and the result reflected in the year end review.

In the past, it had been assumed that Hydro would initiate an RFP process to identify potential non-utility alternatives to be included in the final portfolio of projects that would be

evaluated to determine the optimum expansion plan. However, given the tight timelines associated with the HVDC Link decision and the requirement for additional generation capacity by 2012 there may not be sufficient time to conduct an RFP process. The practicality of conducting an RFP process will be revisited in the year end review.

9.0 Other Issues

9.1 Environmental Considerations

Known environmental costs, such as environmental mitigation and monitoring measures that may be identified under the Environmental Assessment Act, and the current 25,000 tonnes per year limitation on sulphur-dioxide (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 sourcing 1% sulphur No. 6 fuel oil for the HTGS. While there can be additional purchase costs for 1% sulphur over 2% sulphur fuel oil, this improvement in fuel grade has reduced SO_2 emissions by some 50 percent.

SO_2 is the one of the necessary compounds to form acid rain. Exposure can also have negative health effects, especially for those with respiratory illness. Hydro has also participated in studies to evaluate and communicate to Government the potential impact of proposed changes in environmental regulations. These proposed regulations are aimed at further reducing the amount of sulphur that Hydro will be permitted to emit.

Beyond these considerations, 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 and Hydro, by virtue of its Holyrood thermal operations, is a principal emitter in the Province at an average of 1.1 million tonnes per year[9]. In the absence of a transmission link to the North American grid, 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.

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, especially under the Isolated Island scenario. 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.

9.2 HTGS 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 to function as synchronous condensers to provide System voltage support. Due to the age of these assets, significant capital investments may be required to ensure that they are capable of operating 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

[9] Based on the 5-year average of 1,101,872 tonnes per year of CO_2 from 2003 through 2007.

generation sources. Hydro should be prepared to determine what is required for the HTGS to function until its anticipated end of life under both expansion scenarios.

9.3 Energy Conservation

In June 2008, Hydro along with Newfoundland Power presented to the Board the *Five-Year Energy Conservation Plan*. The plan provides an overview of the current conservation marketplace in the Province of Newfoundland and Labrador, and outlines the strategy to be implemented by Newfoundland and Labrador Hydro and Newfoundland Power for joint conservation activities. The plan also outlines technologies, programs, supporting elements and cost estimates that support a long-term goal of development of a conservation culture and sustainable reduction in electricity consumption. Delivery of these programs is scheduled to commence in 2009. The total estimated energy savings through 2013 under this plan are 79 GWh per year. In all likelihood, the energy conserved will not delay the need for additional generation; however, Hydro should continue to assess its impact on the PLF and expansion plans.

10.0 Conclusion

Based on an examination of the System's existing plus committed capability, in light of the 2008 PLF and the generation planning criteria, the Island system can expect capacity deficits starting in 2013 under both the HVDC Link and Isolated Island scenarios and energy deficits starting in 2013 under the HVDC Link scenario and 2014 under the Isolated Island scenario.

Due to the direction given to Hydro under the Provincial Government's Energy Plan, two generation expansion plans are to be maintained until the decision whether or not to sanction 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 Lower Churchill Project is scheduled to be sanctioned in 2009 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 2013, Hydro has identified two possible generation sources. The preferred source depends whether or not the Lower Churchill Project will be sanctioned. Assuming that the project is sanctioned, Hydro will likely proceed with the development of a 50 MW combustion turbine in order to satisfy its capacity and energy requirements until the HVDC Link can be established. However, if the project fails to be sanctioned, Hydro will likely require the construction of the 23 MW Portland Creek hydroelectric plant to meet its capacity requirements. It is likely that the remaining hydroelectric facilities of Island Pond 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. The decision between these two projects will be required in 2009 in order to meet their respective in-service dates.

Also, in late 2008, two 27 MW wind projects will come online. These projects have a positive influence on the capacity calculation; however, their main benefits are in terms of firm energy production, influence on the System energy balance table and environmental and economic benefits of reducing emissions from burning fuel at the HTGS. A third wind project is expected in 2010 for similar reasons; however, no final decision has been made on whether or not to proceed with this project at this time. The final evaluation and decision whether or not to proceed is expected later in 2008 or early in 2009.

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.

The potential impacts of any further production declines in the pulp and paper industry and the potential addition of an oil refinery have not been included as a part of this analysis due

to the uncertainty associated with these events. At the appropriate time, perhaps during the usual timeframe for completion of this annual report on Generation Planning Issues, more information may be available on the future direction of these possible events and facilitate their inclusion into this report. As time moves on, and annual updates to this report are prepared, the timing of future generation projects will become more apparent.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- HVDC Link – Hydro must be prepared to react if the proposed Lower Churchill Project is delayed or fails to receive sanction;
- HTGS End-of-Life – Hydro must determine what is required to ensure the HTGS can be operated until its end-of-life life under both an Isolated Island and HVDC Link future;
- Emissions control considerations – Hydro must remain vigilant in considering the impact that environmental initiatives could have on production costing and future planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling due to increased environmental scrutiny 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 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 and costs.

Appendix A

Table A-1
2008 Planning Load Forecasts

Year	2008 PLF HVDC Link Case		2008 PLF Isolated Island Case	
	Maximum Demand [MW]	Firm Energy [GWh]	Maximum Demand [MW]	Firm Energy [GWh]
2008	1,566	8,112	1,566	8,112
2009	1,582	8,167	1,582	8,167
2010	1,600	8,251	1,600	8,251
2011	1,622	8,380	1,621	8,332
2012	1,652	8,673	1,649	8,606
2013	1,721	9,017	1,714	8,955
2014	1,725	9,079	1,720	9,071
2015	1,730	8,970	1,726	9,022
2016	1,724	8,945	1,730	9,064
2017	1,724	9,009	1,738	9,097
2018	1,739	9,082	1,745	9,124
2019	1,756	9,166	1,752	9,175
2020	1,773	9,253	1,762	9,223
2021	1,792	9,353	1,772	9,280
2022	1,814	9,466	1,785	9,355
2023	1,835	9,577	1,797	9,421
2024	1,857	9,696	1,809	9,479
2025	1,880	9,814	1,821	9,547
2026	1,903	9,929	1,833	9,613
2027	1,926	10,051	1,846	9,689

Appendix B

Table B-1
Fuel Forecast

Year	Residual 1.0%S (6.287 MBTU/BBL) [$/BBL]	Diesel (5.825 MBTU/BBL) [$/litre]
2008	99.90	1.045
2009	86.90	0.815
2010	91.20	0.745
2011	88.00	0.710
2012	88.70	0.715
2013	92.70	0.745
2014	94.60	0.765
2015	96.60	0.785
2016	98.50	0.805
2017	100.80	0.825
2018	103.00	0.845
2019	105.20	0.865
2020	107.50	0.885
2021	109.70	0.900
2022	112.00	0.920
2023	114.40	0.940
2024	116.70	0.960
2025	119.20	0.980
2026	121.70	1.000
2027	124.20	1.020

Source: NL Hydro, Market Analysis Section, June 2008

Table B-2
Escalation Rates

	General Inflation		Construction			Operation & Maintenance	
Year	GDP	Canadian CPI	Hydro & Thermal Plant	Transmission Line	Transformer Station	More Materials Less Labour	More Labour Less Materials
2008	2.5%	2.5%	3.0%	2.5%	2.0%	2.5%	3.0%
2009	2.0%	2.0%	3.0%	2.5%	2.0%	2.5%	3.0%
2010	2.0%	2.0%	3.0%	2.5%	2.0%	2.5%	3.0%
2011	2.0%	2.0%	3.0%	2.5%	2.5%	2.5%	3.0%
2012	2.0%	2.0%	3.0%	2.5%	2.5%	2.5%	3.0%
Beyond 2012	2.0%	2.0%	3.0%	3.0%	2.5%	2.5%	3.0%

Source: NL Hydro, Market Analysis Section, October 2007

Table B-3
Future Resource Capital Cost Flow Estimates

Project	Direct Costs in January 2008$ (x 1,000)*					
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Island Pond	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
Round Pond	[redacted]	[redacted]	[redacted]			[redacted]
Portland Creek	[redacted]	[redacted]	[redacted]			[redacted]
Hardwoods 50 MW CT	[redacted]	[redacted]	[redacted]			[redacted]
Stephenville 50 MW CT	[redacted]	[redacted]	[redacted]			[redacted]
Greenfield-1 50 MW CT	[redacted]	[redacted]	[redacted]			[redacted]
Greenfield-2 50 MW CT	[redacted]	[redacted]	[redacted]			[redacted]
Holyrood 125 MW CCCT	[redacted]	[redacted]	[redacted]			[redacted]
Holyrood 175 MW CCCT	[redacted]	[redacted]	[redacted]			[redacted]
Greenfield 175 MW CCCT	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
HTGS Unit IV	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
Wind 27 MW	[redacted]	[redacted]				[redacted]

* Excludes Escalation and Interest During Construction