File No. ____________

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO
Head Office: St. John's, Newfoundland P.O. Box 12400 A1B 4K7
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July 23, 2007

BY HAND

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

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

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro – 2008 Capital Budget Application

Please find enclosed ten copies of Hydro's 2008 Capital Budget Application filed in accordance with the Provisional Capital Budget Application Guidelines dated June 2, 2005 (the "Provisional Guidelines") and in accordance with the guidelines and conditions for capital budget proposals as outlined by the Board in Order No. P.U. 7 (2002-2003).

The Application is generally consistent and comparable with past applications to allow ease of comparison. Section A sets out the high level summary of the 2008 budget by the categories traditionally used with the General Properties Section broken down into Information Systems and Telecommunications, Transportation and Administration.

Section B contains the detailed project justifications for each period over $50,000. Each project contains the additional information directed by the Provisional Guidelines. For example, the heading for each budget proposal contains information with respect to the type (whether clustered, pooled or other) and classification (whether mandatory, normal or justifiable). Information is then contained in each budget proposal to support the type and classification proposed for the project. Multi-year projects, previously reviewed by the Board, are included as part of Section B.

Section C to the Application provides the information directed by the Provisional Guidelines with respect to materiality. Page C-l lists all projects over $500,000. Page C-2 sets out the projects over $200,000 and less than $500,000, while Pages C-3 and C-4 list all projects for 2008 below $200,000. Page C-5 provides a table listing the number of projects by type.

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Section D to the Application relates to leases, (however there are no items for this section for this application) while Section E sets out the capital budget plan for the period 2002-2011. Section F to the Application contains the status report for the 2007 capital program.

Section G to the Application is the 10-year plan of projected operating maintenance expenditures for the Holyrood Generating Station which the Board directed to be filed annually with the capital budget in Order No. P.U. 14 (2004).

Section H to the Application contains the reports that are referred to in the project proposals in Section B. Section I sets out the 2006 rate base for Hydro.

In due course, Hydro will be providing electronic copies (pdf format) of this Application and of all subsequent materials filed by Hydro, in the usual manner.

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

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

Encl.

c.c. Mr. Peter Alteen,
Newfoundland Power

Mr. Tom Johnson
Consumer Advocate
O'Dea, Earle

Mr. Joseph Hutchings, Q .C.
Poole Althouse

Mr. Paul Coxworthy
Stewart McKelvey Stirling Scales

A APPLICATION TO THE
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2008 Capital Budget Application

AUGUST, 2007

HYDRO
THE POWER OF COMMITMENT

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(cont'd.)

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

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for an Order approving: (1) its 2008 capital budget pursuant to s.41(1) of the Act; (2) its 2008 capital purchases, and construction projects in excess of $50,000 pursuant to s.41 (3) (a) of the Act; (3) its leases in excess of $5,000 pursuant to s. 41 (3) (b) of the Act; and (4) its estimated contributions in aid of construction for 2008 pursuant to s.41 (5) of the Act and for an Order pursuant to s. 78 of the Act fixing and determining its average rate base for 2006.

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

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

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

2. Section A to this Application is Hydro's proposed 2008 Capital Budget in the amount of approximately $45.1 million prepared in accordance with the guidelines and conditions outlined in Order No. P.U. 7 (2002-2003) and the Provisional Capital Budget Application Guidelines dated June 2, 2005 (the "Provisional Guidelines").

3. Section B to this Application is a list of the proposed 2008 Construction Projects and Capital Purchases in excess of $50,000 prepared in accordance with Order No. P.U. 7 (2002-2003) and the Provisional Guidelines.

4. Section C to this Application summarizes Hydro's proposed 2008 capital projects by definitions, by classification and by materiality as required by the Provisional Guidelines.

5. There are no new Leases in excess of $5,000 per year for 2008 listed in Section D.

6. Section E to this Application is a Schedule of Hydro's Capital Expenditures for the period 2002 to 2011.

7. Section F to this Application is a report on the status of the 2007 capital expenditures including those approved by Orders Nos. P.U. 35 (2006), projects under $50,000 not included in these Orders, and the 2006 capital expenditures carried forward to 2007.

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

9. Section H to this Application contains the supplementary reports referred to in various capital budget proposals.

10. Section I to this Application shows Hydro's actual average rate base for 2006 of $1,472,184,000.

11. The proposed capital expenditures for 2008 as set out in this Application are required to allow Hydro to continue to provide service and facilities for its customers which are reasonably safe, adequate and reliable as required by section 37 of the Act.

12. The Applicant has estimated the total of contributions in aid of construction for 2008 to be approximately $275,000. The information contained in the 2008 Capital Budget (Section A) takes into account this estimate of the contributions in aid of construction to be received from customers. All contributions to be recovered from customers shall be calculated in accordance with the relevant policies as approved by the Board.

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

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

(1) Approving Hydro's 2008 Capital Budget as set out in Section A hereto, pursuant to section 41 (1) of the Act;

(2) Approving 2008 Capital Purchases and Construction Projects in excess of $50,000 as set out in Section B hereto, pursuant to section 41 (3) (a) of the Act;

(3) Approving the proposed estimated contributions in aid of construction as set out in paragraph 11 hereof for 2008 as required by section 41 (5) of the Act, with all such contributions to be calculated in accordance with the policies approved by the Board; and

(4) Fixing and determining Hydro's average rate base for 2006 in the amount of $1,472,184,000, pursuant to section 78 of the Act.

DATED at St. John's, Newfoundland, this twenty-third day of July, 2007.

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

Newfoundland and Labrador Hydro
P.O. Box 12400
500 Columbus Drive
St. John's, Newfoundland and Labrador
A1B 4K7
Telephone: (709) 737-1443

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

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for an Order approving: (1) its 2008 capital budget pursuant to s.41(1) of the Act; (2) its 2008 capital purchases, and construction projects in excess of $50,000 pursuant to s.41 (3) (a) of the Act; (3) its leases in excess of $5,000 pursuant to s. 41 (3) (b) of the Act; and (4) its estimated contributions in aid of construction for 2008 pursuant to s.41 (5) of the Act and for an Order pursuant to s. 78 of the Act fixing and determining its average rate base for 2006.

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

AFFIDAVIT

I, John E. Mallam, Professional Engineer, make oath and say as follows:

1. That I am the Vice-President of Engineering Services of Hydro and as such I have knowledge of the matters arising in the within matter.

2. That I have read the contents of the attached Application and those contents are correct and true to the best of my knowledge, information and belief.

SWORN TO in the)
City of St. John's, in the)
Province of Newfoundland and Labrador)
this 23rd day of July, 2008,)
before me:)

Geoffrey P. Young
Barrister - Newfoundland and Labrador

John E. Mallam

Overview

Hydro is required to provide reliable service to its customers, through the provisions of the Hydro Corporation Act, the Electrical Power Control Act, 1994, and the Public Utilities Act. The provision of a safe reliable, least cost supply of electricity requires that Hydro continuously renew, expand and modify its generation, transmission and distribution assets, and the assets that support those systems. Hydro must also address changing environmental and other regulatory requirements, challenges which often require the acquisition of new assets or the improvement of existing assets.

Maintaining Hydro's systems in reliable operating condition is accomplished through a combination of routine maintenance of existing assets, the replacement of assets which have reached the end of their useful service lives (worn beyond the point of economic repair), or by replacing assets with ones which will result in lower life cycle costs.

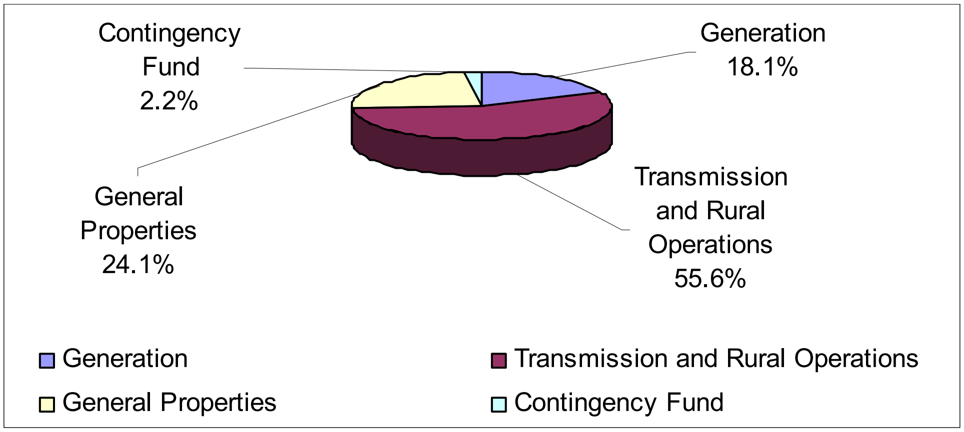
The majority of Hydro's most important assets are about forty years old. This is true of Hydro's largest hydro installation at Bay d'Espoir, the Holyrood Thermal Generating Station, and much of Hydro's transmission and distribution systems. In addition, many other generation assets, such as the Stephenville Gas Turbine, Hardwoods Gas Turbine and Hinds Lake Generating Station are approximately 30 years old.

Many of the capital proposals contained in this, and previous capital budget applications, resulted from the age of Hydro's assets, as the assets have reached the end of their useful lives and require replacement. The quantity and value of these routine sustaining capital proposals can be expected to continue to increase as the assets age, become obsolete and are no longer supported by manufacturers. In other cases, the introduction of newer, more efficient technologies justifies the replacement of old equipment.

The age of Hydro's assets also has implications for efficient operating methods and safety. Plants were constructed at a time when most systems and auxiliary equipment were manually operated. Today, most equipment is automated or remotely controlled, which permits the operators to spend more time focused on maximizing efficiency. Many of the older safety standards are not adequate under current legislation or generally accepted standards, and the modification of facilities is required to eliminate or minimize risk of injury to employees, contractors and the general public. This application contains proposals to improve the safety of Hydro's workplaces and to implement automation or remote control of equipment to facilitate the efficient operation of assets.

Chart 1 shows the breakdown of the 2008 Capital Budget.

Chart 1: 2008 Capital Budget - Summary

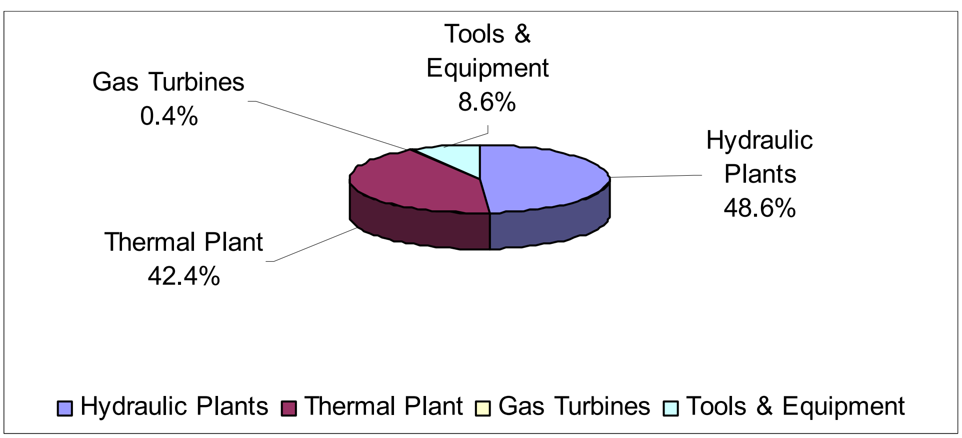


GENERATION ASSETS

On the Island Interconnected System, Hydro owns and operates hydraulic and thermal generation assets with 1,526 MW of net capacity.

The division of the 2008 Capital Budget for Island Interconnected generation among Hydraulic, Holyrood, Gas Turbines and Tools and Equipment Expenditures is shown in Chart 2 below.

Chart 2: 2008 Capital Budget - Generation



Hydraulic Plants

Hydro's hydraulic power plants range in age from 4 to 40 years. They require attention to ensure reliability and to maximize their potential useful operating lives. This application includes proposals for:

- upgrading spherical valve maintenance seals at Cat Arm;
- replacing governor controls on Unit 2 at Cat Arm;
- assessing the condition of the hydraulic structures on the Bay d'Espoir system, many of which are forty years old; and
- replacing cooling water, fire alarm and control systems.

Thermal Plant

The Holyrood Generating Station Units 1 and 2 are now 38 years old while Unit 3 is 27 years old. The generally accepted life expectancy for thermal plants is 30 years. The Holyrood plant remains critical to the reliable power supply on the Island Interconnected system. The capital upgrades contained in this application are necessary to replace assets which are at the end of their useful lives, and those which must be replaced to maintain reliability.

Additionally, the Holyrood Generating Station is one of a small number of heavy oil burning power plants on the east coast of North America which do not have air emission control equipment. With concerns about air pollution rapidly increasing, and with conditions imposed on Hydro under the terms of the provincial Department of Environment and Conservation, Holyrood Thermal Generating Station Certificate of Approval (Section H, Tab 3), plant modifications are required to address environmental concerns. In response to the Federal Government's recently released "Regulatory Framework for Air Emissions", which requires action on sulphur emissions as early as 2012, Hydro must investigate the cost and operational issues associated with the installation of emission control equipment at the Holyrood Generating Station. This application contains a proposal to perform a feasibility study for a scrubber and electrostatic precipitator, which would significantly reduce atmospheric emissions from the Holyrood plant.

Table 2 shows the nature of the 2008 Capital Budget proposals related to Holyrood.

Table 2: 2008 Capital Budget - Holyrood

THERMAL PLANT PROPOSALS	NATURE
Tank Farm Upgrade	Environmental
Replace Unit 2 High Pressure Heater	Useful Life Ended
Upgrade Continuous Emissions Monitoring System	Environmental
Replace Unit 1 and 2 Condenser Valve Actuators	Useful Life Ended
Replace Unit 2 Electromechanical Trip Device	Safety
Precipitator and Scrubber Installation Study	Environmental
Replace 4160 Volt Motor Relays	Reliability
Replace Unit 2 Main Steam Stop Valve	Reliability
Environmental Effects Monitoring Study of Waste Water	Environmental
Upgrade Ambient Monitoring Station	Environmental
Soot Blowing Controls Study	Environmental
Stack Breeching Study	Reliability
Install Safety Egress Lighting	Safety
Autosynchronizing Units 1 and 2	Automation
Install Stator Ground Fault Protection	Safety
Upgrade Meteorological Station	Environmental
Construct Bam Unit Enclosure	Building
Programmable Logic Controller Replacement Study	Reliability
Motor Control Centres Assessment	Reliability
Install UV Domestic Water Treatment	Safety
Jetty Building Ventilation	Building

Gas Turbines

Hydro's gas turbine plants at Stephenville, Hardwoods and Holyrood are more than thirty years old. The generally accepted life expectancy for gas turbine plants is between twenty-five and thirty years. These plants have required considerably more maintenance in recent years and all three have required significant capital expenditures to maintain an acceptable level of reliability and availability. This application contains one proposal relating to a condition assessment of the Holyrood Gas Turbine, to ensure continued reliable operation. From this assessment, it is anticipated that significant capital expenditures will be required for all gas turbines in future years.

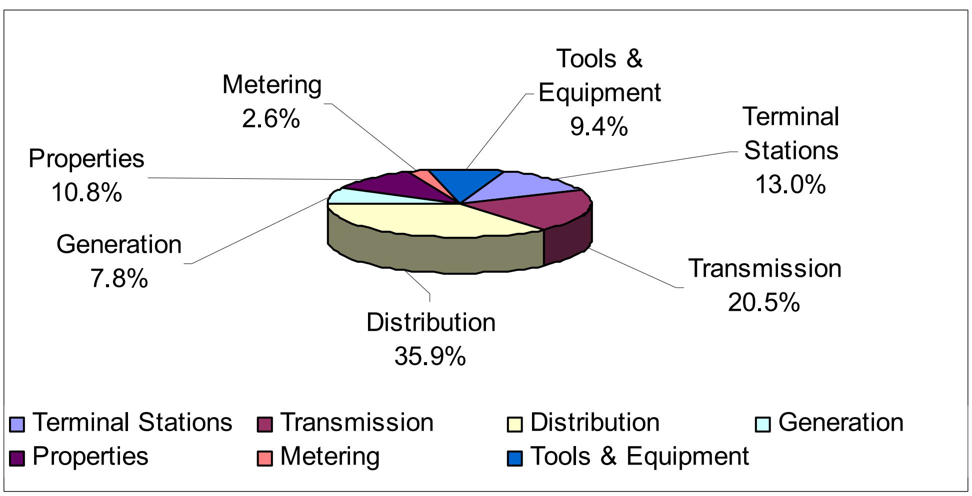
TRANSMISSION AND RURAL OPERATIONS ASSETS

Hydro owns and operates thermal generation with 39 MW of net capacity on the Labrador Interconnected system and owns and operates diesel generation assets with 29 MW net capacity in the 21 isolated rural systems. On the Island Interconnected System, Hydro also owns and operates 3,473 km of transmission lines and 54 high voltage terminal stations operating at voltages of 230, 138 and 69 kV. On the Labrador Interconnected system, Hydro owns and maintains 269 km of 138 kV transmission line and the associated terminal stations interconnecting Happy Valley/Goose Bay to Churchill Falls. In addition, Hydro owns and operates approximately 3,334 km of distribution lines, principally in rural Newfoundland and Labrador.

Hydro's Transmission and Rural Operations assets are aging, and require regular capital expenditures to maintain reliable service, to comply with environmental guidelines, and to ensure the safety of employees, contractors, and the general public.

The division of the 2008 Capital Budget for Transmission and Rural Operations is shown in the chart below.

Chart 3: 2008 Capital Budget - Transmission and Rural Operations



Terminal Stations and Transmission

Many of Hydro's transmission lines were constructed in the 1960s. Because the expected useful lives of transmission assets are typically in the 40-year range, ongoing reconstruction and general upgrades are needed to ensure that Hydro can continue to provide our customers with an acceptable level of reliability.

The terminal station and transmission lines proposals include upgrades to the Corner Brook Frequency converter and ongoing and routine projects such as:

- replacing battery banks and chargers at various stations;
- replacing disconnects in Cow Head and Daniels Harbour;
- upgrading circuit breakers at various stations;
- ongoing wood pole line management; and
- replacing insulators in various locations.

Distribution and Diesel Generation

The 21 remote electrical systems along the coasts of Labrador and the Island are served by diesel generation. Providing service to customers in these communities requires that the fuel storage, diesel generating units and distribution systems all be kept in safe, reliable and environmentally responsible working order. This application includes projects specifically directed towards meeting these requirements.

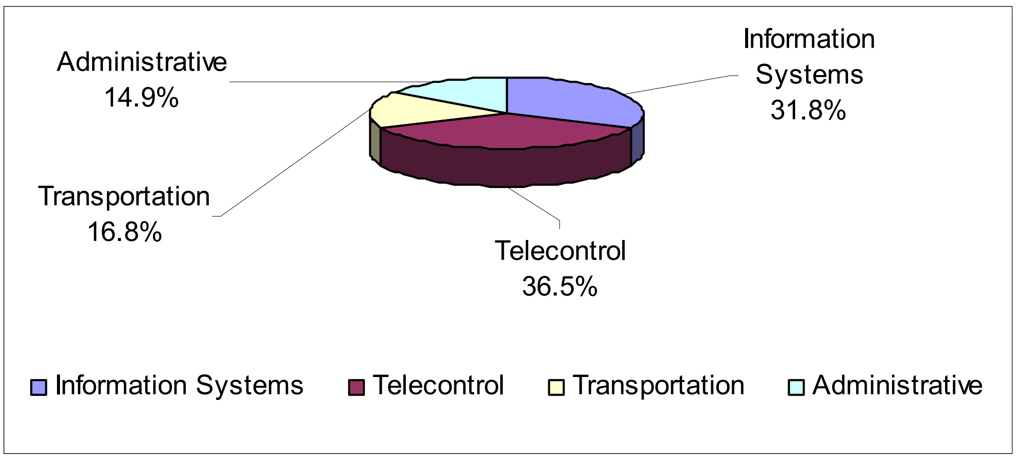
Hydro also provides service to residential and general service customers on the Island Interconnected System. Hydro has included projects in this application that are intended to ensure that distribution lines and equipment that requires replacement due to age are replaced prior to failure. Aside from projects that are designed to ensure reliable service, this application also includes projects to provide service extensions to new customers throughout Hydro's service area.

GENERAL PROPERTIES ASSETS

The General Properties category includes projects related to Hydro's Information Systems, where technology is strategically deployed in a wide variety of business applications. This section of the application also includes proposals for security enhancements, replacement of vehicles and microwave and power line carrier communication facilities, all necessary for the provision of reliable and cost effective service to customers.

Chart 4 shows the breakdown of the General Properties Capital Budget.

Chart 4: Capital Budget - General Properties



Information Systems

The Information Systems proposals include ongoing capital expenditures and are directed towards maintaining Hydro's technological infrastructure ensuring that it remains current and reliable. New infrastructure projects include general application enhancements related to safety and a specific proposal for the provision of an automated work protection code system for Holyrood. Application enhancement projects which utilize technology to ensure the efficiency of the Island Interconnected system are:

- Energy Systems Water Management
- Energy Systems Optimum Powerflow

Telecontrol

Operating an integrated electrical system requires reliable communication systems among Hydro's facilities and employees operating across the system. The 2008 capital budget proposals in this category are primarily infrastructure replacements, and in some cases ongoing replacement or refurbishing programs, for such items as:

- replacing the Holyrood Public Address System;
- replacing the Customer Service Application;
- replacing Power Line Carrier on TL 212 - Sunnyside to Paradise River;
- replacing Remote Terminal Units at Multiple Sites;
- refurbishing Microwave Sites;
- replacing the Dial Backup System;
- installing a Recloser Remote Control at Change Islands; and
- replacing Radomes at Multiple Sites.

In summary, Hydro's Capital Budget Application for 2008 contains various projects designed to provide cost effective and reliable power and energy to the residents and businesses of the province while ensuring employee and public safety and enabling Hydro to fulfill its environmental obligations.

Section A

	Expended to 2007	2008	Future Years	Total
		($000)		
GENERATION	0	8,171	1,183	9,354
TRANSMISSION AND RURAL OPERATIONS	665	25,051	4,569	30,285
GENERAL PROPERTIES	0	10,838	535	11,373
CONTINGENCY FUND		1,000	0	1,000
TOTAL CAPITAL BUDGET	665	45,061	6,287	52,013

	Expended to 2007	2008	2009	Total
		($000)		
GENERATION				
Hydraulic Plant	0	3,974	177	4,151
Thermal Plant	0	3,461	1,006	4,467
Gas Turbines	0	31	0	31
Tools and Equipment	0	705	0	705
TOTAL GENERATION	0	8,171	1,183	9,354
TRANSMISSION & RURAL OPERATIONS				
Terminal Stations	665	3,246	0	3,911
Transmission	0	5,137	2,122	7,259
Distribution	0	8,986	0	8,986
Generation	0	1,956	2,063	4,019
Properties	0	2,714	384	3,098
Metering	0	659	0	659
Tools and Equipment	0	2,353	0	2,353
TOTAL TRANSMISSION & RURAL OPERATIONS	665	25,051	4,569	30,285
GENERAL PROPERTIES				
Information Systems	0	3,444	0	3,444
Telecontrol	0	3,956	182	4,138
Transportation	0	1,826	0	1,826
Administrative	0	1,612	353	1,965
TOTAL GENERAL PROPERTIES	0	10,838	535	11,373
CONTINGENCY FUND		1,000		1,000
TOTAL CAPITAL BUDGET	665	45,061	6,287	52,013

PROJECT DESCRIPTION	Expended to 2007	2008	2009	Total	In-Ser Date	Page Ref
			($000)			
HYDRAULIC PLANT						
Upgrade Spherical Valve Maintenance Seals - Cat Arm		1,060		1,060	Oct. 08	B-5
Replace Governor Controls Unit 2 - Cat Arm		975	74	1,049	Feb. 09	B-7
Arc Flash Analysis - Various Sites		342		342	Dec. 08	B-9
Replace Cooling Water Systems Units 1 and 2 - Bay d'Espoir		264		264	Oct. 08	B-10
Replace 40 kW Diesel Generator - Burnt Dam		157	103	260	Apr. 09	B-14
Install Meteorological Stations - Various Sites		222		222	Oct. 08	B-16
Hydraulic Structure Life Study - Bay d'Espoir		196		196	Nov. 09	B-18
Replace Cooling Water Piping System - Hinds Lake		193		193	Nov. 08	B-20
Salmon Spillway Stoplog Handling System		141		141	Sep. 08	B-23
Upgrade Intake #4 Gate Controls - Bay d'Espoir		116		116	Dec. 08	B-25
Replace Back-Up Air Dryer - Bay d'Espoir		73		73	Jun. 08	B-27
Replace Communications Room Air Conditioner - Bay d'Espoir		64		64	Jun. 08	B-28
Upgrade Access Trail - Venam's Bight		64		64	Sep. 08	B-30
Replace Fire Alarm System - Cat Arm		54		54	Dec. 08	B-32
Replace Auxiliary Service Water Pump - Cat Arm		53		53	Nov. 08	B-34
TOTAL HYDRAULIC PLANT	0	3,974	177	4,151		
THERMAL PLANT						
Tank Farm Upgrade		500		500	Dec. 09	B-36
Replace Unit 2 High Pressure Heater		20	919	939	Sep. 09	B-38
Upgrade Continuous Emissions Monitoring System		689		689	Aug. 08	B-39
Replace Unit 1 and 2 Condenser Valve Actuators		313		313	Oct. 08	B-41
Replace Unit 2 Electromechanical Trip Device		305		305	Dec. 08	B-43
Precipitator and Scrubber Installation Study		272		272	Nov. 08	B-46
Replace 4160 Volt Motor Relays		172		172	Oct. 08	B-48
Replace Unit 2 Main Steam Stop Valve		171		171	Oct. 08	B-50
Environmental Effects Monitoring Study of Waste Water		73	87	160	Jul. 08	B-52
Upgrade Ambient Monitoring Station		128		128	Jul. 08	B-54
Soot Blowing Controls Study		123		123	Nov. 08	B-55
Stack Breeching Study		115		115	Nov. 08	B-56
Install Safety Egress Lighting		97		97	Dec. 08	B-58
Auto Synchronizing Units 1 and 2		93		93	Nov. 08	B-59
Install Stator Ground Fault Protection		85		85	Nov. 08	B-61
Upgrade Meteorological Station		75		75	Jul. 08	B-63
Construct Beta Attenuation Meter (BAM) Unit Enclosure		60		60	Sep. 08	B-65
Programmable Logic Controller Replacement Study		58		58	Jun. 08	B-66
Motor Control Centres Assessment		43		43	Dec. 08	
Install UV Domestic Water Treatment		36		36	Oct. 08	
Jetty Building Ventilation		33		33	Oct. 08	
TOTAL THERMAL PLANT	0	3,461	1,006	4,467		

PROJECT DESCRIPTION	Expended to 2007	2008	2009	Total	In-Ser Date	Page Ref
			($000)			
GAS TURBINES						
Gas Turbine Electrical Assessment - Holyrood		31		31	Dec. 08	
TOTAL GAS TURBINE PLANTS	0	31	0	31		
TOOLS AND EQUIPMENT						
Replace Champion Grader V-9797 - Bay d'Espoir		404		404	Jun. 08	B-68
Purchase Grounding Trucks		61		61	Oct. 08	B-70
Purchase Tools and Equipment Less than $ 50,000	0	240		240		
TOTAL TOOLS AND EQUIPMENT	0	705	0	705		
TOTAL GENERATION	0	8,171	1,183	9,354		

PROJECT DESCRIPTION	Expended to 2007	2008	2009	Total	In-Ser Date	Page Ref
			($000)			
TERMINAL STATIONS						
Purchase Spare Transformer - Upper Salmon	665	1,552		2,217	Oct. 08	B-222
Replace Battery Banks and Chargers - Various Stations		430		430	Nov. 08	B-71
Replace Disconnect Switches - Cow Head and Daniel's Harbour		368		368	Oct. 08	B-73
Upgrade Circuit Breakers - Various Stations		315		315	Nov. 08	B-74
Replace Digital Fault Recorder - Buchans		130		130	Oct. 08	B-75
Replace Compressors - Buchans		94		94	Oct. 08	B-76
Replace Instrument Transformers - Various Stations		74		74	Nov. 08	B-78
Replace Surge Arrestors - Various Stations		67		67	Nov. 08	B-80
Upgrade Station Services - Hardwoods		59		59	Aug. 08	B-82
On-Line Dewpoint Monitoring - Bay d'Espoir		38		38	Oct. 08	
Replace Control Building Roof - Doyles		34		34	Aug. 08	
Secondary Air Line for Switchgear - Cat Arm		33		33	Nov. 08	
Replace Breaker Control Panels - Western Avalon		32		32	Oct. 08	
Replace Equipment Concrete Foundation - Stoney Brook		20		20	Oct. 08	
TOTAL TERMINAL STATIONS	665	3,246	0	3,911		
TRANSMISSION						
Wood Pole Line Management Program		2,188		2,188	Dec. 08	B-83
Replace Insulators TL-232 and TL-253		848	970	1,818	Dec. 09	B-85
Upgrade Corner Brook Frequency Converter		495	1,152	1,647	Dec. 09	B-87
Replace Line Camp 98 - TL-228		500		500	Nov. 08	B-89
Upgrade Line TL-212 - (Sunnyside to Linton Lake)		464		464	Nov. 08	B-92
Construct Transmission Line Equipment Off-Loading Areas		302		302	Oct. 08	B-93
Replace Insulators - Various Stations		294		294	Oct. 08	B-96
Install Remote Ice Growth Detection Beam - Various Stations		46		46	Dec. 08	
TOTAL TRANSMISSION	0	5,137	2,122	7,259		
DISTRIBUTION						
Upgrade Distribution Systems - Various Systems		2,727		2,727	Oct. 08	B-98
Upgrade Distribution Systems - All Service Areas		2,293		2,293	Dec. 08	B-101
Provide Service Extensions - All Service Areas		2,158		2,158	Dec. 08	B-103
Replace Poles - South Brook and Bay d'Espoir		700		700	Oct. 08	B-105
Replace Insulators - Various Systems		623		623	Oct. 08	B-107
Replace Recloser Control Panels - Various Systems		223		223	Nov. 08	B-109
Reconfigure Feeders - Happy Valley		151		151	Oct. 08	B-112
Replace Submarine Cable Terminator - Gaultois		64		64	Sep. 08	B-116
Recloser Assessment - Happy Valley		47		47	Dec. 08	
TOTAL DISTRIBUTION	0	8,986	0	8,986		

PROJECT DESCRIPTION	Expended to 2007	2008	2009	Total	In-Ser Date	Page Ref
			($000)			
GENERATION						
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle		335	938	1,273	Oct. 09	B-117
Diesel Plant Automation - Makkovik and Rigolet		516	379	895	Oct. 09	B-120
Increase Generation Capacity - Charlottetown		18	577	595	Oct. 09	B-122
Replace Switchgear - Cartwright		383	169	552	Jul. 09	B-125
Replace Mufflers - L'Anse au Loup and St. Anthony		479		479	Nov. 08	B-128
Replace Underground Fuel Lines - Little Bay Islands and Grey River		89		89	Aug. 08	B-132
Replace Meter House Equipment - Various Sites		75		75	Nov. 08	B-133
Install Day Tank and Meter - Hopedale		61		61	Jul. 08	B-134
TOTAL GENERATION	0	1,956	2,063	4,019		
PROPERTIES						
Construct New Office,Warehouse,Line Depot Facilities - Happy Valley		1,248	384	1,632	Jul. 09	B-135
Construct Bushing Storage Building - Bishop's Falls		335		335	Sep. 08	B-136
Upgrade Ventilation System - Makkovik		217		217	Sep. 08	B-138
Construct Diesel Plant Extension - William's Harbour		177		177	Oct. 08	B-140
Replace Fire Alarm System - Hopedale and Paradise River		168		168	Dec. 08	B-142
Install Storage Ramp - Holyrood and Port Saunders		135		135	Sep. 08	B-144
Install Chain Link Fencing - Port Hope Simpson		84		84	Oct. 08	B-145
Upgrade Parking Lot - Whitbourne		67		67	Oct. 08	B-147
Install Waste Oil Storage Tank - Cartwright		53		53	Nov. 08	B-149
Survey of Hydro's Primary Right of Ways - Various Sites		52		52	Oct. 08	B-151
Install Waste Oil Storage Tank - L'Anse au Loup		46		46	Dec. 08	
Construct Lube Oil Storage Ramps - Various Sites		44		44	Oct. 08	
Install Pole Storage Ramp - Burgeo		43		43	Aug. 08	
Construct Storage Shed - Paradise River		30		30	Oct. 08	
Install Transformer Storage Ramp - Port Saunders		15		15	Oct. 08	
TOTAL PROPERTIES	0	2,714	384	3,098		
METERING						
Install Automatic Meter Reading - Various Systems		567		567	Oct. 08	B-153
Purchase Meters and Equipment		67		67	Dec. 08	B-156
Purchase Metering Spares		25		25	Dec. 08	
TOTAL METERING	0	659	0	659		

PROJECT DESCRIPTION	Expended to 2007	2008	2009	Total	In-Ser Date	Page Ref
			($000)			
TOOLS & EQUIPMENT						
Replace Off Road Track Vehicles - Bishop's Falls and Whitbourne		746		746	Dec. 08	B-158
Replace Light Duty Mobile Equipment Less than $ 50,000		588		588	Dec. 08	B-160
Installation of Fall Arrest Equipment - Various Sites		405		405	Oct. 08	B-162
Replace Boom 6069 on Track Vehicle - Stephenville		236		236	Dec. 08	B-164
Purchase and Replace Tools and Equipment Less than $ 50,000		263		263		
Purchase Hydraulic Cutters and Presses - Various Sites		66		66	May. 08	B-165
Purchase Forklift for Salvage Stores - Bishop's Falls		49		49	Jun. 09	
TOTAL TOOLS AND EQUIPMENT	0	2,353	0	2,353		
TOTAL TRANSMISSION AND RURAL OPERATIONS	665	25,051	4,569	30,285		

PROJECT DESCRIPTION	Expended to 2007	2008	2009	Total	In-Ser Date	Page Ref
			($000)			
INFORMATION SYSTEMS						
SOFTWARE APPLICATIONS						
New Infrastructure						
Application Enhancements - Work Protection Code		678		678	Oct. 08	B-166
Application Enhancements - Energy Systems Water Management		651		651	Dec. 08	B-168
Application Enhancements - Corporate Systems		373		373	Dec. 08	B-170
Cost Recovery CF(L)Co		(75)		(75)		
Application Enhancements - Energy Systems Optimum Powerflow		216		216	Dec. 08	B-173
Upgrade of Technology						
Corporate Application Environment		331		331	Oct. 08	B-175
Cost Recovery CF(L)Co		(41)		(41)		
TOTAL SOFTWARE APPLICATIONS	0	2,133	0	2,133		
COMPUTER OPERATIONS						
Infrastructure Replacement						
End User Evergreening Program		451		451	Dec. 08	B-178
Upgrade Enterprise Storage Capacity		327		327	Oct. 08	B-181
Cost Recovery CF(L)Co		(65)		(65)		
New Infrastructure						
Replace Peripheral Infrastructure		159		159	Oct. 08	B-183
Video Conferencing		140		140	Dec. 08	B-185
Security Configuration Auditing		72		72	Dec. 08	B-187
Cost Recovery CF(L)Co		(14)		(14)		
Upgrade of Technology						
Server Technology Program - 2008		241		241	Nov. 08	B-189
TOTAL COMPUTER OPERATIONS	0	1,311	0	1,311		
TOTAL INFORMATION SYSTEMS	0	3,444	0	3,444		

PROJECT DESCRIPTION	Expended to 2007	2008	2009	Total	In-Ser Date	Page Ref
			($000)			
TELECONTROL						
NETWORK SERVICES						
Infrastructure Replacement						
Public Address System - Holyrood		1,139		1,139	Dec. 08	B-192
Customer Service Application - Hydro Place		768	182	950	Mar. 09	B-193
Replace Power Line Carrier TL-212 - Sunnyside to Paradise River		466		466	Dec. 08	B-195
Replace Remote Terminal Units - Various Sites		319		319	Dec. 08	B-197
Refurbish Microwave Site - Gull Pond Hill		202		202	Dec. 08	B-199
Replace Dial Backup System - Various Sites		201		201	Dec. 08	B-201
Install Recloser Remote Control - Change Islands		194		194	Nov. 08	B-202
Replace Radomes - Various Sites		124		124	Oct. 08	B-204
Network Infrastructure						
Replace Network Communications Equipment - Various Sites		131		131	Dec. 08	B-205
Test Equipment - Hydro Place and Deer Lake		49		49	Aug. 08	
Wireless Networking - Various Sites		46		46	Oct. 08	
Upgrade of Technology						
Voice Communications Strategy Study - Hydro Place		190		190	Dec. 08	B-207
Replace Network Management Tools - Hydro Place		81		81	Oct. 08	B-209
Upgrade Site Facilities - Various Sites		46		46	Dec. 08	
TOTAL TELECONTROL	0	3,956	182	4,138		
TRANSPORTATION						
Replace Vehicles and Aerial Devices - Various Sites		1,826		1,826	Dec. 08	B-210
TOTAL TRANSPORTATION	0	1,826	0	1,826		
ADMINISTRATION						
Upgrade System Security - Various Sites		906		906	Dec. 09	B-212
Purchase Spare Transformer - Hydro Place		87	353	440	Oct. 09	B-214
Install Computer Room Inergen Fire Protection System - Hydro Place		116		116	Jun. 08	B-216
Safety Hazards Removal - Various Sites		252		252	Dec. 08	B-217
Purchase Office Equip Less than $50,000 - Hydro Place		137		137		
Replace Humidifiers in Air Handling Units - Hydro Place		58		58	Jun. 08	B-219
Replace Air Conditioning Units - Hydro Place		56		56	Jun. 08	B-220
TOTAL ADMINISTRATION	0	1,612	353	1,965		
TOTAL GENERAL PROPERTIES	0	10,838	535	11,373		

Section B

	Expended to 2007	2008	Future Years	Total
		($000)		
GENERATION	0	7,788	1,183	8,971
TRANSMISSION AND RURAL OPERATIONS	665	23,698	4,569	28,932
GENERAL PROPERTIES	0	10,561	535	11,096
CONTINGENCY FUND		1,000		1,000
TOTAL CAPITAL BUDGET	665	43,047	6,287	49,999

PROJECT DESCRIPTION	Expended to 2007	2008	2009	Total	In-Ser Date	Page Ref
			($000)			
Upgrade Spherical Valve Maintenance Seals - Cat Arm		1,060		1,060	Oct. 08	B-5
Replace Governor Controls Unit 2 - Cat Arm		975	74	1,049	Feb. 09	B-7
Arc Flash Analysis - Various Sites		342		342	Dec. 08	B-9
Replace Cooling Water Systems Units 1 and 2 - Bay d'Espoir		264		264	Oct. 08	B-10
Replace 40 kW Diesel Generator - Burnt Dam		157	103	260	Apr. 09	B-14
Install Meteorological Stations - Various Sites		222		222	Oct. 08	B-16
Hydraulic Structure Life Study - Bay d'Espoir		196		196	Nov. 09	B-18
Replace Cooling Water Piping System - Hinds Lake		193		193	Nov. 08	B-20
Salmon Spillway Stoplog Handling System		141		141	Sep. 08	B-23
Upgrade Intake #4 Gate Controls - Bay d'Espoir		116		116	Dec. 08	B-25
Replace Back-Up Air Dryer - Bay d'Espoir		73		73	Jun. 08	B-27
Replace Communications Room Air Conditioner - Bay d'Espoir		64		64	Jun. 08	B-28
Upgrade Access Trail - Venam's Bight		64		64	Sep. 08	B-30
Replace Fire Alarm System - Cat Arm		54		54	Dec. 08	B-32
Replace Auxiliary Service Water Pump - Cat Arm		53		53	Nov. 08	B-34
Tank Farm Upgrade		500		500	Dec. 09	B-36
Replace Unit 2 High Pressure Heater		20	919	939	Sep. 09	B-38
Upgrade Continuous Emissions Monitoring System		689		689	Aug. 08	B-39
Replace Unit 1 and 2 Condenser Valve Actuators		313		313	Oct. 08	B-41
Replace Unit 2 Electromechanical Trip Device		305		305	Dec. 08	B-43
Precipitator and Scrubber Installation Study		272		272	Nov. 08	B-46
Replace 4160 Volt Motor Relays		172		172	Oct. 08	B-48
Replace Unit 2 Main Steam Stop Valve		171		171	Oct. 08	B-50
Environmental Effects Monitoring Study of Waste Water		73	87	160	Jul. 08	B-52
Upgrade Ambient Monitoring Station		128		128	Jul. 08	B-54
Soot Blowing Controls Study		123		123	Nov. 08	B-55
Stack Breeching Study		115		115	Nov. 08	B-56
Install Safety Egress Lighting		97		97	Dec. 08	B-58
Auto Synchronizing Units 1 and 2		93		93	Nov. 08	B-59
Install Stator Ground Fault Protection		85		85	Nov. 08	B-61
Upgrade Meteorological Station		75		75	Jul. 08	B-63
Construct Beta Attenuation Meter (BAM) Unit Enclosure		60		60	Sep. 08	B-65
Programmable Logic Controller Replacement Study		58		58	Jun. 08	B-66
Replace Champion Grader V-9797 - Bay d'Espoir		404		404	Jun. 08	B-68
Purchase Grounding Trucks		61		61	Oct. 08	B-70
TOTAL GENERATION	0	7,788	1,183	8,971		

PROJECT DESCRIPTION	Expended to 2007	2008	2009	Total	In-Ser Date	Page Ref
				($000)		
Purchase Spare Transformer - Upper Salmon	665	1,552		2,217	Oct. 08	B-222
Replace Battery Banks and Chargers - Various Stations		430		430	Nov. 08	B-71
Replace Disconnect Switches - Cow Head and Daniel's Harbour		368		368	Oct. 08	B-73
Upgrade Circuit Breakers - Various Stations		315		315	Nov. 08	B-74
Replace Digital Fault Recorder - Buchans		130		130	Oct. 08	B-75
Replace Compressors - Buchans		94		94	Oct. 08	B-76
Replace Instrument Transformers - Various Stations		74		74	Nov. 08	B-78
Replace Surge Arrestors - Various Stations		67		67	Nov. 08	B-80
Upgrade Station Services - Hardwoods		59		59	Aug. 08	B-82
Wood Pole Line Management Program		2,188		2,188	Dec. 08	B-83
Replace Insulators TL-232 and TL-253		848	970	1,818	Dec. 09	B-85
Upgrade Corner Brook Frequency Converter		495	1,152	1,647	Dec. 09	B-87
Replace Line Camp 98 - TL-228		500		500	Nov. 08	B-89
Upgrade Line TL-212 - (Sunnyside to Linton Lake)		464		464	Nov. 08	B-92
Construct Transmission Line Equipment Off-Loading Areas		302		302	Oct. 08	B-93
Replace Insulators - Various Stations		294		294	Oct. 08	B-96
Upgrade Distribution Systems - Various Systems		2,727		2,727	Oct. 08	B-98
Upgrade Distribution Systems - All Service Areas		2,293		2,293	Dec. 08	B-101
Provide Service Extensions - All Service Areas		2,158		2,158	Dec. 08	B-103
Replace Poles - South Brook and Bay d'Espoir		700		700	Oct. 08	B-105
Replace Insulators - Various Systems		623		623	Oct. 08	B-107
Replace Recloser Control Panels - Various Systems		223		223	Nov. 08	B-109
Reconfigure Feeders - Happy Valley		151		151	Oct. 08	B-112
Replace Submarine Cable Terminator - Gaultois		64		64	Sep. 08	B-116
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle		335	938	1,273	Oct. 09	B-117
Diesel Plant Automation - Makkovik and Rigolet		516	379	895	Oct. 09	B-120
Increase Generation Capacity - Charlottetown		18	577	595	Oct. 09	B-122
Replace Switchgear - Cartwright		383	169	552	Jul. 09	B-125
Replace Mufflers - L'Anse au Loup and St. Anthony		479		479	Nov. 08	B-128
Replace Underground Fuel Lines - Little Bay Islands and Grey River		89		89	Aug. 08	B-132
Replace Meter House Equipment - Various Sites		75		75	Nov. 08	B-133
Install Day Tank and Meter - Hopedale		61		61	Jul. 08	B-134
Construct New Office,Warehouse,Line Depot Facilities - Happy Valley		1,248	384	1,632	Jul. 09	B-135
Construct Bushing Storage Building - Bishop's Falls		335		335	Sep. 08	B-136
Upgrade Ventilation System - Makkovik		217		217	Sep. 08	B-138
Construct Diesel Plant Extension - William's Harbour		177		177	Oct. 08	B-140
Replace Fire Alarm System - Hopedale and Paradise River		168		168	Dec. 08	B-142
Install Storage Ramp - Holyrood and Port Saunders		135		135	Sep. 08	B-144
Install Chain Link Fencing - Port Hope Simpson		84		84	Oct. 08	B-145
Upgrade Parking Lot - Whitbourne		67		67	Oct. 08	B-147
Install Waste Oil Storage Tank - Cartwright		53		53	Nov. 08	B-149
Survey of Hydro's Primary Right of Ways - Various Sites		52		52	Oct. 08	B-151
Install Automatic Meter Reading - Various Systems		567		567	Oct. 08	B-153
Purchase Meters and Equipment		67		67	Dec. 08	B-156
Replace Off Road Track Vehicles - Bishop's Falls and Whitbourne		746		746	Dec. 08	B-158
Installation of Fall Arrest Equipment - Various Sites		405		405	Oct. 08	B-162
Replace Boom 6069 on Track Vehicle - Stephenville		236		236	Dec. 08	B-164
Purchase Hydraulic Cutters and Presses - Various Sites		66		66	May. 08	B-165
TOTAL TRANSMISSION AND RURAL OPERATIONS	665	23,698	4,569	28,932		

PROJECT DESCRIPTION	Expended to 2007	2008	2009	Total	In-Ser Date	Page Ref
				($000)		
Application Enhancements - Work Protection Code		678		678	Oct. 08	B-166
Application Enhancements - Energy Systems Water Management		651		651	Dec. 08	B-168
Application Enhancements - Corporate Systems		373		373	Dec. 08	B-170
Cost Recovery CF(L)Co		(75)		(75)		
Application Enhancement - Energy Systems Optimum Powerflow		216		216	Dec. 08	B-173
Corporate Application Environment		331		331	Oct. 08	B-175
Cost Recovery CF(L)Co		(41)		(41)		
End User Evergreening Program		451		451	Dec. 08	B-178
Upgrade Enterprise Storage Capacity		327		327	Oct. 08	B-181
Cost Recovery CF(L)Co		(65)		(65)		
Replace Peripheral Infrastructure		159		159	Oct. 08	B-183
Video Conferencing		140		140	Dec. 08	B-185
Security Configuration Auditing		72		72	Dec. 08	B-187
Cost Recovery CF(L)Co		(14)		(14)		
Server Technology Program - 2008		241		241	Nov. 08	B-189
Public Address System - Holyrood		1,139		1,139	Dec. 08	B-192
Customer Service Application - Hydro Place		768	182	950	Mar. 09	B-193
Replace Power Line Carrier TL-212 - Sunnyside to Paradise River		466		466	Dec. 08	B-195
Replace Remote Terminal Units - Various Sites		319		319	Dec. 08	B-197
Microwave Site Refurbishing - Gull Pond Hill		202		202	Dec. 08	B-199
Replace Dial Backup System - Various Sites		201		201	Dec. 08	B-201
Install Recloser Remote Control - Change Islands		194		194	Nov. 08	B-202
Replace Radomes - Various Sites		124		124	Oct. 08	B-204
Replace Network Communications Equipment - Various Sites		131		131	Dec. 08	B-205
Voice Communications Strategy Study - Hydro Place		190		190	Dec. 08	B-207
Replace Network Management Tools - Hydro Place		81		81	Oct. 08	B-209
Replace Vehicles and Aerial Devices - Various Sites		1,826		1,826	Dec. 08	B-210
Upgrade System Security - Various Sites		906		906	Dec. 09	B-212
Purchase Spare Transformer - Hydro Place		87	353	440	Oct. 09	B-214
Install Computer Room Inergen Fire Protection System - Hydro Place		116		116	Jun. 08	B-216
Safety Hazards Removal - Various Sites		252		252	Dec. 08	B-217
Replace Humidifiers in Air Handling Units - Hydro Place		58		58	Jun. 08	B-219
Replace Air Conditioning Units - Hydro Place		56		56	Jun. 08	B-220
TOTAL GENERAL PROPERTIES	0	10,561	535	11,096		

Project Title: Upgrade Spherical Valve Maintenance Seals

Location: Cat Arm

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This work includes the retrofit of two spherical valve-maintenance seals with new seals and a new operating mechanism. This involves dewatering the power tunnel, removing both spherical valves, shipping them out of province for machining and retrofitting with a new sliding seal design, testing of seals, and finally returning them to Cat Arm. Machining of the spherical valves cannot be performed on the island of Newfoundland because of their size.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	86.5	0.0	0.0	86.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	787.0	0.0	0.0	787.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	98.9	0.0	0.0	98.9
Contingency	87.3	0.0	0.0	87.3
Total	1,059.7	0.0	0.0	1,059.7

Operating Experience:

The spherical valve maintenance seals provide worker isolation from the penstock pressure of 550 psi during maintenance of equipment within the distributor including governing needles and cables, valves and other parts. Once either of the 1500 mm-diameter spherical valves is in the closed position, water pressure from the penstock is used to apply a flexible stainless steel sealing ring to keep water from entering the downstream water passage.

The power tunnel has been dewatered twice in the last eight years because the spherical valves were unable to provide adequate isolation. A third dewatering will be required to perform further work on the seals. There have been problems with the seals since commissioning, at which time a pump was installed on one spherical valve just to provide enough pressure to apply the seal, as penstock water pressure alone did not work as designed. As use of an electro-mechanical device

Project Title: Upgrade Spherical Valve Maintenance Seals **(cont'd.)**

Operating Experience: (cont'd.)

(the pump) to provide worker protection is unacceptable from a worker safety perspective, modifications were made to the seals in 1999 resulting in the seals being made operational as designed and without the pump. However, periodic high leakage rates for both valves since that time have resulted in further seal replacements in 2006. These rates vary between 9 litres per minute to 120 litres per minute, while some leakages were too high to measure. An acceptable leakage rate based on original commissioning is 0.6 litres per minute.

Project Justification:

Workers who perform maintenance on systems that require the spherical valves for isolation must be confident that the seals are working as required. There is no way of verifying that the seals are applied except through measurement of leakage rates across the seals. Spherical valves elsewhere in the Hydro system use a sliding seal design, instead of a flex-type, thus allowing workers to visually verify that the seal is applied and ensures predictable sealing.

The existing Cat Arm spherical valves do not provide a safe means of isolating the penstock for work downstream, as a result of the unreliable and unpredictable operation of the seal mechanism. As a result the power tunnel must be dewatered to perform even small maintenance tasks on either of the units, defeating the purpose of having spherical valves. The potential for serious power tunnel damage is high as a result of geotechnical concerns during the dewatering process so dewatering should be avoided except in emergencies. The dewatering process also results in nine days of unit unavailability and thus lost production. In addition, the original manufacturer of the valves, VA Tech Hydro (formerly Sulzer Escher Weiss) has been performing retrofits of their maintenance seals of the same design and vintage with sliding-type seals in locations all over the world, as a result of similar sealing safety issues.

Future Plans:

None.

Project Title: Replace Governor Controls Unit 2

Location: Cat Arm

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project involves the purchase and installation of governor controls and feedback devices on the second unit at Cat Arm. The new controls will be a modern design fully supported by the manufacturer. The project includes the replacement of the needle and deflector feedback devices and the needle and the deflector servovalves.

The existing governor controls are a Sulzer Escher Wyss (now VATECH Hydro) type for which support was terminated at the end of 2004. The governor controls on Unit 1 were replaced in October, 2006.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	52.0	0.0	0.0	52.0
Labour	297.7	10.0	0.0	307.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	492.0	0.0	0.0	492.0
Other Direct Costs	34.8	0.0	0.0	34.8
O/H, AFUDC & Escalation	98.2	17.6	0.0	115.8
Contingency	0.0	46.3	0.0	46.3
Total	974.7	73.9	0.0	1,048.6

Operating Experience:

The current controls are part of the original governor system and have been in service since 1985 when the unit was first commissioned. These controls are in operation whenever the generating unit is in service.

From January 1990 to March 2005 there were eight card and three power supply failures on the governor controls for both units. This depleted the inventory stock of EMS-12 cards. VATECH Hydro was able to supply two used EMS-12 and two used EMS-11 cards in 2005 which were tested in the governor and found to work satisfactorily. During the period April 2005 to March 2007, there has been one card replacement and two card recalibrations. In April 2007, VATECH Hydro

Project Title: Replace Governor Controls Unit 2 **(cont'd.)**

Operating Experience: (cont'd.)

provided a list of available cards which included only six of the 24 cards that make up the governor controls. EMS-12 and EMS-11 are among the cards that are no longer available. To date, efforts to source a replacement needle selector switch have been unsuccessful.

The budget for the same governor controls replacement project (excluding the kidney loop filtration system) on Unit 1 in 2006 was $895,200. The actual cost of that project was $897,513.

Project Justification:

This project is necessary as it is for the normal replacement of equipment that has reached the end of its useful life. The existing governor controls are no longer supported by the manufacturer. Card failures in 2005 reduced the inventory stock of the EMS-12 cards to zero. Hydro has been successful in obtaining two used EMS-12 cards and placed them in inventory, however, the reliability of these used cards is unknown. Correspondence with VATECH Hydro confirms that the only support they can provide is the supply of the limited cards that are in inventory. Production of cards has stopped, and most critical cards are not available from VATECH Hydro. If the governor controls fail and replacement parts are not available, a five-month unit outage would be required to procure, install and commission new equipment on an emergency basis.

Hydro's System Operations Department conducted a study in 2004 (see Report "Cat Arm Five-Month Outage Impact", Section H, Tab 1) to determine the impact of such a forced outage in terms of energy production costs due to potentially spilled water. This report was prepared for the loss of the exciter on Unit 2 but it is also valid for the governor control failure as the potential outage times are similar.

This report states that with one unit out of production, the probability of spill would be 40% during a winter outage and 46% if the outage occurred in the spring. The report also states that the cost of a spill would be $3.7 million in winter or $2.6 million in spring and that there is no additional probability of spill if the outage were to occur during summer or fall.

Future Plans:

None.

Project Title: Arc Flash Analysis
Location: Various Sites
Category: Generation - Hydraulic
Type: Other
Classification: Mandatory

Project Description:
This project consists of the completion of arc flash studies for 9 hydraulic sites (Bay d'Espoir, Cat Arm, Upper Salmon, Granite Canal, Hinds Lake, Paradise River, Snooks Arm, Venom Bight, and Roddickton), 3 gas turbines (Hardwoods, Stephenville, and Happy Valley), and 24 diesel plants (Black Tickle, Cartwright, Charlottetown, Happy Valley, Hopedale, L'Anse-au-Loup, Makkovik, Mary's Harbour, Mud Lake, Nain, Norman Bay, Paradise River, Port Hope Simpson, Postville, Rigolet, William's Harbour, Francois, Grey River, Hawke's Bay, Little Bay Islands, McCallum, Ramea, St. Anthony, and St. Lewis).

These studies will quantify the maximum arc flash energy present, the arc flash boundary area, and the flash hazard category for 4160 Volt buses and breakers, 600 Volt switchgear and motor control centres, and 600 Volt power panels. This equipment will be labeled in accordance with the requirements of the Canadian Electrical Code (2006), NFPA 70E-2004, ANSI Z535.4-2002 and IEEE 1584-2002. Investigations and recommendations will be made as to what modifications can be made to equipment to reduce the arc flash levels and associated risks to acceptable levels.

The cost estimate for this work is based on the assumption that an arc flash specialist from an independent consulting firm will be available to be assigned to this work full time to complete the studies. Training for Hydro personnel would be provided in conjunction with the completion of the studies for each of the facilities. The software required to calculate the arc flash levels will be purchased as part of this project. In order to complete these studies within the proposed 12 month schedule, it will be necessary to retain the services of more than one specialist or consulting firm. This will permit the analysis of various systems to be done concurrently rather than sequentially.

Project Title: Arc Flash Analysis **(cont'd.)**

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	20.0	0.0	0.0	20.0
Labour	20.0	0.0	0.0	20.0
Consultant	225.0	0.0	0.0	225.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	13.0	0.0	0.0	13.0
O/H, AFUDC & Escalation	36.0	0.0	0.0	36.0
Contingency	27.8	0.0	0.0	27.8
Total	**341.8**	**0.0**	**0.0**	**341.8**

Operating Experience:

At present, electrical equipment is either not labeled or is generically labeled which provides very little information.

Project Justification:

This project is required to quantify the maximum arc flash energy present, the arc flash boundary area, and the flash hazard category for the plant locations and equipment listed above, to protect workers from arc flash thermal hazards during the performance of their duties.

The results of these studies will define either capital upgrades or replacement of equipment necessary to minimize or eliminate the energy release during an arc flash. These upgrades or replacements are as a result of changes in safety legislation, which makes it necessary to take action to control arc flash hazards and provide safe workplace environments.

Future Plans:

The reports resulting from these studies will form the justifications for project proposals in future capital budget applications.

Project Title: Replace Cooling Water Systems Units 1 and 2

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project will involve replacement of the supply and discharge surface air cooler water piping, components, and a strainer. The four inch piping will be replaced with stainless steel sch 10, which is corrosion and fouling resistant (see attached photos). The six inch piping will be replaced with standard mild steel sch 40 pipe. The system will be equipped with Victaulic fittings to allow ease of inspection and maintenance. The strainer will be replaced with a stainless steel manual backwash basket strainer unit.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	103.6	0.0	0.0	103.6
Labour	110.0	0.0	0.0	110.0
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 & Escalation	28.6	0.0	0.0	28.6
Contingency	21.4	0.0	0.0	21.4
Total	**263.6**	**0.0**	**0.0**	**263.6**

Operating Experience:

The existing system is the unit's original surface air cooler water piping system, which consists of four inch and six inch piping, and has been in service since 1966. Since that time no parts have been replaced, only regular corrective and preventive maintenance has been performed. Fouling and corrosion in the pipe has reached a stage where the piping and its components are at the end of their service lives and piping leaks are likely, which affects unit reliability.

Project Justification:

The piping and its components, as confirmed in the preventive maintenance inspections, is extensively fouled and corroded to the extent that the only option is to replace the piping system with new components. This has to be done to avoid forced unit outages/deratings.

Project Title: Replace Cooling Water Systems Units 1 and 2 **(cont'd.)**

Project Justification: (cont'd.)

A cooling water system study was performed in 2002 for all hydro plants. This study concluded that all four inch piping and smaller should be replaced with stainless steel sch ten for corrosion and fouling protection. This would eliminate future maintenance costs of having to clean out piping due to fouling that occurs on average every five years. Over the piping life of 30 years this would mean the piping system would be dismantled, cleaned, and reassembled five times. By switching the piping material from mild steel to stainless steel this corrosion fouling problem will be eliminated which will increase unit reliability and allow labour forces to focus on other work during the maintenance periods.

Future Plans:

None.

Project Title: Replace Cooling Water Systems Units 1 and 2 **(cont'd.)**

A fouled 4-inch section of surface air cooler piping, removed from service in 2006 due to severe corrosion. Picture taken in August 2006.

This is the same 4-inch section of pipe as in picture #1 after it has been cleaned. The corrosion pitting is on the order of 0.080-0.110 inch deep. Picture taken in August 2006.

Project Title: Replace 40 kW Diesel Generator

Location: Burnt Dam

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

Replace the 40 kW diesel generator set (genset) at Burnt Dam with a 50 kW genset. This proposal consolidates all costs associated with replacing the existing 40 kW genset with a new 50 kW genset, exhaust, radiator and switchgear.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	104.5	26.0	0.0	130.5
Labour	34.5	31.5	0.0	66.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	8.0	13.5	0.0	21.5
O/H, AFUDC & Escalation	10.2	10.2	0.0	20.4
Contingency	0.0	21.9	0.0	21.9
Total	**157.2**	**103.1**	**0.0**	**260.3**

Operating Experience:

The diesel plant at Burnt Spillway is equipped with three diesel generator sets: 75 kW, 40 kW and 25 kW. The 75 kW genset is used during winter gate operations when gate heating is required, the 40 kW genset is capable of raising the gate during summer operation and also for campsite loading and the 25 kW genset is used for domestic loading.

The 40 kW diesel generator set was acquired in 1986. The unit must operate at peak capacity to perform gate operations. To date, it has been overhauled five times with the last overhaul five years ago. During the last overhaul, all components were replaced except for crank shaft and cams, gear train and block. If another overhaul is performed, the crank shaft and block must be replaced.

This unit has reached the end of its useful service life. It consumes approximately four litres of base oil per day, however, it should consume less than one litre per day.

Project Title: Replace 40 kW Diesel Generator **(cont'd.)**

Operating Experience: (cont'd.)

The existing exhaust stack and radiator are the same age as the genset. Existing switchgear is obsolete.

Project Justification:

The existing genset meets the replacement criterion of five overhauls. At the next overhaul period, a complete engine rebuild is required, which is comparable in cost to replacement of the engine for this size of genset. Output voltage of the generator is inconsistent, fluctuating between 610 and 565 volts. Repairs have not corrected the problem. It can no longer reliably meet load requirements. The existing control panel is also obsolete.

Future Plans:

None.

Project Title: Install Meteorological Stations

Location: Various Sites

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

Purchase and install meteorological stations at Cat Arm Intake, Cat Arm Reservoir, Ebbegunbaeg Control Structure and Long Pond Intake. All stations will be equipped to provide precipitation data and air temperature. Some stations will also be equipped to provide reservoir elevations and snow pack. The work will also involve identifying the best measurement sites, and identifying the most appropriate means of returning the signal to the Energy Control Centre.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	57.0	0.0	0.0	57.0
Labour	90.0	0.0	0.0	90.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	5.0	0.0	0.0	5.0
Other Direct Costs	27.3	0.0	0.0	27.3
O/H, AFUDC & Escalation	24.9	0.0	0.0	24.9
Contingency	17.9	0.0	0.0	17.9
Total	**222.1**	**0.0**	**0.0**	**222.1**

Operating Experience:

Hydro uses precipitation data as a key input in its production planning and forecasting activity. Hydro has limited meteorological data being collected for some of its reservoirs. In the past decisions to spill would not have been made, if the data to be provided by the proposed stations had been available. This unnecessary water release equates to lost production. Hydro has successfully installed hydro-meteorological stations at Granite Lake, and has established remote water level recording stations at Victoria Lake and the Ebbegunbaeg Canal.

Project Justification:

Hydro operates numerous hydroelectric developments on the island of Newfoundland that are comprised of single reservoirs and in some instances multi reservoir systems. The watersheds associated with these systems are comprised of variable terrain. This, combined with a variable climate that can be characterized as unstable, leads to much uncertainty in predicting inflows to manage these complex reservoir systems.

Project Title: Install Meteorological Stations **(cont'd.)**

Project Justification: (cont'd.)

Reservoir inflows are heavily influenced by snow melt because of their location and as a result, inflows can rise rapidly, sometimes tenfold in very short periods. Poor precipitation and temperature information can make preparations for spring runoff problematic, leading to potentially unnecessary spills.

Hydro has little, and in some cases, no meteorological observations being taken within these watersheds. At some locations, Environment Canada stations are used in an attempt to correlate these readings to predict inflows at Hydro's reservoirs, but this has proven to be extremely inadequate.

Hydro performs snow core sampling throughout the winter to obtain information on how the snow pack changes throughout the season. However, with no observations at higher elevations within the watershed, Hydro has no direct indication as to how snow pack changes after each snow survey. Access to critical information on snow pack change will improve the decision making process and allow opportunities for more sophisticated inflow forecasting.

The installation of automated meteorological stations will allow access to more reliable information which will lead to improved dispatch decisions and a reduction in reliance on Holyrood production. These stations will provide advance notification of heavy precipitation and/or warm temperatures allowing Hydro to react quicker to heavy rainfall or high runoff events, reducing the risk of spilling.

In the first year of this 5 year program, it is proposed to construct the sites at Cat Arm Intake, Cat Arm Reservoir, Ebbegunbaeg Control Structure and Long Pond Intake in Bay d'Espoir as these are the areas most in need of accurate meteorological information.

Future Plans:

Future installations will be proposed in future capital budget applications.

Project Title: Hydraulic Structures Life Study

Location: Bay d'Espoir and Control Structures

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project includes performance of a life expectancy study with regards to the existing mechanical and electrical equipment for Bay d'Espoir spillway, control and intake structures that have been in service since 1967. The structures include:

1. The four Bay d'Espoir intake structures, each with cable-mounted gates located outside;
2. The Victoria control structure, consisting of four screw stem gates located inside a building;
3. The Burnt spillway structure, consisting of two screw stem gates located outside;
4. The Ebbegunbaeg control structure, consisting of three gates: two screw stem and one cable located inside a building; and
5. The Salmon spillway structure, consisting of three screw stem gates located outside.

The study will be performed by a consultant with expertise in these structures and who is able to compare with structures at other utilities with similar service conditions and vintage.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	24.5	0.0	0.0	24.5
Consultant	85.0	0.0	0.0	85.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	51.2	0.0	0.0	51.2
O/H, AFUDC & Escalation	19.2	0.0	0.0	19.2
Contingency	16.1	0.0	0.0	16.1
Total	196.0	0.0	0.0	196.0

Operating Experience:

Equipment of similar vintage and service conditions have shown deteriorated condition due to age and service conditions in structures at Churchill Falls. Replacement of screw stem hoist parts for the Hind's Lake Spillway in 1998 identified that replacement lead times for such parts was in the

Project Title: Hydraulic Structures Life Study **(cont'd.)**

Operating Experience: (cont'd.)

order of six - ten weeks. There is difficulty finding parts for the large electric hoist motors, gear boxes and screw stem hoists for these structures as some manufacturers no longer carry direct replacement parts, while other manufacturers are no longer in business.

Project Justification:

These structures are 40 years old, and although regular maintenance has been performed to keep them operating, an assessment is required to determine their condition and identify a replacement strategy. Many parts are very close to the end of their useful lives and cannot be easily replaced.

Failure of a significant piece of electrical or mechanical equipment at an intake, spillway or control structure, like a hoist gear box or electric motor, would result in production loss for hydro generation that could increase demand from thermal generation and the associated fuel costs. For screw stem hoists that fail with gates in the open position, this would result in spilled water losses, again reducing hydro plant availability and increasing required thermal generation. If failure of a spillway hoist occurs in the closed position there is risk of overtopping and washing out dykes.

Future Plans:

Further capital proposals are expected for these structures in future years following the recommendations of this study.

Project Title: Replace Cooling Water Piping System

Location: Hind's Lake

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project will involve replacement of all turbine/generator cooling water piping inside the generator housing. The piping will be replaced with stainless steel which is corrosion and fouling resistant. The system will also be equipped with Victaulic fittings to allow ease of inspection, installation, and maintenance. The fouled and corroded condition of the piping is shown in the attached photos.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	65.4	0.0	0.0	65.4
Labour	60.0	0.0	0.0	60.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	32.6	0.0	0.0	32.6
O/H, AFUDC & Escalation	19.6	0.0	0.0	19.6
Contingency	15.8	0.0	0.0	15.8
Total	**193.4**	**0.0**	**0.0**	**193.4**

Operating Experience:

This system has been in service since 1980 with no upgrades; only corrective and preventive maintenance have been performed. The heat exchangers, or coolers, and piping have a history of becoming fouled or totally plugged.

The pipe fouling is a result of internal corrosion to the original mild steel pipe. This corrosion gives the organics in the water a solid point of attachment allowing them to build up and reduce the flow of water through the system. As the water flows become reduced, suspended solids in the water drop out and add to the fouling problem. Switching to stainless steel piping will address the pipe fouling problem, which will eliminate the organic build up and avoid unnecessary unit outages/deratings.

Project Title: Replace Cooling Water Piping System **(cont'd.)**

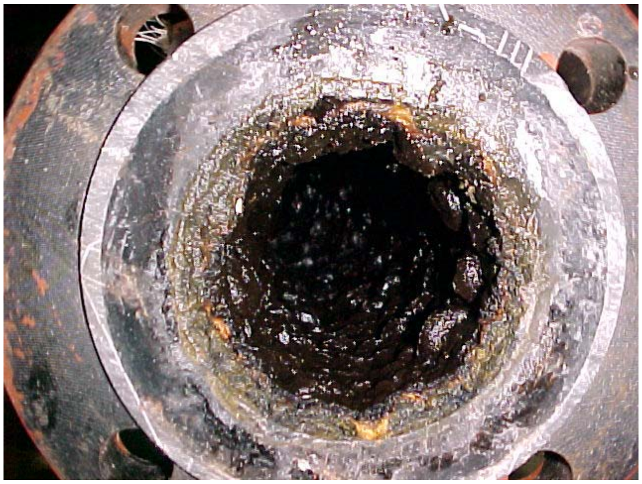
Project Justification:

The piping and its components, as confirmed in preventative maintenance inspections, are extensively fouled and corroded to the extent that they need to be replaced. This needs to be done to prevent forced unit outages or deratings. The cooling water piping and valves are at the end of their service lives and need to be replaced before unit reliability is compromised.

Future Plans:

None.

Project Title: Replace Cooling Water Piping System **(cont'd.)**



Generator Bearing Piping

Surface Air Cooler Piping

Surface Air Cooler Piping

Project Title: Salmon Spillway Stoplog Handling System

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Mandatory

Project Description:

The project generally involves the construction of a structural steel rail and dolly system for storage and handling of the stoplogs. The logs will be positioned on roller dollies which will be winched to a location where they can be picked up by the existing monorail hoist. The system will require site work to provide additional space and concrete foundations for support. The monorail end support will be relocated and one meter added to the monorail beam to provide additional space at the structure.

The stoplogs, each weighing about seven ton, were originally moved to the monorail hoist by a mobile crane which was part of the Bay d'Espoir site equipment. This equipment has been since replaced by conventional boom trucks. Due to the restricted space at the site, the use of boom trucks for handling/moving the stoplogs poses a workplace safety concern.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	23.8	0.0	0.0	23.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	91.3	0.0	0.0	91.3
Other Direct Costs	1.0	0.0	0.0	1.0
O/H, AFUDC & Escalation	13.0	0.0	0.0	13.0
Contingency	11.6	0.0	0.0	11.6
Total	140.6	0.0	0.0	140.6

Operating Experience:

The function of the stoplogs is to provide access to the main spillway gates for servicing, and also for yearly operational testing to ensure gates are available for use when required. The main spillway gates serve to ensure the safety of all dams around the perimeter of Long Pond, some of which are classified as high hazard structures.

Project Title: Salmon Spillway Stoplog Handling System **(cont'd.)**

Project Justification:

Lifting the stoplogs with boom trucks in a restricted space is unsafe due to the number of pinch points and the amount of manual manipulation required. There is high potential for worker injury by falling, pinching and impact. The proposed project will provide a ground-level storage and handling system, eliminating the safety risks associated with boom truck operation.

Future Plans:

None.

Project Title: Upgrade Intake #4 Gate Controls

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

The electrical controls at intake #4 gate will be upgraded to a more reliable system. The new system will use Programmable Logic Controller (PLC) control with a cable reel sensor to precisely control the position of the current intake gate. This system will offer accurate gate position feedback with better maintainability. A redundant penstock-priming device (i.e. rate of fill) will also be employed to ultimately eliminate all safety concerns with filling the penstock after partial or complete dewatering.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	35.0	0.0	0.0	35.0
Labour	55.0	0.0	0.0	55.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	3.0	0.0	0.0	3.0
O/H, AFUDC & Escalation	13.2	0.0	0.0	13.2
Contingency	9.3	0.0	0.0	9.3
Total	**115.5**	**0.0**	**0.0**	**115.5**

Operating Experience:

Intake #4 gate is presently equipped with a single electric hoist, an electromagnetic brake and a mechanical fan brake that is used during the emergency lowering of the intake gate. Hoist operation is achieved through five control pushbuttons and one selector switch for local/remote operation. Five limit switches enable the gate control.

Originally, gate position was determined using two proximity switches mounted directly to the gate or guide interface on the base of the intake gate. This allowed for the gate to stop precisely during a raise command, thereby filling the penstock slowly and thus preventing the formation of a

Project Title: Upgrade Intake #4 Gate Controls **(cont'd.)**

Operating Experience: (cont'd.)
pressure bubble that could rise up through the penstock and ultimately destroy the venthouse and/or injure personnel in the process.

Project Justification:
Proximity switches, currently located underwater, were found to be unreliable. A switch would fail to close for gate position indication, and a replacement of switch requires dewatering of the penstock. Upgrading will eliminate these underwater proximity switches and gate position will be implemented using a positioning system of higher accuracy and reliability which will not be submerged. In addition, there is currently no redundant device to prevent the gate from traveling past the prime position and filling the penstock too quickly. The new system will provide this feature.

There have been two major incidents during penstock filling, resulting from malfunction of this mechanism, that resulted in the complete destruction of the intake venthouse and presented extensive risk of injury to personnel. In addition, intake #4 does not have a spherical valve to permit isolation of the unit for maintenance. Dewatering of the penstock is therefore required for such maintenance, which poses risk or injury.

Future Plans:
Similar upgrades for these intake controls will be proposed in future budget applications.

Project Title: Replace Back-Up Air Dryer

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

The scope of work is to procure and install an air dryer to replace the existing back-up air dryer for Bay d'Espoir Powerhouse 1.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	30.2	0.0	0.0	30.2
Labour	29.6	0.0	0.0	29.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.6	0.0	0.0	0.6
O/H, AFUDC & Escalation	6.4	0.0	0.0	6.4
Contingency	6.0	0.0	0.0	6.0
Total	**72.8**	**0.0**	**0.0**	**72.8**

Operating Experience:

The existing back-up air dryer is operating ineffectively and is beyond its useful life. In 2005-2006, this air dryer was operated while maintenance was being performed on the primary air dryer. During that period, the dew point increased to an unacceptable level. The actual age of the dryer is unknown, but one of the components has a nameplate dated 1975.

Project Justification:

The dry air system at Bay d'Espoir Powerhouse 1 is used to operate the unit breakers in the switchyard and the unit governors. The back-up air dryer is operated when the main air dryer is down for maintenance. Operating experience has shown that the existing back-up air dryer is incapable of supplying air with a dew point required for reliable operation of the unit breakers and governors. All dry air for the switchyard is supplied from Powerhouse 1 and piped to the yard. Without compressed air, operation of the equipment in the switchyard for all seven units is not possible.

Future Plans:

None.

Project Title: Replace Communications Room Air Conditioner

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

The scope of work is to replace the existing air conditioner which services the Bay d'Espoir Powerhouse #1 Communications Room and Secondary Communications Room, including all associated ductwork.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	24.2	0.0	0.0	24.2
Labour	27.8	0.0	0.0	27.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	1.1	0.0	0.0	1.1
O/H, AFUDC & Escalation	5.8	0.0	0.0	5.8
Contingency	5.3	0.0	0.0	5.3
Total	**64.1**	**0.0**	**0.0**	**64.1**

Operating Experience:

The existing air conditioning unit has been in service since 1991 and corrective maintenance activity has increased substantially in the last two years totaling approximately $4,700. The thermostat valve, evaporator coils, and condenser coils have leaked R-22 refrigerant. Some tubes have had to be plugged. The ductwork for this system is in poor condition. The reliability of the unit has diminished to the point that a portable unit has been put in place until such time that the permanent replacement is installed.

Project Justification:

It is necessary to replace the existing unit due to its age, to restore reliability. The reliability of this air conditioner is critical since overheating of the communications equipment in these rooms could lead to equipment failure and jeopardize plant availability and production. The refrigerant is a controlled substance listed in the provincial Halocarbon Regulations, under the Environmental Protection Act.

Project Title: Replace Communications Room Air Conditioner **(cont'd.)**

Project Justification: (cont'd.)

Replacement of the unit will reduce the frequency and quantity of refrigerant leaks. Furthermore, the manufacturer of this unit has advised that the unit is no longer supported, since production ceased in 2001 and spare parts are no longer available.

Future Plans:

None.

Project Title: Upgrade Access Trail

Location: Venam's Bight

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

The work involves the mobilization of contract forces to the site to excavate the trail, at specific locations, to grades acceptable for safe use.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	11.6	0.0	0.0	11.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	38.4	0.0	0.0	38.4
Other Direct Costs	2.8	0.0	0.0	2.8
O/H, AFUDC & Escalation	5.6	0.0	0.0	5.6
Contingency	5.3	0.0	0.0	5.3
Total	**63.7**	**0.0**	**0.0**	**63.7**

Operating Experience:

The access trail is used as the main access route to the powerhouse and all other site infrastructure such as the dam or penstock. The access trail is traveled by plant staff on at least a monthly basis and more frequently during summer months when plant maintenance is carried out.

Project Justification:

The only land access to the plant is by an ATV trail. Sections of this trail are very steep over bedrock, causing a safety issue due to slipping of the ATV's along the steep slopes. This condition may result in equipment damage and personal injury (see attached photos). Safety of personnel is of prime concern as well as protection of equipment and material being transported along the trail.

Future Plans:

None.

Project Title: Upgrade Access Trail **(cont'd.)**

Project Title: Replace Fire Alarm System

Location: Cat Arm

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project consists of the replacement of the fire alarm control panel located within the Cat Arm Powerhouse.

This project also includes the replacement of the current fire protection and detection system including smoke and heat detectors (both stand alone and air duct), pull stations, audible alarms and other auxiliary equipment. The new system will use intelligent addressable detectors and will be capable of interfacing with the existing controls for the powerhouse ventilation system and the unit annunciator. The existing wiring will be used whenever possible. The final system will conform to the applicable standards and codes.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	6.0	0.0	0.0	6.0
Labour	18.0	0.0	0.0	18.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	18.0	0.0	0.0	18.0
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escalation	5.2	0.0	0.0	5.2
Contingency	4.4	0.0	0.0	4.4
Total	**53.6**	**0.0**	**0.0**	**53.6**

Operating Experience:

Over the last five years, there have been numerous false alarms attributed to this aging fire alarm system. These nuisance conditions are sporadic and are not repairable. There have also been several trouble conditions caused by various relay failures and failures of the modules or cards contained within the control panel.

Project Title: Replace Fire Alarm System **(cont'd.)**

Project Justification:

Alarm or trouble incidents originating from the fire alarm system usually result in a call out which requires a remote operator to travel to site for further investigation. Due to the system's poor performance and lack of reliability, there is little or no confidence in this system which has significant safety implications. The fire alarm system is required to protect personnel in the facility, minimize fire damage, mitigate the spread of fire, and provide protection to the powerhouse.

Future Plans:

None.

Project Title: Replace Auxiliary Service Water Pump

Location: Cat Arm

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project involves the replacement of the auxiliary service water pump. This pump supplies service water when the two main service water pumps are not operating. The two main service water pumps do not operate when the plant is shut down and therefore the auxiliary pump supplies all service water that is required. The auxiliary service water pump is a critical piece of equipment as it supplies water for the fire protection system, the compressed air water cooled after-coolers and the air conditioning water-cooled condensers. The current auxiliary pump is defective and beyond further repair.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	24.0	0.0	0.0	24.0
Labour	14.3	0.0	0.0	14.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	4.8	0.0	0.0	4.8
O/H, AFUDC & Escalation	5.5	0.0	0.0	5.5
Contingency	4.3	0.0	0.0	4.3
Total	**52.9**	**0.0**	**0.0**	**52.9**

Operating Experience:

The pump has been extensively damaged during routine operation. A work order was issued in March 2007 to dismantle the pump and determine the extent of the damage. When the pump was dismantled it was determined that the pump shaft was broken, the pump column was broken and that part of the pump had fallen to the bottom of the sump in about 12 feet of water. This part has yet to be retrieved from the sump due to plant loading.

Project Title: Replace Auxiliary Service Water Pump **(cont'd.)**

Project Justification:

The pump provides backup to the main service water pump and may be called upon to supply water for the fire protection system, the compressed air water cooled after-coolers and the air conditioning water-cooled condensers. The existing service water pump is defective thus there is no backup for the main service water pump. If the main pumps fail then there will have to be a system outage. The shaft and column of the pump are broken and the material cost of repairing or replacing these vital components, along with the cost of shipping and the cost of labour will be significant. The cost of the total repair project will be equal to or greater than the cost of purchasing a new pump. The pump has been installed since the plant has been operational. If the pump is repaired, maintenance costs and maintenance frequency will continue to increase due to the age of the pump until the pump reaches the end of its life cycle. A new pump will have greatly reduced maintenance costs and will have a much longer life cycle.

Future Plans:

None.

Project Title: Tank Farm Upgrade

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Normal

Project Description:

Tanks 1 and 2 were constructed in 1968 together with the pipelines, lighting, dykes and drainage system. Tanks 3 and 4 were added in 1979. The four tanks (180 feet diameter by 48 feet high) have a storage capacity of 200,000 bbl of bunker C fuel. The 16 inch and 18 inch diamter pipelines are heated with steam or electrical heat trace. The dyke liner is constructed from glacier till. Light fixtures are mounted on 8 poles around the dyked area.

The interior of Tank 2 was inspected in 1998; Tank 3 in 2003; Tank 4 in 2004 and Tank 1 in 2005. The tanks were inspected in accordance with American Petroleum Institute (API) Standard 653. In 2005, SGE-Acres Limited was retained to review and assess the condition of the dyked facilities and to determine the upgrades required to extend the life of the facility by at least 20 years. The report recommends the work commence in 2008. Hydro has decided to defer the bulk of the work by one year to start in 2009, however due to critical work required on the interior of tank 2, it is proposed to implement the recommended work on the interior of tank 2 at the time of the repairs.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	40.8	0.0	0.0	40.8
Consultant	19.2	0.0	0.0	19.2
Contract Work	347.0	0.0	0.0	347.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	52.0	0.0	0.0	52.0
Contingency	41.0	0.0	0.0	41.0
Total	**500.0**	**0.0**	**0.0**	**500.0**

Operating Experience:

The ongoing operation of this facility must be in accordance with industry standards, as well as, provincial and federal regulations. Cost estimates are based on similar work at the facility in recent years.

Project Title: Tank Farm Upgrade **(cont'd.)**

Project Justification:

Inspection of the tanks have identified and confirmed their state of deterioration. The attached engineering consultant's report " Evaluation of Fuel Oil Storage Tanks, Associated Pipelines & Dyked Drainage System", Section H, Tab 2, outlines the work necessary to upgrade the facilities for a further life extension of 20 years. The Implementation Plan is basically for a four-year period beginning in 2009. Due to an internal valve failure in tank 2, which requires tank draining and cleaning to repair, it is proposed to carry out the recommended upgrading work associated with tank 2 during the repair.

Future Plans:

Future upgrades will be proposed in future capital budget applications.

Project Title: Replace Unit 2 High Pressure Heater

Location: Holyrood

Category: Thermal Operations

Type: Other

Classification: Normal

Project Description:

Replace high pressure heater number 5 on Holyrood Unit 2 reusing all existing valves and controls.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	652.5	0.0	652.5
Labour	17.1	13.6	0.0	30.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	64.6	0.0	64.6
Other Direct Costs	0.0	1.6	0.0	1.6
O/H, AFUDC & Escalation	2.5	112.2	0.0	114.7
Contingency	0.0	74.9	0.0	74.9
Total	**19.6**	**919.4**	**0.0**	**939.0**

Operating Experience:

The existing high pressure heater 5 on Unit 2 was installed in 1989. The life expectancy of a shell and tube heat exchanger is usually 15 to 20 years. Due to the age of the heater many of the tubes have experienced up to 80% wall loss. This has resulted in numerous leaks that can only be repaired by plugging the tubes. As the tubes are plugged the area available for heat transfer is reduced. This, in turn, reduces the efficiency of the heater.

Project Justification:

The high pressure heater was placed in service in 1989. In the following 18 years in excess of 10% of the tubes have been plugged. Industry practice use 10% as the benchmark. Amounts in excess of 10% results in decreased performance and efficiency. The procurement and installation cycle for a new heater is approximately 14 months. Failure to replace the heater could result in the loss of this feedwater heater resulting in increased fuel consumption. Loss of the high pressure heater will result in an increase in the operating cost by $1.3 million per year.

Future Plans:

None.

Project Title: Upgrade Continuous Emissions Monitoring System

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Mandatory

Project Description:

Upgrade the Continuous Emissions Monitoring System (CEMS) for compliance with the requirements of the Holyrood Thermal Generating Station Certificate of Approval, see Section H, Tab 3. This will involve the installation of new analyzers, data acquisition, and associated tubing and cabling necessary to convert the existing time-shared CEMS to a system with analyzers dedicated to each unit.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	376.8	0.0	0.0	3776.8
Labour	188.4	0.0	0.0	188.4
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 & Escalation	67.2	0.0	0.0	67.2
Contingency	56.5	0.0	0.0	56.5
Total	**688.9**	**0.0**	**0.0**	**688.9**

Operating Experience:

The CEMS was installed in 2003 as a means to better characterize emissions and monitor combustion. At that time, the system was not legislated and Hydro did not have to comply with the operating and uptime requirements of the Federal Standard regarding CEMS, and consequently, utilized a sequenced design. The time-shared system installed at the facility is more difficult to run. Small problems in one system can lead to data loss from all three units and maintenance on the system can lead to overall system downtime. For the certification testing, the time-shared design has required a unit to operate as a stand alone system with no switching from unit to unit resulting in data loss for the period of testing. The current data acquisition system is unable to individually bias the data from each stack with variables measured during third party certification.

Project Title: Upgrade Continuous Emissions Monitoring System **(cont'd.)**

Project Justification:

In February 2006, the Provincial Department of Environment and Conservation issued a new site Certificate of Approval in which it mandated that the Holyrood Thermal Generating Station comply with all requirements of Environment Canada's 1993 Report Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation (EPS 1/PG/7), including those aspects related to reliability (uptime). To maximize the probability that operating and reliability (uptime) requirements are met, the plant needs to convert the time-shared CEMS to a dedicated design.

Future Plans:

None.

Project Title: Replace Unit 1 and 2 Condenser Valve Actuators
Location: Holyrood
Category: Generation - Thermal
Type: Other
Classification: Mandatory

Project Description:
Ten of the large butterfly valves associated with the condensers serving turbine Units 1 and 2 are manually operated using hand wheels. This project will replace the existing hand wheel mechanisms with combination electric actuators with manual overrides. A push button mechanism will be mounted to a post at each valve to electrically operate the valve.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	150.0	0.0	0.0	150.0
Labour	55.0	0.0	0.0	55.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	50.0	0.0	0.0	50.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	32.3	0.0	0.0	32.3
Contingency	25.5	0.0	0.0	25.5
Total	**312.8**	**0.0**	**0.0**	**312.8**

Operating Experience:
Large manual actuators require a lot of effort by an operator to manually open or close valves. There is a high potential to cause soft tissue injury. There have been lost time incidents as a result of operation of these valves in the past several years. Unit 3 has electric acuators fitted on all of its condenser butterfly valves as installed by original construction. They work well with no concern for injury.

Project Justification:
Lost-time injuries and three condition reports have been filed as a result of operation of these butterfly valves. This condition is a serious concern for operating staff, although they have accepted the situation with the understanding that plans are being put forward for a remedy. If the valves

Project Title: Replace Unit 1 and 2 Condenser Valve Actuators **(cont'd.)**

Project Justification: (cont'd.)

cannot operate for backwash cleaning, as a result of the safety risk, condenser heat transfer becomes inefficient and there is reduced generating unit efficiency. This would remain the case until the condenser could be taken out of service and cleaned by maintenance staff. Installing electric actuators will avoid this problem.

Future Plans:

None.

Project Title: Replace Unit 2 Electromechanical Trip Devices (ETD)
Location: Holyrood
Category: Generation - Thermal
Type: Clustered
Classification: Normal

Project Description:
The Holyrood Unit 2 ETD replacement project will replace the existing ETD with a new modern, highly reliable, two out of three (triple redundancy), electromechanical 125VDC unit as was installed on Unit 1 in 2006. The ETD will interface between the existing turbine controller (GE Mark V) and the turbine's hydraulic system to replace the mechanical bolt trip functionality.

This triple redundant electronic trip system will contain two sets of speed probes (three primary and three emergency). When any two of the primary speed probes detect an overspeed condition of 110% synchronous speed, a trip is initiated in the turbine control system. Similarly a trip is initiated by the emergency probes at 111%. The emergency trip is reduced to 104.5% for test purposes. When a trip is initiated in the turbine control system, it sends a signal to trip the three hydraulic oil trip solenoids. When any two out of the three trip solenoids are de-energized, the hydraulic header will be de-energized, closing all turbine valves and thus tripping the unit. The two out of three configuration allows for reliable operation as well as the ability to safely test the trip solenoids on-line.

Included in this project is the replacement of the low bearing oil pressure trip mechanism in the turbine front standard, with three lube oil pressure transmitters. Any two out of the three transmitters that detect low bearing lube oil pressure will initiate a trip in the turbine control system. Equipment related to the mechanical and electrical trip test system will no longer be required and will also be removed. The mechanical overspeed bolt will not be physically removed to prevent turbine balance problems, but it will be adjusted to its maximum setting to prevent it from causing a trip. As an added benefit, this project will remove all sources of hydraulic oil from the turbine front standard, eliminating this potential source of contamination into the bearing lube oil.

Project Title: Replace Unit 2 Electromechanical Trip Devices (ETD) **(cont'd.)**

Project Description: (cont'd.)

Execution of this project in the same year as the proposed Generator Auto Synchronization and Steam Seal Regulator projects will reduce GE engineering and field support combined costs by including all work in the same contract and schedule.

Project Cost: *($ x1,000)*	2008	2009	Beyond	Total
Material Supply	8.0	0.0	0.0	8.0
Labour	34.5	0.0	0.0	34.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	204.9	0.0	0.0	204.9
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	33.2	0.0	0.0	33.2
Contingency	24.7	0.0	0.0	24.7
Total	**305.3**	**0.0**	**0.0**	**305.3**

Operating Experience:

Overspeed trips via the mechanical bolt have not been consistent. At times the mechanical trip speed has been lower than the primary electrical trip, preventing testing of the electronic overspeed trips. Tripping at a lower speed reduces the reliability of the unit given that the unit may trip during a system excursion when it should not trip. On January 30th, 2003, a system load rejection caused generating Unit 2 to go into overspeed condition as the system frequency rose. The turbine reached a speed of 4290 RPM (119.2% rated speed). Had the turbine reached 4320 RPM (120% rated speed), the unit would have required a major inspection before it could be put back into service. This would have resulted in the unit being unavailable for two to three months during a peak production season, and could have cost millions of dollars for inspection and/or repairs.

The mechanical overspeed trip bolt has been sticking in recent years, reducing the reliability of operation for this equipment protection. In addition, the mechanical online overspeed test arrangement has not worked for quite some time despite several repair attempts during annual outages. Annual summer outages are the only opportunity to fix these issues. The mechanical overspeed test arrangement is out of service for the full operating season if it does not function properly once the unit is returned to service after the annual summer outage. The mechanical overspeed bolt and test arrangement cannot be repaired on-line and an additional outage is not usually possible. This project is the manufacturer's proposed solution to the existing overspeed bolt and test arrangement problems.

Project Title: Replace Unit 2 Electromechanical Trip Devices (ETD) **(cont'd.)**

Project Justification:

Operating the generating unit without a reliable overspeed protection and test mechanism increases the risk of damaging and potentially destroying the turbine and generator if and when this protection is required. Upgrading to an electronic trip system will improve the reliability of the generating unit for maintaining normal production by preventing unnecessary unit trips which are usually underfrequency load shedding events, and for tripping the generating unit to prevent excessive turbine/generator mechanical damage and unavailability caused by operating at excessive overspeed conditions. Being the largest generating unit on the island system, winter production and availability of Unit 2 is critical to prevent extended customer outages during this peak demand season. Since it is not possible to repair defects with the mechanical overspeed protection and test mechanism online, it is necessary to replace it with a solid state on line trip and test system.

Future Plans:

None.

Project Title: Precipitator and Scrubber Installation Study

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Mandatory

Project Description:

This study involves a feasibility study for installation of a wet scrubber and precipitator arrangement on all three existing units at the Holyrood thermal generating station. The study identifies the appropriate scrubber and precipitator technologies and provides details of how such technology integrates with the current thermal generating process at Holyrood. The study will provide firm schedules and pricing for installation.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	35.4	0.0	0.0	35.4
Consultant	187.5	0.0	0.0	187.5
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	27.0	0.0	0.0	27.0
Contingency	22.3	0.0	0.0	22.3
Total	**272.2**	**0.0**	**0.0**	**272.2**

Operating Experience:

Numerous public complaints have been received due to emissions from the plant, including several concentrated incidents related to upsets in normal unit operations, resulting in damage claims to be paid by Hydro. Past health hazard risk assessment has concluded that there is potential for short-term adverse health effects, associated with episodic short-term high concentrations of respiratory irritants. Moreover, larger particulate deposits are considered to be a major aesthetic concern, and directly linked to the psychosocial stress and anxiety concerns voiced by the local community.

Project Justification:

Emissions modeling has shown noncompliance with respect to the ground level concentrations specified in the Provincial Air Pollution Control Regulations. As well, the plant routinely exceeds the

Project Title: Precipitator and Scrubber Installation Study **(cont'd.)**

Project Justification: (cont'd.)

opacity limits specified in these same regulations. The Certificate of Approval issued to the site in February 2006 has decreed that the plant must assess its degree of noncompliance with the Air Pollution Control Regulations and submit to the Department of Environment and Conservation a plan to achieve compliance (by June 2008), see Section H, Tab 3. The Holyrood Thermal Generating Station is virtually the last thermal plant in eastern Canada with no air emission controls equipment.

Considering the new Federal Government Regulatory Framework for Air Emissions relating to particulate and sulphur dioxide, in particular, further reductions will be required, as well as reductions in particulate emissions, for the generating station.

Future Plans:

This study will identify future expenditures required to install a precipitator-scrubber arrangement through the long term capital program. In the meantime further environmental modeling will be performed.

Project Title: Replace 4160 Volt Motor Relays

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Normal

Project Description:

The existing mechanical-thermal over-current protection relays in the Holyrood 4.16 kV switchgear are the original equipment installed in 1969 and 1979. Twelve out of 16 mechanical relays have been replaced on Units 1 and 2 with solid-state relays, but none of the nine on Unit 3 have been replaced. This project will replace the remaining 13 out of the original 25 mechanical-thermal over-current protection relays on Holyrood 4.16 kV switchgear with modern solid-state relays. Any training required for the new relays will be included in this project.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	53.0	0.0	0.0	53.0
Labour	79.0	0.0	0.0	79.0
Consultant	11.0	0.0	0.0	11.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escalation	12.2	0.0	0.0	12.2
Contingency	14.5	0.0	0.0	14.5
Total	**171.7**	**0.0**	**0.0**	**171.7**

Operating Experience:

Mechanical components such as linkages and flags have broken on these relays in recent years. Spare parts are not available for these relays, so they were repaired by temporary means. In January of 2005, a flag indicated that one of the relays had operated broken and was showing activated when the relay did not activate. The temporary repair only lasted a few days. In January of 2006, mechanical linkage in the West Boiler Feedpump relay caused the pump to trip. There were no spares, so the existing linkage had to be repaired and adjusted. This was only a temporary repair that cannot be relied upon on a permanent basis.

Project Title: Replace 4160 Volt Motor Relays **(cont'd.)**

Project Justification:

These relays need to be replaced due to equipment obsolescence. Currently there are no spare replacements or parts for these relays and they are critical for plant operation and protection.

Future Plans:

None.

Project Title: Replace Unit 2 Main Steam Stop Valve

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Normal

Project Description:

Remove the main steam stop valve for Boiler No. 2 and replace it with a new valve. The new valve was purchased and delivered to the plant in 2006.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	5.0	0.0	0.0	5.0
Labour	35.0	0.0	0.0	35.0
Consultant	7.0	0.0	0.0	7.0
Contract Work	93.0	0.0	0.0	93.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	17.3	0.0	0.0	17.3
Contingency	14.0	0.0	0.0	14.0
Total	**171.3**	**0.0**	**0.0**	**171.3**

Operating Experience:

The existing valve is in excess of 30 years old and is obsolete. Attempts have been made to repair the seat but have been unsuccessful. The valve is unable to perform the following functions:

- maintain proper boiler pressure during start-up and shut down operations without burning extra fuel.
- maintain isolation for work permits on downstream equipment.
- maintain boiler pressure for long duration during Dept. of Labour inspection.

Project Justification:

For proper control of the steam flow from the boiler to the turbine it is important that this valve be able to achieve a tight seat when in the closed position. Steam leakage across the valve seat will accelerate seat damage and can lead to downstream equipment damage. If this condition is left unaddressed it will lead to further deterioration and increase the risk of unexpected equipment failure with reduced generation.

Project Title: Replace Unit 2 Main Steam Stop Valve **(cont'd.)**

Project Justification: (cont'd.)

In addition to the above, the existing leaking valve prevents isolation for work permits on downstream equipment. It also prevents the holding of boiler pressure for a long duration.

Future Plans:

None.

Project Title: Environmental Effects Monitoring Study of Waste Water

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Mandatory

Project Description:

The project is an Environmental Effects Monitoring study on Conception Bay that will monitor the impacts of the discharge of the cooling water, the continuous basin's water and the waste water treatment plant's treated water. An outline of the study must be submitted to the Department of Environment and Conservation for review and approval by June 30, 2008 and the results of the completed study must be submitted by June 30, 2009.

This study will involve determination and description of the extent of the thermal plume during summer and winter conditions, examination of the variability of metal and petroleum hydrocarbon body burden in a number of sessile, indigenous indicator marine organisms, and determination of physiological and histopathological changes in indicator species due to plant discharge.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	14.0	10.0	0.0	24.0
Consultant	50.0	50.0	0.0	100.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	1.0	1.0	0.0	2.0
O/H, AFUDC & Escalation	7.5	13.3	0.0	20.8
Contingency	0.0	12.6	0.0	12.6
Total	**72.5**	**86.9**	**0.0**	**159.4**

Operating Experience:

A similar study was conducted in 1999 as a requirement of a Compliance Agreement between Hydro and the Department of Environment and Conservation. Normally regulatory agencies have required facilities with emissions such as those from the Holyrood Thermal Generating Station to conduct environmental effects monitoring studies in receiving waters every five years. However,

Project Title: Environmental Effects Monitoring Study of Waste Water **(cont'd.)**

Operating Experience: (cont'd.)

because of delays in finalizing the Certificate of Approval issued by the Department of Environment and Conservation in February 2006, and results of the previous work, which did not indicate significant effects, the requirement to undertake additional effects monitoring was delayed until 2009.

Project Justification:

This work is a mandatory regulatory requirement. Condition 42 of the Department of Environment and Conservation's Certificate of Approval No. AA06-025458B, for the operation of the Holyrood Thermal Generating Station, requires that Hydro conduct this study to monitor the impacts of the discharge of the cooling water, the continuous basin's water and the waste water treatment plant's treated water on Conception Bay. An outline of the study must be submitted to the Department of Environment and Conservation for review and approval by June 30, 2008 and the results of the completed study must be submitted by June 30, 2009.

Future Plans:

None.

Project Title: Upgrade Ambient Monitoring Station

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Mandatory

Project Description:

The purpose of this project is to upgrade the Ambient Monitoring System for compliance with the requirements of the Holyrood Thermal Generating Station Certificate of Approval. The present 15 year old sulphur dioxide analyzers will be upgraded to include the provision of a hot spare, improve availability and insure compliance with the plant operating certificate.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	96.0	0.0	0.0	96.0
Labour	9.7	0.0	0.0	9.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	11.3	0.0	0.0	11.3
Contingency	10.6	0.0	0.0	10.6
Total	**127.6**	**0.0**	**0.0**	**127.6**

Operating Experience:

Holyrood has made a concerted effort to enhance compliance with uptime and reliability targets for environmental ambient monitoring stations. The four original monitoring stations (Butterpot, Green Acres, Indian Pond and Lawrence Pond) utilize sulphur dioxide (SO_2) analyzers of 1992/93 vintage. The availability and lead times for replacement parts is posing a greater risk to maintaining uptime targets.

Project Justification:

Condition 58 of the Department of Environment and Conservation’s Certificate of Approval No. AA06-025458B for the operation of the Holyrood Thermal generating Station, requires that Hydro operate an ambient air monitoring system as per the conditions of the approval and its amendments. The availability of some sites has fallen as low as 92.4%, below the set target of 95%. To maintain the required uptime targets, replacement of the aging equipment is required.

Future Plans:

None.

Project Title: Soot Blowing Controls Study

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Mandatory

Project Description:

This project will consist of an engineering study to determine what specific changes should be made to the sootblowing systems to reduce the magnitude and frequency of opacity excursions. The study will focus on intelligent sootblowing controls and sootblowing steam pressure control. It will be completed by inhouse Hydro staff with external engineering consultant input.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	50.0	0.0	0.0	50.0
Consultant	15.0	0.0	0.0	15.0
Contract Work	35.0	0.0	0.0	35.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	13.0	0.0	0.0	13.0
Contingency	10.0	0.0	0.0	10.0
Total	**123.0**	**0.0**	**0.0**	**123.0**

Operating Experience:

The Holyrood plant has received complaints from neighbouring residents about particulate emissions and the stack opacity monitoring system indicates that opacity during a sootblowing cycle exceeds regulated limits.

Project Justification:

Opacity excursions caused by sootblowing exceed regulated limits. Also a study of air emissions at Holyrood Thermal Generating Station, performed by consultant CANTOX Environmental Inc. in 2006, recommended that efforts be made to reduce particulate emissions related to sootblowing. The report states that the release of heavy particulate emissions during soot blowing is a source of stress for the community. Reducing these heavy particulate emissions would assist in alleviating the concerns of community members.

Future Plans:

To install a new intelligent soot blowing system for each of the three boilers in 2009. The type of system will be determined by this years engineering study.

Project Title: Stack Breeching Study

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Normal

Project Description:

This project will involve bringing in an outside contractor to study the stack breeching at Holyrood. Stack breeching has been an area of concern for a number of years. There are numerous holes in the breeching and this is an operational and environmental concern. The scope of the study will be to look at the condition of the existing breeching and make recommendations on the best way to proceed, taking into account operational, economical and environmental factors.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	18.5	0.0	0.0	18.5
Consultant	63.0	0.0	0.0	63.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	12.4	0.0	0.0	12.4
O/H, AFUDC & Escalation	11.8	0.0	0.0	11.8
Contingency	9.4	0.0	0.0	9.4
Total	**115.1**	**0.0**	**0.0**	**115.1**

Operating Experience:

Each of the three exhaust stacks at the Holyrood Generating Station has two breeching ducts. These breeching ducts run from each unit's air heater hopper to the unit's exhaust stack. The ducts convey flue gas from inside the plant to the exhaust stacks and then to the atmosphere. The ducts are currently lined with borosilicate tiles, which slows down the corrosion caused by the sulfuric acid in the flue gas. Due to the high temperatures and high concentrations of sulfuric acid in the flue gas, the borosilicate tiles corrode over time. The ducts are corroding and maintenance will have to be performed to maintain the integrity of the system. Maintenance has been performed on the exhaust ducts of all three units over the operational life of the plant, including replacing the steel shell of the ducts and replacing the borosilicate tiles that are used to line the ducts.

Project Title: Stack Breeching Study **(cont'd.)**

Project Justification:

There are numerous holes in the stack breeching on all three units and some type of repair will have to be performed. The release of flue gas through these holes is an operational and environmental concern. In the past borosilicate tiles have been used to line the ducts and slow down the corrosion. The installation of these tiles is a lengthy and costly process. There is currently a need to perform another round of maintenance on the breeching. This study will look at the way maintenance of the breeching is currently handled and compare it to other options that are currently used in the industry. This will help reduce maintenance costs in the future by determining the most cost effective methods to be used on the breeching.

Future Plans:

None.

Project Title: Install Safety Egress Lighting

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Mandatory

Project Description:

The scope of this project is to install additional safety lighting for the egress routes leading from the plant building exit doors to outside emergency ladders. There are a total of 12 routes to be fitted with safety lighting.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	20.0	0.0	0.0	20.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	59.0	0.0	0.0	59.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	10.5	0.0	0.0	10.5
Contingency	7.9	0.0	0.0	7.9
Total	**97.4**	**0.0**	**0.0**	**97.4**

Operating Experience:

There are a total of 12 emergency egress routes from the plant building to outside emergency ladders and stairways. These routes do not have area lighting sufficient for safe egress after dark.

Project Justification:

This project originated from a report generated by Occupational Health and Safety Inspections Branch of the Department of Government Services (Order # 630677-01). The Occupational Health and Safety officer noted that the existing fire and safety escape routes egress paths were not properly lit. In order to improve the poorly lit egress paths it is required that additional lighting be installed.

Future Plans:

None.

Project Title: Auto Synchronizing Units 1 and 2

Location: Holyrood

Category: Generation - Thermal

Type: Clustered

Classification: Normal

Project Description:

There is no automatic synchronizing capability on Units 1 and 2. These units are manually synchronized only.

The project will require an update and installation of software, and associated signals to commission the function in the GE Mark V controllers for Units 1 and 2 to activate automatic synchronization capability. This requires the wiring of potential transformer signals and output communication with the distributed central system. Software installation and control modification will be done using GE engineering. Wiring additions will be performed by Thermal Generation craft labour.

Execution of this project in the same year as the proposed Unit 2 Electromagnetic Trip Device upgrade and Steam Seal Regulator projects will reduce GE engineering and field support combined costs by including all work in the same contract and schedule. Estimates are based on modifying both units in the same trip for the GE Controls Engineer (Stage 1 outage).

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	5.0	0.0	0.0	5.0
Labour	29.9	0.0	0.0	29.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	40.6	0.0	0.0	40.6
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	9.9	0.0	0.0	9.9
Contingency	7.6	0.0	0.0	7.6
Total	**93.0**	**0.0**	**0.0**	**93.0**

Project Title: Auto Synchronizing Units 1 and 2 **(cont'd.)**

Operating Experience:

Presently, generator synchronization is performed manually. An operator watches meters to determine when generator and system voltages and phases are within tolerances for safe synchronization. Then the operator manually closes the breaker to place the unit on-line. This closure is supervised by a synchronism check relay which prevents out of phase breaker operation.

Project Justification:

Improper synchronization of Units 1 and 2 during manual operation can result in damage such as slipped couplings, increased shaft vibration, a change in bearing alignment, loosened stator windings, loosened stator laminations, and fatigue damage to shafts and other mechanical parts. Automatic synchronizing will remove operator involvement with all adjustments done by the synchronizer, this can be performed using the existing GE Mark V turbine controller with the addition of new software logic and voltage signals.

Future Plans:

None.

Project Title: Install Stator Ground Fault Protection

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Normal

Project Description:

Currently generator stator protection only covers 90% of the stator winding on Units 1 and 2, and 95% of the stator winding on Unit 3. Technology now exists to provide 100% stator ground fault protection, which is standard on modern installations.

The scope of this project is to purchase and install additional equipment to provide 100% stator ground fault protection for all three generating units. All work will be performed by Hydro personnel.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	18.2	0.0	0.0	18.2
Labour	49.4	0.0	0.0	49.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.9	0.0	0.0	0.9
O/H, AFUDC & Escalation	9.1	0.0	0.0	9.1
Contingency	6.9	0.0	0.0	6.9
Total	84.5	0.0	0.0	84.5

Operating Experience:

There are no known generator stator ground fault incidents. Off-line testing was performed once every six years in the past, but will be extended to once every nine years to align with the revised turbine-generator maintenance schedule.

Project Justification:

100% stator ground fault protection is consistent with current standards such as Institute of Electrical and Electronics Engineers (IEEE) Standard C37.101 and the IEEE Tutorial on the Protection of Synchronous Generators, 95TP102.

Project Title: Install Stator Ground Fault Protection **(cont'd.)**

Project Justification: (cont'd.)

Operation with one ground fault in the unprotected portion of the generator stator is possible, and there is no way to tell if a ground fault condition exists while the generator is operating. If the unit were to experience a second undetected ground fault, circulating current in the stator winding and structural steel would melt the metal in that portion of the stator. This damage would cost substantially more than Hydro's insurance deductible in addition to creating an extended outage to repair the damage.

Future Plans:

None.

Project Title: Upgrade Meteorological Station

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Mandatory

Project Description:

Upgrade the Meteorological Monitoring System for compliance with the requirements of the Holyrood Thermal Generating Station Certificate of Approval (CA). To meet this certification it is proposed that the Handar brand heated ultrasonic wind sensor and ceilometer be replaced.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	32.0	0.0	0.0	32.0
Labour	30.2	0.0	0.0	30.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	6.8	0.0	0.0	6.8
Contingency	6.2	0.0	0.0	6.2
Total	**75.2**	**0.0**	**0.0**	**75.2**

Operating Experience:

The meteorological station was originally installed to supply ambient weather data for the analysis of plant emissions. The intent was to improve emissions modeling through the use of local meteorological data and to correlate public inquiries and complaints with weather patterns. In the past, operation of the site has not been legislated and has been completed as resources permitted, with the maintenance of other ambient site parameters taking precedence. Maintenance of the site is now legislated as per the site CA, issued February 2006.

Project Justification:

Condition 66 of the Department of Environment and Conservation's Certificate of Approval No. AA06-025458B for the operation of the Holyrood Thermal generating Station, requires that Hydro operate and maintain a meteorological station at Green Acres site in accordance with the guidelines specified in the United States EPA document "Meteorological Monitoring Guidance for Regulatory

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

Project Justification: (cont'd.)

Modeling Applications, "EPA-454/R-99-005, February 2000, or its successors. The current Handar brand heated ultrasonic wind sensor and ceilometer are obsolete and spare parts are no longer available. These instruments will be replaced for compliance with the CA directive.

Future Plans:

None.

Project Title: Construct Beta Attenuation Meter (BAM) Unit Enclosure

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Normal

Project Description:

This project involves the construction of a new shelter to house the existing BAM. This meter measures the fine particulate in the ambient air resulting from Holyrood emissions. The shelter will be approximately 1.5 metres long and 1.5 metres wide with a 2.4 metre high ceiling. It will be fitted with electric power for heat, lights and wall receptacles and also a small air conditioning unit. In addition a telephone line will be installed for communications. A technician's platform will be constructed on the outside at roof elevation to allow servicing of the intake mast. The platform will be accessible by stairs.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	10.0	0.0	0.0	10.0
Labour	25.0	0.0	0.0	25.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	14.0	0.0	0.0	14.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	5.9	0.0	0.0	5.9
Contingency	4.9	0.0	0.0	4.9
Total	**59.8**	**0.0**	**0.0**	**59.8**

Operating Experience:

Servicing the existing particulate monitor has been difficult since it was first installed because this sensitive piece of equipment has been exposed to the outdoor elements. The harsh weather conditions of Newfoundland sometimes causes disruption to timely maintenance of the monitor which adversely affects the plant environmental monitoring program.

Project Justification:

This project is required to ensure maximum reliability of the particulate monitor equipment for compliance with our environmental monitoring program as approved by the Environment and Conservation Department.

Future Plans:

None.

Project Title: Programmable Logic Controller Replacement Study

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Normal

Project Description:

Programmable Logic Controllers (PLCs) on several critical processes at Holyrood are at the end of their service lives. The scope of the study is to assess the availability of spare parts and technical support for the hardware and software for each PLC. The study will review replacing the PLCs with Foxboro Distributed Control System (DCS) modules. The Foxboro DCS is the plant control system that controls the boilers, Unit 3 burner management and other processes. The study will determine the need and benefits of replacing the PLCs with Foxboro modules, the cost, and the schedule.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	47.4	0.0	0.0	47.4
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 & Escalation	5.5	0.0	0.0	5.5
Contingency	4.7	0.0	0.0	4.7
Total	**57.6**	**0.0**	**0.0**	**57.6**

Operating Experience:

There have been a number of failures on the PLCs. See the attached table "PLC Failures".

Project Justification:

The manufacturer of the PLCs for the Burner Management on Units 1 and 2, the Plant Warm Air Makeup System, the Waste Treatment Plant and the Wastewater Treatment plant has given notice that these products reached the end of commercialization on June 30, 2006. The manufacturer has outlined different end of service dates for different cards. The study will identify the cards in each PLC and the corresponding end of service date. The PLC for the Gas Turbine is by another manufacturer and a failure on that PLC caused an outage of 3 months on the gas turbine while parts were being sourced.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Programmable Logic Controller Replacement Study **(cont'd.)**

PLC Failures		
Date	**Description**	**Amount**
03/23/04	Hardware	$ 400
12/04/03	Software	113
10/20/03	Software	340
03/14/03	Install New System	15,179
02/28/02	Software	415
02/22/02	Hardware	1,632
10/11/01	Software Scrambled	864
07/17/01	Software	110
03/16/01	Software Sequence	236
01/24/01	Software Sequence	394
01/29/00	Software	569
	Total	$ 20,252

Project Title: Replace Champion Grader V-9797

Location: Bay d'Espoir

Category: Generation - Tools and Equipment

Type: Other

Classification: Normal

Project Description:

This project is to replace an existing Champion Grader, complete with V-plow and wing unit for snow operation.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	360.0	0.0	0.0	360.0
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 & Escalation	8.4	0.0	0.0	8.4
Contingency	36.0	0.0	0.0	36.0
Total	**404.4**	**0.0**	**0.0**	**404.4**

Operating Experience:

This piece of equipment is the only one of its type in Bay d'Espoir, used daily to maintain the access roads to our major generating stations. In addition, the grader is a critical piece of equipment that is used on a regular basis to maintain the crests of our dams/dykes. This unit is currently 14.5 years old and maintenance costs are significant, particularly during 2006. Maintenance costs incurred over the last five years are:

Year	($000)
2006	41.8
2005	13.6
2004	28.1
2003	26.4
2002	23.6

It should be noted that a substantial portion of the 2006 repairs are related to replacement of tandem axles.

Project Title: Replace Champion Grader V-9797 **(cont'd.)**

Project Justification:

This grader is a very critical piece of equipment used to maintain approximately 400 km of roads to access our plants and structures throughout the system. It is also used during the winter months in order to keep the access road to Salmon River Spillway and the Upper Salmon plant open. Substandard roads result in significant safety concerns for our employees, increase response times and increase wear and tear to our fleet of vehicles. The fact that many of our roads lack proper topping has had the result of reducing the availability of this machine and due to its age and work requirements it now has a high breakdown rate which is unacceptable. In 2008 it is anticipated that a major overhaul will be required in the order of $150,000. Even with this overhaul due to its design and work requirements it is predicted that the repairs will only be effective for a short duration before we will again be faced with more breakdowns.

Future Plans:

None.

Project Title: Purchase Grounding Trucks

Location: Holyrood

Category: Generation - Tools and Equipment

Type: Other

Classification: Normal

Project Description:

This project consists of purchasing two 4160V grounding trucks for the Holyrood Thermal Generating Station. To ensure compatibility, the new grounding trucks will be the same as those that currently exist.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	50.0	0.0	0.0	50.0
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 & Escalation	6.3	0.0	0.0	6.3
Contingency	5.0	0.0	0.0	5.0
Total	**61.3**	**0.0**	**0.0**	**61.3**

Operating Experience:

To ensure the equipment to be worked on is isolated and de-energized the load side of the 4160V feeders is grounded to ensure work safety and meet the requirements of the work protection code.

Project Justification:

During unit outages at the Plant, station breakers are removed from the cabinets and grounding trucks are installed for isolation and de-energization. Currently there is not a sufficient number of grounding trucks available to meet the needs of the Plant. It is therefore necessary to purchase two 4160V grounding trucks that are compatible with those that currently exist.

Future Plans:

None.

Project Title: Replace Battery Banks and Chargers

Location: Various Stations

Category: Transmission and Rural Operations - Terminals

Type: Other

Classification: Normal

Project Description:

This project consists of the supply and installation of flooded-cell battery banks at the following locations: Springdale, Doyles, Buchans, Stoney Brook and Western Avalon Terminal Stations, two charger systems located at the Stephenville Gas Turbine and the Oxen Pond Terminal Station, and the supply and installation of a flooded-cell battery bank and charger system for Paradise River Generating Plant. As well, the English Harbour West Terminal Station battery bank will be replaced with a Value Regulated Lead Acid (VRLA) 12 V DC cell due to space limitations.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	202.3	0.0	0.0	202.3
Labour	75.1	0.0	0.0	75.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	61.6	0.0	0.0	61.6
Other Direct Costs	12.8	0.0	0.0	12.8
O/H, AFUDC & Escalation	43.4	0.0	0.0	43.4
Contingency	35.2	0.0	0.0	35.2
Total	**430.4**	**0.0**	**0.0**	**430.4**

Operating Experience:

Please see the report "Stationary Battery Replacement Program" Section H, Tab 4.

The history of expenditures for this project for the past four years is as follows:

Year	Budget ($000)	Actual ($000)
2006	564	587
2005	529	479
2004	307	311
2003	223	235

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

Project Justification:

These battery systems are used to provide a highly reliable power source for the station's remote control and communications equipment, ensuring overall reliability of supply to our customers is maintained. Terminal Station battery banks and chargers systems together provide the DC supply for the station protection and control, and equipment operation. These systems are an integral component to the relay protection systems for the station equipment, the transmission lines and the energy management system. Failure to replace the batteries could cause or extend customer outages. Further details are included in the report "Stationary Battery Replacement Program", Section H, Tab 4.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Replace Disconnect Switches

Location: Cow Head and Daniel's Harbour

Category: Transmission and Rural Operations - Terminals

Type: Other

Classification: Normal

Project Description:

This project consists of the replacement of five 69 kV disconnects at Cow Head Terminal Station and seven 69 kV disconnects at Daniel's Harbour Terminal Station. All new disconnects will be manually operated.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	205.0	0.0	0.0	205.0
Labour	86.0	0.0	0.0	86.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	10.6	0.0	0.0	10.6
O/H, AFUDC & Escalation	35.8	0.0	0.0	35.8
Contingency	30.2	0.0	0.0	30.2
Total	**367.6**	**0.0**	**0.0**	**367.6**

Operating Experience:

The switches are used for normal station and line switching and isolations. Switch operation is consistently problematic and switches normally have to be forced open because of the wearing of parts and linkages and the corrosion caused by the sea coast marine environment.

Project Justification:

The justification for this project is based on safety and reliability. The corrosion and wear on the operating linkages and jaw assemblies creates the safety hazard of switch parts breaking and falling on the operator during switching operations. These switches are 30 years old and replacement parts are not available, and they are required to be opened and closed regularly for routine maintenance and system dispatch purposes. Positive and reliable switch operation is essential to providing reliable customer services in these situations.

Future Plans:

None.

Project Title: Upgrade Circuit Breakers

Location: Various Stations

Category: Transmission and Rural Operations - Terminals

Type: Other

Classification: Normal

Project Description:

This project consists of an upgrading program to refurbish all Brown Boveri DCVF, DCF, and DLF styles of air blast breakers. The upgrade consists of replacement of all seals and gaskets as well as overhauls of all valves, interrupters and contacts assemblies. This project is the second year of a long-term plan to upgrade all air blast breakers on this system.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	160.0	0.0	0.0	160.0
Labour	103.0	0.0	0.0	103.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	15.5	0.0	0.0	15.5
O/H, AFUDC & Escalation	36.7	0.0	0.0	36.7
Contingency	0.0	0.0	0.0	0.0
Total	**315.2**	**0.0**	**0.0**	**315.2**

Operating Experience:

The first generation of Air Blast breakers on Hydro's system is approaching forty years of service. In recent years problems have occurred with air leaks, valves sticking, etc. resulting in increased maintenance cost as well as breaker unavailability. In particular there have been numerous problems with the unit breakers at Bay d'Espoir resulting in generating units being unavailable. These problems are common with other utilities and owners of DCF/DCVF Breakers. There are sixty-six breakers of this type in service on the Hydro system and they are critical to maintain reliable system operations.

Project Justification:

Upgrading these breakers will provide a life extension which is considered more cost effective than a replacement program. The upgrades will restore the full level of reliability and performance that is necessary for these breakers.

Future Plans:

Upgrades of breakers in future years will be proposed in future capital budget applications.

Project Title: Replace Digital Fault Recorder

Location: Buchans Terminal Station

Category: Transmission and Rural Operations - Terminals

Type: Other

Classification: Normal

Project Description:

This project involves the replacement of the existing 16 channel fault recorder in the Buchans Terminal Station with a new 32 channel unit. The digital fault recorders have been installed in major stations throughout the system to assist in analyzing events and faults occurring on the system. The new recorder will have sufficient channels to monitor both the 230 kV and 66 kV systems.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	63.0	0.0	0.0	63.0
Labour	44.0	0.0	0.0	44.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.5	0.0	0.0	2.5
O/H, AFUDC & Escalation	9.5	0.0	0.0	9.5
Contingency	10.9	0.0	0.0	10.9
Total	**129.9**	**0.0**	**0.0**	**129.9**

Operating Experience:

Besides the channel limitation on the existing fault recorder, the existing recorder has seen several failures since it was placed in service in 1985. The Central Processing Unit (CPU) board, front panel, modem and battery have been repaired or replaced in recent years. Since the recorder is obsolete, the failed parts are not available and parts have to be sent back to the manufacturer for repairs.

Project Justification:

The existing fault recorder is 22 years old and the technology used in this type of fault recorder is obsolete. Recent problems such as CPU board and communication failures have caused the recorder to be unavailable for periods of up to seven months. The 66 kV system required for addition of Star Lake generation and Duck Pond Mine requires additional monitoring channels on the fault recorder. A new digital fault recorder will solve the obsolescence problem and increase the fault channel recording capacity in Buchans Terminal Station.

Future Plans:

None.

Project Title: Replace Compressors

Location: Buchans Terminal Station

Category: Transmission and Rural Operations - Terminals

Type: Other

Classification: Normal

Project Description:

This project involves the replacement of two Ingersoll Rand 15T2 model T30, three-stage high pressure compressors at the Buchans Terminal Station complete with new control panel.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	47.0	0.0	0.0	47.0
Labour	26.0	0.0	0.0	26.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	4.3	0.0	0.0	4.3
O/H, AFUDC & Escalation	8.4	0.0	0.0	8.4
Contingency	7.8	0.0	0.0	7.8
Total	**93.5**	**0.0**	**0.0**	**93.5**

Operating Experience:

The compressed air system is a critical system for the operation of air blast circuit beakers within a terminal station. The compressed air has a dual function in that it provides the mechanical energy to open and close the breaker as well as provide the interrupting medium to extinguish the arc during the opening operation. If the circuit breaker has no compressed air supply the pressure will eventually drop to a point at which the breaker will not be able to operate during a fault condition. As a result, a longer duration and wider spread outage to customers is possible. With the aging assets and increased corrective maintenance, the existing compressors must be considered for replacement.

Compressors at the Buchans Terminal Station have been in service since the early 1970's and corrective maintenance costs are high. Since late 1999, there have been forty-one maintenance jobs on the compressors at the Buchans terminal station, at a total cost of $76,287.

Project Title: Replace Compressors **(cont'd.)**

Operating Experience: (cont'd.)

The following replacements or repairs have been performed since 1999:

Component	Repairs/Replacement
Unloaders	23
Valves	14
Coolers	6
Pressure Switches and Gauges	5
Gaskets	8
Pistons, Rings and Bearings	7
Cylinder Heads	6
Crank Shafts	2

Project Justification:

As noted in the operating experience, there has been a high failure rate and increased maintenance costs associated with the compressors at the Buchans Terminal Station. For comparison, an installation at Stony Brook with new compressors installed in 1999 has seen only three corrective maintenance jobs completed to date at a cost of $2,500 compared with 41 corrective maintenance jobs at a cost of $76,287 at Buchans. Stoney Brook Terminal Station has experienced improved reliability and significantly lower operating costs as compared to the Buchans Terminal Station. With the compressed air system being critical to the terminal stations containing air blast circuit breakers, faulty compressors must be replaced.

Future Plans:

None.

Project Title: Replace Instrument Transformers

Location: Various Stations

Category: Transmission and Rural Operations - Terminals

Type: Other

Classification: Normal

Project Description:

This project involves the purchase and installation of replacement instrument transformers (potential transformers, capacitive voltage transformers and current transformers) at various terminal stations.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	61.0	0.0	0.0	61.0
Labour	4.5	0.0	0.0	4.5
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 & Escalation	8.2	0.0	0.0	8.2
Contingency	0.0	0.0	0.0	0.0
Total	**73.7**	**0.0**	**0.0**	**73.7**

Operating Experience:

Instrument transformers have a typical service life of 30 to 40 years, depending on the service conditions. Units are inspected and tested regularly and replacements are made based on these maintenance assessments or in-service failures. The maintenance assessments for instrument transformers are visual inspection and voltage/current checks of the secondary circuits. In the last two years there were fourteen instrument transformers replaced and as the remaining instrument transformers age it is expected the number of failures will increase. As a result, in future years, the capital budget for instrument transformer replacements may increase. This proposal provides for an allowance of capital dollars for replacements on an as required basis.

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

Operating Experience: (cont'd.)

The history of expenditures for this project for the past four years is as follows:

Year	Budget ($000)	Actual ($000)
2006	78.0	81.4
2005	75.0	54.0
2004	77.0	65.2
2003	73.8	60.4

Project Justification:

Instrument transformers provide critical inputs to protection, control and metering equipment required for the reliable operation and protection of the electrical system. Instrument transformers which fail in-service can result in faults on the electrical system and outages to customers.

Replacement of instrument transformers is the only option available. When these units fail, they are not repairable and require replacement. The normal utility practice in North America is to hold a reserve inventory and replace units as they fail. Project estimates are based on an equal number of units in each voltage class failing, or requiring replacement. It has also been identified that older vintage instrument transformers may contain PCBs, and Hydro has a program in place to reduce PCBs in its system of assets, requiring PCB filled instrument transformers to be replaced.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Replace Surge Arrestors

Location: Various Stations

Category: Transmission and Rural Operations - Terminals

Type: Other

Classification: Normal

Project Description:

This project involves the purchase and installation of replacement surge arrestors at various terminal stations across the three operating regions of Hydro.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	49.5	0.0	0.0	49.5
Labour	10.0	0.0	0.0	10.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	7.6	0.0	0.0	7.6
Contingency	0.0	0.0	0.0	0.0
Total	**67.1**	**0.0**	**0.0**	**67.1**

Operating Experience:

The operating experience for surge arrestors is that they fail because of lightning strikes and switching surges, and generally these failures are unpredictable. An exception to these failures is for the older gap type arrestors which have an expected useful life of approximately twenty to twenty-five years. In these cases, the manufacturer's recommendation is that the arrestors be replaced with the new gapless type arrestor. Typically, across the system, there has been an average of fourteen surge arrestors replaced each year.

The history of expenditures for this project for the past four years is as follows:

Year	Budget ($000)	Actual ($000)
2006	70.0	66.9
2005	68.4	79.7
2004	70.3	65.1
2003	68.6	35.5

Project Title: Replace Surge Arrestors **(cont'd.)**

Project Justification:

Surge arrestors provide critical over voltage protection of power system equipment from lightning and switching surges. Units that fail are not repairable and the only option available is to replace them. Surge arrestors are inspected and tested regularly and replacements are made based on maintenance assessments as well as in-service failures. This capital proposal provides for the replacement of the units that fail in service as well as those identified during testing as needing to be replaced.

Due to the wide variety of service conditions it is difficult to estimate the useful life or predict failures in surge arrestors. However, manufacturers recommend twenty years as a suitable replacement period depending on the service conditions and the lightning activity in the area.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Upgrade Station Services

Location: Hardwoods Terminal Station

Category: Transmission and Rural Operations - Terminals

Type: Other

Classification: Normal

Project Description:

This project consists of relocating the point of supply for the backup station service from Bus B8 to Bus B9 at Hardwoods Terminal Station. The connection to Bus B9 will be made by installing several spans of distribution line around the outside of the station and relocating the station service transformer bank.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	18.0	0.0	0.0	18.0
Labour	26.0	0.0	0.0	26.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	5.0	0.0	0.0	5.0
O/H, AFUDC & Escalation	5.0	0.0	0.0	5.0
Contingency	4.9	0.0	0.0	4.9
Total	**58.9**	**0.0**	**0.0**	**58.9**

Operating Experience:

The primary and backup station service for this station is currently supplied from the same Bus B8. Thus if Bus B8 is out of service, then there is no station service available.

Project Justification:

In order to maintain continuous station service supply to Hardwoods Terminal Station in the event of a planned or forced outage to Bus 8, it is necessary to relocate the backup station service supply to Bus 9. This will provide a reliable back up station service supply and eliminate the need for portable generation during station outages.

Future Plans:

None.

Project Title: Wood Pole Line Management Program

Location: Various Sites

Category: Transmission and Rural Operations - Transmission

Type: Pooled

Classification: Normal

Project Description:

The project is the third year of an ongoing program of inspection, treatment and replacement of line components (poles, conductor and hardware) on Hydro's transmission system.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	357.0	0.0	0.0	357.0
Labour	1,032.9	0.0	0.0	1,032.9
Consultant	50.0	0.0	0.0	50.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	374.6	0.0	0.0	374.6
O/H, AFUDC & Escalation	192.2	0.0	0.0	192.2
Contingency	181.5	0.0	0.0	181.5
Total	**2,188.3**	**0.0**	**0.0**	**2,188.3**

Operating Experience:

Hydro operates approximately 2,400 km (26,000 poles) of wood pole transmission lines operating at 69, 138 and 230 kV. Historically, Hydro's pole inspection and maintenance practices followed the traditional utility approach of sounding inspections, only. In 1998, Hydro took core samples on selected poles to test for preservative retention levels and pole decay. The results of these additional tests raised concerns regarding the general preservative retention levels in wood poles. Between 1998 and 2003, additional coring and preservative testing confirmed that there were a significant number of poles which had a preservative level below what was required to maintain the design criteria for the lines. 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 analysis confirmed that a more formal wood pole line management program was required.

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

Operating Experience: (cont'd.)

The history of expenditures for this project for the past three years is as follows:

Year	Budget ($000)	Actuals ($000)
2006	2,302.6	2,362.5
2005	2,587.6	2,612.5
2004	324.6	332.5

Project Justification:

A report titled "Wood Pole Line Management Progress Report - 2006 Inspection Program" was filed with Hydro's 2005 Capital Budget Application under Section G Appendix 2. This report recommended that a formal program be established to manage wood pole line assets. The program consists of visual inspection, non-destructive testing and selected treatment of the wood poles. Poles that are deteriorated beyond the point where treatment could extend the life are identified for replacement. Field data is collected and stored electronically, and a comprehensive database of the program results is maintained. The program will extend the life of the wood pole assets by an average of ten years with a net benefit of $4.5 million in deferred replacement costs over that same period.

A report titled "Wood Pole Line Management Progress Report - 2006 Inspection Program" is included in Section H, Tab 5, of the Application which provides an update of the 2006 program, a progress report of 2007 work and a forecast of the proposed objectives for 2008 and beyond.

Future Plans:

This is an ongoing program that will provide for all poles to be inspected and treated and any poles rejected will be replaced. Future replacements will be proposed in future capital budget applications.

Project Title: Replace Insulators TL-232 and TL-253

Location: Stoney Brook to Buchans and Jackson's Arm to Coney Arm

Category: Transmission and Rural Operations - Transmission

Type: Pooled

Classification: Normal

Project Description:

TL-232 is a 230 kV radial transmission line running from Stony Brook to Buchans - a distance of 84 km. It is constructed with H-Frame wooden pole structures and steel towers (365 wood and two steel). The line was constructed in 1981 to provide a parallel link to the central region of the island. The line provides a critical link in providing energy to this region.

TL-253 is a 69 kV radial transmission line running from Jackson's Arm to Coney Arm - a distance of 12 km. The line was constructed in 1982 with wood pole structures to provide service to distribution systems in the area.

The scope of this project includes the replacement of all suspension insulators on these transmission lines.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	534.0	90.0	0.0	624.0
Labour	163.0	155.0	0.0	318.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	405.0	0.0	405.0
Other Direct Costs	38.0	27.0	0.0	65.0
O/H, AFUDC & Escalation	89.9	174.5	0.0	264.4
Contingency	23.1	118.1	0.0	141.2
Total	848.0	969.6	0.0	1,817.6

Project Cost: *($ x1,000)*	**TL-232**	**TL-253**
Material Supply	540.0	84.0
Labour	209.0	109.0
Consultant	0.0	0.0
Contract Work	405.0	0.0
Other Direct Costs	27.0	38.0
O/H, AFUDC & Escalation	231.8	32.6
Contingency	118.1	23.1
Total	1,530.9	286.7

Project Title: Replace Insulators TL-232 and TL-253 **(cont'd.)**

Operating Experience:

Each year of the annual preventive maintenance cycle, approximately 20% of the lines undergo insulator testing and defective Canadian Ohio Brass Company (COB) insulators are detected. Over a five year cycle, the number of structures with defective insulators averages 13%. This failure rate is typical of the COB insulators failing in a random manner and thus insulators tend to fail without warning. As seen with other lines on the system, this trend is expected to continue with each inspection cycle making the replacement of only the defective insulators cost prohibitive and a poor long term strategy. Wide spread failure of COB insulators in the utility industry has resulted in Hydro deciding to remove these insulators to ensure reliability of these lines. All lines have been prioritized based on the criticality of the line, number and location of COB insulators and performance indices.

Project Justification:

The insulators presently in-service were manufactured by COB, and were installed during the original construction of TL-232 and TL-253. These COB insulators are part of a group of insulators that have experienced industry wide failures due to cement growth causing radial cracks that resulted in moisture intrusion. Given the industry wide failure rates for COB insulators of this vintage, replacing them at this time represents the least customer impact as well as the most effective strategy and will result in the increased reliability of these systems.

TL-232 is a critical component in providing system reliability, especially during periods of peak loading. The failure of existing COB insulators would result in system wide ramifications. This project is proposed over the course of two years due to the long delivery time (six to eight months) on suspension insulators.

TL-253 is only 12 km, serving approximately 811 customers on the Jackson's Arm, Hampden and Coney Arm distribution systems and Rattle Brook Generating Station. This project can be completed in one year utilizing in-stock inventory of insulators.

Future Plans:

None.

Project Title: Upgrade Frequency Converter

Location: Corner Brook Terminal Station

Category: Transmission and Rural Operations - Transmission

Type: Other

Classification: Normal

Project Description:

This project consists of the replacement of the starting system, voltage regulation system and rewind of the 60 Hz rotor, for the Corner Brook Frequency Converter.

Initially there were two frequency converters on the system, one at Corner Brook and one at Grand Falls. The Grand Falls unit was de-commissioned in 2002. Since both converters were identical designs, the rotor from Grand Falls will be taken and rewound in 2008. This rewind will take several months. Once the rewound rotor is received back at Corner Brook, the Corner Brook Converter will be taken out of service and the new rewound rotor installed. This strategy will minimize the downtime on the Corner Brook Converter.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	81.0	2.0	0.0	83.0
Labour	153.0	38.0	0.0	191.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	210.0	800.0	0.0	1,010.0
Other Direct Costs	0.0	4.0	0.0	4.0
O/H, AFUDC & Escalation	50.5	179.5	0.0	230.0
Contingency	0.0	128.8	0.0	128.8
Total	**494.5**	**1,152.3**	**0.0**	**1,646.8**

Operating Experience:

The starting system and voltage regulator designs are obsolete and have been a source of continuous maintenance difficulties. The technology is outdated and parts and servicing is unavailable.

Project Title: Upgrade Corner Brook Frequency Converter **(cont'd.)**

Project Justification:

This work is recommended in an Engineering report entitled "Engineering Condition Assessment of the Corner Brook Frequency Converter - April 7, 2005" under Section H, Tab 3 of Hydro's 2006 Capital Budget Application. Installation of new starting and voltage regulation systems, which can be maintained over the long term, must be completed to ensure the reliability of this installation.

Future Plans:

None.

Project Title: Replace Line Camp 98 - TL-228

Location: TL-228 at Structure 98

Category: Transmission and Rural Operations - Transmission

Type: Other

Classification: Normal

Project Description:

This project involves the demolition of the existing brick clad wood frame survival building located near structure 98 on TL-228. A new 24' x 32' concrete block metal clad survival building will be constructed at the same location. This project is required to ensure the timely restoration of transmission line TL-228 in the event of a catastrophic failure during winter storm conditions. Environmental permits for demolition and construction will be required for this project.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	5.0	0.0	0.0	5.0
Labour	50.0	0.0	0.0	50.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	307.2	0.0	0.0	307.2
Other Direct Costs	50.0	0.0	0.0	50.0
O/H, AFUDC & Escalation	46.6	0.0	0.0	46.6
Contingency	41.2	0.0	0.0	41.2
Total	**500.0**	**0.0**	**0.0**	**500.0**

Operating Experience:

The existing survival building near structure 98 on transmission line TL-228 is approximately 35 years old. This building is used as a base camp for emergency restoration work, and is considered to be the most critical of the 15 survival buildings that exist within Hydro. Due to infrequent use and maintenance neglect the building is currently not habitable.

Project Justification:

A new survival building is required near structure 98 on transmission line TL-228 to house work crews in the event of a catastrophic failure of the line. The nearest access road to this location is 30 kilometers to the west. The existing survival building is approximately 35 years old and at the end of its useful life. From a structural perspective a major upgrade of this building would not be practical

Project Title: Replace Line Camp 98 - TL-228 **(cont'd.)**

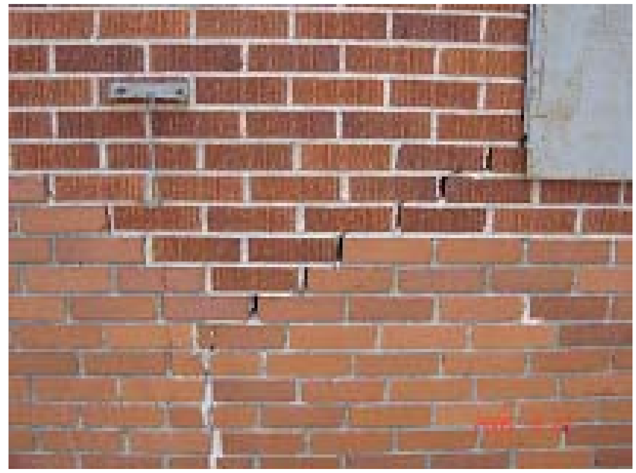
Project Justification: (cont'd.)

because the exterior load bearing walls require replacement due to extensive deterioration (see attached pictures). From a health perspective this building is not habitable due to mold and mildew issues. Therefore, it is necessary that a new building be constructed at this critical location. This new building will continue to be used as a base camp for emergency line restoration work.

Future Plans:

None.

Project Title: Replace Line Camp 98 - TL-228 **(cont'd.)**



Project Title: Upgrade Line TL-212

Location: Sunnyside to Linton Lake

Category: Transmission and Rural Operations - Transmission

Type: Other

Classification: Normal

Project Description:

This project will upgrade 14 locations along TL-212 where low clearances have resulted in outages on the line. Operation (clearance) problems have occurred in the steel sections of TL-212. These events not only disrupt service but are a major safety issue.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	205.0	0.0	0.0	205.0
Labour	38.0	0.0	0.0	38.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	132.4	0.0	0.0	132.4
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	50.8	0.0	0.0	50.8
Contingency	37.5	0.0	0.0	37.5
Total	**463.7**	**0.0**	**0.0**	**463.7**

Operating Experience:

Over the last several years, clearance problems have occurred in the steel sections of TL-212. There has been a history of outages caused by these clearances, in addition to the safety hazards associated with the condition.

Project Justification:

There are 14 locations on TL-212 where line clearance does not meet the standard clearance of 22 feet. These clearance problems present both safety and operating concerns. To improve the operation performance of the line and reduce the risk to the general public it is necessary to correct the clearance problems associated with TL-212.

Future Plans:

None.

Project Title: Construct Transmission Line Equipment Off-Loading Areas

Location: Various Sites

Category: Transmission and Rural Operations - Transmission

Type: Other

Classification: Mandatory

Project Description:

It is estimated that there are approximately 100 roadside locations that require either construction of new earthen ramps or improvements to existing access sites. These areas are located on the Bay d'Espoir, Burin Peninsula, Buchans, Spingdale, Hampton, Jackson's Arm, Howley, and Burgeo highways. The 20 sites proposed to be constructed in 2008 are situated on the Buchans and Burgeo highways.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	35.0	0.0	0.0	35.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	200.0	0.0	0.0	200.0
Other Direct Costs	16.0	0.0	0.0	16.0
O/H, AFUDC & Escalation	25.7	0.0	0.0	25.7
Contingency	25.1	0.0	0.0	25.1
Total	**301.8**	**0.0**	**0.0**	**301.8**

Operating Experience:

Hydro's transmission crews gain access to transmission lines from hundreds of different points along the Trans Canada Highway and the province's secondary highways. There are designated trails that connect the highways to the transmission line access points. In a great number of these locations, particularly on the secondary highways, Hydro's transmission crews face unsafe conditions when unloading off-road vehicles from trucks and trailers due to narrow shoulders and steep embankments. At many of the sites, traffic lanes have to be blocked off to unload the equipment which creates hazards to the motoring public and to Hydro's employees. In many cases, the highway sight lines to these trail access locations are short which is especially hazardous in rain, fog, snow or icy conditions.

Project Title: Construct Transmission Line Equipment Off-Loading Areas **(cont'd.)**

Operating Experience: (cont'd.)

Where there is no safe and legal parking in close proximity to the trail access points, transmission maintenance crews face delays in moving their vehicles to safe parking areas and retrieving them when work is completed. In addition, off-loading equipment in these locations often requires additional personnel for traffic control. In areas where safe highway access to an approved trail is not available, crews are required to travel long distances along transmission line right-of-ways to gain access to work locations. Because off-road travel is so much slower than highway travel, this can cause significant delays and result in reduced productivity. Please see attached photos for illustration of the existing operating conditions.

Project Justification:

The primary justification for this project is the safety of the motoring public and of Hydro's employees. A secondary justification is reduced times and reduced numbers of personnel to deploy off-road vehicles and maintenance staff to carry out work. An engineering report entitled "Transmission Line Equipment Off-Loading Sites" is attached, Section H Tab 6.

Future Plans:

Further construction projects will be proposed in future capital budget applications.

Project Title: Construct Transmission Line Equipment Off-Loading Areas **(cont'd.)**

Truck is parked on a narrow highway shoulder causing partial obstruction to traffic. Note pylons placed in the adjacent traffic lane.

This section of the highway shows a steep-sloped roadside embankment, making offloading at this location very difficult. In this case, the excavator was offloaded at a separate location and traveled to the transmission site.

Vehicles are unable to move off the paved driving surface while attempting to park on the shoulder.

This highway location shows a very narrow shoulder (less than 0.5 m). Roadside vehicles which may be parked at this location would pose a hazard for on-coming traffic.

Project Title: Replace Insulators

Location: Various Stations

Category: Transmission and Rural Operations - Transmission

Type: Other

Classification: Normal

Project Description:

This project involves the purchase and installation of 230, 138, 69 and 25 kV, station post and suspension insulators, at various terminal stations in the Central Region. Due to the quantity of insulators to be replaced and the number of outages required to complete the work, the plan is to complete the replacements over a five-year period. This capital budget proposal is for year three of the five-year plan.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	125.0	0.0	0.0	125.0
Labour	119.0	0.0	0.0	119.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	18.0	0.0	0.0	18.0
O/H, AFUDC & Escalation	32.3	0.0	0.0	32.3
Contingency	0.0	0.0	0.0	0.0
Total	**294.3**	**0.0**	**0.0**	**294.3**

Operating Experience:

Canadian Ohio Brass (COB), multicone and cap and pin insulators are known to have cement growth problems which result in insulator failures causing bus or station outages. Cement growth occurs when moisture is absorbed in the cement and through the thermal cycle process pressure is applied to the porcelain resulting in cracks in the insulator. Such cracks will reduce the electrical and mechanical strength of the insulator. This problem has been well documented in the utility industry and as a result, Hydro has been replacing COB insulators on its transmission lines for several years. In terminal stations, there have been several in-service failures causing major outages to customers. An example of this was the failure of a cap and pin insulator on Bus 4 disconnect at Massey Drive Terminal Station in 2002 which resulted in process interruptions for Corner Brook Pulp and Paper. Also, insulators have broken off while crews have been performing maintenance, creating unsafe conditions for workers.

Project Title: Replace Insulators **(cont'd.)**

Operating Experience: (cont'd.)

The history of expenditures for this project for the past four years is as follows:

Year	Budget ($000)	Actuals ($000)
2006	306.8	256.2
2005	228.0	163.3
2004	0.0	0.0
2003	236.3	253.5

Project Justification:

Insulators provide electrical insulation between energized and de-energized equipment and ground. When insulators fail they provide a short circuit to ground, which could result in an outage to customers. To help prevent such outages from occurring, Hydro plans to replace all COB, multicone and cap and pin insulators in all of its terminal stations within the next five years. Year one of this five-year plan began in 2006 with the replacement of 20% of the problem insulators.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Upgrade Distribution Systems

Location: Various Systems

Category: Transmission and Rural Operations - Distribution

Type: Pooled

Classification: Normal

Project Description:

This project consists of general upgrades to the following distribution systems:

1. Glenburnie system, Line 1 serving the community of Curzon Village;
2. St. Anthony system, Line 3 serving the Goose Cove area and the downtown area of St. Anthony;
3. Mary's Harbour system
4. Port Hope Simpson system
5. Bear Cove system, Line 4 serving the community of Anchor Point;
6. South Brook system, Line 1 serving the Robert's Arm/Triton area; and,
7. Wabush system, Line 11 serving the Aliant Variable Omni-Directional Radio (VOR) on Beacon Tower. This tower is part of the NAV Canada navigation system for the airport.

The project includes the replacement of pin type insulators and suspension insulators, cutouts and crossarms plus other equipment including automatic splicing sleeves, deadends, substandard and deteriorated primary and secondary conductor.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	649.0	0.0	0.0	649.0
Labour	364.5	0.0	0.0	364.5
Consultant	0.5	0.0	0.0	0.5
Contract Work	1,147.0	0.0	0.0	1,147.0
Other Direct Costs	92.0	0.0	0.0	92.0
O/H, AFUDC & Escalation	248.5	0.0	0.0	248.5
Contingency	225.8	0.0	0.0	225.8
Total	**2,727.3**	**0.0**	**0.0**	**2,727.3**

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

Project Cost: *($ x1,000)*	**Glenburnie System**	**St. Anthony System**	**Mary's Hr. System**	**Port Hope Simpson System**
Material Supply	130.5	136.0	62.5	41.0
Labour	67.0	107.0	40.0	37.5
Consultant	0.0	0.0	0.5	0.0
Contract Work	230.0	130.0	105.5	82.0
Other Direct Costs	14.5	22.0	9.0	9.0
O/H, AFUDC & Escalation	47.6	45.6	24.1	18.9
Contingency	44.3	39.5	21.9	17.0
Total	**533.9**	**480.1**	**263.5**	**205.4**

Project Cost: *($ x1,000)*	**Bear Cove System**	**South Brook System**	**Wabush L1 System**
Material Supply	41.5	220.5	17.0
Labour	30.5	62.0	20.5
Consultant	0.0	0.0	0.0
Contract Work	45.5	512.0	42.0
Other Direct Costs	7.0	21.5	9.0
O/H, AFUDC & Escalation	12.8	89.7	9.8
Contingency	12.5	81.7	8.9
Total	**149.8**	**987.4**	**107.2**

Operating Experience:

The lines and poles on these systems have been subjected to numerous ice storms and high winds. There has been an extremely high rate of failure of S&C cutouts over the years. The blackjack poles have been in place since the lines were constructed. The #4 copper conductor has been in service since the systems were built and has failed on a number of occasions due to ice loading and high winds. A section of the lines have long histories of outages and problems due to the extreme weather conditions and equipment failures experienced. The S&C cutouts, in particular, are prone to porcelain failure when being opened or closed and are a safety risk to employees.

Project Justification:

Regular inspections of these systems resulted in deficiencies being identified. Pin type insulators are the original equipment, and the porcelain type insulators are prone to failure. Falling shards of broken porcelain pose a risk to the worker and the dangling energized primary lead could contact the pole or other equipment in the pole causing a violent flash or could cause other equipment to become energized, putting the worker at risk of electrical contact.

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

Project Justification: (cont'd.)

The copper conduit becomes brittle and susceptible to failure. Failure to complete the work could result in significant interruptions of power to customers in these communities.

Future Plans:

None.

Project Title: Upgrade Distribution Systems

Location: All Service Areas

Category: Transmission and Rural Operations - Distribution

Type: Pooled

Classification: Normal

Project Description:

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

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	975.0	0.0	0.0	975.0
Labour	935.0	0.0	0.0	935.0
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 & Escalation	173.0	0.0	0.0	173.0
Contingency	210.0	0.0	0.0	210.0
Total	**2,293.0**	**0.0**	**0.0**	**2,293.0**

Operating Experience:

An analysis of historical expenditures (i.e. 2002 - 2006) on distribution upgrades is shown in the following table. All historical dollars (table below) were converted to 2006 dollars using the Statistics Canada Utility Distribution Line Construction Index and a five-year average calculated.

Region	**Avg. Annual Expenditures (2002 - 2006) (2006 $Thousands)**
Central	885
Northern	938
Labrador	396
Total	2,219

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

Operating Experience: (cont'd.)

The five year actual expenditures for these areas are as follows:

Region	Expenditures ($000)									
	2002		2003		2004		2005		2006	
	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual
Central	551	429	576	816	531	964	628	1,135	701	909
Northern	614	803	628	587	611	1,274	616	996	836	835
Labrador	165	443	272	255	329	432	357	364	375	404
Total	$ 1,330	$ 1,675	$ 1,476	$1,658	$ 1,471	$ 2,670	$ 1,601	$ 2,495	$ 1,912	$ 2,148

Project Justification:

Based on this five-year average for distribution system upgrades for the period 2002 - 2006 the following budget was developed, assuming distribution line cost escalation in 2008 of approximately 2.3%.

Region	2008 Budget ($000)
Central	915
Northern	969
Labrador	409
Total	2,293

Future Plans:

This is an annual allotment which is adjusted from year to year depending on historical expenditures.

Project Title: Provide Service Extensions

Location: All Service Areas

Category: Transmission and Rural Operations - Distribution

Type: Pooled

Classification: Normal

Project Description:

This project is an annual allotment based on past expenditures to provide for service connections (including street lights) to new customers. This summary identifies the total budget for all three operating regions.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	917.0	0.0	0.0	917.0
Labour	881.0	0.0	0.0	881.0
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 & Escalation	165.0	0.0	0.0	165.0
Contingency	195.0	0.0	0.0	195.0
Total	2,158.0	0.0	0.0	2,158.0

Operating Experience:

An analysis of average historical expenditure (i.e. 2002 - 2006) on new customer connections is shown in the following table. All historical dollars were converted to 2006 dollars using the Statistics Canada Utility Distribution Line Construction Index and a 5-year average was calculated.

Region	**Avg. Annual Expenditures (2002 - 2006) (2006 $Thousands)**
Central	880
Northern	616
Labrador	592
Total	2,089

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

Operating Experience: (cont'd.)

The five year actual expenditures for these areas are as follows:

Region	Expenditures ($000)									
	2002		2003		2004		2005		2006	
	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual
Central	331	631	459	854	503	1,070	619	840	761	824
Northern	327	530	432	472	464	729	504	611	580	614
Labrador	323	787	557	473	591	484	605	556	643	535
Total	$ 1,001	$ 1,948	$ 1,048	$1,799	$ 1,558	$ 2,283	$ 1,828	$ 2,007	$ 1,984	$ 1,973

Project Justification:

Based on the five-year average of service extension expenditures for the period 2002 - 2006 the following budget was developed assuming distribution line cost escalation in 2008 of 2.3%.

Region	**2008 Budget ($000)**
Central	910
Northern	637
Labrador	612
Total	2,158

Future Plans:

This is an annual allotment, which is adjusted from year to year depending on historical expenditures.

Project Title: Replace Poles

Location: South Brook and Bay d'Espoir

Category: Transmission and Rural Operations - Distribution

Type: Pooled

Classification: Normal

Project Description:

This project consists of pole replacement on the following distribution systems:

1. A portion of the South Brook distribution Line 1 servicing the communities of South Brook, Port Anson, and Miles Cove. This project includes the replacement of 75 deteriorated poles on the system.
2. A portion of the Bay d'Espoir distribution Line 1 servicing the communities of St. Joseph's, St. Vincent's, St. Veronica, Milltown, Morrisville and St. Alban's. This project includes the replacement of 50 deteriorated poles on the system.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	154.5	0.0	0.0	154.5
Labour	99.7	0.0	0.0	99.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	293.7	0.0	0.0	293.7
Other Direct Costs	29.5	0.0	0.0	29.5
O/H, AFUDC & Escalation	65.0	0.0	0.0	65.0
Contingency	57.8	0.0	0.0	57.8
Total	**700.2**	**0.0**	**0.0**	**700.2**

The breakdown is as follows:

Project Cost: *($ x1,000)*	**South Brook System**	**BDE System**
Material Supply	85.0	69.5
Labour	53.0	46.7
Consultant	0.0	0.0
Contract Work	154.0	139.7
Other Direct Costs	19.5	10.0
O/H, AFUDC & Escalation	34.8	30.2
Contingency	31.2	26.6
Total	**377.5**	**322.7**

Project Title: Replace Poles **(cont'd.)**

Operating Experience:

This South Brook distribution system was constructed in the mid 1960's and the original poles are still part of the existing system. Regular maintenance inspections identified 75 poles on the South Brook System to be of substandard quality due to age deterioration resulting in an unacceptable number of near vertical splits. The existing poles are 37 years old.

Regular maintenance inspection identified 50 poles on the Bay d'Espoir System to be of substandard quality due to age deterioration resulting in an unacceptable number of near vertical splits. The existing poles are 37 years old.

Project Justification:

The existing poles were identified as being "B" condition which indicates that they be replaced in 1 to 5 years. These poles will create climbing hazards for the line personnel. In the interest of safety, system reliability and to minimize the System Average Interruption Duration Index (SAIDI) impact it is recommended to complete the work under planned conditions rather than an emergency call out situation. Failure to complete this work could result in significant interruptions of power supply to Hydro's customers in these communities.

Future Plans:

None.

Project Title: Replace Insulators

Location: Various Systems

Category: Transmission and Rural Operations - Distribution

Type: Pooled

Classification: Normal

Project Description:

This project consists of insulator replacements on the following systems:

1. Westport system, Line 2 serving the communities of Westport and Purbeck's Cove on the Baie Verte Peninsula.
2. Coney Arm system, Line 1 serving the various facilities of the Cat Arm Generating Station.
3. Hinds Lake system, Line 1 serving the various facilities of the Hinds Lake Generating Station.
4. Upper Salmon system, Line 1 serving the various facilities of the Generating Station.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	170.5	0.0	0.0	170.5
Labour	100.5	0.0	0.0	100.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	206.0	0.0	0.0	206.0
Other Direct Costs	37.0	0.0	0.0	37.0
O/H, AFUDC & Escalation	56.9	0.0	0.0	56.9
Contingency	51.6	0.0	0.0	51.6
Total	**622.5**	**0.0**	**0.0**	**622.5**

The breakdown of the costs by individual system is as follows:

Project Cost: *($ x1,000)*	**Westport**	**Coney Arm**	**Hind's Lake**	**Upper Salmon**
Material Supply	13.5	29.0	52.5	75.5
Labour	22.9	26.6	23.0	28.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	30.5	38.0	56.0	81.5
Other Direct Costs	7.5	11.0	8.0	10.5
O/H, AFUDC & Escalation	8.3	11.7	15.2	21.7
Contingency	7.5	10.5	14.0	19.6
Total	**90.2**	**126.8**	**168.7**	**236.8**

Project Title: Replace Insulators **(cont'd.)**

Operating Experience:

These insulators have been in service for over 20 years and were manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP). These insulators have been a problem throughout the Hydro system. Failure of these insulators generally occurs during adverse weather conditions and as a result impact restoration time considerably.

Project Justification:

Regular inspections have identified insulators with hairline cracks through the porcelain. These insulators have experienced industry-wide failures due to cement growth breakdown causing radial cracking that resulted in moisture intrusion. Replacement of these insulators is essential to improve system security and reliability. Mechanical breakdown of the insulators is a safety issue with line workers.

Future Plans:

None.

Project Title: Replace Recloser Control Panels
Location: Various Systems
Category: Transmission and Rural Operations - Distribution
Type: Other
Classification: Normal

Project Description:
This project involves the purchase and installation of eight stainless steel control panels for distribution reclosers. This consists of: two for Change Islands (CH2-R1, CH3-R1), three for Fogo Island (FO4-R1, FO5-R1 FO6-R1) and three for Bottom Waters (BW1-R1, BW2-R1, BW3-R1).

Four of these distribution reclosers will also require an upgrade of their sensing CTs in order to be compatible with the latest version digital control. The recloser control panel would be in compliance with Hydro Engineering Distribution Standard D1-06-01 (latest revision) which is 'Three Phase Electronic Recloser Specification'. Remote Supervisory Control and Data Acquisition (SCADA) access capability is also included in the upgrade. Operating and Maintenance Training will be provided by the manufacturer for operating staff in 2008 which is the first year of the recloser replacement program for Central Region.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	120.0	0.0	0.0	120.0
Labour	44.0	0.0	0.0	44.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	18.0	0.0	0.0	18.0
O/H, AFUDC & Escalation	22.1	0.0	0.0	22.1
Contingency	18.4	0.0	0.0	18.4
Total	**222.5**	**0.0**	**0.0**	**222.5**

Operating Experience:
These electronic recloser control panels are mounted outdoors and are therefore exposed to all weather conditions including severe salt contamination in rural coastal communities. The majority of these reclosers were installed in the 1980's and a rusting problem with their painted steel control cabinet has become an ongoing maintenance problem at these locations. The weather conditions that these recloser control panels have been subjected to over their 20 year life has caused severe

Project Title: Replace Recloser Control Panels **(cont'd.)**

Operating Experience: (cont'd.)

rusting of the painted steel enclosure which in turn has caused corrosion to the internal electronic circuit boards. This type of problem has already affected the operating integrity of the distribution reclosers at Change Islands, Fogo Island and Burgeo. See attached photographs.

Project Justification:

The distribution recloser is a key protective device for detection of various types of system faults and the automatic restoration of power when these line faults are only temporary in nature, and it also enables isolation of the faulted line section should the system fault be permanent. Therefore, the operating integrity of this key protective device must not be compromised by the failure of an internal electronic component as the result of a severe rusting condition for the recloser control panel. The replacement recloser control cabinet shall be stainless steel construction which is now the standard design requirement for new installations in order to protect against severe salt contamination. The new recloser control will also have remote control capability should a future telecommunications network be established at these sites.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Replace Recloser Control Panels **(cont'd.)**


Change Islands Recloser FH1-R1


Change Islands Recloser FH1-R1


Change Islands Recloser FH1-R1


Change Islands Recloser CH3-R1


Change Islands Recloser CH3-R1

Project Title: Reconfigure Feeders

Location: Happy Valley

Category: Transmission and Rural Operations - Distribution

Type: Other

Classification: Normal

Project Description:

The scope of the work involves the following:

1. Construction of approximately 400 metres of 3-Phase line using 4/0 AASC conductor to extend Line 2 to connect into what is currently Line 10 between Poles 3 and 4. The section of Line 10 between the terminal station and pole 4 would be de-energized during this time to allow connection of Line 2.

2. Construct span with disconnect between Line 3 and C38 at the intersection of Grand Street and Cabot Crescent (approx 75 m). A portion of Line 5 would be switched onto Line 3.

3. The load on Line 10 is to be transferred to Line 16 by closing Normally Opened (N/O)Tie Switch Line 10 to Line 16-1.

4. Recloser No. HS2-R1 is to be relocated to a location near the beginning of Line 16 to protect Line 10 from faults on Line 16.

5. Protection settings on Recloser No. HV16-R1 will need to be adjusted to accommodate the increase in load from Line 10.

6. A new N/O Tie Switch will be added between Line 2 and Line 10 as a provision for switching loads during maintenance.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	38.0	0.0	0.0	38.0
Labour	29.5	0.0	0.0	29.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	40.0	0.0	0.0	40.0
Other Direct Costs	16.5	0.0	0.0	16.5
O/H, AFUDC & Escalation	14.3	0.0	0.0	14.3
Contingency	12.4	0.0	0.0	12.4
Total	**150.7**	**0.0**	**0.0**	**150.7**

Project Title: Reconfigure Feeders **(cont'd.)**

Operating Experience:
Not applicable.

Project Justification:
The distribution system in Happy Valley has experienced considerable growth in recent years, with the strongest growth on feeders 1, 7, and 8. Feeders 1 and 8 are the primary lines which supply Happy Valley, and the most heavily loaded feeders in the Happy Valley Distribution System. These feeders supply power to Hunt Street Substation, and Corte Real Substation. From Hunt Street Substation feeders 2, 3, and 4 extend into primarily the western end of Happy Valley, and feeders 5 and 6 extend from Corte Real Substation into the Eastern end of the town.

The main trunk section of Line 1 is constructed of 2/0 ACSR conductor, while the main trunk section of Line 8 is constructed of 477 ASC conductor as far as Hunt Street Substation and 2/0 ACSR conductor from Hunt Street Substation to Corte Real Substation.

The conductor 2/0 ACSR has a rated winter ampacity of 353 A, and 477 ASC has a rated winter ampacity of 785 A. For a three-phase line operating at 25 kV the capacity of the 2/0 ACSR and 477 ASC lines is 15.25 MVA and 33.9 MVA respectively.

The load on Line 1 is nearing the rated capacity of the 2/0 ACSR conductor. A new Long Term Care Facility (approximately 1.5 MW) will be constructed adjacent to the Melville Health Centre in 2009 and will be supplied from Line 2. The addition of this new load will result in the overload of Line 1. As a result upgrading will be required in 2008 in anticipation of this new load. Options investigated for addressing the loading on Line 1 included reconductoring of Line 1 with a larger capacity conductor, transferring some load from Line 1 to Line 8, or constructing a third feeder into the Happy Valley region.

Reconductoring of Line 1 addresses the problem of load on Line 1 but there is also a limitation with the primary protection at the Happy Valley terminal station and in order to increase the loading on Line 1 it will also be necessary to replace the existing recloser on Line 1 with a circuit breaker.

Project Title: Reconfigure Feeders **(cont'd.)**

Project Justification: (cont'd.)

While Line 8 has considerable room for additional growth there is the same problem with the primary protection at the Happy Valley Terminal station and in order to transfer additional load onto Line 8 it will also be necessary to replace the existing recloser with a circuit breaker.

Typically feeder construction would be the most costly option, however the Happy Valley system is an exception. Over time extensions to Line 2 from Hunt Street Substation have brought the end of this feeder very near to the Happy Valley Terminal Station. Extending this feeder (approximately 400 metres) and connecting it to Happy Valley terminal station effectively creates a third feeder in the Happy Valley area from the main terminal station. Line 2 currently carries 60 % of the power delivered to Hunt Street Substation by Line 1. This reconfiguration will allow Line 1 to be significantly off-loaded freeing up capacity to handle future load growth.

The options of reconductoring Line 1 and replacing the reclosers at the terminal station with breakers are orders of magnitude higher in cost than the above option, and as such a detailed economic analysis of these options was not performed.

The system in its existing configuration will not be able to accommodate the load growth for beyond the forecast period. The above option is the preferred technical and economic alternative to ensure quality of service to customers for beyond the forecast period.

Future Plans:

None.

Project Title: Reconfigure Feeders **(cont'd.)**

Project Justification: (cont'd.)

Table 1: Load Forecast Fall 2006

Happy Valley Distribution System
Forecasted Loads for Feeders 1, 2, and 8 at point of supply.

Forecasted primary feeder loads without reconfiguration						
Year	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Peak Demand L1 (MW)	13.9	14	14.2	14.5	14.7	14.9
Peak Demand L2 (MW)*	7.3	7.4	7.5	7.6	7.7	7.8
Peak Demand L8 (MW)	13.8	14	14.2	14.4	14.6	14.8
* L2 is fed by L1 at Hunt Street Substation.						
Forecasted primary feeder loads after reconfiguration						
Year	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Peak Demand L1 (MW)	9.2	9.3	9.5	9.6	9.8	9.9
Peak Demand L2 (MW)	7.4	7.5	7.6	7.7	7.8	7.9
Peak Demand L8 (MW)	10.8	10.9	11.1	11.3	11.4	11.6

* L2 is fed by from the Happy Valley Terminal Station.

Based on Fall 2006 Operating Load Forecast provided by Economic
Analysis Branch of System Planning

Future Plans:

None.

Project Title: Replace Submarine Cable Terminator

Location: Gaultois

Category: Transmission and Rural Operations - Distribution

Type: Other

Classification: Normal

Project Description:

Replace eight terminators on the mainland to the Gaultois Distribution system submarine cables.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	20.5	0.0	0.0	20.5
Labour	27.0	0.0	0.0	27.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	6.0	0.0	0.0	6.0
O/H, AFUDC & Escalation	5.5	0.0	0.0	5.5
Contingency	5.4	0.0	0.0	5.4
Total	**64.4**	**0.0**	**0.0**	**64.4**

Operating Experience:

This submarine cable system was constructed in 1988 with terminators having an expected service life of 20 years. Since its installation, there have been three terminators replaced due to premature failures. When a terminator fails, it results in a total power outage to the community. The terminator site is inaccessible by land, and a helicopter must be used to access this site. In poor weather conditions, this results in extended outages of approximately one or two days.

Project Justification:

Maintenance inspections indicate that the remaining terminators are aged and deteriorated. Failures combined with the expiration of the expected service life, could result in significant interruptions of power supply to Hydro's 126 customers on this distribution system.

Future Plans:

None.

Project Title: Replace Diesel Units

Location: Norman Bay, Cartwright and Black Tickle

Category: Transmission and Rural Operations - Generation

Type: Pooled

Classification: Normal

Project Description:

This project consists of the following:

1. Norman Bay: Replacement of Unit No. 561 (30 kW) with a 36 kW unit and plant automation.
2. Cartwright: Replacement of Unit No. 567 (600 kW) with a 470 kW unit.
3. Black Tickle: Replacement of Unit No. 287 (300 kW) with a 300 kW unit.

As well as the genset replacement, the work also includes replacement of the mufflers and exhaust systems. At Norman Bay and Black Tickle, the work will also include the replacement of the unit control switchgear.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	192.5	443.9	0.0	636.4
Labour	87.5	204.7	0.0	292.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	22.4	69.7	0.0	92.1
O/H, AFUDC & Escalation	32.0	117.7	0.0	149.7
Contingency	0.0	102.2	0.0	102.2
Total	334.4	938.1	0.0	1,272.5

Project Cost: *($ x1,000)*	**Norman Bay**	**Cartwright**	**Black Tickle**
Material Supply	189.5	254.4	192.5
Labour	109.5	98.9	83.8
Consultant	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0
Other Direct Costs	28.0	31.3	32.8
O/H, AFUDC & Escalation	50.5	58.4	40.8
Contingency	32.8	38.5	30.9
Total	410.3	481.4	380.8

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

Operating Experience:

At Norman Bay, Unit No. 561 has 77,423 cumulative operating hours and has been overhauled four times. The plant presently has three gensets which are started and stopped automatically based on system load. The plant control system is hard-wired relay logic that is interfaced to each engine controller, which together with a master load controller, was installed as a packaged system in the 1980's and is now obsolete. There have been 50 forced system outages over the last five years caused by genset shutdown and the majority of these were caused by failure of a genset to come on-line once initiated by the Amster load controller. The present automatic control system also has no computer equipment interface to provide a detailed log of diesel generating equipment alarms and shutdowns in order to establish the sequence of events (SOE) following each power system outage.

Unit No. 567 was purchased and installed in Cartwright diesel plant in 1996. In recent years this genset has had considerable downtime because of delays in obtaining replacement parts for maintenance. Examples of the delays include more than a month to obtain a crankshaft, and 40 days to obtain cylinder liners and piston rings. This unit is currently on restricted use due to low compression on two cylinders and is derated to 350 kW.

Unit No. 287 in Black Tickle was installed in 1978. It has 110,289 cumulative operating hours with 44,429 operating hours since the last major overhaul (as of March 24, 2007). It has been overhauled three times and an overhaul originally scheduled for 2005 will be partially performed in 2007 to extend operating life into 2008. Due to long deliveries on new equipment, a new genset will be tendered in 2008 and installed in 2009, by which time Unit 287 will have an expected 115,000 to 120, 000 cumulative operating hours. This unit should be replaced based upon the 90,000 hour replacement criteria.

Project Justification:

The generation/switchgear replacement portion of this project is justified on end of life replacement. The generators have either met the established criteria for replacement of 90,000 hours, or exhibit extenuating operating problems that dictate replacement. Replacement is required to meet the firm generation requirement for the plants.

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

Project Justification: (cont'd.)

In the case of Norman Bay, short duration loads have a significant effect on the plant and cause disturbances to the system, which exceed plant capacity and cause total plant outages. The existing master load controller, which was installed in the 1980's is not capable of dispatching the generators to mitigate the effects of these system disturbances.

The new plant automation involves logic controllers, computer equipment and an operator display interface which is compatible with the latest diesel genset digital control and data network. The new plant automation system will reduce the number of power system outages and be able to provide a computer log of SOE should any power system disturbances or system outages occur. These replacements units will also offer improved fuel efficiency, and lower emissions thus improving the plant's overall performance.

Future Plans:

None.

Project Title: Diesel Plant Automation

Location: Makkovik and Rigolet

Category: Transmission and Rural Operations - Generation

Type: Pooled

Classification: Normal

Project Description:

This project includes the purchase and installation of programmable logic controller (PLC) and personal computer (PC) equipment required for the automation of generating equipment at both diesel plants. The operator interface will provide all diesel generating data including a system event log for equipment alarms and shutdowns as well as substation recloser trips. Remote communications capability will be provided to the plant automation system for data access and download.

At Makkovik, the work also includes purchase and installation of three standard 600 V, 1000 amp diesel control panels complete with drawout type breaker for the existing generating units.

At Rigolet a 2 metre x 6 metre extension of the diesel plant is required in order to create a new control room (4 metre x 6 metre) which is required for installation of an operator console complete with computer server, monitor, printer and uninterruptible power supply.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	301.0	68.0	0.0	369.0
Labour	91.0	116.0	0.0	207.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	40.0	0.0	0.0	40.0
Other Direct Costs	30.0	60.0	0.0	90.0
O/H, AFUDC & Escalation	54.3	64.6	0.0	118.9
Contingency	0.0	70.6	0.0	70.6
Total	**516.3**	**379.2**	**0.0**	**895.5**

Project Cost: *($ x1,000)*	**Rigolet**	**Makkovik**
Material Supply	75.0	294.0
Labour	111.0	96.0
Consultant	0.0	0.0
Contract Work	40.0	0.0
Other Direct Costs	49.0	41.0
O/H, AFUDC & Escalation	45.1	73.8
Contingency	27.5	43.1
Total	**347.6**	**547.9**

Project Title: Diesel Plant Automation **(cont'd.)**

Operating Experience:

The plants are semi-attended therefore generation equipment alarms that occur while the operator is not there can't be acted upon in order to avoid a system outage, and the majority of the 41 forced system outages at Makkovik and the 22 at Rigolet since 2002 were related to generation equipment. One of the control panels to be replaced at Makkovik is 1970's vintage, is used on the diesel generating unit for load and fault interruption, and provides manual synchronizing only. The breaker itself is a fixed molded case design which requires a total diesel plant outage for maintenance checks and emergency repairs. The two remaining generating unit control panels at Makkovik are 1980's vintage and have drawout breakers with obsolete parts which have a history of failure.

Project Justification:

In each plant, the operator spends a significant amount of time manually starting and stopping various gensets. The plants are semi-attended therefore, the operator has only a certain amount of time to carry out all of the functions such as starting and stopping diesel units, equipment checks and maintenance. The time he spends on dispatching units lessens the time he has to do the checks and maintenance. Operating the plant in an efficient manner requires the operators to dispatch the diesel units for system load changes and this is especially important when the fish plant such as the one in Makkovik is operating.

If there is an equipment alarm on any of the gensets during the hours that the operator is not in the plant a shutdown of any genset will result in a system outage because of generation overload. If the plant was automated the alarmed genset would be replaced immediately by another genset and thus avoid a system outage and plant downtime.

Future Plans:

None.

Project Title: Increase Generation Capacity

Location: Charlottetown

Category: Transmission and Rural Operations - Generation

Type: Other

Classification: Normal

Project Description:

The purpose of this project is to increase generation at the Charlottetown Diesel Plant. This proposal consolidates all costs associated with replacement of diesel generating Units 204 (250 kW, Cat D343, circa 1980) and 2019 (250 kW, Cat 3406 circa 1988) with a new 725 kW unit, complete with new switchgear radiator, and exhaust stack to meet engine requirements.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	345.2	0.0	345.2
Labour	12.0	88.4	0.0	100.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	4.0	31.8	0.0	35.8
O/H, AFUDC & Escalation	2.2	62.9	0.0	65.1
Contingency	0.0	48.2	0.0	48.2
Total	**18.2**	**576.5**	**0.0**	**594.7**

Operating Experience:

Unit 204 currently has 84,991 cumulative operating hours and has been overhauled five times. It is expected to reach 90,000 hours by the time it is replaced in 2009.

Unit 2019 currently has 97,245 cumulative operating hours and has been overhauled five times.

Project Justification:

Increased generation at Charlottetown is needed by 2010 to maintain Hydro's firm generation requirements for customers served by this plant.

Project Title: Increase Generation Capacity **(cont'd.)**

Project Justification:

Engineering has identified that one 250 kW unit will have reached its maximum operating hours in 2009 and require replacement. A second 250 kW unit will require replacement due to its maximum operating hours criteria by 2010. Based on the most recent load forecast for the Charlottetown system, peak load will exceed firm capacity in early 2010. It is proposed to replace both existing 250 kW units with a single new 725 kW unit that will increase firm capacity by 225 kW for a total of 1,750 kW and ensure that firm capacity criterion is met beyond the forecast period. The replacement of two obsolete smaller (250 kW) units with a single larger 725 kW unit is the most cost effective means of addressing both the unit obsolescence and total growth requirement.

Analysis suggests that the optimal solution for Charlottetown would be three 725 kW units and the single 300 kW unit. This would provide enough firm generation to adequately serve load, for most if not all of the year, with only two of the three 725 kW units available at any time. The 300 kW unit would be used to shoulder the dispatching steps between placing more than one 725 kW unit online at any given time thus maintaining efficient loading on all online units. The effect would be increased fuel efficiency, reduced emissions and reduced operating costs.

The table below summarizes the existing and proposed station configuration, nameplate ratings and firm generation capacity.

	Installed kW (2007)	**Proposed Installed kW (2009)**
Diesel Generation Capacity	725 725 300 250 250	725 725 725 300
Total Generation Capacity	**2,250**	**2,475**
Firm Generation	**1,525**	**1,750**

Project Title: Increase Generation Capacity **(cont'd.)**

Project Justification: (cont'd.)

The following load projection is based on Hydro's "Operating Load Forecast Hydro Rural Systems 2006-2012" as prepared in fall 2006.

Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Peak Demand (kW Gross)	1,481	1,487	1,496	1,518	1,543	1,565	1,573
% of Firm Generation	97%	98%	98%	100%	101%	103%	103%

Future Plans:

None.

Project Title: Replace Switchgear

Location: Cartwright

Category: Transmission and Rural Operations - Generation

Type: Other

Classification: Normal

Project Description:

This project includes:

1. Purchase five standard switchgear control panels to replace existing 600 V switchgear,
2. Convert existing space into a separate control room for the switchgear control panels,
3. Install switchgear control panels, and
4. Purchase and install a power-system backup protective relay, including new current and potential transformer.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	287.0	21.0	0.0	308.0
Labour	43.0	48.0	0.0	91.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	14.0	22.0	0.0	36.0
O/H, AFUDC & Escalation	39.3	34.1	0.0	73.4
Contingency	0.0	43.5	0.0	43.5
Total	383.3	168.6	0.0	551.9

Operating Experience:

The existing switchgear control panels were installed in the 1980's and are now undersized for the control equipment installed in them. Electrical safety for operating and maintenance staff is an issue since some 600V power equipment is located alongside some control equipment, while some control equipment is mounted in the 600V compartment at the rear. The maintenance of these panels has become more frequent due to the present condition of the control equipment and wiring caused by continuing exposure to high levels of heat/humidity and vibration from the four diesel gensets in the engine hall. Control wiring identification is also in very poor condition and there are ongoing issues with terminal block alignment and space. Operating and maintenance staff are also being exposed to the high levels of heat and humidity while in close proximity to operating gensets.

Project Title: Replace Switchgear **(cont'd.)**

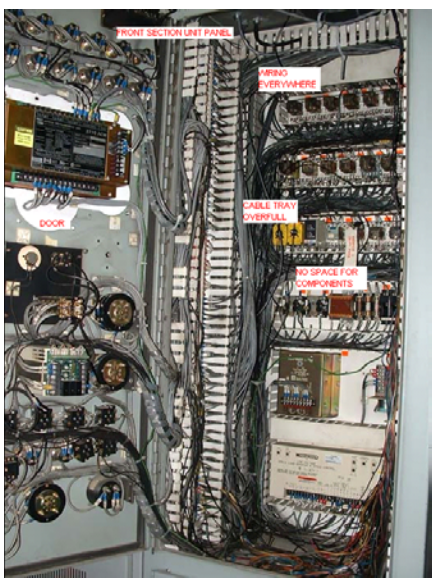
Project Justification:

The existing switchgear panels are undersized since control equipment is mounted on back of panel doors, at the top of each panel and in the 600V bus compartments. The latter is an electrical safety hazard for maintenance work because of the close proximity to the 600V bus. Hydro's present Engineering Standard for Diesel Switchgear requires a separate compartment for control equipment, resulting in isolation from any power equipment rated above 300 V. The switchgear panels are currently located in the engine hall, and there are safety issues for maintenance staff performing work on them while in close proximity to operating gensets, as well as the heat and noise in that area of the plant. A separate control room for the new switchgear control panels resolves those safety issues.

Future Plans:

None.

Project Title: Replace Switchgear **(cont'd.)**



Project Title: Replace Mufflers

Location: L'Anse au Loup and St. Anthony

Category: Transmission and Rural Operations - Generation

Type: Pooled

Classification: Normal

Project Description:

This project consists of the replacement of existing carbon steel exhaust systems on four diesel units at L'Anse au Loup and four diesel units at St. Anthony with stainless steel, meeting existing environmental requirements.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	225.2	0.0	0.0	225.2
Labour	117.9	0.0	0.0	117.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	47.4	0.0	0.0	47.4
O/H, AFUDC & Escalation	49.7	0.0	0.0	49.7
Contingency	39.0	0.0	0.0	39.0
Total	**479.2**	**0.0**	**0.0**	**479.2**

A break down is as follows:

Project Cost: *($ x1,000)*	**L'Anse Au Loup 2008**	**St. Anthony 2008**
Material Supply	132.7	92.5
Labour	66.9	51.0
Consultant	0.0	0.0
Contract Work	0.0	0.0
Other Direct Costs	25.6	21.8
O/H, AFUDC & Escalation	28.8	20.9
Contingency	22.5	16.5
Total	**276.5**	**202.7**

Operating Experience:

The mufflers and exhaust systems are corroded and cracked due to corrosion and condensation. Refer to attached photos.

Project Title: Replace Mufflers **(cont'd.)**

Project Justification:

The current stand-by operating mode of both diesel plants has accelerated deterioration of the mufflers and other exhaust system components. The existing carbon steel systems are badly corroded as a result of intermittent operation of the plant and acceleration of atmospheric corrosion as well as internal corrosion. A change in exhaust system materials from carbon steel to stainless steel will prolong the life of the exhaust systems.

Future Plans:

None.

Project Title: Replace Mufflers **(cont'd.)**

L'Anse au Loup

Project Title: Replace Mufflers **(cont'd.)**

St. Anthony

Project Title: Replace Underground Fuel Lines

Location: Little Bay Islands and Grey River

Category: Transmission and Rural Operations - Generation

Type: Other

Classification: Normal

Project Description:

This project will remove the existing underground fuel lines and replace them with above ground lines. In areas where the pipe must be run below grade, it will be installed within a culvert or other containment as appropriate to allow for visual inspection and maintenance.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	14.5	0.0	0.0	14.5
Labour	42.2	0.0	0.0	42.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	16.0	0.0	0.0	16.0
O/H, AFUDC & Escalation	8.5	0.0	0.0	8.5
Contingency	7.3	0.0	0.0	7.3
Total	**88.5**	**0.0**	**0.0**	**88.5**

Operating Experience:

Significant portions of the existing fuel lines currently run underground and have been in service for approximately 20 years. These lines cannot be inspected without excavation and risking damage to the lines.

Project Justification:

The risk related to the continued operation of these underground fuel lines increases with age. Inspection of these lines is required, and that inspection requires careful excavation and visual inspection for deterioration. Since the lines have to be excavated for inspection, they will be modified to enable visual inspection and to facilitate maintenance in the future.

Future Plans:

None.

Project Title: Replace Meter House Equipment

Location: Various Sites

Category: Transmission and Rural Operations - Generation

Type: Pooled

Classification: Mandatory

Project Description:

This project involves the removal and disposal of fuel meters, associated valves, equipment and piping and the installation of new isolation valves and new piping at Nain, Rigolet and Makkovik. In addition, a new air eliminator strainer will be installed at Nain.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	16.0	0.0	0.0	16.0
Labour	37.5	0.0	0.0	37.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	8.0	0.0	0.0	8.0
O/H, AFUDC & Escalation	7.7	0.0	0.0	7.7
Contingency	6.2	0.0	0.0	6.2
Total	75.4	0.0	0.0	75.4

Operating Experience:

The existing meter houses were built in 1978 and 1985 to house equipment which metered the amount of fuel transferred from the supplier's vessel to Hydro's fuel storage tanks. The meters are no longer used and they, along with the associated valving, have developed leaks which continuously have to be fixed. In addition, the valves are difficult to operate.

Project Justification:

The bulk meters are no longer used and the plant operators now meter the fuel deliveries by dipping the tanks before and after a fuel delivery to verify the amount received. The existing gate valves which are old, installed between 1978 and 1985, and leaky will be replaced by new butterfly type valves, a new Hydro standard.

Future Plans:

None.

Project Title: Install Day Tank and Meter

Location: Hopedale

Category: Transmission and Rural Operations - Generation

Type: Other

Classification: Mandatory

Project Description:

This project involves the installation of a day tank and fuel meter in the Hopedale diesel plant to allow fuel reconciliation to be performed in accordance with regulations.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	12.0	0.0	0.0	12.0
Labour	25.5	0.0	0.0	25.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	13.1	0.0	0.0	13.1
O/H, AFUDC & Escalation	5.5	0.0	0.0	5.5
Contingency	5.1	0.0	0.0	5.1
Total	**61.2**	**0.0**	**0.0**	**61.2**

Operating Experience:

Currently, fuel reconciliation cannot be completed, as there is no metering of fuel consumed to allow for comparison of fuel inventory against measured consumption. Also, this plant does not have a day tank, and therefore, tank dips are made while continuing to draw fuel from the bulk tank. All other prime power plants in the isolated diesel system have day tanks installed. Hydro has been subject to the Storage and Handling of Gasoline and Associated Products (GAP) Regulations since their inception, in 1982.

Project Justification:

Section 18(2) of the GAP Regulations, Newfoundland and Labrador, Regulation 58/03, requires aboveground storage tanks, other than a storage tank system connected to a heating appliance or a waste oil collection tank, to have dip or gauge readings reconciled with receipt and withdrawal records at least weekly. This plant currently has no fuel meter or day tank installed, making it impossible to comply with this legislation.

Future Plans:

None.

Project Title: Construct New Office, Warehouse and Line Depot Facilities

Location: Happy Valley

Category: Transmission and Rural Operations - Properties

Type: Other

Classification: Normal

Project Description:

This work is based on the construction of a new 885 square metre office, warehouse and line depot building at a new site. It also includes all site work including excavation and backfilling, paving, fencing and the construction of equipment storage ramps. Land costs are based on the purchase of two commercial lots in Happy Valley, Goose Bay.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	26.2	0.0	0.0	26.2
Labour	61.0	10.0	0.0	71.0
Consultant	105.0	26.0	0.0	131.0
Contract Work	835.0	175.0	0.0	1,010.0
Other Direct Costs	85.0	0.0	0.0	85.0
O/H, AFUDC & Escalation	135.7	41.0	0.0	176.7
Contingency	0.0	132.3	0.0	132.3
Total	**1,247.9**	**384.3**	**0.0**	**1,632.2**

Operating Experience:

Hydro presently occupies a 372 square metre office building on Royal Street and a 464 square metre line depot and warehouse building on Hunt Street in Happy Valley, Goose Bay. The office building is currently leased on a monthly renewal basis, following the expiry of a long term lease in 2005. The line depot and warehouse is owned by Hydro and is located within a fenced yard, measuring 69.5 metres x 95.4 metres, which extends from Hunt Street to Royal Street.

Project Justification:

In 2004, the line depot and warehouse building required significant repairs and upgrading and the rental office lease was about to expire. Hydro therefore commenced an investigation into options available to provide office, warehouse, line depot and storage yard facilities in Happy Valley. The existing leased office space is not adequate and has a history of health issues with respect to air quality and mould growth. See Report, Section H, Tab 7.

Future Plans:

None.

Project Title: Construct Bushing Storage Building

Location: Bishop's Falls

Category: Transmission and Rural Operations - Properties

Type: Other

Classification: Normal

Project Description:

This project involves the construction a 15 metre long x 10 metre wide x 8 metre high pre-engineered metal building to house spare bushings. The building will be built on a concrete pier, beam slab foundation, have minimum lighting, and no heating will be required. An overhead crane will be installed to move the bushings.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	38.0	0.0	0.0	38.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	225.0	0.0	0.0	225.0
Other Direct Costs	14.0	0.0	0.0	14.0
O/H, AFUDC & Escalation	30.2	0.0	0.0	30.2
Contingency	27.7	0.0	0.0	27.7
Total	**334.9**	**0.0**	**0.0**	**334.9**

Operating Experience:

In Bishop's Falls warehouse there are 134 bushings of different types and voltage classes used as spares to maintain power transformer and oil circuit breakers currently in service throughout the system. The bushings in service and critical spare bushings range in age from one to 40 years. Spare bushings are currently located outside, uncovered and subject to the elements and environmental conditions. During a bushing replacement exercise in late 2006 and early 2007 it was noticed that several bushings were showing visual signs of deterioration with the insulation paper peeling from the bottom of the bushing. A plan to Doble Test all stored bushings was initiated. One hundred of the 134 bushings, all stored outdoors, have been tested. Of this 100 tested, 25 have been identified as not serviceable with an additional 25 being questionable requiring further investigation and testing.

Project Title: Construct Bushing Storage Building **(cont'd.)**

Project Justification:

Spare bushings are critical spare parts for power transformers and oil circuit breakers. Bushings stored outdoors deteriorate early and because of this, have failed testing when required for service. As a result critical spare parts may not be available when needed which could result in longer durations of electrical outages. Having equipment out of service for extended periods of time will severely affect Hydro's ability to provide a least cost and quality service to its customers. Bushing manufacturers recommend storage in a dry indoor location. This building is required to preserve the condition of the spare bushings which have a value of $894,000. Inadequate storage has already rendered 25 units ($170,000 value) not serviceable and the condition of at least another 25 units of equal value is questionable.

Future Plans:

None.

Project Title: Upgrade Ventilation System

Location: Makkovik

Category: Transmission and Rural Operations - Properties

Type: Other

Classification: Normal

Project Description:

The purpose of this project is to Increase ventilation flow rate and improve air movement at the Makkovik Diesel Plant to provide 40,000 cubic feet per metre of air flow.

1. Remove the existing obstructed wall-mounted supply fan and two roof mounted general exhaust fans.

2. Supply and install two new, high capacity, supply fans and three new high capacity, roof mounted exhaust fans.

3. Select fan locations to promote airflow around the gensets for best cooling efficiency.

4. Supply and install a fan control panel to control air flow rates to suit conditions.

5. Supply and install local ventilation to the office and workshop located adjacent to the engine hall.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	68.0	0.0	0.0	68.0
Labour	89.1	0.0	0.0	89.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	21.2	0.0	0.0	21.2
O/H, AFUDC & Escalation	20.4	0.0	0.0	20.4
Contingency	17.8	0.0	0.0	17.8
Total	**216.5**	**0.0**	**0.0**	**216.5**

Project Title: Upgrade Ventilation System **(cont'd.)**

Operating Experience:

The ventilation system at the Makkovik diesel plant was designed and installed in 1990 at which time the plant firm capacity was 500 kW. Firm capacity has since been increased to 1162 kW to meet increased demand, and the ventilation system can no longer maintain reasonable temperatures within the engine hall.

With the existing ventilation equipment, engine hall temperatures can be expected to regularly exceed 40 degrees Celsius during peak periods in summer.

High combustion air temperatures and ambient temperatures reduce the available power of diesel engines and contribute to overheating.

High engine hall temperatures cause heat stress on maintenance and operating personnel which increases health risks. This is partially addressed currently by reducing exposure with short work periods, resulting in reduced wrench time.

Project Justification:

The current ventilation flow rate of 19,000 cubic feet per minute cannot supply the necessary air flow to keep temperatures in the engine hall to a level that is acceptable for worker safety. Temperatures in the plant over the past five years have been regularly higher than American Conference of Governmental Industrial Hygienists, the industry-accepted authority, identified safe limits. Further plant capacity increases will increase the heat generated in the engine hall even more.

High engine hall temperatures limit work duration and pose health risks to employees working in this environment. High ambient temperatures also contribute to engine overheating and reduce engine performance.

This work is required to achieve safe working conditions and ensure reliability of generation.

Future Plans:

None.

Project Title: Construct Diesel Plant Extension

Location: William's Harbour

Category: Transmission and Rural Operations - Properties

Type: Other

Classification: Normal

Project Description:

This project involves the construction of an extension to the William's Harbour Diesel Plant. The proposed extension is 7.6 metres wide x 4.6 metres long. Work will include a concrete foundation, concrete floor slab, steel columns, metal siding and metal roof. The proposed extension shall include an office, washroom and kitchen area.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	38.0	0.0	0.0	38.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	98.0	0.0	0.0	98.0
Other Direct Costs	9.5	0.0	0.0	9.5
O/H, AFUDC & Escalation	16.6	0.0	0.0	16.6
Contingency	14.6	0.0	0.0	14.6
Total	**176.7**	**0.0**	**0.0**	**176.7**

Operating Experience:

With the requirement for computers in the diesel plants, the only wall and floor space currently available in the plant is in the washroom area.

Project Justification:

The plant in William's Hr. was built in 1987 with minimum space allocated for an office and washroom. Since that time technology has advanced and the requirement for computers, programmable logic controls, heating and ventilation controls is a standard in all plants and with the limited space available in this plant it has become necessary to use the washroom space as part of the office area. The office area is approximately 24 metres x 24 metres with an exit door,

Project Title: Construct Diesel Plant Extension **(cont'd.)**

Project Justification: (cont'd.)

washroom door, desk, filing cabinets and a bench. The accommodation trailer was moved down into the community to take advantage of existing services, requiring that maintenance crews have to travel to the trailer for coffee break, lunch and to use washroom facilities. The proposed extension would provide all these facilities under one roof close to the job.

Future Plans:

None.

Project Title: Replace Fire Alarm System

Location: Hopedale and Paradise River

Category: Transmission and Rural Operations - Properties

Type: Other

Classification: Normal

Project Description:

This project involves the design and installation of a new fire alarm system for the Hopedale and Paradise River diesel plants.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	2.0	0.0	0.0	2.0
Labour	20.0	0.0	0.0	20.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	116.0	0.0	0.0	116.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	16.2	0.0	0.0	16.2
Contingency	13.8	0.0	0.0	13.8
Total	**168.0**	**0.0**	**0.0**	**168.0**

Operating Experience:

The fire alarm system in the Hopedale diesel plant does not function properly and is presently not in service. Function testing of the system has determined that the panel has extensive, non-corrective problems related to the power supply, zone cards and the cpu. The control panel is an Edward's ESA 2000 which has been discontinued by the manufacturer and replacement parts and/or services are no longer available. There is no fire alarm system in the Paradise River plant.

Project Justification:

Fire alarm systems provide early detection of fires in the diesel plants with smoke and heat detectors. Upon detection of a fire, the systems will sound alarms and activate an auto dialer to notify Hydro personnel. If a fire is detected inside the engine hall, the systems will mitigate damage and the spread of fire by shutting down ventilation into the engine hall, disabling the transfer of fuel into the engine hall from bulk storage, and shutting down the generating units.

The fire detection systems are required to protect personnel in the facility, minimize fire damage, mitigate the spread of fire, and provide protection to the diesel plant. Similar fire alarm systems are

Project Title: Replace Fire Alarm System **(cont'd.)**

Project Justification: (cont'd.)

installed in all diesel plants throughout the system. Such systems are considered prudent utility practice in the industry, and as such, are a standard part of all diesel plant designs. In the absence of a functioning fire alarm system, a fire in the plant could result in a complete loss of the plant and a sustained interruption of service to the customers. Depending on the time of year, such an event would create emergency situations.

Future Plans:

None.

Project Title: Install Storage Ramp

Location: Holyrood and Port Saunders

Category: Transmission and Rural Operations - Properties

Type: Pooled

Classification: Normal

Project Description:

Install a 3.0 metre x 60.0 metre storage ramp in the Port Saunders and Holyrood yards. The ramps are to be constructed from steel posts supporting steel beams and decked with a treated timber platform. These ramps will be used to store material that is currently stored on the ground.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	10.0	0.0	0.0	10.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	100.0	0.0	0.0	100.0
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escalation	12.2	0.0	0.0	12.2
Contingency	11.2	0.0	0.0	11.2
Total	**135.4**	**0.0**	**0.0**	**135.4**

Operating Experience:

Yard materials are currently stored on the ground.

Project Justification:

Storage ramps are standard equipment for outdoor storage facilities such as Port Saunders and Holyrood yards. Hydro currently has similar ramps in Bishop's Falls and Bay d'Espoir facilities. They are used to keep equipment raised from ground level so that it is not susceptible to damage from handling, yard traffic, snow clearing operations and weather conditions. During winter months goods stored on the ground take longer to access which affects productivity of both stores and operations personnel. These ramps also provide efficiencies in off-loading multi-piece shipments as they provide a laydown area during the process.

Future Plans:

None.

Project Title: Install Chain Link Fencing

Location: Port Hope Simpson

Category: Transmission and Rural Operations - Properties

Type: Other

Classification: Normal

Project Description:

This project includes construction of a new gated and electrically grounded chain link fence around the entire perimeter of the diesel plant site. The rear section of the existing fence around the radiator and exhaust stacks will be incorporated into the new perimeter fence and the remaining fence will be removed. Also included is borrow fill for embankment construction and grading.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	10.0	0.0	0.0	10.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	55.0	0.0	0.0	55.0
Other Direct Costs	4.0	0.0	0.0	4.0
O/H, AFUDC & Escalation	8.1	0.0	0.0	8.1
Contingency	6.9	0.0	0.0	6.9
Total	**84.0**	**0.0**	**0.0**	**84.0**

Operating Experience:

The Port Hope Simpson Diesel Plant is adjacent to the Trans Labrador Highway. The facility consists of a diesel plant, electrical substation, two fuel storage tanks, line storage shed and an equipment storage ramp. Although the radiator and exhaust stacks are fenced and there is a barrier gate at the site entrance, the remainder of the site is readily accessible by foot, all terrain vehicles and snowmobiles.

Project Justification:

Currently the Port Hope Simpson yard has a chain link fence around the radiators and exhaust stacks only. Access to the sub-station, fuel storage tanks, pole storage ramp, equipment storage ramp, line depot shed and plant by foot, snowmobile and all terrain vehicles is unimpeded. The

Project Title: Install Chain Link Fencing **(cont'd.)**

Project Justification: (cont'd.)

southern section of the new Trans Labrador Highway, opened in 2001, passes in close proximity and now makes the site more accessible to a much larger transient public. It is recommended that the fuel tank farm be fenced to prevent access to the fuel storage tanks and mitigate environmental concerns with respect to being freely accessible to the public. The concerns with respect to theft, vandalism and public safety are much greater than before the new highway was opened and it is recommended that the entire perimeter be fenced to mitigate those concerns.

Future Plans:

None.

Project Title: Upgrade Parking Lot

Location: Whitbourne

Category: Transmission and Rural Operations - Properties

Type: Other

Classification: Normal

Project Description:

This project includes the upgrading and paving of the Whitbourne Area office access road and parking area.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	58.8	0.0	0.0	58.8
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 & Escalation	1.8	0.0	0.0	1.8
Contingency	5.9	0.0	0.0	5.9
Total	**66.5**	**0.0**	**0.0**	**66.5**

Operating Experience:

Route 80 is the public highway which is used to access our Whitbourne Area office facilities. This highway was upgraded a number of years ago to tie into the Trans Canada Highway.

The upgrade to Route 80 resulted in an increased grade from our parking lot to the highway, to the extent that in the winter months there is difficulty accessing Route 80 due to the grade and slippery conditions. This is especially true for line trucks towing equipment trailers.

In order to access Route 80, one exits Hydro's parking lot, stops, assesses traffic flow and then attempts to move onto the highway. During slippery winter conditions it is very difficult to get the larger vehicles moving once we stop to assess traffic.

Practice has been to position a flag person on the highway to attempt to control traffic and then have the trucks make a running approach to Route 80. Once the truck gains access to the highway, it stops, picks up the traffic control person and then proceeds.

Project Title: Upgrade Parking Lot **(cont'd.)**

Project Justification:
Route 80 is especially busy during the peak morning traffic period and it is difficult and unsafe for employees and the general public when we have to impede traffic in order to access the highway.

We have had a number of instances where traffic ignores our efforts to gain access, resulting in several near miss incidents. Employees at Whitbourne have expressed safety concerns about this issue on several occasions. Engineering has completed an assessment of the problem and identified a solution which entails upgrading and paving of a portion of the parking lot, to lessen the grade and improve our access.

Completion of this work prior to the onset of the 2008/2009 winter season will enhance the safety of both employees and the traveling public.

Future Plans:
None.

Project Title: Install Waste Lube Oil Tank

Location: Cartwright

Category: Transmission and Rural Operations - Properties

Type: Other

Classification: Normal

Project Description:

This project involves the purchase and installation of a 20,000 litre double wall vacuum sealed, horizontal waste lube oil tank in the community of Cartwright on the Labrador coast. The tank shall be located in the diesel plant yard in a suitable area convenient for loading and offloading used lube from other Labrador Region's diesel plant sites located on the northern coast of Labrador. The tank will be equipped with a mounting platform and a lockable steel box to house a lube oil transfer pump to be used in transferring waste oil from 205 litre drums which have been shipped in from other plants. A tanker truck would remove oil from the tank for disposal.

Project Cost: *($ x1,000)*	2008	2009	Beyond	Total
Material Supply	31.5	0.0	0.0	31.5
Labour	10.0	0.0	0.0	10.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escalation	5.4	0.0	0.0	5.4
Contingency	4.4	0.0	0.0	4.4
Total	53.3	0.0	0.0	53.3

Operating Experience:

The storage and handling of plastic pail and steel drums is becoming an environmental issue and restrictions placed on each area, limits the amount of waste lube oil that can be stored at one time. With the amount of shipping and storage involved in handling steel drums, denting and rusting are an environmental concern and also, by the time they get back to the supplier they do not qualify for the $50.00 credit on the initial deposit.

Project Title: Install Waste Lube Oil Tank **(cont'd.)**

Project Justification:

The environmental compliance directive, at present, states "…used oil in a quantity that does not exceed 205 litres a site, may be stored in an 18 gallon 205 litre steel drum." The six northern coast diesel plants accumulate, in total, approximately 20,000 litres of used lube oil annually. The oil from the coast is presently shipped to Cartwright for forwarding to Happy Valley thus resulting in the drums being offloaded twice before they reach their destination. With the new Trans Labrador Highway opened all used lube oil from northern Labrador can now be disposed of from Cartwright with no need for reshipment to Happy Valley. It can be stored in one large, waste oil storage tank and a waste oil handler would only need to pick up and dispose of it once annually thus reducing shipping and disposal costs. Storing waste oil in one approved tank reduces the risk of accidents and environmental incidents.

Future Plans:

None.

Project Title: Survey of Hydro's Primary Distribution Line Right of Way

Location: Various Sites

Category: Transmission and Rural Operations - Properties

Type: Other

Classification: Normal

Project Description:

Performance of legal surveys and preparation of documentation to acquire Crown Land easements for approximately 160 km of primary distribution line in operation throughout the Province.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	37.1	0.0	0.0	37.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	5.0	0.0	0.0	5.0
O/H, AFUDC & Escalation	5.7	0.0	0.0	5.7
Contingency	4.2	0.0	0.0	4.2
Total	**52.0**	**0.0**	**0.0**	**52.0**

Operating Experience:

Many of the older distribution lines were constructed without obtaining easements. The effort to obtain easement title to the primary distribution lines on Crown Land began in 2004. Assuming continued funding, title for the distribution systems located on Crown Land will be in place by the end of 2014.

The history of expenditures for this project for the past three years is as follows:

Year	Budget ($000)	Actual ($000)
2006	49.9	51.2
2005	49.6	93.4
2004	48.8	48.6

Project Title: Survey of Hydro's Primary Distribution Line Right of Way **(cont'd.)**

Project Justification:

The distribution lines occupy Crown Land contrary to the Crown Lands Act and lack of adequate title is a significant risk to the operation should competing requirements for the land arise. In addition, maintenance and upgrading of the lines is cumbersome and costly without appropriate legal easements.

Future Plans:

Capital funding for legal surveys for future years will be proposed in future capital budget applications.

Project Title: Install Automatic Meter Reading

Location: Various Systems

Category: Transmission and Rural Operations - Metering

Type: Pooled

Classification: Normal

Project Description:

This project is to implement a one-way Automatic Meter Reading (AMR) system in the Hawkes Bay to Cow Head service areas. The proposed system utilizes a one-way power line carrier communications system that is designed for rural area applications. It includes telephone communications to head office from local substations. The required computer applications to interface with Hydro's customer billing systems were implemented as part of the year one proposal. This proposal is the second year of a multi-year program executed on a system by system basis considering such factors, as staffing, reading cost per meter, etc.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	300.0	0.0	0.0	300.0
Labour	159.4	0.0	0.0	159.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	14.9	0.0	0.0	14.9
O/H, AFUDC & Escalation	63.8	0.0	0.0	63.8
Contingency	28.5	0.0	0.0	28.5
Total	**566.6**	**0.0**	**0.0**	**566.6**

Operating Experience:

This system will replace manual handheld devices and local supporting infrastructure (computers and modems). The head office supporting infrastructure for handheld devices will remain in place for all remaining services areas. The system being implemented was piloted in the St. Brendan's service area in 2003/ 2004 and proved to be reliable and accurate.

Project Justification:

The AMR Project initiative will reduce controllable costs and improve customer satisfaction .

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

Project Justification: (cont'd.)

With respect to cost, the projected operating cost/meter for the Hawkes Bay to Cow Head service areas for 2009 is $43/meter. The implementation of AMR will lower this cost to $9/meter. The cumulative present worth analysis of AMR and the current system has a positive net present value starting in 2018 (10 1/2 years), and totals approach $110,718 in 2022, as per the attached table.

Improvements in customer service will come from:

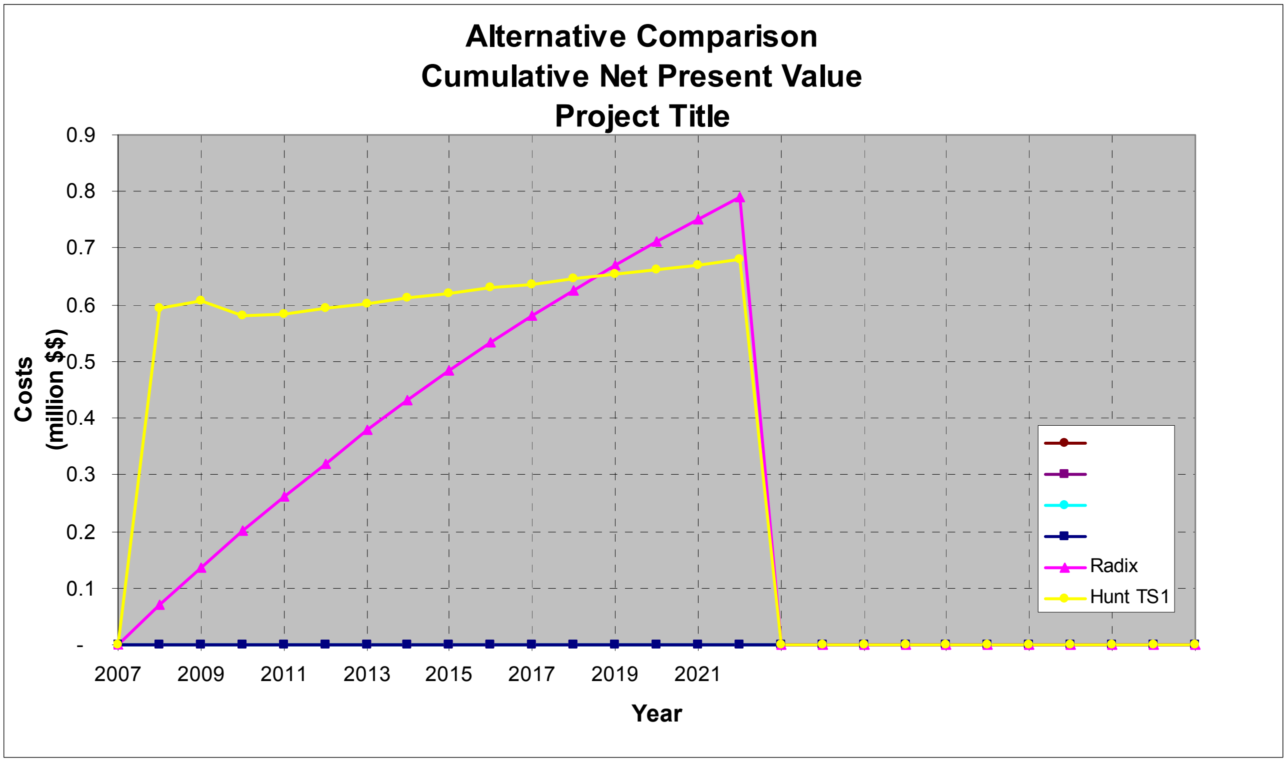
1. Elimination of meter reading errors;
2. Elimination of estimated readings;
3. More detailed usage information to help customers track consumption patterns; and
4. More flexible billing options such as consolidated bills and customer selected bill dates.

In additional to the above, implementation of AMR will improve safety as a result of reduced employee risk exposure and will provide a benefit to the environment as a result of less vehicle usage.

Future Plans:

Further expansion of the AMR program will be proposed in future capital budget applications.

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



AMR 2008 Alternative Comparison *Cumulative Net Present Value* *To The Year* 2022		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Hunt TS1	679,101	0
Radix	789,818	110,718

Project Title: Purchase Meters and Equipment

Location: Hydro Place

Category: Transmission and Rural Operations - Meters

Type: Other

Classification: Normal

Project Description:

To provide capital funds for the purchase of demand/energy meters, current and potential transformers, metering cable and associated hardware for use throughout the system and for the release of residential meters from inventory for use throughout the system as required.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	60.0	0.0	0.0	60.0
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 & Escalation	1.3	0.0	0.0	1.3
Contingency	6.0	0.0	0.0	6.0
Total	**67.3**	**0.0**	**0.0**	**67.3**

Operating Experience:

Meters and associate equipment are required for new customers services and the replacement of old, worn, damaged or vandalized equipment. The history of expenditures for the past five years is as follows:

Year	Budget ($000)	Actual ($000)
2006	92.5	59.0
2005	148.0	113.7
2004	98.0	55.9
2003	96.0	88.4
2002	171.9	185.4

Project Title: Purchase Meters and Equipment **(cont'd.)**

Project Justification:

For revenue metering of new and upgraded residential and general service customer services, and replacement of worn or obsolete meters and metering equipment. A minimum but uninterrupted inventory of revenue meters must be maintained to ensure the availability of equipment required to meter customers' services for revenue purposes. We endeavour to purchase only the numbers of meters required to replace meters which are retired due to age, damage or obsolescence and to supply for new customer service.

Future Plans:

Monitoring and maintaining metering equipment stock levels is an ongoing commitment. Quantities of meters purchased depends on such variables as numbers of new customer service requests, and the rate of meter retirement due to age, obsolescence, shipping damage, vandalism, etc.

Project Title: Replace Off Road Track Vehicles

Location: Bishop's Falls and Whitbourne

Category: Transmission and Rural Operations - Tools and Equipment

Type: Other

Classification: Normal

Project Description:

This project involves the replacement of units V7646 (Whitbourne) and V7649 (Bishop's Falls), 1988 model heavy-duty, off-road tracked vehicles. These are crew cab, cargo carrying units with a backhoe attachment and will be replaced with similarly configured units.

Project Cost: *($ x1,000)*	**2008**	**2009**	**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 & Escalation	19.9	0.0	0.0	19.9
Contingency	66.0	0.0	0.0	66.0
Total	**745.9**	**0.0**	**0.0**	**745.9**

Operating Experience:

These units are utilized by Transmission Line crews to access remote transmission lines for planned maintenance and in response to forced outages. The crew-cab provides protection from the elements to line persons, with the cargo deck and backhoe attachment adding versatility to the unit as a work vehicle at remote sites.

Project Justification:

This project provides for the normal replacement of two heavy-duty, off-road tracked vehicles in accordance with the replacement criteria of 15 to 20 years. Theses units will be 20 years old at the time of replacement. Experience demonstrates that the heavy-duty off-road equipment is subject to rapid escalation in downtime as it ages.

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

Project Justification: (cont'd.)

Technological improvements in cab design have reduced the noise and heat levels in the cab. Drive trains have improved from mechanical to hydrostatic. These units are now fully automatic instead of manual transmission. The operator and passenger seats are improved from bench to suspension seating, providing an improved ride for the occupants. Safety improvements include interlocks on the doors to prevent operation of the unit with the doors open, and an automatic braking system.

This configuration unit allows it to multi-task as a crew transport, as well as a work vehicle, eliminating the need for an excavator to accompany the units when excavation work is necessary.

These units are an integral part of our off-road fleet and are utilized for maintenance activities and for emergency response to forced outages. These units have an average life expectancy of 18 years and will be worn out when disposed. Purchase of these units has been our past practice, however we will undertake a lease/purchase analysis of the units at the time of tender.

Future Plans:

None.

Project Title: Replace Light Duty Mobile Equipment Less than $50,000

Location: Various Sites

Category: Transmission and Rural Operations - Tools and Equipment

Type: Other

Classification: Normal

Project Description:

This project consists of the replacement of 24 snowmobiles, 20 ATV's, seven light duty trailers, two heavy-duty trailers, two pole trailers, one backhoe attachment, one forklift and one garden tractor.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	522.0	0.0	0.0	522.0
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 & Escalation	13.6	0.0	0.0	13.6
Contingency	52.2	0.0	0.0	52.2
Total	**588.0**	**0.0**	**0.0**	**588.0**

Operating Experience:

Operating and maintenance staff regularly use snowmobiles and ATV's to access remote areas for maintenance, repair and operation of the transmission system. The equipment being used requires regular replacement.

The history of expenditures for this project for the past four years is as follows:

Year	Budget ($000)	Actual ($000)
2006	274.3	243.3
2005	259.7	244.8
2004	300.0	274.6
2003	543.6	158.5

Project Title: Replace Light Duty Mobile Equipment Less than $50,000 **(cont'd.)**

Project Justification:

This project provides for the normal replacement of light-duty, mobile equipment which is at the end of its life cycle and is no longer dependable. The units being replaced meet or exceed replacement criteria. The light duty mobile equipment being replaced is comprised of 24 snowmobiles (average age six years), 20 ATV's (average age six years), seven light-duty trailers (average age 15 years), two heavy-duty trailers (average age 15 years), two pole trailers (average age 12 years), one backhoe attachment (age 13 years), one forklift (age 20 years) and one garden tractor (age 15 years).

The life expectancy of light duty mobile equipment varies significantly, dependant on a number of factors including location, annual utilization and conditions under which the equipment is used. The type of equipment is assessed for replacement as it reaches the established replacement criteria:

Snowmobiles:	Line Crews*	3-5 Years
	Others	5-7 Years
ATV's	Line Crews*	3-5 Years
	Others	5-7 Years
Trailers:	Light	8-10 Years
	Heavy	10-15 Years
Attachments		10-15 Years
Forklifts		15-20 Years
Lawn/Garden Tractors		12-15 Years

* The shorter life for line crew snowmobiles and ATV's is a reflection of the extensive use over very harsh terrain.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Installation of Fall Arrest Equipment

Location: Various Sites

Category: Transmission and Rural Operations - Tools and Equipment

Type: Other

Classification: Mandatory

Project Description:

The work includes design and installation of fall protection systems for various facilities in the system. This will be the continuation of a four year program started in 2005 but which has now been extended for a fifth year until 2009. This will include systems for fixed ladders, horizontal life lines, rigid rail systems, guard rails, a platform for Cat Arm insulator access, guard rails for Holyrood penthouse, horizontal life lines for gas turbine building, transformer anchors, Nain Diesel Plant roof and other site specific systems as required. All the work so far completed was considered priority one. In 2008 work will be carried out on the remaining priority one sites. Work will be carried out by contract and/or by in-house forces depending upon the circumstances.

In 2009 work will be completed on sites with lesser priority. Fall protection devices will be designed and installed to suit site conditions. This will include sites such as hydro plants, intake and control gates, day tank and additive tank and other sites as required by each region.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	84.0	0.0	0.0	84.0
Labour	38.0	0.0	0.0	38.0
Consultant	20.0	0.0	0.0	20.0
Contract Work	200.0	0.0	0.0	200.0
Other Direct Costs	18.0	0.0	0.0	18.0
O/H, AFUDC & Escalation	44.5	0.0	0.0	44.5
Contingency	0.0	0.0	0.0	0.0
Total	**404.5**	**0.0**	**0.0**	**404.5**

Operating Experience:

N/A

Project Title: Installation of Fall Arrest Equipment **(cont'd.)**

Project Justification:

The fall protection program started in 2005 and most facilities with a priority one rating have been equipped with fall protection devices. These included vertical fuel storage tanks, diesel plants and hydro and thermal power plants. This work is to continue until all facilities are properly equipped with safety devices in compliance with provincial safety regulations. Most top priority project sites have been addressed over the last three years and most likely all will have been addressed by the end of 2008. In 2009 work will continue on sites with a lesser priority rating, in accordance with the list prepared by each region in the Hydro system.

Future Plans:

Future installations will be proposed in future capital budget applications.

Project Title: Replace Boom 6069 on Track Vehicle

Location: Stephenville

Category: Transmission and Rural Operations - Tools and Equipment

Type: Other

Classification: Normal

Project Description:

This project consists of the replacement of V6069, a 1980 model, 47 foot center mounted boom on heavy-duty off-road tracked vehicle V7974. The work includes removal of the existing crane, purchase, mounting and certification of the new unit.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	200.0	0.0	0.0	200.0
Labour	10.0	0.0	0.0	10.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	5.0	0.0	0.0	5.0
Contingency	21.0	0.0	0.0	21.0
Total	236.0	0.0	0.0	236.0

Operating Experience:

This project provides for the normal replacement of a 47 foot center mounted boom due to its age, condition and technological obsolescence.

This unit will be 28 years old at replacement and is obsolete. This is the only boom equipped heavy duty off-road vehicle stationed at Stephenville, and is a critical tool for the line crew in their response to large maintenance projects or major forced outages. Mounting of a new crane on the existing heavy duty off-road unit is the least cost alternative, as the life expectancy of the chassis is another 10 to 15 years.

Project Justification:

Purchase of this unit is the only viable option as vendors do not lease this type of equipment, and it will be at the end of its service life when the chassis, on which it will be mounted, is disposed.

Future Plans:

None.

Project Title: Purchase Hydraulic Cutters and Presses

Location: Various Sites

Category: Transmission and Rural Operations - Tools and Equipment

Type: Other

Classification: Normal

Project Description:

This project involves the purchase of hydraulic cutters and presses for four new material handler aerial devices. These units are being used by other utilities and Hydro, and are proving to be very efficient requiring very little maintenance. Also required to purchase, one set of hydraulic cutters for Stephenville Transmission Crew.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	65.0	0.0	0.0	65.0
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 & Escalation	1.2	0.0	0.0	1.2
Contingency	0.0	0.0	0.0	0.0
Total	**66.2**	**0.0**	**0.0**	**66.2**

Operating Experience:

Hydraulic tools are user-friendly and ergonomically designed for use in elevated buckets by lineworkers.

Project Justification:

Line crews report that these tools are very useful and much easier to work with when working from the aerial device. This will reduce the manual labour that is being done now with the hard press and ratchet cable cutters. As a result, long term health and safety will be improved for lineworkers due to tools which are ergonomically designed.

Future Plans:

None.

Project Title: Application Enhancements – Work Protection Code

Location: St. John's

Category: General Properties - Information Systems

Type: Other

Classification: Normal

Project Description:

This project involves the purchase and installation of software, which will provide tools for the safe and effective application of work protection. This will assist in providing workers with a safe work area to perform their work. The implementation of this software system will automate the process of safety code permits in the Holyrood plant. Safety code permits are used to isolate equipment to be worked on in a safe way.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	226.0	0.0	0.0	226.0
Labour	130.0	0.0	0.0	130.0
Consultant	213.0	0.0	0.0	213.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	52.2	0.0	0.0	52.2
Contingency	56.9	0.0	0.0	56.9
Total	**678.1**	**0.0**	**0.0**	**678.1**

Operating Experience:

Hydro's Work Protection Code system was created to provide a safe work environment in which hazards can either be eliminated or controlled. It consists of important principles which, when combined with safe work practices, will provide workers with a safe work area to perform their work. These procedures are applicable to all individuals required to perform work on Hydro owned or operated property, circuits, or equipment. Historically, the Work Protection procedures have been organized using manual paper-based processes. Since 1998 there have been 39 Work Permit/Lockout incidents in Holyrood of the following type: four major incidents, 25 moderate incidents and ten minor incidents.

Project Justification:

Please see the report entitled "Protection Code Management Software for Holyrood", Section H, Tab 8 for a detailed analysis. The system will provide an effective, consistent and standard means

Project Title: Application Enhancements – Work Protection Code **(cont'd.)**

Project Justification: (cont'd.)
of creating work protection documentation. This will enable adherence to work flow rules and tag management, and will permit archiving.

The benefits of this system are:

- Safety - reduces chances for operating errors, which translates to less time spent analyzing errors.
- Standardization – provides a standard interface for the Work Protection activities for the plant.
- Efficiency – increases the efficiency of generation and checking, relieving operator workloads; potentially translates to shorter outages as the tool enables users to more quickly adapt to changes in plant status and configuration.
- Regulatory – enables work protection and plant configuration management mandates to be satisfied and provides an audit trial for conformance.
- Accuracy – allows the Holyrood Plant to complete up-to-date information for decision making. Greater accuracy of permits translates into shorter outage times for the Holyrood plant.
- Configuration Control – provides the unit operator, who has responsibility for all activities on the unit, with greater control of the unit configuration. This information is also available for efficient maintenance planning.

This project supports the corporate safety goal which will result in higher compliance to the safety code and fewer safety incidents in the Holyrood plant due to safety code compliance.

Future Plans:
Application enhancements are a continuing requirement in order for Hydro to ensure efficiencies. There is no prior history for this budget.

Project Title: Application Enhancements – Energy Systems Water Management Decision Support System

Location: St. John's

Category: General Properties - Information Systems

Type: Other

Classification: Justifiable

Project Description:

The project proposed is to purchase and install a short term Water Management Decision Support System (DSS). Water management activities dictate the manner in which water is released from Hydro's major reservoirs, and heavily influences each hydroelectric plant's conversion factor. This software will assist in translating long term reservoir and thermal dispatch guidance into daily and hourly schedules.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	510.0	0.0	0.0	510.0
Labour	35.0	0.0	0.0	35.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	51.7	0.0	0.0	51.7
Contingency	54.5	0.0	0.0	54.5
Total	**651.2**	**0.0**	**0.0**	**651.2**

Operating Experience:

Hydro operates nine major reservoirs in three river systems. These reservoirs represent the majority of the hydraulic storage for the operation of Hydro's Island Interconnected system. Our present decision support system for managing this resource provides guidance only on a weekly basis. A study conducted by Synexus Global Incorporated in 2006 indicated that there are opportunities to enhance water release and unit dispatch decisions, by augmenting Hydro's current long term DSS with a short term water management DSS. The resultant improved decisions will allow Hydro to, on average, extract more energy from existing hydroelectric resources. This would directly offset production from Holyrood with its attendant cost and environmental impacts. Under the proposed project, Hydro would acquire such a system.

Project Title: Application Enhancements - Energy Systems Water Management Decision Support System **(cont'd.)**

Project Justification:

Please see the report entitled “Implementation of a Short Term Water Management Decision Support System”, Section H, Tab 9 for a detailed analysis. The primary benefit is derived from the expected reduction of energy requirements from Holyrood resulting from the improved annual hydroelectric production that the project will facilitate. From an environmental perspective, Sulphur Dioxide and Carbon Dioxide emissions over this period would be reduced on the order of 22 metric tones and 3000 metric tones per year respectively. A Net Present Value (NPV) Analysis was performed based on both the Long Term Forecast and the Low Price Forecast for fuel.

NPV Analysis			
Alternative	**Payback Period**	**NPV**	**Analysis Period**
Short Term Water Management with Long Term Forecast	3.5 Years	$1,783,000	10 Years
Short Term Water Management with Low Price Forecast	6 Years	$474,000	10 Years

Future Plans:

Application enhancements are a continuing requirement in order for Hydro to ensure operational efficiencies. There is no prior history for this budget as it relates to the Energy Control Centre.

Project Title: Application Enhancements - Corporate Systems

Location: St. John's

Category: General Properties - Information Systems

Type: Pooled

Classification: Normal

This Information Systems project is necessary to enhance the functionality of software applications. The proposed application enhancement projects are:

1) Make minor enhancements to applications to respond to unforeseen requirements such as legislative and changing business requirements.

2) Rebuild Hydro's Internet Website to support effective communication with customers and other stakeholders.

3) Continue making changes to Hydro's Intranet to enhance functionality and to support information sharing.

4) Acquire software which will manage and control application changes as they move from test environment to production environment.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	27.0	0.0	0.0	27.0
Labour	141.0	0.0	0.0	141.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	140.0	0.0	0.0	140.0
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escalation	31.5	0.0	0.0	31.5
Contingency	31.0	0.0	0.0	31.0
Sub-Total	372.5	0.0	0.0	372.5
Cost Recoveries	(74.5)	0.0	0.0	(74.5)
Total	**298.0**	**0.0**	**0.0**	**298.0**

Operating Experience:

Hydro must continue to enhance its corporate applications in order to maintain and improve efficiency. The corporate applications are used to support all aspects of business operations. Improving these applications either through vendor supplied functionality or internal software development ensure that Hydro is able to respond to changing business requirements.

Project Title: Application Enhancements - Corporate Systems **(cont'd.)**

Project Justification:

1) **Minor Enhancements**

   Total: $144,300 CF(L)Co: $28,900 Net: $115,400

   Minor enhancements are justified on the basis of meeting business requirements during the year. This allocation has been used in the past to create enhancements to safety, environmental compliance and audit applications as well as to fulfill PUB directives from the Board such as full time equivalent reporting and equalized billing. Some examples of initiatives completed in 2006 under the enhancements budget consist of Audit Management System, Customer Inquiry (MCAS) System, Key Performance Indicator (KPI) Dashboard, Capital Asset Projection Model (CAPM), etc.

2) **Hydro's Internet Website Rebuild**

   Total: $110,100 CF(L)Co: $22,000 Net: $88,100

   The internet site is to be redeveloped to support the effective communication with customers and other stakeholders. It is used as an information portal by external users to obtain information on, and conduct business with the company including Public Tenders, Press Releases, Hydrowise, corporate information, new business initiatives, etc. The internet site was originally developed in 1998 and upgraded in 2004. The internet site is being updated to improve and provide additional functionality and information to our customers, business community and general public.

3) **Corporate Intranet Enhancements:**

   Total: $83,500 CF(L)Co: $16,700 Net: $66,800

   The corporate Intranet site was originally developed in 2002 and seven distinct areas of business information have been developed. The areas of business information include Corporate Communications, Human Resources, Environment, Properties, Customer Services, Rates & Financial Services and Business Process Improvement. An Intranet review was completed in 2006 and the recommendation was to expand intranet functionality which will ensure effective communication and support corporate information sharing. This budget allows for the refresh of informational areas in 2008.

Project Title: Application Enhancements - Corporate Systems **(cont'd.)**

Project Justification: (cont'd.)

4) Lotus Notes Change Management

Total: $34,600 CF(L)Co: $6,900 Net: $27,700

Acquire software which will manage and control application changes as they move from test environment to the production environment. This will reduce the risk of human errors, provide greater internal controls, and ensure audit compliance when developing and maintaining applications.

The following table provides the history of the Application Enhancement budget for years 2002 – 2006:

Year	Budget *($000)*	Actual *($000)*	Upgrade/License[(1)]
2006	780.0[(2)]	390.0	Upgrade
2005	398.0	334.0	Upgrade
2004	463.0	464.0	Upgrade
2003	47.0	45.0	Upgrade
2002	517.0	478.0	License/Upgrade

[(1)]Upgrade refers to adding or extending functionality of applications

[(2)]The "Enhancements to the Capital and Operating Process Applications" component of this budget was cancelled. Budgeted amount for this component: $390.0

Future Plans:

Application enhancements are a continuing requirement in order for Hydro to ensure business efficiencies.

Project Title: Application Enhancements – Energy Systems Optimum Powerflow

Location: St. John's

Category: General Properties - Information Systems

Type: Other

Classification: Justifiable

Project Description:

The project proposes the purchase and installation of Optimum Power Flow (OPF) software for Hydro's Energy Control Center. This software will improve the operational efficiency of the system by reducing transmission line losses from hydraulic generation. This will reduce the need for as much thermal generation at the Holyrood Plant and, thereby reduce Holyrood fuel needs and costs.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	98.0	0.0	0.0	98.0
Labour	24.0	0.0	0.0	24.0
Consultant	55.3	0.0	0.0	55.3
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	4.1	0.0	0.0	4.1
O/H, AFUDC & Escalation	16.2	0.0	0.0	16.2
Contingency	18.1	0.0	0.0	18.1
Total	**215.7**	**0.0**	**0.0**	**215.7**

Operating Experience:

Hydro estimates currently indicate a 3.2 % loss of power during transmission from the generating plant to our customer. A portion of these losses are offset by generation of thermal power from Holyrood. Using OPF this value could be reduced to 3.1%. As a result fuel needs and costs at Holyrood can be reduced.

Project Justification:

Please see the report entitled "Implementation of Optimum Power Flow in the Reduction of Transmission Losses", Section H, Tab 10 for a detailed analysis. OPF can decrease transmission line losses. At an average rate of 1 MW over an hour, the potential savings would range from $277,000 to $529,000 per year. These savings are derived from the avoidance of fuel at the Holyrood plant. The benefits will be achieved by the use of OPF recommended generator voltages and transformers tap settings. This project supports corporate

Project Title: Application Enhancements - Energy Systems Optimum Power Flow **(cont'd.)**

Project Justification: (cont'd.)
goals in environment and operational excellence. A Net Present Value (NPV) Analysis was performed based on both the Long Term Forecast and the Low Price Forecast for fuel.

NPV Analysis			
Alternative	**Payback Period**	**NPV**	**Analysis Period**
OPF with Long Term Forecast	Year 1	$3,299,000	10 Years
OPF with Low Price Forecast	Year 1	$1,529,000	10 Years

Future Plans:
Application enhancements are a continuing requirement in order for Hydro to ensure operational efficiencies. There is no prior history for this budget as it relates to the Energy Control Centre.

Project Title: Corporate Application Environment

Location: St. John's

Category: General Properties - Information Systems

Type: Pooled

Classification: Normal

Project Description:

The scope of this project is to upgrade Lotus Notes and replace existing Distribution Planning Software.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	48.0	0.0	0.0	48.0
Labour	70.4	0.0	0.0	70.4
Consultant	148.0	0.0	0.0	148.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	10.0	0.0	0.0	10.0
O/H, AFUDC & Escalation	26.8	0.0	0.0	26.8
Contingency	27.6	0.0	0.0	27.6
Sub-Total	330.8	0.0	0.0	330.8
Cost Recoveries	(40.8)	0.0	0.0	(40.8)
Total	**290.0**	**0.0**	**0.0**	**290.0**

Operating Experience:

There are approximately 40 corporate applications and supporting systems that enable Hydro to operate and provide least cost and reliable power to customers. Upgrades to applications throughout their life cycle are a normal and necessary requirement. Hydro reviews its software application portfolio on a yearly basis and uses two main criteria to determine if an upgrade to an environment is warranted. First, the status of vendor support for the applications is reviewed. Next, any functionality improvements are reviewed in the context of providing business value either through improved functionality or improvements in service.

Project Justification:

This project includes upgrades to Lotus Notes and the replacement of PSS/Adept Distribution Planning Software. Continued growth of the application environment provides the flexibility to meet new functional requirements.

Project Title: Corporate Application Environment **(cont'd.)**

Project Justification: (cont'd.)

1) **Lotus Notes Upgrade**

   Total: $269,100 CF(L)Co: $40,800 Net: $228,300

   Budget amounts are based on actual previous upgrade costs. This software was last upgraded in 2004 to version 6.5. Further updates to this software were released in 2005 (Version 7.0) and 2007 (Version 8.0). Functionality that can provide business value, and has been requested by the business, is available in the latest release. This functionality includes enhanced Web Conferencing (allowing presentations to be given using PC's), integration of real time information into Intranet and internet sites and enhanced user interface with greater functionality in email, address book, calendars and instant messaging.

2) **PSS/Adept Replacement**

   Total: $61,700 CF(L)Co: $0.00 Net: $61,700

   This project will replace the PSS/ADEPT application for distribution planning, used in system planning since 1986 with good results. The provider of this software (Siemens - PTI) has elected to discontinue support of this program. The software is used for modeling Hydro distribution systems to predict the voltages and currents flowing at different locations in the system. The results from applying the load forecast for a system allow system planning to determine if and when work will be required in order to maintain quality of service and to study alternatives. In addition to performing load flow studies, the software is also used to perform fault calculations and motor starting analysis. The software is used on a daily basis as a tool for system planning activities with regards to distribution planning. The proposed replacement product will be purchased externally. This estimate is based on a financial and operational review of competitive products. The budget estimate is based on lowest cost (with due regard to functionality) using cumulative net worth calculations.

Project Title: Corporate Application Environment **(cont'd.)**

Project Justification: (cont'd.)

Please refer to the following table for expenditures in each year from 2004 to 2006 for Corporate Application Environment.

Year	**Budget*** ***($000)***	**Actual*** ***($000)***	**By Application**
2006	556.0	156.0	Industrial Billing Software
		217.0	Diesel Plant Automation
		31.0	Aspen Relay Database
		36.0	ERP Technical Review
		116.0	Showcase Upgrade
2005	222.0	67.0	Citrix Metaframe
		85.0	ITIL Tools
		56.0	Network Mgmt - Cisco Works
2004	540.0	132.0	JD Edwards
		81.0	Showcase Strategy
		190.0	Lotus Notes
		71.0	AS400/OS400

*** Amounts shown are totals after CF(L)Co. Cost Recovery.**

Future Plans:

Application enhancements and upgrades are an ongoing life cycle based on business demands and vendor support levels.

Project Title: End User Evergreening Program
Location: Multiple Sites
Category: General Properties - Computer Operations
Type: Pooled
Classification: Normal

Project Justification:

This project is part of Hydro's personal computer program and involves the replacement and addition of personal computers (PC's). Based on the age of existing Computers, each year an appropriate number of computers will be refreshed. This infrastructure ensures that the Corporation has a reliable secure computer environment required to support efficient operations.

The scope of the proposed personal computer program includes the replacement of 165 computers; 75 desktop PC's that were deployed in 2003 and 90 Laptops deployed in 2004. In addition to these, it includes funds to purchase an additional ten desktops and ten notebooks for normal growth.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	304.0	0.0	0.0	304.0
Labour	21.0	0.0	0.0	21.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	52.3	0.0	0.0	52.3
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	36.4	0.0	0.0	36.4
Contingency	37.7	0.0	0.0	37.7
Total	**451.4**	**0.0**	**0.0**	**451.4**

Operating Experience:

Hydro's computer infrastructure supports the applications and information that are used by its employees in carrying out its day-to-day business. This project is necessary to maintain reliable performance on its computers.

Project Title: End User Evergreening Program **(cont'd.)**

Operating Experience: (cont'd.)
Hydro's computer refresh program defines computer replacement life cycles to be: laptops four years, desktops five years and thin clients[(1)] six years. This staged refresh program has allowed Hydro to manage equipment costs and PC deployment in a controlled and consistent manner.

Minimum specifications for replacement of PC's are reviewed on an annual basis to ensure that the PC's in service remain effective. Industry best practices, technology and application trends are taken into consideration when specifications for computer devices are decided for the current year.

Project Justification:
Hydro needs to keep its PC's current in order to adequately support and protect the IT applications and information required to operate its business. The replacement and addition of PC components to achieve this goal requires investment over the lifecycle of the computers.

The benefits of the refresh program are that computers are replaced in a planned and consistent manner. This allows for even distribution of budgets and ensures that the computers are available and reliable to support the user's applications. Continued review of the computer lifecycle allows Hydro to adjust plans based on performance, technology changes and new business requirements.

Hydro has over 800 end-user PC's in service. It is important to refresh this equipment on a regular cycle to keep the technology current to maintain a reliable, efficient and productive workforce.

The North American industry standard life cycle for end-user devices is three years for Notebooks, five years for Desktops and five plus years for thin-clients. Gartner[(2)] recommends three years for Notebooks and four to five years for Desktops. Newfoundland Hydro has adopted a four-six year

[(1)]A thin-client is a networked computer without a hard disk drive, where the data processing occurs on a server or multiple servers. This allows the end-user to access files and application software without the need to install them on the local computer.
[(2)]Gartner Inc. is the leading provider of research and analysis on the global Information Technology industry. They assist companies in making informed technology and business decisions by providing in-depth analysis and advice on virtually all aspects of technology.

Project Title: End User Evergreening Program **(cont'd.)**

Project Justification: (cont'd.)

life cycle and uses extended warranties to ensure reliable operation. Newfoundland Power also follows a four-six year lifespan for their computer equipment.

The following table shows the years 2003 to 2006 for the Personal Computer Program.

Year	Budget *($000)*	Actual *($000)*	# of Notebooks	# of Desktops	# of Thin-Client Devices
2006(3)	0.0	0.0		0	0
2005	711.0	663.0	123	88	68
2004	793.0	796.0	101	139	113
2003	774.0	795.0	73	80	113

This project is subjected to a lease or purchase cost benefit analysis to determine the lowest cost alternative. The cost benefit analysis is done in the year of replacement to ensure consideration of incentives or other benefits that may be offered by the providers.

Future Plans:

The personal computer infrastructure will be refreshed on an ongoing basis.

(3) In 2006 Hydro extended the computer life cycle by 1 year and therefore did not incur capital cost in 2006.

Project Title: Upgrade Enterprise Storage Capacity

Location: Various Sites

Category: General Properties - Computer Operations

Type: Pooled

Classification: Normal

Project Description:

This project is to provide an additional three Terabytes (TB) of disk storage to the Storage Area Network (SAN) to serve the Enterprise Resource Planning (ERP) Midrange Computer (iSeries) and Intel Enterprise Servers. The SAN was installed in 2003 to provide efficient management and growth of the disk storage for the iSeries and Intel Servers. This project will ensure that Hydro has the storage capacity for the existing requirements.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	267.0	0.0	0.0	267.0
Labour	3.0	0.0	0.0	3.0
Consultant	5.0	0.0	0.0	5.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	24.6	0.0	0.0	24.6
Contingency	27.5	0.0	0.0	27.5
Sub-Total	327.1	0.0	0.0	327.1
Cost Recoveries	(65.4)	0.0	0.0	(65.4)
Total	**261.7**	**0.0**	**0.0**	**261.7**

Operating Experience:

Disk capacity has grown at a rate of approximately 30% per year over the last five years and is projected to grow at this rate into the future. Sun StorageTek[(1)] states this is slightly below the industry standard growth rates (50-70% per year). Storage Resource Management Tools, installed in 2007, allow Hydro to effectively manage data and minimize disk usage.

(1) NOTE: Sun StorageTek is a world wide technology company that enables businesses, through its information lifecycle management strategy, to align the cost of storage with the value of information. The company's innovative storage solutions manage the complexity and growth of information, lower costs, improve efficiency and protect investments. It is a subsidiary of Sun Microsystems, Inc.

Project Title: Upgrade Enterprise Storage Capacity **(cont'd)**

Project Justification:

The servers that are attached to the SAN are used by Hydro employees on a daily basis. Loss of the performance of these servers due to disk space unavailability would have a negative effect on employee productivity and customer service.

Please refer to the following table for expenditures in each year from 2003 to 2006 for Enterprise Storage.

Year	Budget *($000)*	Actual *($000)*	Description
2006	0.0	0.0	No Disk Required
2005	463.5	463.5	SAN Disk and Tape Library Expansion
2004	0.0	0.0	No Disk Required
2003	2,049.0	2,000.0	Initial SAN purchase and Installation.

- **Amounts shown are after Cost Recovery**
- **Amounts shown are for all Storage, Tape and Disk**

Future Plans:

The future plans for the Enterprise Storage is to effectively manage disk usage and to reduce data growth requirements.

Project Title: Replace Peripheral Infrastructure
Location: Hydro Place
Category: General Properties - Computer Operations
Type: Pooled
Classification: Normal

Project Description:
This project consists of the replacement of four Multi-Function Devices (MFD's) used for printing, copying, and scanning.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	123.0	0.0	0.0	123.0
Labour	10.0	0.0	0.0	10.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	12.7	0.0	0.0	12.7
Contingency	13.3	0.0	0.0	13.3
Total	**159.0**	**0.0**	**0.0**	**159.0**

Operating Experience:
The units scheduled for replacement have been in service for over five years and normal maintenance contracts have expired. As the devices age, they require more maintenance and service time resulting in loss of reliability and productivity. If these units are kept in service until catastrophic failure occurs then the office is without any scanning, coping, faxing or high volume printing services. Depending on the location it may take four-five weeks to replace the unit and will require considerable unbudgeted funding. Industry best practices indicate that the typical service life for a peripheral device is four to five years.

Project Justification:
This is the continuation of the evergreen program to replace peripheral devices as they reach the end of their useful lives. The manufacturer will only guarantee the operation of these MFD's for a period of five years.

Project Title: Replace Peripheral Infrastructure **(cont'd.)**

Project Justification: (cont'd.)

Please refer to the following table for expenditures in each year from 2002 to 2006 for peripherals. Peripherals can range from a small printer at an approximate price of $1,000 to a high-speed copier/printer priced at $50,000.

Year	Budget ($000)	Actual ($000)	Number of Units
2006	199.0	196.0	8
2005	117.0	121.0	56
2004	101.0	101.0	14
2003	99.0	104.0	7
2002	130.0	133.0	17

This project is subjected to a lease or purchase cost benefit analysis to determine the lowest cost alternative. The cost benefit analysis is done in the year of replacement to ensure consideration of incentives or other benefits that may be offered by the providers.

Future Plans:
The ongoing plan involves a coordinated effort to keep Hydro's peripheral infrastructure in good working order and using current technologies while delivering a cost effective solution to the end-user needs.

Project Title: Video Conferencing

Location: Various Sites

Category: General Properties - Computer Operations

Type: Pooled

Classification: Normal

Project Description:

This project consists of the addition of four video conference units, a digital video recorder and a multiple site conference unit that would allow up to 50 locations to participate.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	112.0	0.0	0.0	112.0
Labour	5.0	0.0	0.0	5.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	11.2	0.0	0.0	11.2
Contingency	11.7	0.0	0.0	11.7
Total	**139.9**	**0.0**	**0.0**	**139.9**

Operating Experience:

Video conferencing technology enables face to face meetings from the convenience of the office without the expense of travel and lost travel time. For several years staff has been using video conferencing between its office locations in Churchill Falls, Bishop's Falls, Bay d'Espoir, Holyrood, Port Saunders, St. Anthony, Happy Valley, Deer Lake and St. John’s. The intent of this proposal is three fold:

- Increase the number of video conference units permitting more locations to participate in on-line meetings and presentations. This involves a new unit for Whitbourne and Stephenville plus replacing the smaller unit in Happy Valley.
- Install a Video Conference Switch that will permit all locations to participate in a group meeting. This will also permit conferences between Hydro locations and third parties located globally.
- Acquire a video recorder to record presentations for live broadcast or playback later.

Project Title: Video Conferencing **(cont'd.)**

Project Justification:

Video Conferencing

Until recently Hydro could only host a meeting between two locations but with improvements in technology a four way conference unit became feasible. During the past two years Hydro has purchased two of these four way conference units and utilizes them on a regular basis to conduct regional meetings. Hydro realizes the convenience of such equipment and would like to install a corporate wide video conference system that could unite all of Hydro's offices in Newfoundland and Labrador. This proposal would purchase the necessary equipment to tie all Hydro's locations together as well as connect to external parties simultaneously.

Digital Video Recorder

Currently Hydro has no capability to record a presentation and deliver it to all users in a timely manner. A digital video recorder would use the existing video conference units to broadcast the live presentation to multiple locations in real time and record it as well so users could view it at a later time.

Future Plans:

Hydro plans to continuously expand its video conferencing capability to allow any user to connect to any other location(s) as easily as making a phone call. The purchase of a multi-way conferencing unit will make this a viable solution.

Project Title: Security Configuration Auditing

Location: St. John's

Category: General Properties - Computer Operations

Type: Other

Classification: Normal

Project Description:

The Information Systems (IS) Security program for 2008 consists of one initiative.

Configuration Auditing - a program to deploy a system to detect and reconcile configuration changes made to our critical hardware resources.

Corporate Information Technology (IT) security guarantees the confidentiality, integrity and availability of Hydro's data.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	27.3	0.0	0.0	27.3
Labour	20.2	0.0	0.0	20.2
Consultant	16.3	0.0	0.0	16.3
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	1.8	0.0	0.0	1.8
Contingency	6.4	0.0	0.0	6.4
Sub-Total	72.0	0.0	0.0	72.0
Cost Recoveries	(14.4)	(0.0)	(0.0)	(14.4)
Total	**57.6**	**0.0**	**0.0**	**57.6**

Operating Experience:

A number of security-related programs have been developed to address ongoing business goals and requirements while at the same time adhering to the three principals of IT security – data confidentiality, data integrity, and data availability. Hydro's administration and operational network infrastructures are growing and becoming more sophisticated. These systems support employees, customers and vendors and take advantage of web-enabled technologies and enhanced functionalities offered by remote access capabilities. A configuration auditing initiative will provide system administrators the assurance that any changes to infrastructure components are as a result of a valid change request and not the result of a breach of security.

Project Title: Security Configuration Auditing **(cont'd.)**

Project Justification:

Configuration auditing supports information confidentiality and data integrity by detecting changes in infrastructure components and reconciling them with authorized change requests. Appropriate configuration controls reduce the risks associated with unauthorized change (downtime because of system failure, the introduction of security vulnerabilities and insider security threats). In order to satisfy regulatory and audit compliance and to more efficiently consolidate the security operations in a heterogeneous environment, a management tool is required to aggregate, filter, and then normalize the data and produce useful information. Currently data from key infrastructure devices (firewalls, intrusion detection system, etc.) is being produced in massive amounts. The data is not reviewed in a timely manner.

Consolidating and analyzing the data and then presenting it in a timely fashion, will ensure any potential threat is dealt with in a pro-active manner. Key security devices will be monitored in the customer network including firewalls, Windows servers, AS/400, etc. The extensive reporting capabilities for operators and administrators will enable them to understand changes in traffic patterns and to detect emerging attacks that may not be evident from a single venue. Security efforts will focus on real threats, providing both the information and tools needed to respond quickly, accurately, and efficiently.

Spending comparisons for the past four years is as follows:

Year	Budget ($000)	Actual ($000)	Comments
2006	76.4	70.2	Personal Firewall and Intrusion Detection System/Intrusion Prevention System
2005	156.1	154.1	Secure Remote Access and Security Strategy Deployment
2004	75.0	86.0	SPAM tool and password management (PSync)
2003	N/A	N/A	

Future Plans:

None.

Project Title: Server Technology Program

Location: Various Sites

Category: General Properties - Computer Operations

Type: Other

Classification: Normal

Project Description:

This project is a part of Hydro's server technology program and involves the replacement, addition and upgrade of hardware components and software related to Hydro's shared server infrastructure and upgrades to the server-based office productivity tools. Based on the age of existing servers, each year an appropriate number of servers will be refreshed. This infrastructure ensures that the Corporation has a reliable secure infrastructure environment required to support efficient operations.

The scope of the proposed server technology program includes the replacement of 18 Blade Servers within the St. John's Server Farm and the addition of three Blade Servers. Provision has also been provided to cover labour costs to join Wabush and Happy Valley to the St. John's Citrix Farm. This will allow the removal of the Lotus Notes Server, File Server, and Disk Array from these locations.

Project Cost: *($ x1,000)*	2008	2009	Beyond	Total
Material Supply	147.0	0.0	0.0	147.0
Labour	55.0	0.0	0.0	55.0
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 & Escalation	18.8	0.0	0.0	18.8
Contingency	20.2	0.0	0.0	20.2
Total	**241.0**	**0.0**	**0.0**	**241.0**

Operating Experience:

Hydro's server infrastructure supports the applications that are used by its employees in carrying out its day-to-day business. This project is necessary to maintain reliable performance on its servers. Hydro uses its existing servers for office productivity tools (e.g. Word, Excel); email; Intranet/Internet and various database systems, as well as software tools required to monitor and manage servers and its infrastructure. There is also provision in this budget to add Wabush and

Project Title: Server Technology Program **(cont'd.)**

Operating Experience: (cont'd.)

Happy Valley Offices to the Citrix Farm at St. John's. This will require that three additional blade servers be added to support the added users. This will eliminate most of the standalone equipment at these offices such as File servers, Email servers, and Disk Storage Arrays.

Project Justification:

Hydro needs to keep its server and operating systems current in order to adequately support and protect the IT infrastructure required to operate its business. The replacement, addition and upgrading of hardware components to achieve this goal requires investment over the lifecycle of the infrastructure.

The factors that are driving Hydro's proposal to replace/upgrade its server environment include:

- Addressing obsolescence/maintaining vendor support;
- Providing security/managing the infrastructure;
- Supporting current versions of applications; and,
- Exploiting technology advances.

Technical Definitions:

<u>Obsolescence/Vendor Support</u> - Without vendor support, the functions and services reliant on the server infrastructure are at risk as security and support patches for the operating system will no longer be available. As a result, Hydro's ability to support and ensure continuation of the functions and services is impeded.

<u>Servers</u> - Industry standards indicate that server hardware has a useful life of five years. Beyond this timeframe reliability and support become issues. At this time the Vendor support and inventory of spare parts are discontinued. As the servers are used by Hydro employees to provide support in running the business on a daily basis, loss of availability of these servers would have a negative effect on employee productivity by not allowing access to software applications that are used by them to run the business.

Project Title: Server Technology Program **(cont'd.)**

Project Justification: (cont'd.)

Blade Server - A server architecture that houses multiple server modules ("blades") in a single chassis. It is widely used in datacenters to save space and improve system management.

Citrix Farm - A group of network servers that are housed in one location. A server farm provides bulk computing for specific applications such as Web site hosting or Application hosting.

Please refer to the following table for expenditures in each year from 2003 to 2006 for the Server Technology Program.

Year	Budget *($000)*	Actual *($000)*	# of Machines Replaced
2006	(1) 0.0	0.0	0
2005	212.0	179.0	12
2004	639.0	(2) 609.0	28
2003	119.0	117.0	13

(1) Server lifecycle was extended by one year, thus the refresh program was deferred by a year.

(2) This includes servers ($182.0) plus migration to new operating system and supporting office productivity tools.

The benefits of the refresh program are that servers are replaced in a planned and consistent manner. This allows for even distribution of budgets and ensures that the servers are available and reliable to support the user’s applications. Continued review of the server lifecycle allows Hydro to adjust plans based on server performance, technology changes and new business requirements.

Future Plans:

This is an ongoing refresh program to maintain server performance.

Project Title: Public Address System

Location: Holyrood

Category: General Properties - Telecontrol

Type: Other

Classification: Mandatory

Project Description:

The Public Address (PA) system at the Holyrood Thermal Generating Station is used to page staff, warn of potential dangerous situations and facilitate communications between plant floors and to the control room. This project consists of the replacement of deteriorated and obsolete paging equipment and extension of the coverage area to include areas currently not reached using the existing system.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	80.3	0.0	0.0	80.3
Consultant	50.0	0.0	0.0	50.0
Contract Work	800.0	0.0	0.0	800.0
Other Direct Costs	3.5	0.0	0.0	3.5
O/H, AFUDC & Escalation	111.9	0.0	0.0	111.9
Contingency	93.4	0.0	0.0	93.4
Total	**1,139.1**	**0.0**	**0.0**	**1,139.1**

Operating Experience:

The existing paging system was part of the original site installation in 1970, making the system 37 years old. It has reached the end of its useful life and is now obsolete; as well, the system cannot be extended to cover certain areas of the facility that must be reached during emergencies, including plant out buildings, chemical storage building, the tank farm and the marine terminal. The system has deteriorated and some replacement parts are no longer available.

Project Justification:

The Holyrood paging system is the primary emergency communications system and is critical for safe operation of the facility. Failure to upgrade and extend the reach of the current system could result in loss of life, plant, and equipment if personnel are unable to be alerted of dangerous situations.

Future Plans:

None.

Project Title: Customer Service Application

Location: Hydro Place

Category: General Properties - Telecontrol

Type: Other

Classification: Normal

Project Description:

Hydro currently leases a service that is managed and maintained by Aliant for its residential customer billing and outage information system. This system provides 24 hour, seven days a week access for customers, which permits:

1) customers to obtain personal billing and account information, or to obtain power outage information for their specific region;

2) meter readers to retrieve and update specific customer account information; and

3) Hydro administrators to update power outage information, and to generate usage and performance based reports.

The scope of this project is to replace the existing Aliant supplied application with a new billing and Outage Information System. The new system as presented herein requires:

1) an upgrade to the Hydro Place Private Branch Exchange (PBX) system to support the new application;

2) the provisioning and installation of an Interactive Voice Response (IVR) system to replace the existing telephone interface; and

3) the development of a World Wide Web (WWW) application to replace the existing Internet interface.

Project Title: Customer Service Application **(cont'd.)**

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	110.0	52.1	0.0	162.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	572.8	22.4	0.0	595.2
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	84.9	31.3	0.0	116.2
Contingency	0.0	75.8	0.0	75.8
Total	**767.7**	**181.6**	**0.0**	**949.3**

Operating Experience:

The existing system was developed by Aliant and is proprietary; it restricts Hydro from utilizing any of the existing system components to reduce or offset any new capital costs. On September 22, 2006 Aliant issued Newfoundland and Labrador Hydro a Notice of Discontinuation of Multi-Channel Application Service, identifying the end of life of the existing system as October 31, 2008. The service will be discontinued as of that date.

Project Justification:

The Hydro billing and outage information system has resulted in reduced call volumes and increased Customer Services personnel productivity; the provisioning of flexible billing and outage information for utility customers; and meter reader accessibility to update customer account information. This capital budget proposal is based on the least known cost alternative as of June 2007. A Net Present Value (NPV) analysis of the two alternatives considered at this time, a leased system and a Hydro-owned system, show NPVs of $957,00 and $640,000 respectively. Please refer to the attached report entitled "Replacement of Customer Services Billing and Outage Information System" Section H, Tab 11, for more information.

Future Plans:

None.

Project Title: Replace Power Line Carrier
Location: TL-212 Sunnyside to Paradise River
Category: General Properties - Telecontrol
Type: Other
Classification: Normal

Project Description:

This project consists of the supply, installation and commissioning of communications equipment to replace the existing Power Line Carrier and associated equipment on TL-212 between the Sunnyside Terminal Station and the Paradise River Generating Plant. This equipment will be selected to meet operational requirements. The Powerline Carrier on TL-212 carries power system protection circuits as well as operational voice and data in support of the Energy Control Center.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	292.8	0.0	0.0	292.8
Labour	73.3	0.0	0.0	73.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	13.4	0.0	0.0	13.4
O/H, AFUDC & Escalation	48.8	0.0	0.0	48.8
Contingency	38.0	0.0	0.0	38.0
Total	**466.3**	**0.0**	**0.0**	**466.3**

Operating Experience:

This power line carrier was installed in 1988-1989. Reliability is an issue due to the unavailability of parts and the age of the equipment.

Project Justification:

The equipment will have been in service for 20 years and is now obsolete. The Power Line Carrier model ETI 21 with the NSD 60 teleprotection module have been phased out by the manufacturer ABB. The manufacturer has indicated that, due to the unavailability of components, the discontinued products can rarely be repaired. As such continued utilization of this equipment poses the risk of failure and hence loss of communications required for the protection and control of the

Project Title: Replace Power Line Carrier **(cont'd.)**

Project Justification: (cont'd.)

power system. The decommissioned equipment will provide spare components for other obsolete power line carriers awaiting replacement. Replacement of the power line carriers ensures communications to monitor and control power devices to provide uninterrupted service to our customers and protection of the transmission assets.

Future Plans:

None.

Project Title: Replace Remote Terminal Units

Location: Various Sites

Category: General Properties - Telecontrol

Type: Other

Classification: Normal

Project Description:

This is a continuation of a program to replace obsolete Remote Terminal Units (RTUs). The project scope for 2008 consists of the replacement of three RTUs at the following sites: Grand Falls Frequency Converter, Deer Lake Power Plant and Grandy Brook Terminal Station. This project also proposes to enhance RTU processor and communications capabilities at the Stony Brook and Sunnyside Terminal Stations.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	145.2	0.0	0.0	145.2
Labour	98.6	0.0	0.0	98.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	14.3	0.0	0.0	14.3
O/H, AFUDC & Escalation	35.0	0.0	0.0	35.0
Contingency	25.8	0.0	0.0	25.8
Total	**318.8**	**0.0**	**0.0**	**318.8**

Operating Experience:

The RTUs being replaced are 18-20 years old. All are manufacturer discontinued and no longer supported. The RTUs being enhanced were installed in 2000 and 2002.

The history of expenditures for this project for the past five years is as follows:

Year	**Budget ($000)**	**Actuals ($000)**
2006	350.9	226.0
2005	183.0	204.0
2004	313.8	325.0
2003	285.2	288.0
2002	311.4	311.0

Project Title: Replace Remote Terminal Units **(cont'd.)**

Project Justification:

The RTUs have been manufacturer discontinued and spare parts and repair services are no longer available. RTUs are critical assets used in conjunction with the Energy Management System (EMS) to control the delivery of power to our customers. Failure to replace this equipment may result in an impact on service to our customers in either reduced reliability or extended customer outages. Replacement of these RTUs ensures the reliability and continuity of service to our customers by ensuring that generation, transmission and distribution assets are able to be dispatched.

Enhanced RTUs will provide more functionality by utilizing the IP based operational data network.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Refurbish Microwave Site
Location: Gull Pond Hill
Category: General Properties - Telecontrol
Type: Other
Classification: Normal

Project Description:
This project involves the refurbishing of the West Coast Microwave site located at Gull Pond Hill. The microwave system is used to support generation, transmission and administrative functions. The Gull Pond Hill site was installed in 1979 and has never been refurbished. This program will extend the useful life of this site.

The work will include the following:

1) Installation of aircraft hazard marking system;
2) structural member replacement;
3) guy wire replacement;
4) anchor repair or replacement;
5) building and foundation replacement.

The microwave system is a crucial asset that supports the reliable operation of the generation and transmission systems for the province. It carries the Supervisory Control and Data Acquisition (SCADA) traffic that connects the provincial Energy Control Center (ECC) to all the plants and terminal stations. It also carries the teleprotection signals for the protection of the majority of the 230KV transmission lines. The West Coast microwave system also supports the operational voice system used by ECC, the VHF mobile radio system used by operations personnel such as the line crews that perform annual or emergency maintenance on the transmission lines and the data facilities for administrative functions. The microwave system is directly related to the reliable delivery of power for all Newfoundland and Labrador Hydro customers.

The only alternative is to delay refurbishment. By refurbishing this site now their useful life is being extended, thereby minimizing the impact to the customer of the cost of capital assets.

Project Title: Refurbish Microwave Site **(cont'd.)**

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	32.9	0.0	0.0	32.9
Consultant	19.2	0.0	0.0	19.2
Contract Work	108.0	0.0	0.0	108.0
Other Direct Costs	3.9	0.0	0.0	3.9
O/H, AFUDC & Escalation	21.8	0.0	0.0	21.8
Contingency	16.4	0.0	0.0	16.4
Total	**202.2**	**0.0**	**0.0**	**202.2**

Operating Experience:

This microwave site has been in operation since 1979 with no major refurbishing done and minor maintenance completed annually. The towers and guy wires are showing signs of rusting and oxidation. The buildings are experiencing shifting foundations and other similar indications of deterioration.

Project Justification:

This microwave site is one of the major components of the reliable generation of electricity for the province. Without refurbishing, this microwave site will deteriorate to a level where catastrophic structural failure would happen. This would result in direct loss of control of the grid for the Energy Control Center (ECC) and therefore extended power outages. Also the loss of teleprotection on the transmission lines could cause severe damage to equipment and extend outages even longer.

To ensure that this project will be completed at the lowest possible cost, Newfoundland and Labrador Hydro will solicit competitive bids for all materials and external labor under the Provincial Tendering Act.

Future Plans:

Future refurbishing projects will be proposed in future capital budget applications.

Project Title: Replace Dial Backup System

Location: Various Sites

Category: General Properties - Telecontrol

Type: Other

Classification: Normal

Project Description:

This project consists of the replacement of obsolete dial backup modems and switching equipment. This system is used to connect with Remote Terminal Units (RTUs) at selected key terminal stations in the event of an extended telecommunications outage on the primary circuit.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	102.0	0.0	0.0	102.0
Labour	48.5	0.0	0.0	48.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	11.0	0.0	0.0	11.0
O/H, AFUDC & Escalation	23.6	0.0	0.0	23.6
Contingency	16.2	0.0	0.0	16.2
Total	**201.3**	**0.0**	**0.0**	**201.3**

Operating Experience:

The equipment being replaced is almost 20 years old, is at the end of its useful life, and has had no manufacturer support or replacement parts available for several years.

Project Justification:

The system being replaced is used at selected terminal stations when an extended telecommunications outage is experienced; for example, when the Aliant circuit connecting ECC with the Northern Peninsula is out of service, this system allows communication with affected terminal stations. As well, when communications facilities carried on the power line are out of service because of line maintenance, this system will permit remote operation of affected stations. Failure to replace the system may cause or extend customer outages if critical components fail and ECC cannot communicate with stations.

Future Plans:

None.

Project Title: Install Recloser Remote Control

Location: Change Islands

Category: General Properties - Telecontrol

Type: Other

Classification: Normal

Project Description:

This project will install and commission all communications, Supervisory Control and Data Acquisition (SCADA) and support infrastructure needed to enable the remote control of the reclosers, FH1-R1 and FH1-R2 on Change Islands from the Energy Control Center at Hydro Place in St John's, using the existing SCADA Link from Farewell Head Terminal Station. This will involve the installation of a point to point radio link between Farewell Head Terminal Station and Change Islands, upgrades to the FH1-R1 and FH1-R2 communications interface, and installation of support services, such as DC power Backup, antenna structures and associated hardware to connect Farewell Head Terminal Station to the Change Islands Reclosers.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	74.7	0.0	0.0	74.7
Labour	66.4	0.0	0.0	66.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	17.1	0.0	0.0	17.1
O/H, AFUDC & Escalation	20.0	0.0	0.0	20.0
Contingency	15.8	0.0	0.0	15.8
Total	**194.0**	**0.0**	**0.0**	**194.0**

Operating Experience:

The five-year average for System Average Interruption Frequency Index (SAIFI) on the Change Islands/ Fogo Island distribution system, with a total 1,750 customers, is 7.52. The duration index System Average Interruption Duration Index (SAIDI) is 22.51. The SAIFI rating is on par with the Hydro average of 6.88 but the SAIDI rating is 2.10 times the Hydro average of 10.7. Faults and weather events such as lightning storms in the summer and freezing rain, sleet and/or high winds in the winter result in operation of the distribution reclosers located on Change Islands. The resulting lock out of the recloser can results in extended outages for both Change Islands and Fogo Island customers.

Project Title: Install Recloser Remote Control **(cont'd.)**

Project Justification:

The Change Islands and Fogo Island distribution systems are interconnected via submarine cable and overhead power lines with two distribution reclosers, FH1-R1 and FH1-R2, on Change Islands. These distribution reclosers provide fault protection for their respective distribution systems, and in the case of FH1-R2, also protect the submarine cable to Fogo Island. When faults occur during severe weather conditions one or both of these reclosers may repeatedly trip and then lock out. Currently the only way to restore service once a lock out has occurred is for linemen to physically go to the recloser and manually reset it. Change Islands does not have permanent Hydro employees, so this function can only be completed by a linecrew from either Fogo Island or Bishop's Falls, who can only arrive by ferry or helicopter. Any weather delays will mean an extended outage to Change Islands and Fogo Island. By installing this system, lock outs can be remotely reset, reducing outage duration and providing better service for our customers. Please see the attached report "Change Islands Reclosers Remote Control Analysis", Section H, Tab 12.

Future Plans:

None.

Project Title: Replace Radomes

Location: Various Sites

Category: General Properties - Telecontrol

Type: Other

Classification: Normal

Project Description:

This project will replace the protective radomes on nine microwave radio antennas. Two radomes are planned to be replaced at the Gull Pond Hill microwave site, four at the Sandy Brook Hill microwave site, and three at Hind's Lake Gnerating station. Other sites may be substituted for these if damage is found to have occurred on other radomes.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	13.0	0.0	0.0	13.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	86.8	0.0	0.0	86.8
Other Direct Costs	1.7	0.0	0.0	1.7
O/H, AFUDC & Escalation	12.1	0.0	0.0	12.1
Contingency	10.2	0.0	0.0	10.2
Total	**123.8**	**0.0**	**0.0**	**123.8**

Operating Experience:

Due to exposure to wind, sun, rain, and ice, radomes deteriorate over time. They have an average life of seven years. When the radome weakens, tears form in the fabric and damage to antenna components may occur. Failure of radomes in 1993 caused extensive outages to the microwave system which lasted for several months, owing to significant lead times associated with ordering, procurement and installation of microwave antennas. In order to mitigate this risk, Hydro has proposed a radome replacement program for the 80 microwave antennas it currently maintains.

Project Justification:

Radomes have an average life of seven years and must be replaced before failure. Radome failures are unacceptable as damage to microwave dishes would result in extensive outages and costly repairs. See attached report "Microwave Antenna Radome Replacement Program", Section H, Tab 13.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Replace Network Communications Equipment

Location: Various Locations

Category: General Properties - Telecontrol

Type: Other

Classification: Normal

Project Description:

The communications network allows employees to perform administrative and operational computer related activities and to obtain Energy Management System data at a variety of locations. This project will replace five obsolete network components. In addition, the project includes the installation of facilities required to extend network access to remote locations as required.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	36.0	0.0	0.0	36.0
Labour	41.4	0.0	0.0	41.4
Consultant	3.0	0.0	0.0	3.0
Contract Work	5.0	0.0	0.0	5.0
Other Direct Costs	19.9	0.0	0.0	19.9
O/H, AFUDC & Escalation	14.8	0.0	0.0	14.8
Contingency	10.5	0.0	0.0	10.5
Total	130.6	0.0	0.0	130.6

Operating Experience:

The five routers being replaced under this project have reached the end of their useful lives and are now obsolete. Manufacturer support for all these devices ends in 2008.

The history of expenditures for this project for the past four years is as follows:

Year	**Budget ($000)**	**Actuals ($000)**
2006	96.7	143.0
2005	0.0	0.0
2004	45.5	50.0
2003	46.5	47.0

Project Title: Replace Network Communications Equipment **(cont'd.)**

Project Justification:

The network devices addressed herein are required to support growth which occurs at offices, terminal stations, power plants and microwave repeater sites. The demand for new services includes office automation traffic such as e-mail and work requests, and access to substation automation functions such as remote high speed access to meters and Intelligent Electronic Devices (IEDs).

The obsolete routers being replaced were installed in 2000-2001 and are no longer supported by the manufacturer. The manufacturer ceased developing software to address bugs and problems with the routers in 2004. As of 2008, the manufacturer will completely cease support of any kind, meaning that technical support and replacement parts are no longer available at all.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Voice Communications Strategy Study
Location: Hydro Place
Category: General Properties - Telecontrol
Type: Other
Classification: Normal

Project Description:

This project consists of a study to determine the proper strategy for the future replacement of Hydro's operational and administrative voice communications equipment. The result of this study will be a strategy to determine the optimal method of replacement of Hydro's operational voice systems, as well as a strategy for the optimal timing and method of replacement of Administrative telephone systems.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	75.3	0.0	0.0	75.3
Consultant	75.0	0.0	0.0	75.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	3.5	0.0	0.0	3.5
O/H, AFUDC & Escalation	20.7	0.0	0.0	20.7
Contingency	15.4	0.0	0.0	15.4
Total	**189.9**	**0.0**	**0.0**	**189.9**

Operating Experience:

Hydro purchased its administrative telephone systems in the 1990s, as they were demonstrably more cost effective than leased services available at the time. Manufacturer support for these systems is ending, as they are being replaced by newer Voice Over Internet Protocol (VOIP) systems. The operational system components range in age from 15 to over 30 years, and all components are obsolete.

Project Justification:

Hydro owns and maintains voice communications equipment at many locations. Operational voice equipment is used to provide voice communications between and among terminal stations, generating stations, and the Energy Control Centre. This equipment is critical to the safe and

Project Title: Voice Communications Strategy Study **(cont'd.)**

Project Justification: (cont'd.)

reliable operation of the power grid, as it bypasses the public telephone network and therefore remains in service during emergencies such as the Aliant outage of October 2006. Much of this system operates over PLC (Power Line Carrier) and replacement components are not easily obtainable. In order to ensure the operational voice system can continue to meet the need for reliable voice communication, this study is necessary to determine what options exist and which will be the most cost effective in the long term for Hydro.

Future Plans:

This Engineering study will establish a multi-year capital project program for upgrading the Western Orderwire System.

Project Title: Replace Network Management Tools

Location: Hydro Place

Category: General Properties - Telecontrol

Type: Other

Classification: Mandatory

Project Description:

This project proposes to purchase the Cisco Security Manager (CSM) system, including software and hardware required to operate the system. This system is used to remotely manage firewall devices.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	31.5	0.0	0.0	31.5
Labour	30.0	0.0	0.0	30.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	4.5	0.0	0.0	4.5
O/H, AFUDC & Escalation	8.7	0.0	0.0	8.7
Contingency	6.6	0.0	0.0	6.6
Total	**81.3**	**0.0**	**0.0**	**81.3**

Operating Experience:

None. This product has not been used before at Hydro.

Project Justification:

Currently there are 24 firewall devices used in Hydro's communications network, and this number is expected to grow. They are scattered around the entire province, from St. John's to the coast of Labrador. Most of these devices were installed as a result of a directive from the Department of Government Services in order to address access to safety and health information and Material Safety Data Sheets. This tool will be used to manage and monitor these devices remotely. If the product is not acquired, changes to or troubleshooting of these devices may require travel to the remote site, which is not only costly, but can result in outages lasting several days.

Future Plans:

None.

Project Title: Replace Vehicles and Aerial Devices

Location: Various Sites

Category: General Properties - Administration

Type: Other

Classification: Normal

Project Description:

The scope of work is to replace 33 transportation vehicles (cars, pick-ups and vans) and five work vehicles (line and boom trucks).

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	1,616.2	0.0	0.0	1,616.2
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 & Escalation	48.2	0.0	0.0	48.2
Contingency	161.6	0.0	0.0	161.6
Total	**1,826.0**	**0.0**	**0.0**	**1,826.0**

Operating Experience:

The vehicles being replace have become unreliable and are uneconomical to maintain.

These vehicles fall within the industry standard replacement criteria for vehicle age and kilometers as follows:

Transportation Vehicles: 5-7 years or 150,000 kms

Work Vehicles: 7-10 years or 200,000 kms

The following is a summary of the five years history for vehicles and aerial device purchases:

			Units Purchased	
Year	**Budget ($000)**	**Actual ($000)**	**Vehicles**	**Aerial Devices**
2006	1,732.6	1,689.0	45	9
2005	1,327.6	916.7	31	3
2004	2,223.2	2,327.0	35	4
2003	2,080.7	1,620.6	36	7
2002	1,897.4	1,508.9	36	8

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

Project Justification:

This project provides for the normal replacement of on-road fleet vehicles based on projected age and kilometers at disposal. Hydro requires reliable vehicles for the efficient delivery of its service. The vehicles being replaced are at the end of their life cycle and are no longer dependable. The transportation vehicles are an average six years service and 170,000 kms. The work vehicles have an average ten years service and 183,000 kms.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Upgrade System Security

Location: Various Sites

Category: General Properties - Administration

Type: Other

Classification: Normal

Project Description:

The project consists of the installations of additional security fences/gates, outdoor lighting systems, closed circuit cameras, cards access systems, property key - locking systems, intrusion alarms, and anti-climbing devices, etc. In 2007, the physical security upgrades at the various sites across the Hydro system will be prioritized. The first priority items will be completed with funds approved for 2007. Upgrades for 2008 and 2009 will be completed with funds applied for in this proposal.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	305.0	0.0	0.0	305.0
Labour	305.0	0.0	0.0	305.0
Consultant	70.0	0.0	0.0	70.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	54.0	0.0	0.0	54.0
O/H, AFUDC & Escalation	99.9	0.0	0.0	99.9
Contingency	72.4	0.0	0.0	72.4
Total	**906.3**	**0.0**	**0.0**	**906.3**

Operating Experience:

Following Sept 11, 2001, the Canadian Electrical Association established a Critical Infrastructure Protection Group (CIP). The CIP mandate was to promote initiatives to strengthen the protection of Canada's critical energy infrastructure and to provide a network of liaison within the utility industry to deal with issues related to emergency preparedness, safety and security. It was through Hydro's involvement in CIP that it recognized the need for assessing and upgrading major infrastructure and property security. In 2003 and 2005 Hydro commissioned consultant managed studies of several of its facilities. These studies resulted in general recommendations for security upgrades which will be prioritized as part of the 2007 work.

Project Title: Upgrade System Security **(cont'd.)**

Project Justification:

Since Sept 11, 2001, the role of security has changed dramatically. A properly structured and deployed security program will reduce the possibility and possibly eliminate some preventable losses by implementation of crime control, opportunity reduction and security awareness training programs. There are several established professional and legal standards that 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 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.

Future Plans:

Future upgrades will be proposed in future capital budget applications.

Project Title: Purchase Spare Transformer

Location: Hydro Place

Category: General Properties - Administration

Type: Other

Classification: Normal

Project Description:

This project consists of the purchase of a spare service transformer for Hydro Place. The unit will be designed as an exact replacement for the existing unit. The spare transformer will be stored at the Hydro warehouse facility at Holyrood. Scheduled inspection, maintenance and testing will be performed by Hydro Operations staff.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	50.0	250.0	0.0	300.0
Labour	20.0	17.0	0.0	37.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	8.0	8.0	0.0	16.0
O/H, AFUDC & Escalation	8.5	42.6	0.0	51.2
Contingency	0.0	35.3	0.0	35.3
Total	**86.5**	**352.9**	**0.0**	**439.4**

Operating Experience:

The existing transformer was installed in 1989. It is regularly tested and inspected and is in good condition. Within the last five years, two power interruptions occurred due to failure of equipment on the transformer. Loss of business continuity occurred in both instances, the first was in 2006 for four hours while the second was in 2007 and lasted 17 hours.

Project Justification:

This project is justified on the basis of business continuity. If the existing transformer failed in service, Hydro Place would be unavailable for normal business operations until a replacement unit could be secured and installed. The Hydro Place facility is served by a single uniquely designed transformer and there are no other transformers available within Hydro's inventory, or in the inventory of Hydro's customers, that could be used to service the building. Newfoundland Power

Project Title: Purchase Spare Transformer **(cont'd.)**

Project Justification: (cont'd.)

maintains a spare service transformer as a contingency for its customers but this unit does not have the correct winding configuration to serve Hydro Place. If the transformer failed before a spare was acquired, Hydro would have to search for a replacement or alternative configurations. This could take days or up to several weeks. Delivery times for the purchase and delivery of a replacement transformer are in the order of 12 to 14 months.

Future Plans:

None.

Project Title: Install Computer Room Inergen Fire Protection System

Location: Hydro Place

Category: General Properties - Administration

Type: Other

Classification: Normal

Project Description:

The scope of work is to design, supply and install an Inergen fire suppression system to protect the equipment in the Information Systems (IS) Computer Room on Level 1 of Hydro Place.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	0.5	0.0	0.0	0.5
Labour	28.7	0.0	0.0	28.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	66.9	0.0	0.0	66.9
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	10.0	0.0	0.0	10.0
Contingency	9.6	0.0	0.0	9.6
Total	**115.7**	**0.0**	**0.0**	**115.7**

Operating Experience:

Existing fire protection in this room consists of a pre-action sprinkler system, designed to protect the building structure.

Project Justification:

The equipment in the Information Systems (IS) Computer Room has critical importance since it houses the JDEdwards, Lotus Notes and office products applications and the AS/400 computer system and other servers for the corporation. Existing fire protection in this room consists of a pre-action sprinkler system, designed to protect the building structure. Exposure to water from this fire system would likely damage the computer equipment and result in loss of access to all computer equipment and systems for the corporation. This project would reduce that risk to an acceptable level. The proposed Inergen fire suppression system can extinguish a fire with no collateral damage to the computer equipment.

Future Plans:

None.

Project Title: Safety Hazards Removal
Location: Various Sites
Category: General Properties - Administration
Type: Other
Classification: Mandatory

Project Description:

The purpose of this project is to ensure adequate capital funding is available to quickly address capital-related safety issues as they are identified. Hydro has recently replaced its condition reporting process with a Safe Work Observation Program, and re-trained its employees in the importance of identifying and reporting conditions before they progress into incidents or accidents, in an effort to avoid injuries or fatalities.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	112.0	0.0	0.0	112.0
Labour	56.0	0.0	0.0	56.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	56.0	0.0	0.0	56.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	28.3	0.0	0.0	28.3
Contingency	0.0	0.0	0.0	0.0
Total	**252.3**	**0.0**	**0.0**	**252.3**

Operating Experience:

Since its implementation the Safe Work Observation Program has resulted in the identification of many previously undocumented safety and health deficiencies and unsafe conditions. These observations cover a wide range of safety and health concerns related to areas such as fall arrest/restraint, emergency response/egress, lighting levels, substandard ventilation and containment of dust and chemicals.

Included are things like safety railings that do not meet current standards, ladders that currently provide inadequate means of egress for emergencies, inadequate lighting of emergency escape routes, manual valve actuators that should be automatic for fast emergency operation, and inadequate ventilation in areas that may contain hazardous dust and chemicals.

Project Title: Safety Hazards Removal **(cont'd.)**

Project Justification:

This capital proposal is required to address mandatory safety issues. The Safe Work Observation Program involves workers actively looking for safety hazards and spotting problems that may otherwise be overlooked, and lead to serious health & safety issues for customers, employees or contractors of Hydro, and to the public. The work will involve addressing substandard conditions immediately, rather than being added to a project list for subsequent years, and remaining a risk for the intervening time. This project will provide Hydro with a means to address the situation when capital work is identified as the solution. Work will be identified as capital in accordance with Hydro's policy, which identifies a capital expenditure as an expenditure for:

(a) new, replacement, modified, or upgraded equipment or systems;
(b) feasibility studies for potential future capital programs;
(c) purchases with unit prices in excess of $1,000 and a useful life in excess of two (2) years; and
(d) components of a unit of property comprising an addition to or betterment of a unit of property and in addition having a purchase cost exceeding the materiality dollar value established in Hydro's policy.

Future Plans:

It is intended that this work continue on an annual basis, through the capital process, to provide an ongoing means for removing safety hazards from the workplace.

Project Title: Replace Humidifiers in Air Handling Units

Location: Hydro Place

Category: General Properties - Administration

Type: Other

Classification: Normal

Project Description:

Replace existing Nortec humidifiers with an energy efficient stainless steel humidifier system for Air Handling Units at Hydro Place.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	52.0	0.0	0.0	52.0
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 & Escalation	1.2	0.0	0.0	1.2
Contingency	5.2	0.0	0.0	5.2
Total	**58.4**	**0.0**	**0.0**	**58.4**

Operating Experience:

Existing humidifier tanks are a non serviceable component of the system, as they get less efficient and fail they have to be replaced. The controls for the system are obsolete, there is one unit not working and there are no parts available for repairs.

Project Justification:

All Heating/Ventilation/Air Conditioning (HVAC) Equipment at Hydro Place has been regularly serviced and maintained under a service contract with Johnson Controls since the building opened in 1989. Johnson Controls, as part of preventative maintenance planning, is recommending the replacement of all existing Nortec Humidifiers and upgrade with an energy efficient cost savings stainless steel humidifier system. A total of 10 are to be replaced and Johnson Controls are recommending two annually over a five-year period. This will be year one of the program.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Replace Air Conditioning Units

Location: Hydro Place

Category: General Properties - Administration

Type: Other

Classification: Normal

Project Description:

Replace Liebert Air Conditioning Unit #13, Energy Control Centre (ECC) Computer Room at Hydro Place.

Project Cost: *($ x1,000)*	**2008**	**2009**	**Beyond**	**Total**
Material Supply	50.0	0.0	0.0	50.0
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 & Escalation	1.2	0.0	0.0	1.2
Contingency	5.0	0.0	0.0	5.0
Total	**56.2**	**0.0**	**0.0**	**56.2**

Operating Experience:

This unit has had significant outages due to equipment failure over the past several years as listed in the attached table. There has also been refrigerant leaks which is an environmental problem.

Year	Description	Cost
2006	Evaporator and compressor leakage	$16,800
2005	Thermostatic expansion valve and blower motor failure	7,600
2003	Motherboard failure	8,000
2002	Gasket replacement on compressors	2,000
2000	Condensor replacement	28,000

Project Justification:

All Air Conditioning Units at Hydro Place have been regularly serviced and maintained under a service contract provided by Johnson Controls since the building opened in 1989. Johnson Controls as part of preventative maintenance planning are recommending replacement due to the

Project Title: Replace Air Conditioning Units **(cont'd.)**

Project Justification: (cont'd.)

age of the equipment, excessive failures and long delivery times for parts for this particular unit. This unit controls the air conditioning in the ECC Computer Room and is of critical importance to the ECC Operation.

Future Plans:

Future replacements will be proposed in future capital budget applications.

1. **Purchase Spare Transformer - Upper Salmon**

   This project was included in an application filed with the Board on July 14, 2006 and which the Board approved in Order No. P.U. 35 (2006). The cost of copper and steel has increased dramatically over the past year and most transformer manufacturers are experiencing an increase in demand for new transformers. This has resulted in a cost increase from $1.4 million to $2.2 million as well as a delay in delivery. The project in-service date has been extended by one year to October of 2008.

Section C

PROJECT DESCRIPTION	Expended to 2007	2008	2009	Total	Type	Page Ref
		($000)				
MANDATORY PROJECTS						
Public Address System - Holyrood		1,139		1,139	Other	B-192
Upgrade Continuous Emissions Monitoring System		689		689	Other	B-39
TOTAL MANDATORY PROJECTS	0	1,828	0	1,828		
NORMAL PROJECTS						
Upgrade Distribution Systems - Various Systems		2,727		2,727	Pooled	B-98
Upgrade Distribution Systems - All Service Areas		2,293		2,293	Pooled	B-101
Purchase Spare Transformer - Upper Salmon	665	1,552		2,217	Other	B-222
Wood Pole Line Management Program		2,188		2,188	Pooled	B-83
Provide Service Extensions - All Service Areas		2,158		2,158	Pooled	B-103
Replace Vehicles and Aerial Devices - Various Sites		1,826		1,826	Other	B-210
Replace Insulators TL-232 and TL-253		848	970	1,818	Pooled	B-85
Upgrade Corner Brook Frequency Converter		495	1,152	1,647	Other	B-87
Construct New Office,Warehouse,Line Depot Facilities - Happy Valley		1,248	384	1,632	Other	B-135
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle		335	938	1,273	Pooled	B-117
Upgrade Spherical Valve Maintenance Seals - Cat Arm		1,060		1,060	Other	B-5
Replace Governor Controls Unit 2 - Cat Arm		975	74	1,049	Other	B-7
Customer Service Application - Hydro Place		768	182	950	Other	B-193
Replace Unit 2 High Pressure Heater		20	919	939	Other	B-38
Upgrade System Security - Various Sites		906		906	Other	B-212
Diesel Plant Automation - Makkovik and Rigolet		516	379	895	Pooled	B-120
Replace Off Road Track Vehicles - Bishop's Falls and Whitbourne		746		746	Other	B-158
Replace Poles - South Brook and Bay d'Espoir		700		700	Pooled	B-105
Application Enhancements - Work Protection Code		678		678	Other	B-166
Replace Insulators - Various Systems		623		623	Pooled	B-107
Increase Generation Capacity - Charlottetown		18	577	595	Other	B-122
Install Automatic Meter Reading - Various Systems		567		567	Pooled	B-153
Replace Switchgear - Cartwright		383	169	552	Other	B-125
Tank Farm Upgrade		500		500	Other	B-36
Replace Line Camp 98 - TL-228		500		500	Other	B-89
TOTAL NORMAL PROJECTS	665	24,630	5,744	31,039		
JUSTIFIABLE PROJECTS						
Application Enhancements - Energy Systems Water Management		651		651	Other	B-168
TOTAL JUSTIFIABLE PROJECTS	0	651	0	651		

PROJECT DESCRIPTION	Expended to 2007	2008	2009	Total	Type	Page Ref
		($000)				
MANDATORY PROJECTS						
Installation of Fall Arrest Equipment - Various Sites		405		405	Other	B-162
Arc Flash Analysis - Various Sites		342		342	Other	B-9
Replace Unit 1 and 2 Condenser Valve Actuators		313		313	Other	B-41
Construct Transmission Line Equipment Off-Loading Areas		302		302	Other	B-93
Precipitator and Scrubber Installation Study		272		272	Other	B-46
Safety Hazards Removal - Various Sites		252		252	Other	B-217
TOTAL MANDATORY PROJECTS	0	1,886	0	1,886		
NORMAL PROJECTS						
Replace Mufflers - L'Anse au Loup and St. Anthony		479		479	Pooled	B-128
Replace Power Line Carrier TL-212 - Sunnyside to Paradise River		466		466	Other	B-195
Upgrade Line TL-212 - (Sunnyside to Linton Lake)		464		464	Other	B-92
End User Evergreening Program		451		451	Pooled	B-178
Purchase Spare Transformer - Hydro Place		87	353	440	Other	B-214
Replace Battery Banks and Chargers - Various Stations		430		430	Other	B-71
Replace Champion Grader V-9797 - Bay d'Espoir		404		404	Other	B-68
Replace Disconnect Switches - Cow Head and Daniel's Harbour		368		368	Other	B-73
Construct Bushing Storage Building - Bishop's Falls		335		335	Other	B-136
Replace Remote Terminal Units - Various Sites		319		319	Other	B-197
Upgrade Circuit Breakers - Various Stations		315		315	Other	B-74
Replace Unit 2 Electromechanical Trip Device		305		305	Clustered	B-43
Application Enhancements - Corporate Systems		298		298	Pooled	B-170
Replace Insulators - Various Stations		294		294	Other	B-96
Corporate Application Environment		290		290	Pooled	B-175
Replace Cooling Water Systems Units 1 and 2 - Bay d'Espoir		264		264	Other	B-10
Upgrade Enterprise Storage Capacity		262		262	Pooled	B-181
Replace 40 kW Diesel Generator - Burnt Dam		157	103	260	Other	B-14
Server Technology Program - 2008		241		241	Pooled	B-189
Replace Boom 6069 on Track Vehicle - Stephenville		236		236	Other	B-164
Replace Recloser Control Panels - Various Systems		223		223	Other	B-109
Install Meteorological Stations - Various Sites		222		222	Other	B-16
Upgrade Ventilation System - Makkovik		217		217	Other	B-138
Refurbish Microwave Site - Gull Pond Hill		202		202	Other	B-199
Replace Dial Backup System - Various Sites		201		201	Other	B-201
TOTAL NORMAL PROJECTS	0	7,530	456	7,986		
JUSTIFIABLE PROJECTS						
Application Enhancements - Energy Systems Optimum Powerflow		216		216	Other	B-173
TOTAL JUSTIFIABLE PROJECTS	0	216	0	216		

PROJECT DESCRIPTION	Expended to 2007	2008	2009	Total	Type	Page Ref
		($000)				
MANDATORY PROJECTS						
Environmental Effects Monitoring Study of Waste Water		73	87	160	Other	B-52
Salmon Spillway Stoplog Handling System		141		141	Other	B-23
Upgrade Ambient Monitoring Station		128		128	Other	B-54
Soot Blowing Controls Study		123		123	Other	B-55
Install Safety Egress Lighting		97		97	Other	B-58
Replace Network Management Tools - Hydro Place		81		81	Other	B-209
Upgrade Meteorological Station		75		75	Other	B-63
Replace Meter House Equipment - Various Sites		75		75	Pooled	B-133
Install Day Tank and Meter - Hopedale		61		61	Other	B-134
TOTAL MANDATORY PROJECTS	0	854	87	941		
NORMAL PROJECTS						
Hydraulic Structure Life Study - Bay d'Espoir		196		196	Other	B-18
Install Recloser Remote Control - Change Islands		194		194	Other	B-202
Replace Cooling Water Piping System - Hinds Lake		193		193	Other	B-20
Voice Communications Strategy Study - Hydro Place		190		190	Other	B-207
Construct Diesel Plant Extension - William's Harbour		177		177	Other	B-140
Replace 4160 Volt Motor Relays		172		172	Other	B-48
Replace Unit 2 Main Steam Stop Valve		171		171	Other	B-50
Replace Fire Alarm System - Hopedale and Paradise River		168		168	Other	B-142
Replace Peripheral Infrastructure		159		159	Pooled	B-183
Reconfigure Feeders - Happy Valley		151		151	Other	B-112
Video Conferencing		140		140	Pooled	B-185
Install Storage Ramp - Holyrood and Port Saunders		135		135	Pooled	B-144
Replace Network Communications Equipment - Various Sites		131		131	Other	B-205
Replace Digital Fault Recorder - Buchans		130		130	Other	B-75
Replace Radomes - Various Sites		124		124	Other	B-204
Upgrade Intake #4 Gate Controls - Bay d'Espoir		116		116	Other	B-25
Install Computer Room Inergen Fire Protection System - Hydro Place		116		116	Other	B-216
Stack Breeching Study		115		115	Other	B-56
Replace Compressors - Buchans		94		94	Other	B-76
Auto Synchronizing Units 1 and 2		93		93	Clustered	B-59
Replace Underground Fuel Lines - Little Bay Islands and Grey River		89		89	Other	B-132
Install Stator Ground Fault Protection		85		85	Other	B-61
Install Chain Link Fencing - Port Hope Simpson		84		84	Other	B-145
Replace Instrument Transformers - Various Stations		74		74	Other	B-78
Replace Back-Up Air Dryer - Bay d'Espoir		73		73	Other	B-27
Replace Surge Arrestors - Various Stations		67		67	Other	B-80
Upgrade Parking Lot - Whitbourne		67		67	Other	B-147
Purchase Meters and Equipment		67		67	Other	B-156
Purchase Hydraulic Cutters and Presses - Various Sites		66		66	Other	B-165
Replace Communications Room Air Conditioner - Bay d'Espoir		64		64	Other	B-28
Upgrade Access Trail - Venam's Bight		64		64	Other	B-30
Replace Submarine Cable Terminator - Gaultois		64		64	Other	B-116
Purchase Grounding Trucks		61		61	Other	B-70

PROJECT DESCRIPTION	Expended to 2007	2008	2009	Total	Type	Page Ref
		($000)				
NORMAL PROJECTS (continued)						
Construct Beta Attenuation Meter (BAM) Unit Enclosure		60		60	Other	B-65
Upgrade Station Services - Hardwoods		59		59	Other	B-82
Replace Humidifiers in Air Handling Units - Hydro Place		58		58	Other	B-219
Programmable Logic Controller Replacement Study		58		58	Other	B-66
Security Configuration Auditing		58		58	Other	B-187
Replace Air Conditioning Units - Hydro Place		56		56	Other	B-220
Replace Fire Alarm System - Cat Arm		54		54	Other	B-32
Replace Auxiliary Service Water Pump - Cat Arm		53		53	Other	B-34
Install Waste Oil Storage Tank - Cartwright		53		53	Other	B-149
Survey of Hydro's Primary Right of Ways - Various Sites		52		52	Other	B-151
TOTAL NORMAL PROJECTS	0	4,452	0	4,452		

Type	Number	($000)
Clustered	2	398
Pooled	21	17,830
Other	89	30,771
Total	**112**	**48,999**

* *Includes multi-year projects*

Section D

<u>THERE ARE NO ITEMS FOR THIS SECTION</u>

Section E

	ACTUALS ($000)					BUDGET ($000)				
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
GENERATION	5,233	5,572	4,443	9,352	7,557	12,222	8,336	14,367	22,303	26,935
TRANSMISSION AND RURAL OPERATIONS	29,560	9,961	14,678	16,691	19,249	22,028	25,610	21,218	21,521	11,126
GENERAL PROPERTIES	5,424	16,973	8,863	7,909	14,411	8,717	11,115	14,268	21,524	12,972
TOTAL CAPITAL EXPENDITURES	40,217	32,506	27,984	33,952	41,217	42,967	45,061	49,853	65,348	51,033

Section F

	Expenditures Prior To 2007	PUB Approved Budget 2007	2007 Expenditures To June 30	Expected Total Expenditures 2007	Var. from Approved to Expected Expenditures
GENERATION	3,308	12,057	1,090	11,782	(275)
TRANSMISSION AND RURAL OPERATIONS	1,665	21,266	5,022	22,707	1,441
GENERAL PROPERTIES	4,837	8,391	778	8,457	66
ALLOWANCE FOR UNFORESEEN EVENTS	0	1,000	497	1,000	0
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	14	253	19	253	0
TOTAL CAPITAL BUDGET	9,824	42,967	7,406	44,199	1,232

Approved P.U. # 35 (2006) 2007 Capital Budget	**37,684**
Carryover Projects 2007 to 2007	**5,065**
2007 New Projects under $50,000 Approved by Hydro	**218**
TOTAL APPROVED CAPITAL BUDGET	**42,967**

	Expenditures Prior To 2007	PUB Approved Budget 2007	2007 Expenditures To June 30	Expected Total Expenditures 2007	Var. from Approved to Expected Expenditures
GENERATION					
NEW GENERATION SOURCE					
Generation Projects	1,135	421	356	388	(33)
HYDRO PLANTS					
Construction Projects	46	1,813	(65)	1,701	(112)
Tools and Equipment	0	83	49	79	(4)
THERMAL PLANT					
Construction Projects	2,127	8,262	727	8,136	(126)
Property Additions	0	599	21	599	0
Tools and Equipment	0	42	0	42	0
GAS TURBINES					
Construction Projects	0	837	2	837	0
TOTAL GENERATION	3,308	12,057	1,090	11,782	(275)
TRANSMISSION AND RURAL OPERATIONS					
TRANSMISSION	625	7,046	1,228	7,100	54
SYSTEM PERFORMANCE & PROTECTION	29	261	4	261	0
TERMINALS	43	1,617	274	1,617	0
DISTRIBUTION	0	7,746	2,384	8,162	416
GENERATION	968	2,145	553	3,121	976
GENERAL					
Metering	0	811	31	811	0
Properties	0	655	54	655	0
Tools and Equipment	0	985	494	980	(5)
TOTAL TRANSMISSION AND RURAL OPERATIONS	1,665	21,266	5,022	22,707	1,441

	Expenditures Prior To 2007	PUB Approved Budget 2007	2007 Expenditures To June 30	Expected Total Expenditures 2007	Var. from Approved to Expected Expenditures
GENERAL PROPERTIES					
INFORMATION SYSTEMS & TELECOMMUNICATIONS	4,426	3,999	619	4,000	1
ADMINISTRATIVE	411	4,392	159	4,457	65
TOTAL GENERAL PROPERTIES	4,837	8,391	778	8,457	66
ALLOWANCE FOR UNFORESEEN EVENTS	0	1,000	497	1,000	0
PROJECTS APPROVED FOR LESS THAN $50,000	14	253	19	253	0
TOTAL CAPITAL BUDGET	9,824	42,967	7,406	44,199	1,232

	Expenditures Prior To 2007	PUB Approved Budget 2007	2007 Expenditures To June 30	Expected Total Expenditures 2007	Var. from Approved to Expected Expenditures	Variance Explanation Reference
NEW GENERATION SOURCE						
GENERATION PROJECTS						
Island Pond Development - Feasibility Update	895	108	80	108	0	
Portland Creek Development - Final Feasibility Study	240	280	276	280	0	
Wind Generation Inventory Study		33	0	0	(33)	
TOTAL GENERATION PROJECTS	1,135	421	356	388	(33)	
HYDRO PLANTS						
CONSTRUCTION PROJECTS						
Replace Penstock - Snook's Arm Generating Station	0	292	(130)	292	0	
Replace Unit 1 Governor Controls - Cat Arm	0	32	34	32	0	
Replace Underground Fuel Tanks - Cat Arm Powerhouse	0	15	15	15	0	
Provide Remote Operation By-Pass Fisheries Comp. Valve - Granite Canal	46	82	3	82	0	
Upgrade Access Road - Upper Salmon		675	6	675	0	
Upgrade Access Road - Burnt Dam		309	1	309	0	
Upgrade Cooling Water System Unit 1 and 2 - Bay 'd'Espoir		112	0	0	(112)	1
Replace Station Service Control - Bay d'Espoir		105	0	105	0	
Replace Air Dryer - Cat Arm		76	0	76	0	
Replace Bridge Paradise Access Road		66	3	66	0	
Stator Windings Design Review - Bay d'Espoir		49	3	49	0	
TOTAL CONSTRUCTION PROJECTS	46	1,813	(65)	1,701	(112)	
Tools and Equipment						
Purchase and Replace Tools and Equipment Less than $50,000	0	83	49	79	(4)	
TOTAL TOOLS AND EQUIPMENT	0	83	49	79	(4)	
TOTAL HYDRO PLANTS	46	1,896	(16)	1,780	(116)	

	Expenditures Prior To 2007	PUB Approved Budget 2007	2007 Expenditures To June 30	Expected Total Expenditures 2007	Var. from Approved to Expected Expenditures	Variance Explanation Reference
THERMAL PLANT						
CONSTRUCTION PROJECTS						
Upgrade Control System	0	55	194	205	150	2
Purch/Inst Anti-Fouling System for Cooling Water Systems	836	16	80	16	0	
Addition of Disconnecting Means to 600 Volt MCC Branch Feeders	1,084	1,138	129	1,138	0	
Fire Protection Upgrades	28	1,797	32	1,797	0	
Replace Superheater Unit 2	4	3,133	270	3,133	0	
Study of Regeneration Waste Treatment	137	35	19	35	0	
Modify Boiler Protection and Control	38	79	3	79	0	
Turbine and Generator Upgrade Unit 3		1,654	0	1,654	0	
Contaminated Water Treatment		276	0	0	(276)	3
UPS Battery Monitoring Program		79	0	79	0	
TOTAL CONSTRUCTION PROJECTS	2,127	8,262	727	8,136	(126)	
PROPERTY ADDITIONS						
Air Preheater Steam Condenser Pumps - Unit 3		599	21	599	0	
TOTAL PROPERTY ADDITIONS	0	599	21	599	0	

	Expenditures Prior To 2007	PUB Approved Budget 2007	2007 Expenditures To June 30	Expected Total Expenditures 2007	Var. from Approved to Expected Expenditures	Variance Explanation Reference
TOOLS AND EQUIPMENT						
Purchase and Replace Tools and Equipment Less than $50,000	0	42	0	42	0	
TOTAL TOOLS AND EQUIPMENT	0	42	0	42	0	
TOTAL THERMAL PLANTS	2,127	8,903	748	8,777	(126)	
GAS TURBINES						
CONSTRUCTION PROJECTS						
Replace Fuel Piping - Hardwoods, Stephenville	0	530	0	530	0	
Gas Turbine Assessments - Hardwoods, Stephenville	0	307	2	307	0	
TOTAL GAS TURBINE PLANTS	0	837	2	837	0	
TOTAL GENERATION	3,308	12,057	1,090	11,782	(275)	

	Expenditures Prior To 2007	PUB Approved Budget 2007	2007 Expenditures To June 30	Expected Total Expenditures 2007	Var. from Approved to Expected Expenditures	Variance Explanation Reference
TRANSMISSION						
Upgrade Corner Brook Frequency Converter	186	676	75	676	0	
Replace Insulators TL-231 - (230kV Bay d'Espoir - Stoney Brook)	439	478	416	478	0	
Wood Pole Line Management Program		2,148	375	2,148	0	
Replace Insulators - TL-251, TL-252 and TL-234		2,118	352	2,118	0	
Upgrade Corner Brook Frequency Converter		1,320	0	1,320	0	
Supply and Install Bridge - South West River		212	10	266	54	
Install Deadend Structure - Conne River Tap TL-220		94	0	94	0	
TOTAL TRANSMISSION	625	7,046	1,228	7,100	54	
SYSTEM PERFORMANCE & PROTECTION						
Upgrade Breaker Controls - Bay d'Espoir and Buchans Terminal Stations	29	6	3	6	0	
Purch/Install 138 kV Protection Upgrades - Springdale, Howley, Indian River		215	1	215	0	
Upgrade Breaker Controls - OPD/SSD Terminal Station		40	0	40	0	
TOTAL SYSTEM PERFORMANCE & PROTECTION	29	261	4	261	0	

	Expenditures Prior To 2007	PUB Approved Budget 2007	2007 Expenditures To June 30	Expected Total Expenditures 2007	Var. from Approved to Expected Expenditures	Variance Explanation Reference
TERMINALS						
Replace Air Compressor and Dryer - Grand Falls Frequency Converter	20	48	28	48	0	
Replace Air Compressors - Holyrood Terminal Station	4	76	53	76	0	
Install Transformer Oil Monitoring System - Upper Salmon	19	34	1	34	0	
Hawkes Bay Terminal Station Safety and Reliability Upgrade		349	0	349	0	
Replace Insulators - Various Stations		313	19	313	0	
Upgrade Breakers - Various Stations		258	93	258	0	
Replace Breaker B7C1 - Hardwoods		136	8	136	0	
Replace Instrument Transformers - Various Stations		80	3	80	0	
Replace Compressors - Various Stations		78	0	78	0	
Replace Battery Bank - Various Stations		72	1	72	0	
Replace Battery Chargers - Various Stations		72	1	72	0	
Replace Surge Arrestors - Various Stations		71	47	71	0	
Install RIGD (Remote Ice Growth Detection) Beam - Various Stations		30	20	30	0	
TOTAL TERMINALS	43	1,617	274	1,617	0	
DISTRIBUTION						
Upgrade Distribution Feeders - Various Sites		1,418	404	1,418	0	
Service Extensions		2,085	705	2,461	376	4
Distribution Upgrades		2,035	998	2,035	0	
Replace Distribution Lines - South Brook, Harbour Breton		741	102	741	0	
Replace Distribution Line Poles		837	159	877	40	
Upgrade Unit 290 and Upgrade Fuel Storage - William's Harbour		479	16	479	0	
Grey River Stack Modifications		151	0	151	0	
TOTAL DISTRIBUTION	0	7,746	2,384	8,162	416	

	Expenditures Prior To 2007	PUB Approved Budget 2007	2007 Expenditures To June 30	Expected Total Expenditures 2007	Var. from Approved to Expected Expenditures	Variance Explanation Reference
GENERATION						
Construct New Diesel Plant - St. Lewis	322	369	406	439	70	
Replace Diesel Generating Units - Various Locations	555	146	47	186	40	
Replace Control Panel - Rigolet	66	69	90	84	15	
Install Nox Monitor - Little Bay Islands	25	81	2	81	0	
Purchase Spare Transformer - Upper Salmon		1,366	6	2,217	851	5
Replace Diesel Unit Breakers - Mary's Harbour		114	2	114	0	
TOTAL GENERATION	968	2,145	553	3,121	976	
GENERAL						
METERING						
Automatic Meter Reading		696	0	696	0	
Purchase Meters and Equipment		94	31	94	0	
Purchase Metering Spares		21	0	21	0	
TOTAL METERING	0	811	31	811	0	
PROPERTIES						
Installation of Fall Arrest Equipment - Hydro facilities		251	52	251	0	
Upgrade Fuel Storage - Norman Bay		222	1	222	0	
Installation of Card Access System - Bishop's Falls and Whitbourne		131	1	131	0	
Legal Survey of Distribution Line Right-of-Ways - 2007		51	0	51	0	
TOTAL PROPERTIES	0	655	54	655	0	

	Expenditures Prior To 2007	PUB Approved Budget 2007	2007 Expenditures To June 30	Expected Total Expenditures 2007	Var. from Approved to Expected Expenditures	Variance Explanation Reference
TOOLS AND EQUIPMENT						
Confined Space Entry Equipment	0	13	11	13	0	
Replace Off Road Track Vehicle - Unit No. 7696 - Cow Head		307	0	307	0	
Replace Light Duty Mobile Equipment Less than $ 50,000		241	209	241	0	
Replace Doble Relay Test Equipment - St. Anthony, Happy Valley		174	122	174	0	
Replace Off Road Track Vehicle - Unit No. 7734 - Flowers Cove		139	91	139	0	
Purchase and Replace Tools and Equipment Less than $ 50,000	0	111	61	106	(5)	
TOTAL TOOLS AND EQUIPMENT	0	985	494	980	(5)	
TOTAL GENERAL	0	2,451	579	2,446	(5)	
TOTAL TRANSMISSION AND RURAL OPERATIONS	1,665	21,266	5,022	22,707	1,441	

	Expenditures Prior To 2007	PUB Approved Budget 2007	2007 Expenditures To June 30	Expected Total Expenditures 2007	Var. from Approved to Expected Expenditures	Variance Explanation Reference
INFORMATION SYSTEMS						
SOFTWARE APPLICATIONS						
INFRASTRUCTURE REPLACEMENT						
NEW INFRASTRUCTURE						
Application Enhancements - 2007		149	22	149	0	
Cost Recovery CF(L)Co		(27)	(7)	(27)	0	
Upgrade of Technology						
Corporate Application Environment - 2007		377	10	377	0	
Cost Recovery CF(L)Co		(75)	(7)	(75)	0	
TOTAL SOFTWARE APPLICATIONS	0	424	18	424	0	
COMPUTER OPERATIONS						
INFRASTRUCTURE REPLACEMENT						
Enterprise Storage Capacity Upgrade		186	0	186	0	
Cost Recovery CF(L)Co		(37)	(12)	(37)	0	
End User Infrastructure Evergreen Program - 2007		395	54	395	0	
NEW INFRASTRUCTURE						
Peripheral Infrastructure Replacement - 2007		139	119	139	0	
Security Information Management System		73	61	73	0	
Cost Recovery CF(L)Co		(15)	(5)	(15)	0	
UPGRADE OF TECHNOLOGY						
Server Technology Program - 2007		82	20	82	0	
TOTAL COMPUTER OPERATIONS	0	823	237	823	0	

	Expenditures Prior To 2007	PUB Approved Budget 2007	2007 Expenditures To June 30	Expected Total Expenditures 2007	Var. from Approved to Expected Expenditures	Variance Explanation Reference
TELECONTROL						
NETWORK SERVICES						
INFRASTRUCTURE REPLACEMENT						
Replace VHF Mobile Radio System	5,483	2,185	355	2,185	0	
Cost Recovery - WST	(1,796)	(1,680)	(497)	(1,680)	0	
Replace Power Line Carrier TL-240 - Churchill Falls - Goose Bay	81	24	34	24	0	
Microwave Site Refurbishing - Bay D'Espoir Hill & Blue Grass Hill	251	156	79	156	0	
Replace Battery System - Multiple Sites	312	92	107	92	0	
Westcoast Communications System - Study	95	42	21	42	0	
Replace Battery System - Multiple Sites		485	3	485	0	
Microwave Site Refurbishing - 2007		364	5	364	0	
Replace Remote Terminal Units - Multiple Sites		321	4	321	0	
Replace VHF Radio Communications - Burnt Dam		226	10	226	0	
Replace Radomes - Multiple Sites		27	0	27	0	
Network Infrastructure						
IRIG-B Distributions		103	0	103	0	
Communications Network Technology		102	39	102	0	
Test Equipment		49	28	49	0	
Hydro Place Wireless		44	29	45	1	
UPGRADE OF TECHNOLOGY						
MWIC Quad - Diversity Upgrade		114	116	114	0	
Network Management Tools		49	21	49	0	
Upgrade Site Facilities		49	10	49	0	
TOTAL NETWORK SERVICES	4,426	2,752	364	2,753	1	
TOTAL INFORMATION SYSTEMS & TELECONTROL	4,426	3,999	619	4,000	1	

	Expenditures Prior To 2007	PUB Approved Budget 2007	2007 Expenditures To June 30	Expected Total Expenditures 2007	Var. from Approved to Expected Expenditures	Variance Explanation Reference
ADMINISTRATIVE						
VEHICLES						
Replace Vehicles - Hydro System - 2007		2,686	76	2,686	0	
Purchase Trucks, Snowmobiles, lifts, storage bldings- Labrador Coast		842	5	907	65	
ADMINISTRATION						
Construct New Warehouse - Port Saunders	411	66	74	66	0	
Security Assessment of System Operations		668	2	668	0	
Replace Storage Ramp - Bishop's Falls		62	0	62	0	
Purchase and Replace Admin Office Equip less than $50,000		68	2	68	0	
TOTAL ADMINISTRATIVE	411	4,392	159	4,457	65	
TOTAL GENERAL PROPERTIES	4,837	8,391	778	8,457	66	

	Expenditures Prior To 2007	PUB Approved Budget 2007	2007 Expenditures To June 30	Expected Total Expenditures 2007	Var. from Approved to Expected Expenditures	Variance Explanation Reference
ALLOCATION FOR UNFORESEEN EVENTS						
Cartwright Distribution - Upgrade Sleet Storm		113	103	113	0	
Daniel's Harbour Distribution Line Re-Route		81	65	81	0	
Ice Storm Damage - Northern		231	185	231	0	
Replace Insulators on TL-221		252	144	252	0	
Allocation for Unforeseen Events		323	0	323	0	
TOTAL ALLOCATION FOR UNFORESEEN EVENTS	0	1,000	497	1,000	0	
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO						
Install Oil Water Separators - Various Stations	14	35	16	35	0	
Come By Chance TS - Annuciator Replacement		49	0	49	0	
Replace Hawkes Bay Battery Charger		4	3	4	0	
High Angle Rescue Equipment		4	0	4	0	
Vibration Monitoring System Upgrade - Hardwoods and Stephenville		49	0	49	0	
Transfer and Overhaul Unit 2058 - Little Bay Islands		49	0	49	0	
Replace Portable Oil Dielectric Test Set		8	0	8	0	
Replace Lube Oil Storage Tank		6	0	6	0	
Corporate Emergency Response Centre		49	0	49	0	
TOTAL PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	14	253	19	253	0	

1. **Upgrade Cooling Water System Units 1 and 2 Bay d'Espoir**

   This project was included in an application filed with the Board on July 14, 2006 and which the Board approved in Order No. P.U. 35 (2006). This project involved the replacement of all surface air-cooling and discharge piping and associated components. Due to a requirement to expand the scope of work and due to substantial increases in the costs of stainless steel piping, fittings and components since the estimate was prepared, this capital project, originally estimated to cost $112,000, is now forecast to cost $263,000. The job was not undertaken in 2007 and is proposed to be undertaken in 2008 and is found in this application at page B-12.

2. **Upgrade Control System - Holyrood**

   This project is in-service however training has to be provided for Hydro personnel in the operation and the design of the system. The overall cost of the project has increased to $3,281,000 due to installation problems that resulted in additional motor logic and installation work.

3. **Holyrood - Construct Contaminated Water Treatment Pilot Plant**

   This pilot project is phase 2 of a three-phase project to address the discharge of contaminated water from the Holyrood Thermal Generating Station. This project was included in an application filed with the Board on July 14, 2006 and which the Board approved in Order No. P.U. 35 (2006) and is for the construction and operation of a pilot plant. Its estimated cost was $338,500 but it is now believed that it will cost in excess of $400,000. Meanwhile, preliminary estimates for the cost of phase 3, the actual processing plant, is that it will cost in excess of $1.5 million. At present, Hydro has a variance from the legislator, permitting the discharge of this waste stream as long as it is diluted in the plant cooling water discharge. Due to the escalating costs of this project, it was decided that this project be cancelled and that other alternatives be investigated.

4. Construct 2 Single-Phase Distribution Lines

Forty cabin owners in the Northwest Arm cottage Area, near the St. Anthony Airport, have requested a distribution line constructed to provide electrical supply to their cabins in that area. The request was reviewed with regard to Hydro's policy for provision of power to cabin lots. The proposal was costed and submitted to the Public Utilities Board for approval and was approved by the PUB in early April of this year. A Contribution In Aid of Construction (CIAC) was compiled and forwarded to the customers. The CIAC was calculated on a non-refundable option, where the cost is determined based on the percentage of potential customers that have accepted service. The maximum potential customers in the area is 52 and the total line extension is approximately 59 kilometers.

5. Purchase Spare Transformer - Upper Salmon

This project was included in an application filed with the Board on July 14, 2006 and which the Board approved in Order No. P.U. 35 (2006). The cost of copper and steel has increased dramatically over the past year and most transformer manufacturers are experiencing an increase in demand for new transformers. This has resulted in a cost increase from $1.4 million to $2.2 million as well as a delay in delivery. The project in-service date has been extended by one year to October of 2008.

PLAN OF PROJECTED OPERATING

MAINTENANCE EXPENDITURES

2008 - 2017

FOR HOLYROOD GENERATING STATION

NEWFOUNDLAND AND LABRADOR HYDRO

JULY 2007

Table Of Contents

1 INTRODUCTION

In the Decision and Order No. P. U.14 (2004) of the Board of Commissioners of Public Utilities (“the Board”), dated May 4,2004, (the "Order") Newfoundland and Labrador Hydro (“Hydro”) is required to **“file a ten year plan of maintenance expenditures for the Holyrood Generating Station with its annual capital budget application, until otherwise directed by the Board**” (p. 64 and Paragraph 12, p. 166 of the Order).

This requirement is specifically related to system equipment maintenance costs; therefore, capital expenditures have not been included in the following report. Capital expenditures for Holyrood are submitted annually to the Board with other Hydro capital proposals as part of annual capital budget applications, and vary from year to year.

This report addresses the identified and expected maintenance expenditures for the years 2008 to 2017 inclusive. With respect to these expenditures it must be noted that Unit No’s. 1 and 2, as well as two of the main fuel storage tanks and other associated ancillary equipment, are in excess of 35 years old. Unit No. 3 is in excess of 25 years old, along with its associated equipment, including the other two main fuel storage tanks. While many components of this equipment have been replaced and additional items added through the maintenance and capital program over the years, numerous pieces of equipment and components are original.

An accurate ten year plan of system equipment maintenance is difficult to complete given the harsh operating environment, varied production requirements and the age of the units. This report, however, outlines for the next ten years, maintenance items that are anticipated at this time. This plan, of course, will change as time progresses. The operating condition of the equipment will be continuously reviewed and, undoubtedly, events will occur that are not foreseen at this time, which will require changes in the currently anticipated annual maintenance. As can be seen from this report, there must be variation in annual operating costs for the Holyrood Thermal plant. It is not possible to “levelize” the cost of maintaining a plant such as Holyrood where there are numerous components and systems integrated together to form a fossil fired thermal electric generating system.

2 MAINTENANCE PHILOSOPHY

The Board, in its Order as related to the Holyrood Thermal Plant, noted at p. 64 that **"The Board will require NLH's10 year plan of maintenance expenditures for the Holyrood Generating Station to be updated annually to reflect changing operating circumstances."**

It would be useful to first review the three main types or categories of maintenance undertaken at Holyrood.

2.1 <u>Preventive Maintenance</u>

While it is true that any plant will incur greater maintenance costs as it ages, Holyrood has used, and continues to use, up-to-date maintenance techniques and practices to maintain plant efficiency, availability and reliability. These include preventive, predictive and condition-based maintenance techniques, which are usually referred to by the overall term of "Preventive Maintenance". The basic principle underlying this approach to maintenance is timely intervention to prevent imminent or catastrophic failure, which may cause a substantial safety exposure, an increase in cost or an extended unavailability of the unit or system.

Preventive maintenance, in its specific sense, comprises routine inspections, checks and component replacement at specific time intervals, to prevent failures known, or reasonably expected, to occur within a definable time or operating hour interval during the life of the equipment, e.g. generator brush wear, air and oil filter replacements, etc. This also includes discarding equipment or components rather than repairing them when it is less expensive to do so.

Predictive maintenance involves routine testing of equipment to determine deterioration rates and initiating and carrying out repairs in a timely manner before a failure occurs, e.g. ultrasonic thickness checks on fluid lines to monitor erosion wear rates, non-destructive testing of boiler and turbine components to determine fatigue, wear or corrosion rates and remaining life. Predictive maintenance items include such things as boiler and auxiliary equipment annual overhaul, among other items, wherein an assessment is made of components or subsystems that are only accessible during these overhauls.

There is also regular or continual monitoring of equipment operating parameters with a comparison of the results with optimum conditions to determine the most economic time to intervene and perform remedial work that is intended to return the equipment to optimum performance levels, e.g. air heater washes, generator winding insulation condition, oil sampling and testing, etc.

Turbine major and minor overhauls are, effectively, long-term predictive and preventive maintenance activities. A turbine major overhaul is a major disassembly, inspection and repair of the whole turbine. Since this is a very expensive and time consuming activity, the time between these overhauls is extended to minimize the recurring cost and maximize the equipment operating time, and thus useful life of the internal wearing components. Prior to 1988, these major overhauls were carried out at four-year intervals; a subsequent assessment of the risk and cost savings resulted in extending these overhauls to six-year intervals.

In 2003, a study was undertaken by Hartford Steam Boiler Insurance Company, using their proprietary program called Turbine Overhaul Optimization Program (TOOP). This assesses the causes of failure, the risk of failure and the maintenance history of the Turbines, and then proposes the optimum frequency between major overhauls. This assessment concluded that the Turbine major overhaul interval could be extended to 9 years from the major overhaul of Unit 1 in 2003, the major overhaul of Unit 2 in 2005 and the major overhaul of Unit 3 in 2007, providing that certain upgrades of internal components are made. These recommendations have been accepted and all upgrades are now completed.

Turbine valve overhauls are carried out at three-year intervals, between major overhauls. This has been found necessary, due to the critical nature of the safety and reliability aspects of these valves to the turbine operation and integrity, and will continue to be maintained on this three-year interval between major overhauls.

Beginning in 2008, the Preventive Maintenance program will be enhanced to include the extra costs associated with plant cleaning in areas where Asbestos and Heavy Metals have been identified as potential health hazards.

2.2 Corrective Maintenance

In addition to the preventive maintenance tactics outlined in (2.1) above, there are also corrective maintenance requirements. These include repairs to equipment as it fails or reaches the point where preventive maintenance has identified that the equipment is approaching the end of its useful service life. E.g. wear and tear on pumps, pipes and valves in the main and auxiliary systems, motor rewinds due to failed or deteriorated winding insulation, or as a result of adverse conditions (humidity, salt laden atmosphere, etc), replacement of corroded piping equipment and boiler tube failure repairs etc. In 2003, Unit 2 suffered three Superheater Tube failures and their analysis indicated a common tube failure problem had developed. An approved Capital Budget proposal will see the replacement of Unit 2 Boiler Superheater tubes in September 2007.

Beginning in 2008, the Corrective Maintenance program will be enhanced to include the extra costs associated with plant cleaning in areas where Asbestos and Heavy Metals have been identified as potential health hazards.

2.3 <u>Projects</u>

Operating projects are those major cost repairs and inspections that are required to return structures and equipment to their original or near original condition to maintain structural integrity, possibly extend plant life, improve efficiency, improve availability and prevent or reduce environmental risks. Such projects include repairs to building structural steel, roof repairs/replacement, fuel oil tank and pipeline inspection and coating, replacement of equipment or components no longer supported by the original manufacturer. A major Asbestos Abatement program commenced in 2005 and will be completed over a three-year period. Due to the significant cost (approaching $9.0 million), Hydro was given approval to treat this as an extraordinary repair, which will mean an annual cost will be recovered over an additional five years, bringing the total cash flow period to eight years, 2005 to 2012.

In 2006 a major failure of Unit 2 boiler waterwall tubing resulted in three months of unexpected down time plus extensive repairs that cost $2.5 million. This cost was amortized over a five year period (2007-2011) within the plant operating budget. A root cause analysis was conducted by an external consultant which identified one of the major contributions to this failure as insufficient boiler chemical cleaning frequency (current industry practice is 8 - 10 years, regardless of tube loading condition). To perform future chemical cleaning of the Holyrood boilers, operating projects have been identified starting with Unit 2 in 2016 and Unit 1 in 2017 at an individual cost of approximately $380,000. Updates to the 10-year plan for 2018 will identify an operating project for Unit 3 at a similar but escalated cost.

3 COST VARIABILITY

Preventive maintenance costs are generally incurred annually at a constant level and do not fluctuate significantly. This does not apply to corrective maintenance costs, which are unavoidable and somewhat unpredictable due to the changing energy production demands on the units from year to year. These changing demands give rise to changes in wear rates, the majority of which cannot be monitored closely enough for reasonably accurate prediction, without incurring excessive inspection costs. Excessive inspection may in itself introduce increased risk of failure and thus additional cost, so all must be considered in balancing the most appropriate amount of inspection with accepted levels of failure. These costs however, generally balance from one year to another.

The turbine and valve overhaul costs are cyclic in nature. With three units in the plant on a nine-year major Turbine overhaul cycle interspersed with a three-year minor valve overhaul, this component of the system equipment maintenance cost is one of the significant reasons for the observed annual fluctuations that make normalizing annual maintenance costs difficult.

Unit	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
No. 1		Minor			Major			Minor		
No. 2	Minor			Minor			Major			Minor
No. 3			Minor			Minor			Major	
General Cost	↓				↑	↓	↑	↓	↑	↓

Similarly, major operating projects, because of their extended maintenance intervals (years) or non-repeatability also add to the annual fluctuations of the system equipment maintenance costs and have to be executed when plant conditions permit.

Maintenance projects for the Holyrood Thermal plant are planned on a five-year basis, but as with any plan, it is not ‘fixed’ or definitive, as other events can cause a shift in the prioritization of such projects. This five-year maintenance plan is regularly updated by Hydro as time progresses.

4 DETAILED ANALYSIS

Attached are Appendices 1 to 9, which set out the ten-year maintenance plan for the Holyrood Thermal plant, as requested by the Board. Appendix 1 is a summary and indicates the expected expenditures in each of the major equipment groupings containing system equipment maintenance (SEM) costs for the years 2008 to 2017. Appendices 2 to 9, inclusive, show the expected SEM costs categorized according to Preventive, Corrective, Overhauls and Major Operating Projects for each of the major equipment groupings containing SEM costs.

This plan was prepared using the 2008 preventive, corrective and overhaul data and the current 2008 to 2012 operating project lists from Hydro's five-year plan for the Holyrood Thermal Plant as the base data. Considerable judgment of plant personnel had to be used to prepare a ten-year plan.

Hydro does not normally use any escalation in its five-year operating plan at the Plant or regional level. This five-year plan is primarily used for internal purposes and generation of work plans rather than detailed financial planning. However, in the attached ten-year plan, an escalation factor has been used, the source of which is the Fall 2006 Hydro forecast. A single escalation rate was used in this exercise and assumed a 50% weighting of Labour escalation and 50% of Material escalation, and is as follows:

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
%	2.4	2.4	2.3	2.3	2.5	2.5	2.5	2.5	2.5	2.5

Appendices 2 to 9 list the categories of SEM costs for the years 2008 to 2017 in each of the major equipment groupings containing SEM. The categories listed are:

Preventive – Annual	Routine preventive maintenance activities carried out every year.
Corrective	Typical but unknown breakdown/ emergency repairs carried out during the year.
Turbine – Major	Major overhauls now planned every nine years per Unit basis.
Turbine – Minor	Major valve overhauls currently carried out every three years, between major overhauls per unit basis.
Boiler – Annual	Boiler overhauls carried out annually.
Boiler - Amortized Cost	Five-year amortized cost of repairs completed on Unit 2 boiler in 2006.
Operating Projects	Non-capitalized projects, justified on the basis of Safety, Environment, Reliability or Cost Benefit Analyses.

Appendices 2, 3 and 4 (for Units 1, 2 and 3 respectively) use all of the foregoing categories. Appendices 5 to 9 are for the remaining equipment groupings of Common Equipment, Building and Grounds, Water Treatment Plant, Waste Water Treatment Plant and Environmental Monitoring and use only Preventive, Corrective and Major Operating Projects.

It must be noted that the Appendices do not itemize preventive and corrective items. The preventive maintenance (PM) program consists of approximately 1000 PMs performed on plant equipment annually. Corrective items include a large number of low cost jobs, the majority of which are largely unknown until they happen; thus, it is not practical to provide a breakout of the costs. Projects included in the headings of Operating Projects, Turbine - Major and Turbine - Minor work have been itemized in the year that the work is planned for execution.

Hydro's normal five-year plan identifies specific projects up to 2012. For the period 2013 to 2017, Hydro used an average per unit of the project budgets for the three units over the years 2008 to 2012 with escalation. This approach was taken, as it is not practical or possible to determine specific work items, which are essentially unknown for the period of 2013 to 2017.

5 SUMMARY

This Plan presents the best available information at this time for a ten-year forecast of the maintenance projects for the Holyrood Plant and is based on the 2008 system equipment maintenance budget. As with any forecast, it is subject to change depending on the operating demands of the plant, the results of inspections and assessments of changing equipment conditions.

The Plan takes into account up-to-date maintenance tactics and known restoration and inspection work. As can be seen from the Plans, fluctuations in the annual cost cannot be eliminated due to the nine-year Turbine Overhauls and three-year Valve Overhauls, as well as the large but infrequent Major Operating projects.

APPENDIX 1

TOTAL HOLYROOD SEM[1] 10 YEAR MAINTENANCE EXPENDITURES ESCALATED (K)

	($000)										
	Base Year 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
UNIT 1 Total SEM	1,505	1,840	1,637	1,570	3,690	1,721	1,765	2,265	1,972	2,291	
UNIT 2 Total SEM	2,559	2,056	1,989	2,500	1,607	1,719	3,895	1,807	2,233	2,444	
UNIT 3 Total SEM	1,950	1,500	1,999	1,570	1,715	2,110	1,765	1,809	4,151	2,451	
Common Equipment Total SEM	3,653	3,687	3,586	2,832	2,131	1,565	1,604	1,644	1,686	1,728	
Buildings and Grounds Total SEM	590	570	599	469	480	461	473	485	497	509	
Water Treatment Plant Total SEM	133	208	261	267	300	202	207	241	302	310	
Waste Water Treatment Plant Total SEM	126	123	135	129	142	136	149	142	157	150	
Environmental Monitoring Total SEM	300	410	346	429	330	485	346	473	401	497	
Total Holyrood SEM	10,816	10,394	10,553	9,766	10,395	8,400	10,204	8,866	11,399	10,379	
Total Operating Projects	3,764	3,192	3,181	2,235	1,442	967	851	1,057	1,517	1,745	
Total Operating Projects Less Asbestos Abatement	1,501	929	1,051	893	838	967	851	1,057	1,517	1,745	

SEM[1] – System Equipment Maintenance

APPENDIX 2

HOLYROOD 10 YEAR MAINTENANCE PLAN

	($000)										
Unit 1	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
Preventive – Yearly	159	163	167	170	175	179	183	188	193	198	
Corrective	396	406	415	424	435	446	457	468	480	492	
Turbine Major Overhaul					2,081						
Turbine Valve Overhaul		340						409			
Boiler Annual Overhaul	910	932	953	975	1,000	1,025	1,050	1,076	1,103	1,131	
Operating Projects											
Unit 1 Boiler Chemical Clean										390	
Overhaul Boiler Feed Pump East	40							47			
Overhaul Boiler Feed Pump West			102						118		
Projects – Lump Sum for Future Years						72	74	76	78	80	
Total – Unit 1	1,505	1,840	1,637	1,570	3,690	1,721	1,765	2,265	1,972	2,291	
Total Operating Projects Unit 1	40	0	102	0	0	72	74	123	196	470	

APPENDIX 3

	($000)										
Unit 2	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
Preventive – Yearly	157	161	164	168	172	177	181	186	190	195	
Corrective	396	406	415	424	435	446	457	468	480	492	
Turbine Major Overhaul							2,133				
Turbine Valve Overhaul	340			370						430	
Boiler Annual Overhaul	910	932	953	975	1,000	1,025	1,050	1,076	1,103	1,131	
Boiler 2 Amortized Repair Cost	456	456	456	456							
Operating Projects											
Unit 2 Boiler Chemical Clean									381		
Overhaul Boiler Feed Pump East		102								116	
Overhaul Boiler Feed Pump West				106							
Replace Unit 2 Main Boiler Stop Valve	150										
Upgrade 2 Turbine Emerg Trip Device	150										
Projects - Lump Sum for Future Years						72	74	76	78	80	
Total - Unit 2	**2,559**	**2,056**	**1,989**	**2,500**	**1,607**	**1,719**	**3,895**	**1,807**	**2,233**	**2,444**	
Total Operating Projects Unit 2	300	102	0	106	0	72	74	76	459	196	

APPENDIX 4

Unit 3	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
	($000)										
Preventive – Yearly	159	163	167	170	175	179	183	188	193	198	
Corrective	396	406	415	424	435	446	457	468	480	492	
Turbine Major Overhaul									2,297		
Turbine Valve Overhaul			362			389				430	
Boiler Annual Overhaul	910	932	953	975	1,000	1,025	1,050	1,076	1,103	1,131	
Auxiliary Equipment Annual Overhaul											
Operating Projects											
Overhaul Cooling Water Pump East	60										
Overhaul Boiler Feed Pump East			102							120	
Overhaul Boiler Feed Pump West					106						
Unit 3 Boiler Chemical Clean	425										
Projects – Lump Sums for Future Years						72	74	76	78	80	
Total - Unit 3	**1,950**	**1,500**	**1,999**	**1,570**	**1,715**	**2,110**	**1,765**	**1,809**	**4,151**	**2,451**	
Total Operating Projects Unit 3	485	0	102	0	106	72	74	76	78	200	
Total SEM for all Three Units	**6,014**	**5,396**	**5,624**	**5,640**	**7,012**	**5,551**	**7,425**	**5,880**	**8,356**	**7,186**	
Total Project Work for Three Units	825	102	204	106	106	216	222	275	733	866	

APPENDIX 5

Common Equipment	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
	($000)										
Preventive – Yearly	207	212	217	222	227	233	239	245	251	257	
Corrective	1,118	1,145	1,172	1,198	1,228	1,259	1,291	1,323	1,356	1,390	
Operating Projects											
Asbestos Abatement	2,263	2,263	2,130	1,342	604						
Pipe Surveillance	50	51	52	54	55	56	58	59	61	62	
Plant Color Coding	15	15	16	16	16	17	17	18	18	19	
Projects – Lump Sum for Future Years											
Total Common Equipment	**3,653**	**3,687**	**3,586**	**2,832**	**2,131**	**1,565**	**1,604**	**1,644**	**1,686**	**1,728**	
Total Operating Projects Common Equipment	2,328	2,330	2,198	1,412	675	73	75	77	79	81	
Total Operating Projects less Asbestos Abatement	65	67	68	70	71	73	75	77	79	81	

APPENDIX 6

	($000)										
Buildings Grounds	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
Preventive – Yearly	65	66	68	69	71	73	75	77	78	80	
Corrective	155	159	163	166	170	175	179	184	188	193	
Operating Projects											
Coat Interior Liner Panels	100	102	105	107	110	113	115	118	121	124	
Repair & Repaint Structural Steel	90	92	94	96	99	101	104	107	109	112	
Exhaust Stack Maintenance	150	150	170	30	30						
Loading Door CW Pumphouse 1	30										
Projects - Lump Sum for Future Years											
Total – Buildings and Grounds	**590**	**570**	**599**	**469**	**480**	**461**	**473**	**485**	**497**	**509**	
Total Operating Projects Buildings and Grounds	370	345	369	234	239	214	219	225	230	236	

APPENDIX 7

	($000)										
Water Treatment (WT) Plant	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
Preventive – Yearly	53	54	56	57	58	60	61	63	64	66	
Corrective	80	82	84	86	88	90	92	95	97	99	
Operating Projects											
Resin Replacement (A Train)			48						56		
Resin Replacement (B Train)				49						57	
Resin Replacement (C Train)					51						
Resin Replacement (Mixed Bed A)					104	52					
Resin Replacement (Mixed Bed B)							53				
Resin Replacement (U1 Polisher)		72						83			
Resin Replacement (U2 Polisher)				75						88	
Resin Replacement (U3 Polisher)			74						85		
Total WT Plant and Environmental	**133**	**208**	**261**	**267**	**300**	**202**	**207**	**241**	**302**	**310**	
Total Operating Projects WT Plant	0	72	122	125	154	52	53	83	141	145	

APPENDIX 8

	($000)										
Waste Water Treatment (WWT) Plant	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
Preventive – Yearly	70	72	73	75	77	79	81	83	85	87	
Corrective	30	31	31	32	33	34	35	36	36	37	
Operating Projects											
WWTP Periodic Basin Cleaning & Inspection		21		22		23		24		26	
WWTP Continuous Basin Clean-Out			22		23		24		25		
110V AC Power Supply to Landfill	17										
Filter Fabric Replacement-Plat Press	9		9.2		9.6		10.1		10.6		
Projects - Lump Sum for Future Years											
Total WWT Plant	**126**	**123**	**136**	**129**	**142**	**136**	**149**	**143**	**157**	**150**	
Total Operating Projects WWT Plant	26	21	31	22	32	23	34	24	35	26	

APPENDIX 9

	($000)										
Environmental Monitoring	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
Preventive – Yearly	25	26	26	27	28	28	29	30	30	31	
Corrective	60	61	63	64	66	68	69	71	73	75	
Operating Projects											
Emissions Monitoring	150	154	157	161	165	169	173	177	182	186	
Stack Emissions Testing		102		107		113		118		124	
CEMS RATA Testing	60	61	63	64	66	67	69	71	73	75	
OPEP Exercise	5	5	5	5	6	6	6	6	6	6	
Tube Bundle Replacement – All Units			32			35			37		
Projects - Lump Sum for Future Years											
Total Environmental Monitoring	**300**	**410**	**347**	**429**	**330**	**485**	**346**	**473**	**401**	**497**	
Total Operating Projects Env. Monitoring	215	323	257	338	236	389	248	373	298	392	

Section H

Tab 1

Cat Arm Five-Month Outage Impact

Newfoundland And Labrador Hydro

2004

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1 BACKGROUND AND SCOPE

The Cat Arm hydroelectric generating station is located on the Great Northern Peninsula between the Cat Arm Reservoir and White Bay. The plant provides 733GWh of annual production via two 63.5MW units. Concern has been expressed regarding the impacts of a sudden, 5-month loss of Cat Arm Unit 2 due to failure of its excitation system.

The purpose of this study is to quantify the impact of this loss, on energy production costs due to potentially spilled water. Water may be spilled as a result from operational activities undertaken to compensate for the loss of Cat Arm Unit 2. In order to reflect variations in the start time of the loss, the impact was assessed for an outage starting in each of the four seasons. Other impacts such as the capacity of the system to meet peak loads and maintenance requirements were not addressed in this study.

2 METHODOLOGY

Hydro operates an integrated hydrothermal system wherein thermal production from Holyrood is combined with hydroelectric production to meet the system load. Changes in total hydroelectric generation are reflected in changes to thermal production with appropriate cost implications. Furthermore, Hydro optimizes its operations across all of its generating facilities. Thus, changes in hydroelectric generation at one facility have a cascading effect on other hydroelectric facilities, even those in completely separate river systems.

Preliminary work by Hydro's Generation Engineering department indicates that the minimum duration that Cat Arm Unit 2 would be out of service as a result of the loss of the excitation system is five months. This time is based upon a fast tracked purchasing and engineering process.

To model the impacts of the loss, the Vista Decision Support System (Vista for short) was used. Vista models the system hydroelectric water and thermal resources and dispatches generation in the most efficient manner using a multi-year planning horizon. The tool uses reservoir storage information and assumed future conditions to effectively balance the hydrothermal mix to meet system load in the most economical way. Using pre-planned outages Vista will minimize costs by attempting to draw down reservoirs prior to an outage to minimize spill at that reservoir. However, for the purposes of studying the unexpected loss of a unit, this capability of Vista is inappropriate. Accordingly, the study methodology required representing a sudden loss applied to normal system conditions without the advantage of reservoir draw down.

To identify the impact of an outage at Cat Arm Unit 2, two simulations were run in tandem. The first simulation created a base case to use as a benchmark. This simulation had no outages planned throughout its entire run. The second simulation had a five-month outage applied to Cat Arm Unit 2. This outage began on the first simulation day and hence was sudden in nature. In effect, Vista did not have time to plan for the outage and move water in an attempt to avoid spill.

Comparison of the outage case versus the base case provided a good measure of impact the outage had on the system. Any change between the two cases was a direct result of the outage, as all other variables were held constant. The impact of the outage was quantified using the difference in total system spilled water and increased Holyrood production as key indicators.

Analysis of the impact was completed over the entire system rather than solely comparing the results at the Cat Arm Reservoir as Vista attempts to use the water in the most economical fashion. This means the optimal solution may avoid a spill at Cat Arm but force it at any other reservoir. In reality, increased spill from any location in the system would reflect the Cat Arm unit outage impact.

2.1 Scenarios

As the outage on Cat Arm Unit 2 could occur at any given time and reservoir operation varies with the seasons, analysis was completed using four different scenarios. Each scenario begins on the first Monday before their respective seasonal dates of January 1, April 1, July 1 and October 1. Also each scenario used a 12-year average elevation for its respective start date. Each scenario ran until Sunday, July 2, 2007 and finished with the same target reservoir level to give a reasonably accurate estimate of the system operation. Table 1 and Table 2 summarize the different cases used and their respective water levels.

Table 1 - Case Definitions

	Scenario 1 Winter Outage	Scenario 2 Spring Outage	Scenario 3 Summer Outage	Scenario 4 Autumn Outage
Simulation Start Date	Dec 27/04	Mar 28/05	Jun 27/05	Sep 26/05
Simulation End Date	Jul 2/07	Jul 2/07	Jul 2/07	Jul 2/07
Outage Start Date	Dec 27/04	Mar 28/05	Jun 27/05	Sep 26/05
Outage End Date	May 27/05	Aug 28/05	Nov 27/05	Feb 26/06

2.2 Assumptions

Vista requires certain assumptions to be made in order to effectively perform water management. Due to the nature of reservoir management, instant cause and effect relationships may not exist. Therefore, a distant planning horizon was chosen in order to gain confidence in the analysis. An outlook until mid 2007 captures all effects of the Cat Arm outage.

Reservoir water levels are very important to Vista. To derive the water levels shown in Table 2 above some statistical analysis of historical records was completed. Daily water levels were studied from 1992 to present and average levels surrounding the case beginning dates were derived. As reservoir storage varies throughout the year, this data was required to provide a reasonable condition of the reservoirs heading into the commencement date of the simulation.

TABLE 2 - Reservoir Water Level Summary

	Starting Water Level (M)				Ending Water Level (M)
	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**	**All Scenarios**
Victoria	324.029	323.064	324.904	323.866	321.210
Burnt Pond	313.859	313.929	313.399	313.689	312.550
Granite Lake	311.770	311.770	311.770	311.770	311.700
Meelpaeg	270.896	270.570	271.709	270.724	269.360
Upper Salmon	246.806	246.784	246.805	246.692	246.820
Long Pond	180.908	180.493	181.711	180.995	180.540
Hinds Lake	309.076	307.626	310.177	309.050	309.000
Grand Lake	85.540	84.910	86.700	86.160	86.500
Paradise River	36.730	37.190	36.170	36.800	35.000
Cat Arm	390.551	387.623	392.287	391.064	384.750

Due to the recent addition of the Granite Canal hydroelectric power plant, no average values were available for the Granite Lake Reservoir. Experience has shown us that Granite Lake operates in a very narrow band. Therefore, a typical water level within this band was selected for all simulation cases.

System Operations standard reservoir ending water levels were used for each scenario.

Another key requirement was the load forecast for the duration of the simulation. The Spring 2004 official load forecast provided by Economic Analysis was used for the study.

TABLE 3 - Plant Conversion Factors

Plant	GWh/MCM
Bay d'Espoir	0.4335
Upper Salmon	0.1297
Granite Canal	0.0938
Hinds Lake	0.5382
Cat Arm	0.9004
Paradise River	0.0914
Deer Lake Power	0.1722

Unit conversion factors represent the amount of energy a unit can produce from 1 million cubic meters of water. Table 3 provides the 2003 updated plant conversion factors. The conversion factors were used to relate spill and storage quantities in Vista to energy values.

Unit availability was addressed by setting the system operational conditions such that there was no planned outages for any unit other that Cat Arm Unit 2. Therefore, for the entire base case simulation all units were available. During the outage case, Cat Arm Unit 2 was unavailable for a period of five months. A normal maintenance schedule would have units unavailable at various times through out the calendar year. This would influence Vista in the sense that the tool would know about planned outages in advance and turbine water in the most efficient manner. However, the loss of Cat Arm Unit 2 would have a substantial impact on outage planning for other units and schedules would be adjusted to meet system needs. Accordingly, these impacts need not be reflected in the current analysis.

2.3 Sensitivity

There were two other scenarios created and simulated to give confidence in the sensitivity of the analysis. These two additional scenarios target the winter and spring months and use the current 2004 firm target values for reservoir elevations rather than 12-year averages.

The 12-year average values were used to derive storage in each reservoir. The total system storage energy from these average values was compared to the 2004 Vista minimum system storage targets. This system target storage is the minimum total stored energy in all reservoirs required to weather a repeat of historically low inflows and still serve all load. The comparison of the system 12-year average levels to Vista stored energy targets gave a conversion factor to effectively equate 12-year average storage levels to Vista minimum reservoir storage targets. From this we could derive Vista minimum target elevations for each reservoir. These target elevations which are summarized in Table 4 below, were then used to test the sensitivity of the two worst scenarios.

3 RESULTS

Table 5 provides a summary of the results of the analysis, highlighting the impact of an unexpected 5-month loss of Cat Arm Unit 2 at various points of the year. The analysis indicates that in all scenarios, the loss of the unit is compensated for by an increase in thermal production over the course of the simulation. For winter and spring outages, the required adjustment from Holyrood is, on average, much higher than that required for summer and fall cases. The analysis also shows that for the loss of the unit in winter and spring, there is a substantial increase in average spill volume whereas the loss is negligible, on average, if it takes place during the summer or fall. The analysis indicates that the system can absorb, on average, about 20 GWh of thermal energy and not spill. However, there may be an increased cost to the system as overall system dispatch may suffer decreased efficiency for certain hydraulic sequences. Detailed explanation of these costs is beyond the resolution of the model employed in the exercise. Since the loss of Cat Arm Unit 2 in the winter or spring requires average thermal production above this 20 GWh threshold, a portion of the thermal production is wasted via spillage.

The fact that spills were dependent upon the period of the year in which the unit was assumed to have failed warranted further investigation. Analysis of the thermal production and spill profiles for the four scenarios revealed that spill is most likely and extensive during the spring runoff. If the unit fails during the winter or spring there is insufficient time to draw the Cat Arm reservoir down to the point where one surviving unit can handle the run-off and stay below the spillway elevation. For outages that take place after the runoff (ie. summer) or that are restored in time to allow drawdown of the reservoir prior to the runoff (ie. fall outages), the spill impact is negligible.

TABLE 4 - Sensitivity Case Definitions

	Scenario 5 Winter Outage	Scenario 6 Spring Outage	
Sim Start Date	Dec 27/04	Mar 28/05	
Sim End Date	Jul 2/07	Jul 2/07	
Outage Start	Dec 27/04	Mar 28/05	
Outage End	May 27/05	Aug 28/05	
	Start Level	**Start Level**	**End Level (All Scenarios)**
Victoria	324.081	321.818	321.210
Burnt Pond	313.859	313.929	312.550
Granite Lake	311.770	311.770	311.700
Meelpaeg	270.931	269.646	269.360
Upper Salmon	246.813	246.597	246.820
Long Pond	180.936	179.823	180.540
Hinds Lake	309.106	307.187	309.000
Grand Lake	85.540	84.910	86.500
Paradise River	36.730	37.190	35.000
Cat Arm	390.609	386.616	384.750

Individual sequences were assessed to determine how the spill was distributed among the 50 sequences simulated. As noted above, spill impacts were due to inability to draw the Cat Arm reservoir down sufficiently in advance of the spring runoff. Accordingly, spill attention was focused on the Cat Arm reservoir for the winter and spring scenarios.

Figure 1 is a histogram of spill predictions for Cat Arm for the winter outage scenario. Of the 50 sequences simulated, 20 show spill at Cat Arm as a result of the forced outage. Spill for these 20 sequences range from a low of 2 GWh to a high of 164 GWh. The median of the spill quantities is 66 GWh.

Figure 2 is a histogram of spill predictions for Cat Arm for the spring outage scenario. Of the 50 sequences, 23 show spill at Cat Arm as a result of the outage. Spill for these 23 sequences range from a low of 3 GWh to a high of 257 GWh. The median of the spill quantities is 46 GWh. Overall, the probability of a spill event is higher for spring outage than a winter outage, however the amount of spill is generally lower.

The sensitivity analysis on the winter and spring scenarios revealed no significant changes from their respective average scenarios. This tends to give confidence that the average scenarios have a low sensitivity and are not significantly affected by small changes in system storage.

4 IMPLICATIONS

The analysis provided in the report is based upon average water levels and average spill values. In reality, spill can vary from insignificant amounts to extreme amounts. As well, reservoir conditions may be different than those assumed. If water levels are higher, spill impacts will be higher, and conversely so for lower reservoir levels.

The cost implications of the loss of Cat Arm Unit 2 are dependant upon the period during which the outage takes place. If the unit was to fail in the winter there is a 40% chance of spill. If in fact a spill does occur, an average cost on the order of $3.7 million could be expected. If the unit were to fail in the spring there is a 46% chance of spill. Although there is a greater chance of spill, the volumes are on average much less, and an average cost of $2.6 million could be expected. If the unit fails in summer or fall, no additional cost would be expected.

Costing estimates are derived by using the following formula.

$$\text{Cost} = \frac{\text{Potential Energy Spilled X Cost of Fuel}}{\text{Holyrood Conversion}}$$

Where:

- Potential Energy Spilled is in GWh
- Cost of Fuel is set at the current CAD$36/bbl
- Holyrood Conversion is 630kWh/bbl or 6.3×10^{-4} GWh/bbl

TABLE 5 - VISTA SIMULATION RESULTS

Scenario	Description	Average Increase in Spill (GWh)*	Increase in Holyrood Production (GWh)
Scenario 1	Jan Outage	31	56
Scenario 2	Apr Outage	25	42
Scenario 3	Jul Outage	2	12
Scenario 4	Oct Outage	1	20
Scenario 5	Jan Outage	31	54
Scenario 6	Apr Outage	22	39

* Averaged across all 50 sequences

Figure 1 - Distribution of Cat Arm Spill - Scenario 1
Five Month Outage Dec 27/04 to May 27/05

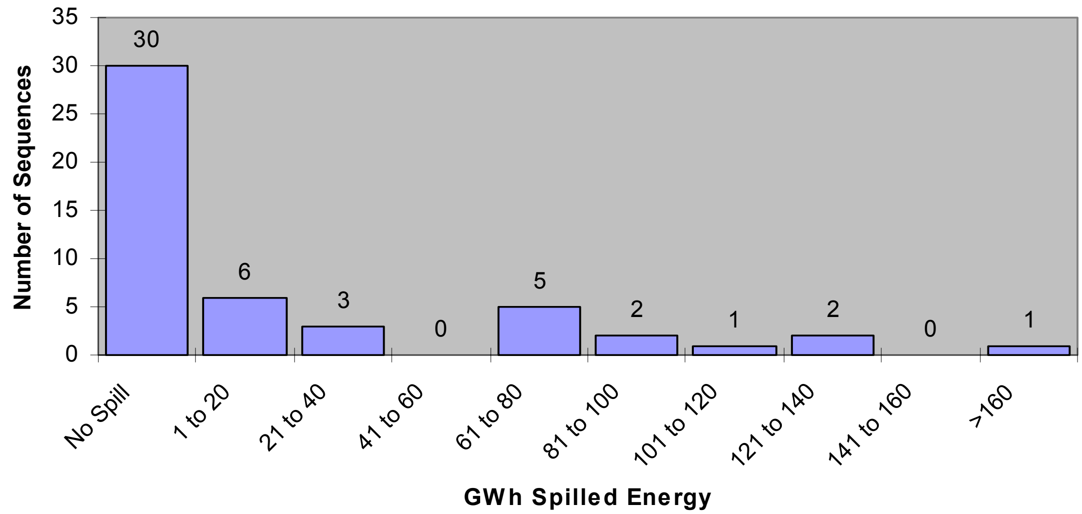
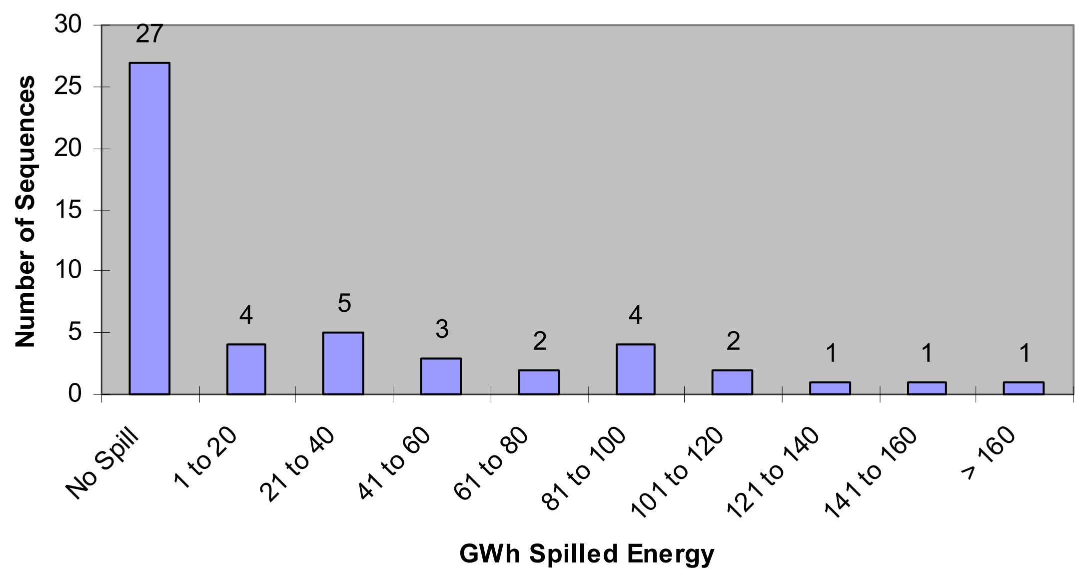


Figure 2 - Distribution of Cat Arm Spill - Scenario 2
Five Month Outage Mar 28/05 - Aug 28/05



Tab 2

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

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
GREG SAUNDERS
SIGNATURE
DATE
NEWFOUNDLAND & LABRADOR

FINAL REPORT

SGE Acres Limited
Bally Rou Place, Suite E200
280 Torbay Road
St. John's, NL A1A 3W8

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 PEG-NL G0208
which is valid for the year 2006

March 2006
16806D1

SGE Acres

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Drawings

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.

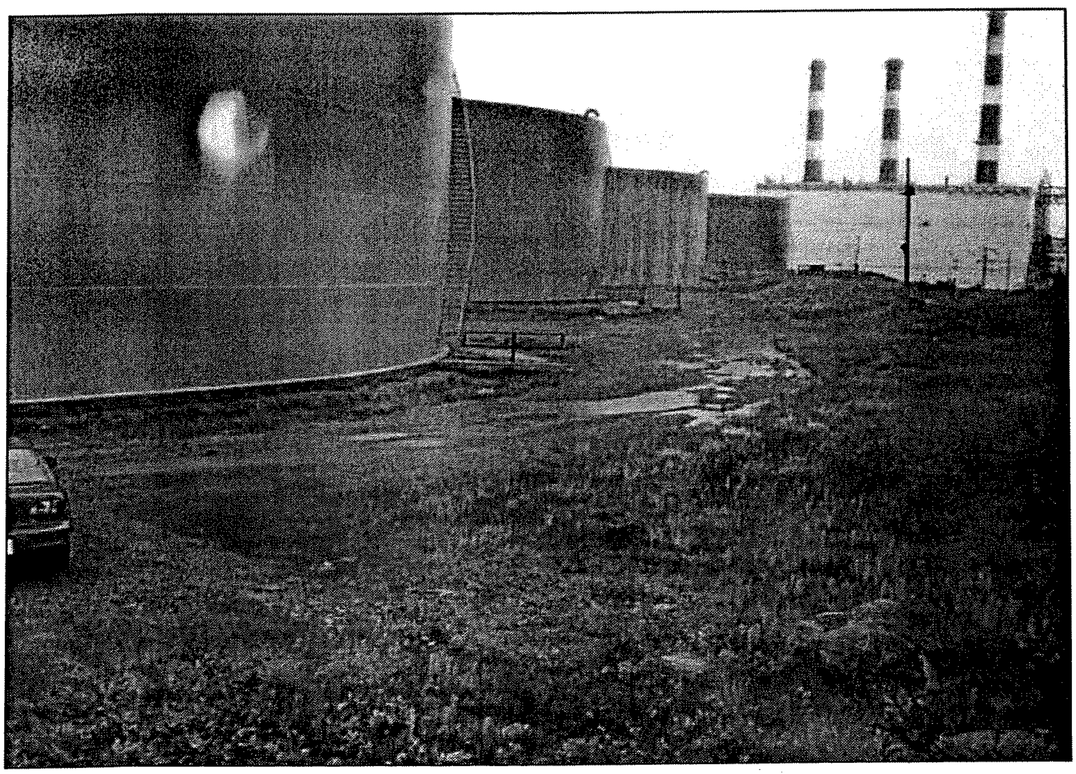
The tanks are separated by intermediate berms; surface drainage within each dyke being independent of the others – except that all drainage eventually is directed to Dyke 2 for release by operators.

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:

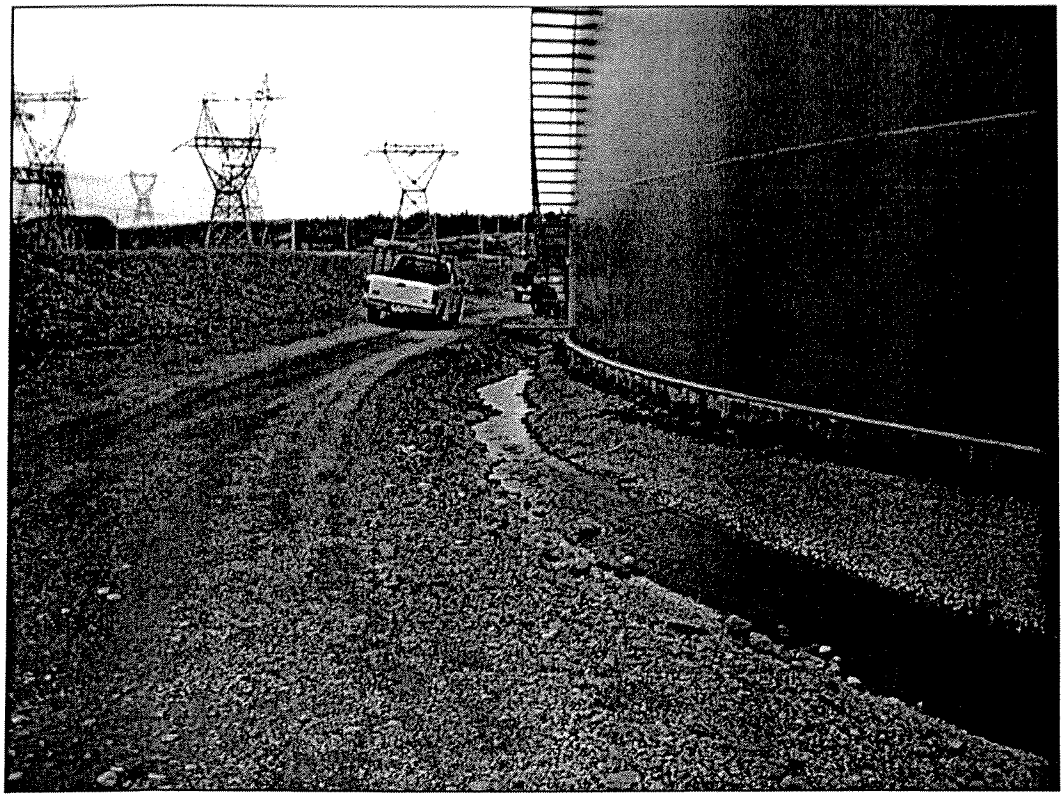
- 0.2% to 0.4% in ditches immediately adjacent to the tanks but some local high points exist. Note that these ditches do not extend all the way to the main drain on the west side.
- 0.4% in swale west of Tank 1 and Tank 2.
- Minus 0.3% in the swale west of Tank 3 – this ditch is actually back-graded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

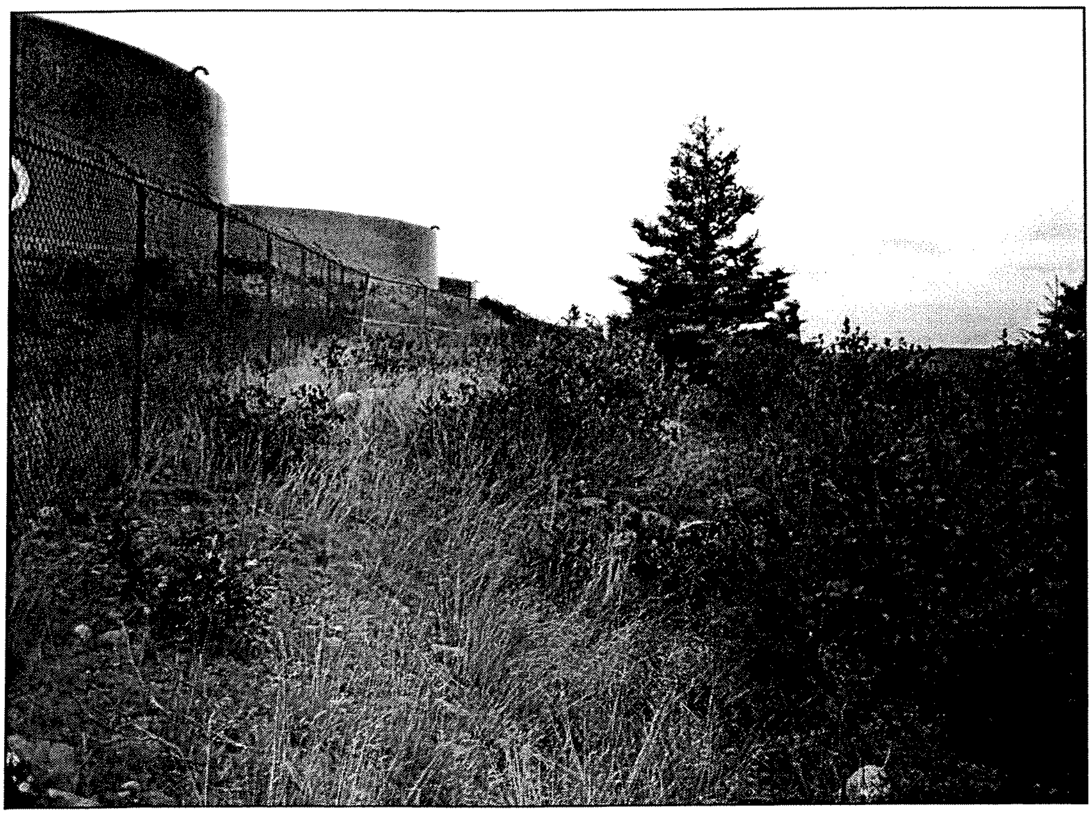
The inlet screen between Tank #2 and Tank #3 and the underground piping. The inlet and the pipes need to be replaced.

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

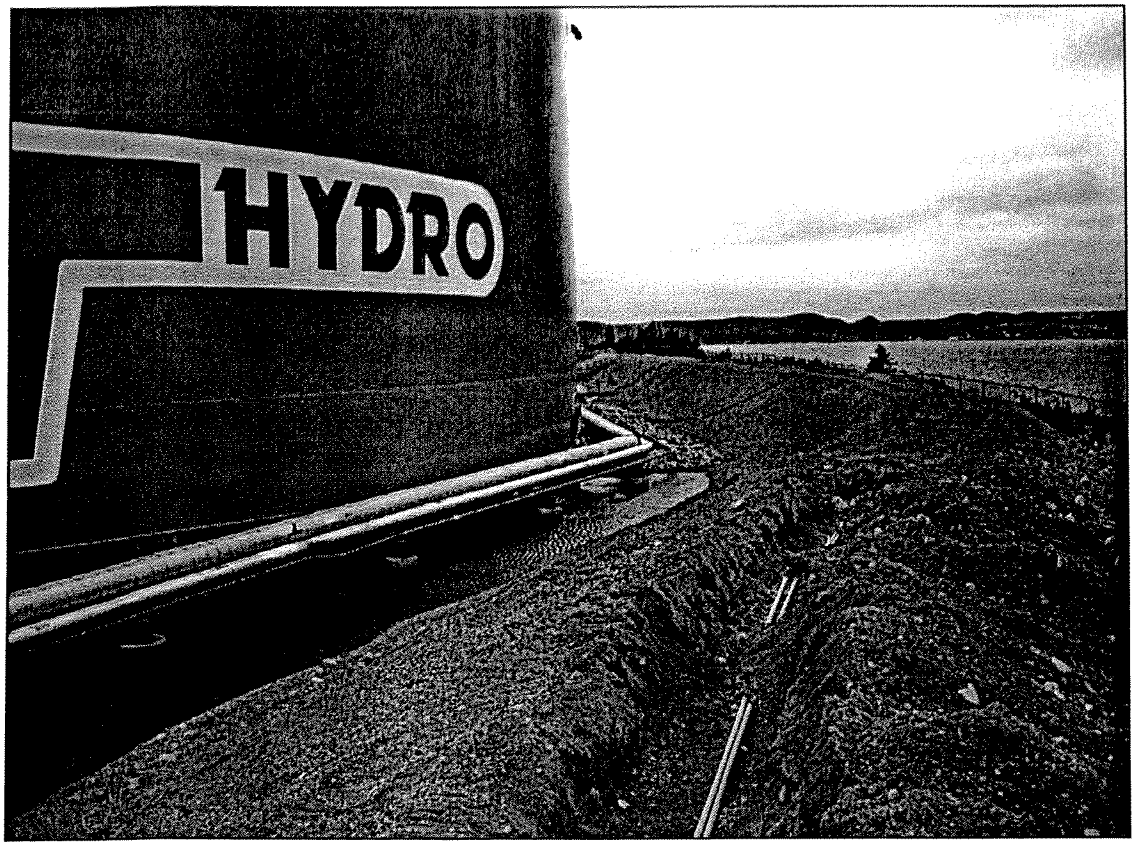
The main dyke is formed by a continuous gravel berm, approximately 2.3 meters high, constructed of impervious till, on the east, north, and west sides while on the south side an excavated embankment serves as the dyke wall. Design elevation of the top of the berm is approximately 17.8 m. Surveys indicate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

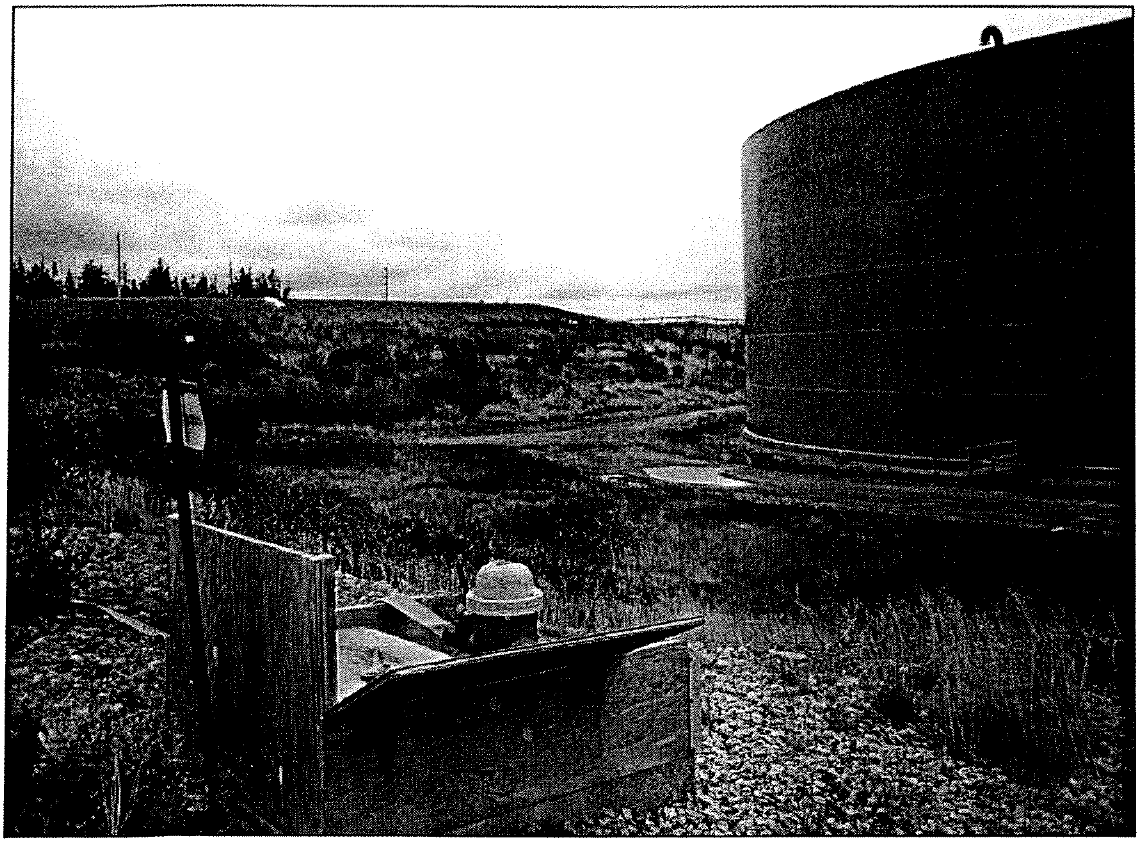
- Liner adequacy needs to be confirmed, that is, for thickness and permeability.
- Penetrations into the till liner may exist, e.g., pipe support bases.

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

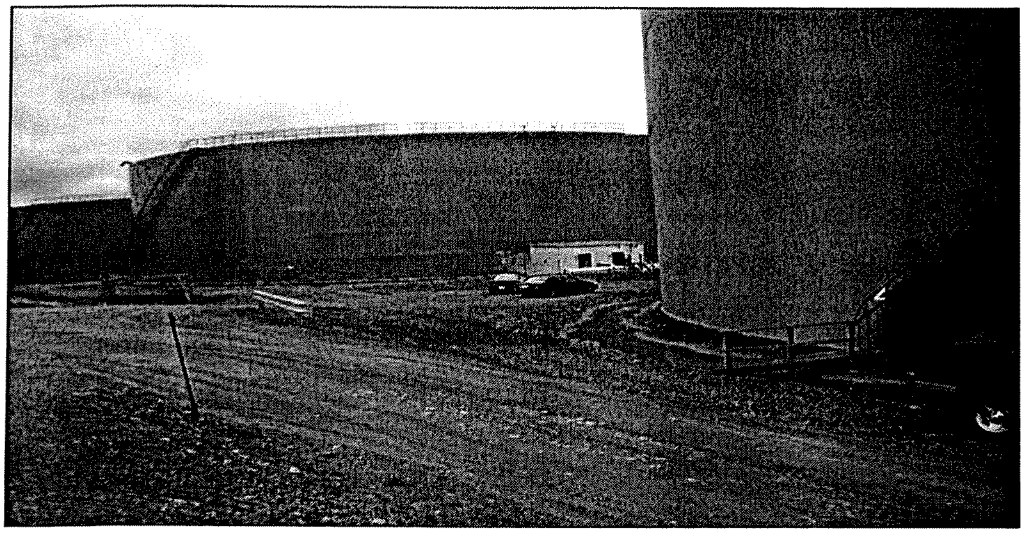
Vehicle access is provided into the dyke from the east side where the main access road crosses the berm. Access within the dyke by vehicle is not available on the west side due to the above ground piping, otherwise all other sides of the tanks can be accessed fairly readily. The condition of the gravel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



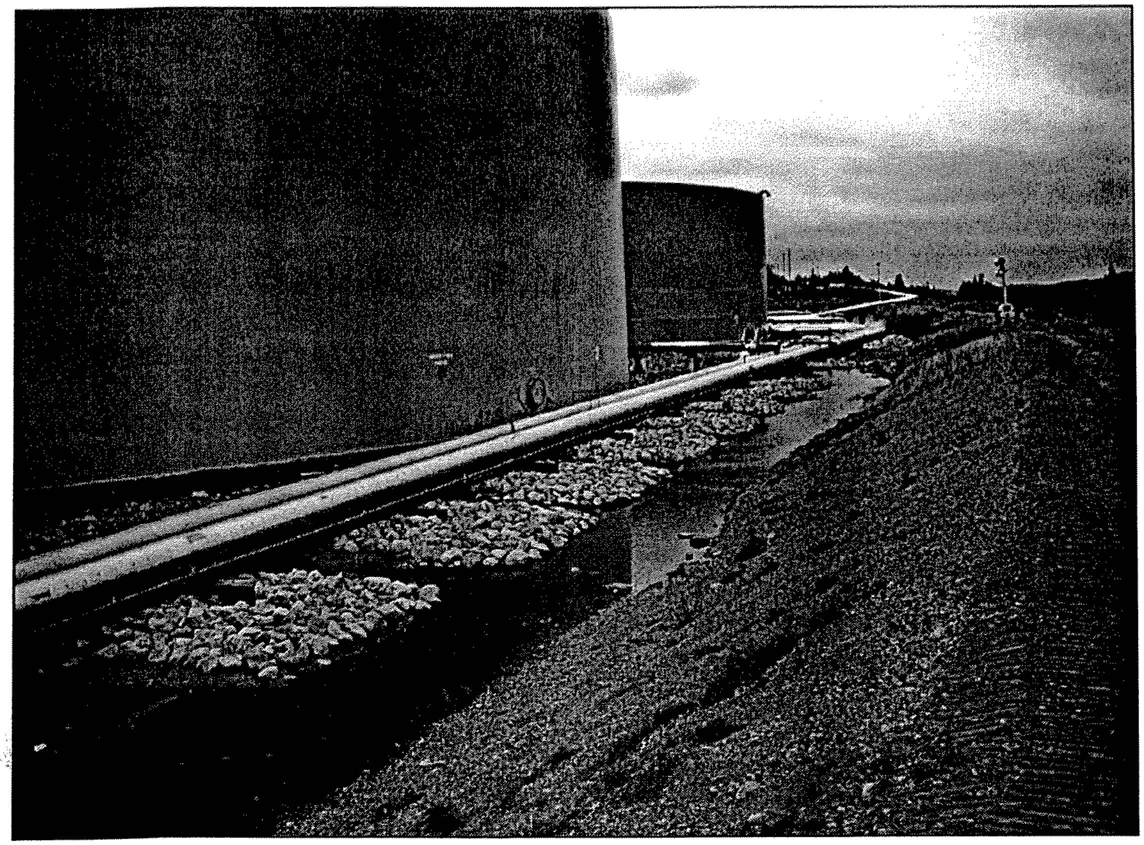
Vehicle access - provided into the dyke from the east side where the main access road crosses the dyke.

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.



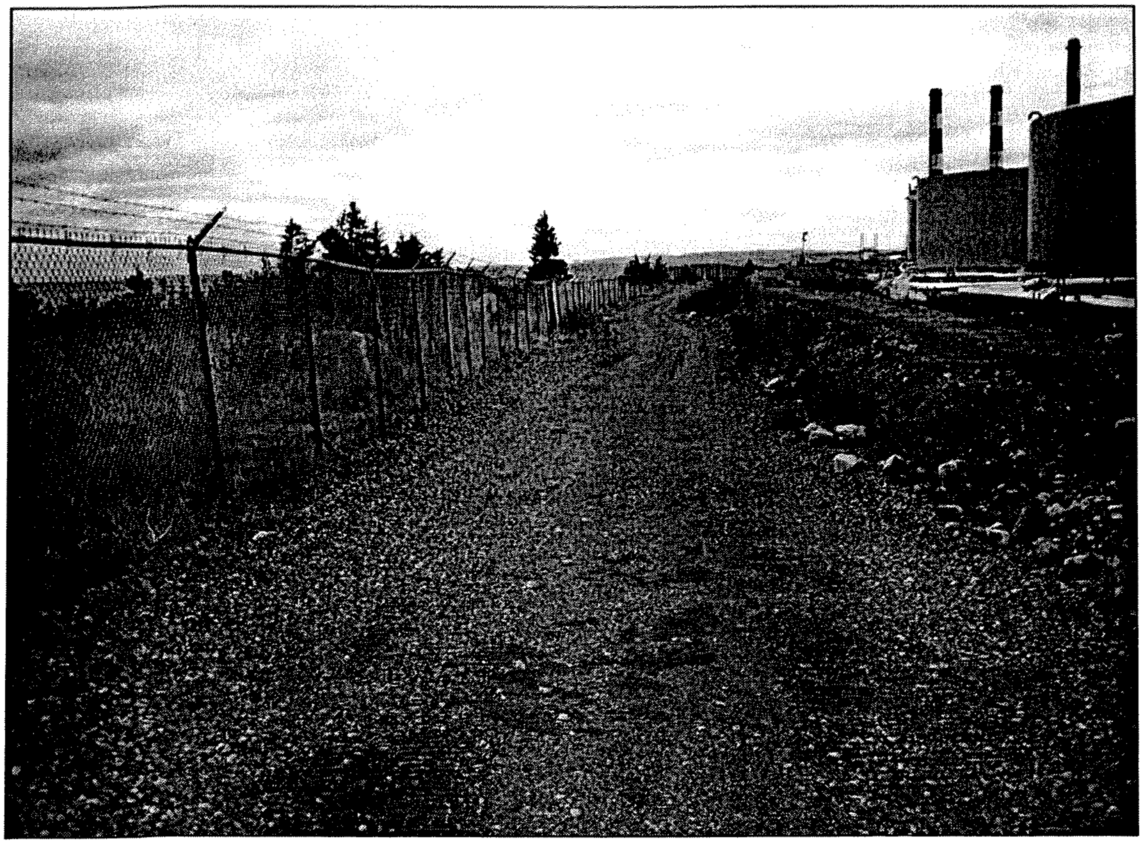
Pipe support bases - rock ballasting around many of the existing in-ground concrete pipe supports

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**

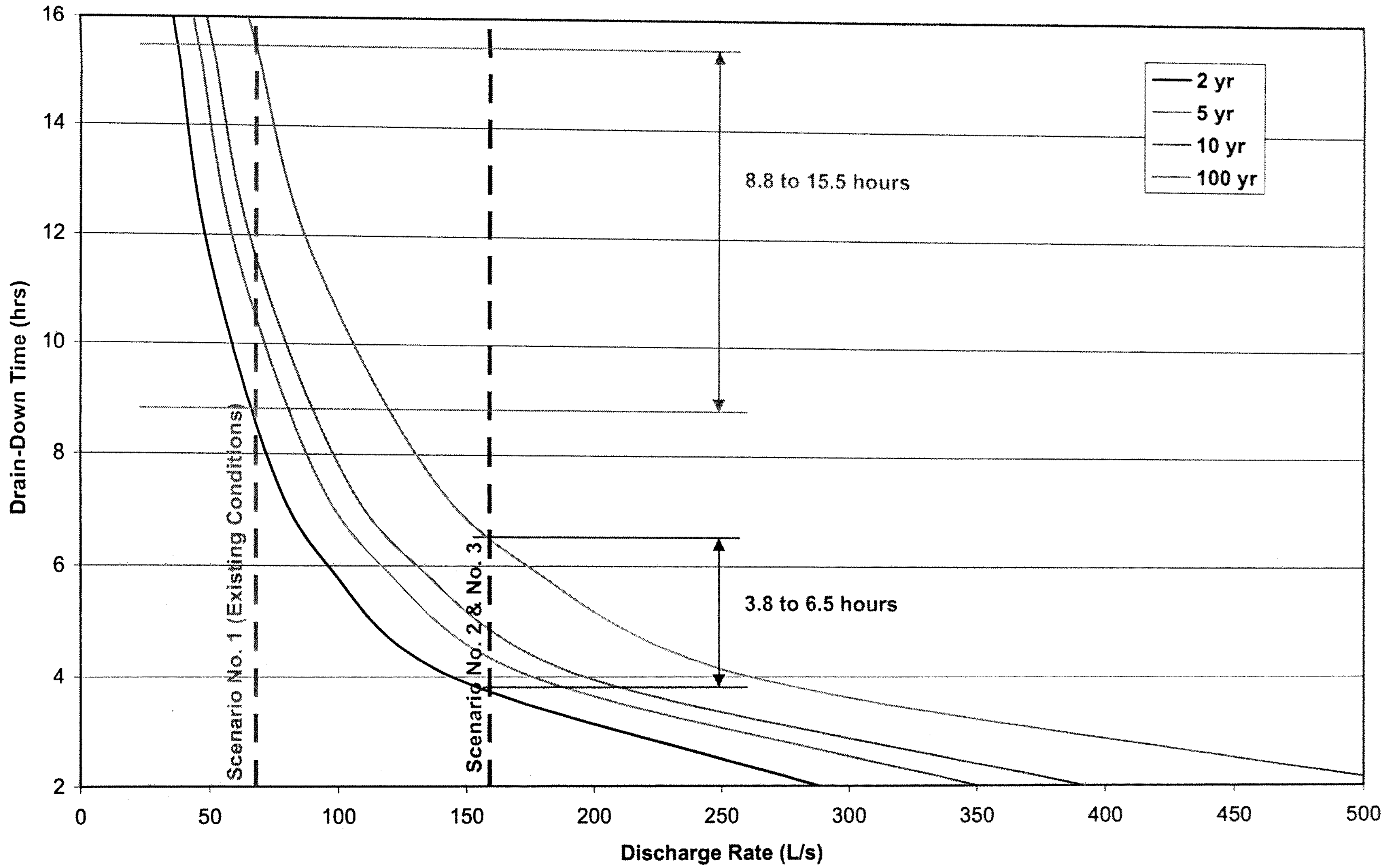
Combined piping discharge capacity = 157 l/s = 2,075 gpm
- theoretically can drain dyke in approx 3 to 7 hours

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



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

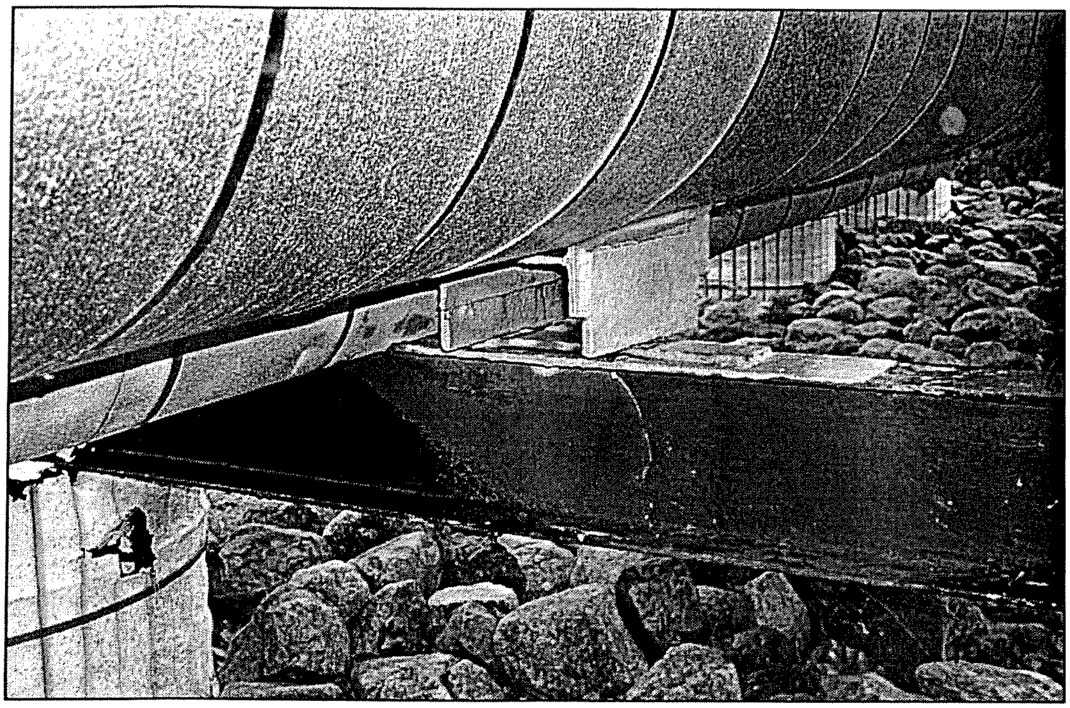


Photo 1: Main line expansion loop at Tank 4. Extension plates welded to saddle and spacer plate on beam.

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.

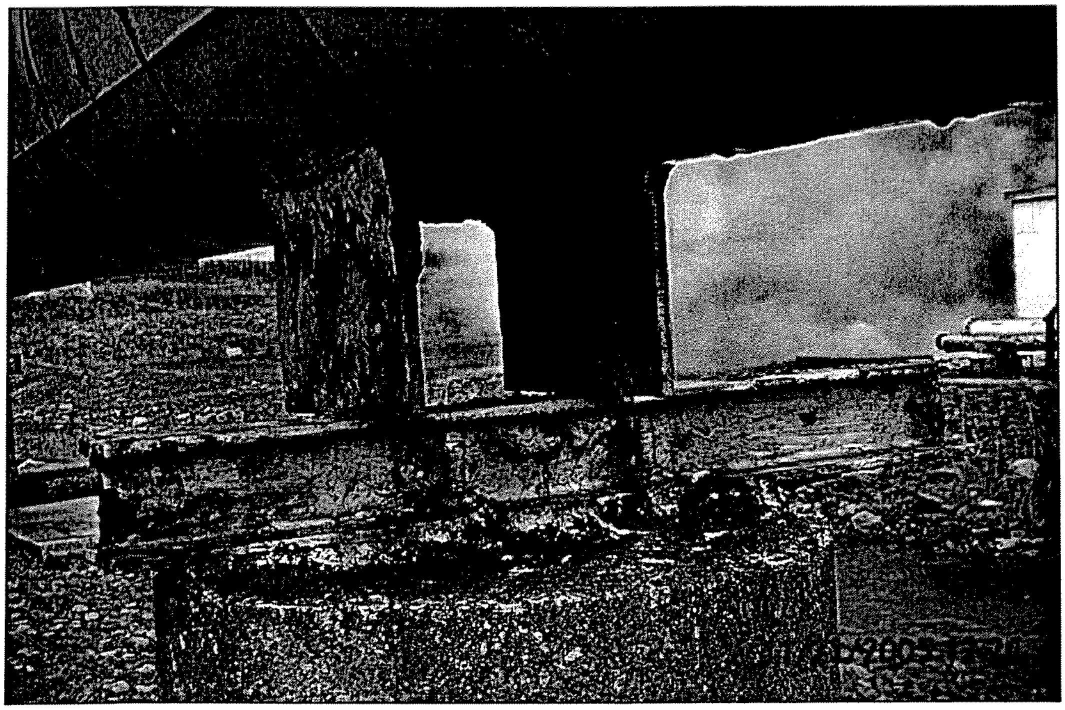


Photo 4: Branch Line to Tank 3. Severe corrosion of saddle and support.

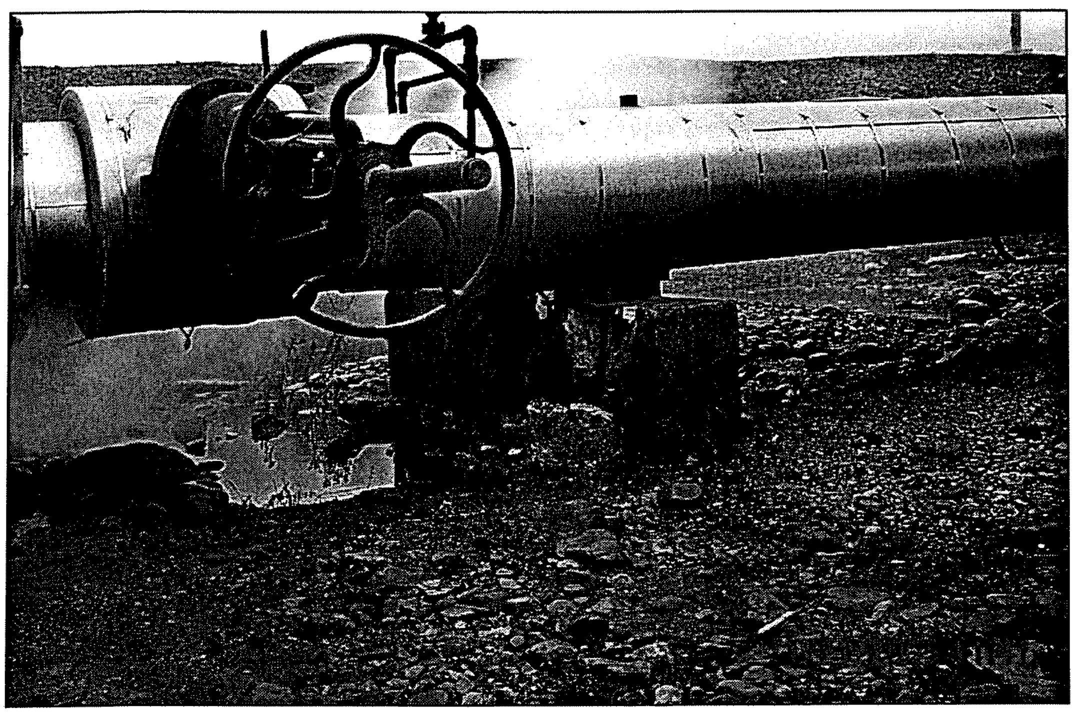


Photo 5: Anchor Block between Tanks 1 and 2. Anchor block completely failed.

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.

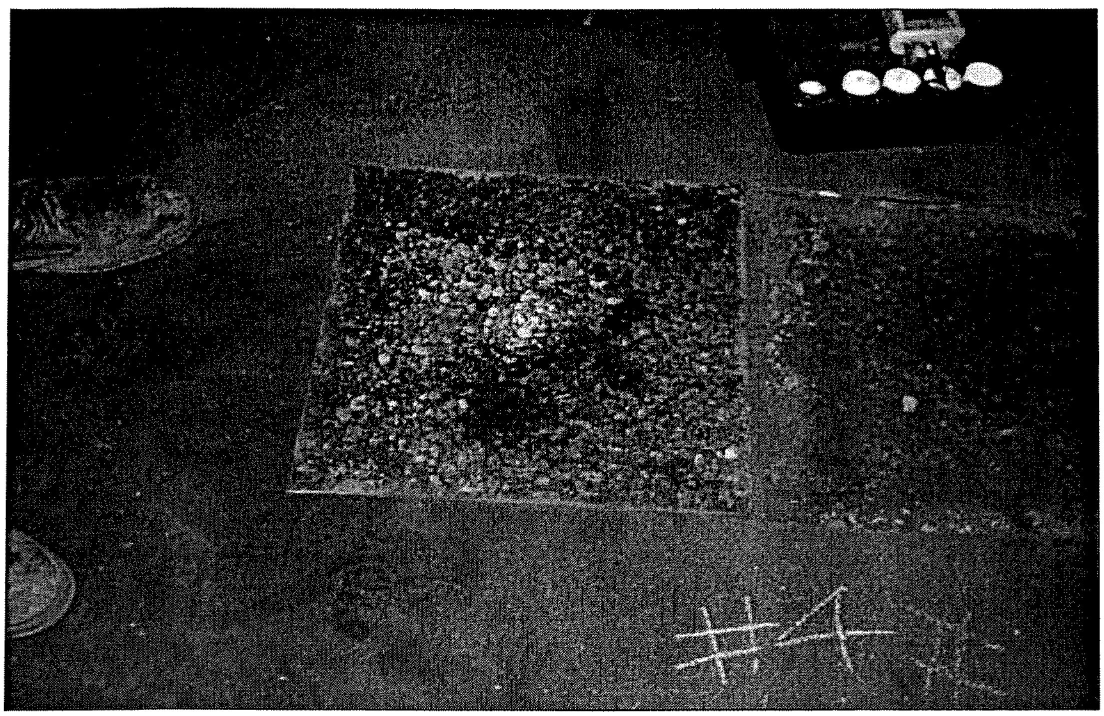


Photo 1 - Tank No. 4 - Floor Plate – Underside of Bottom Plate Exposed (Left Hand Side) - Soil Exposed for Testing (Right Hand Side)

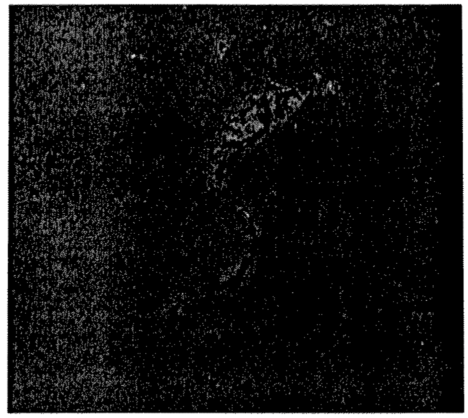


Photo 2 - Tank No. 4 - Surface Laminations

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

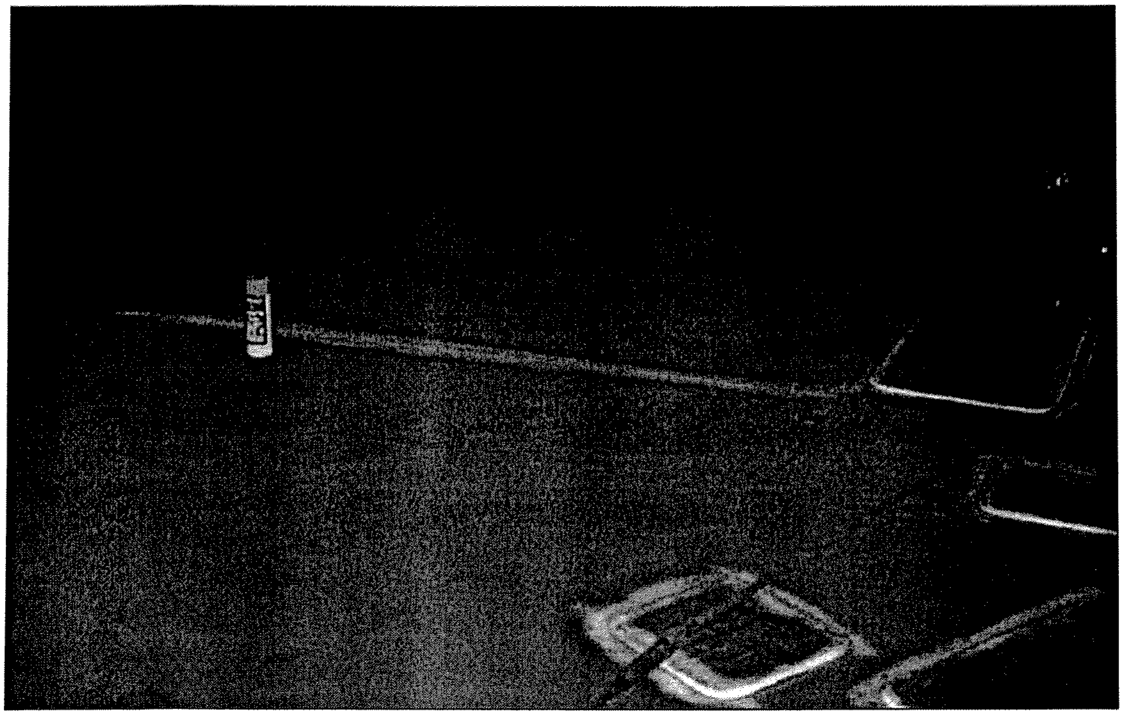


Photo 4 - Tank No. 4 - Floor Plate - Repair Patch Plates and Inspection of Lap Joint

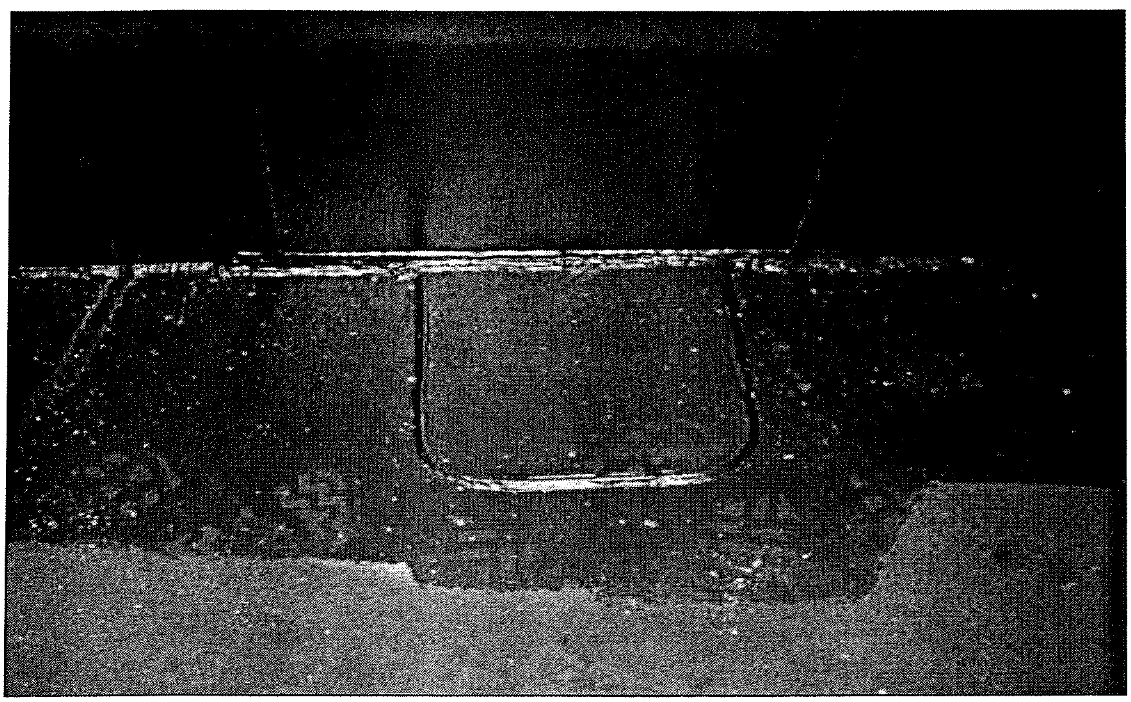


Photo 5 - Tank No. 1 – Interior View of Insert Plate and Floor Repair Patch

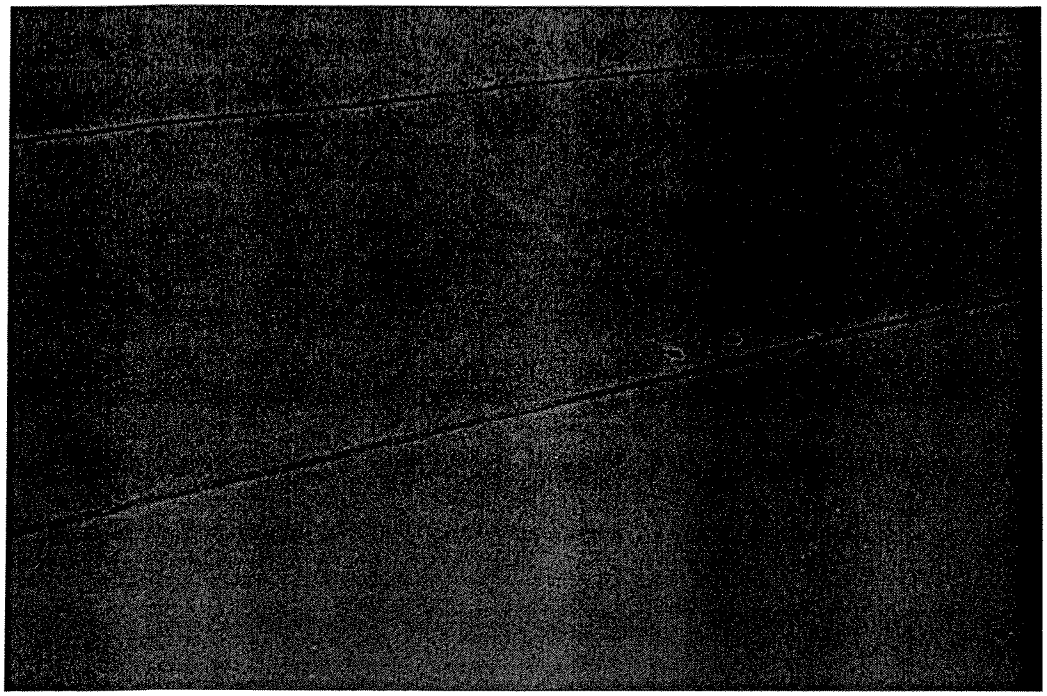


Photo 6 - Tank No. 1 – Roof Plates Showing Location of Thickness Measurements

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

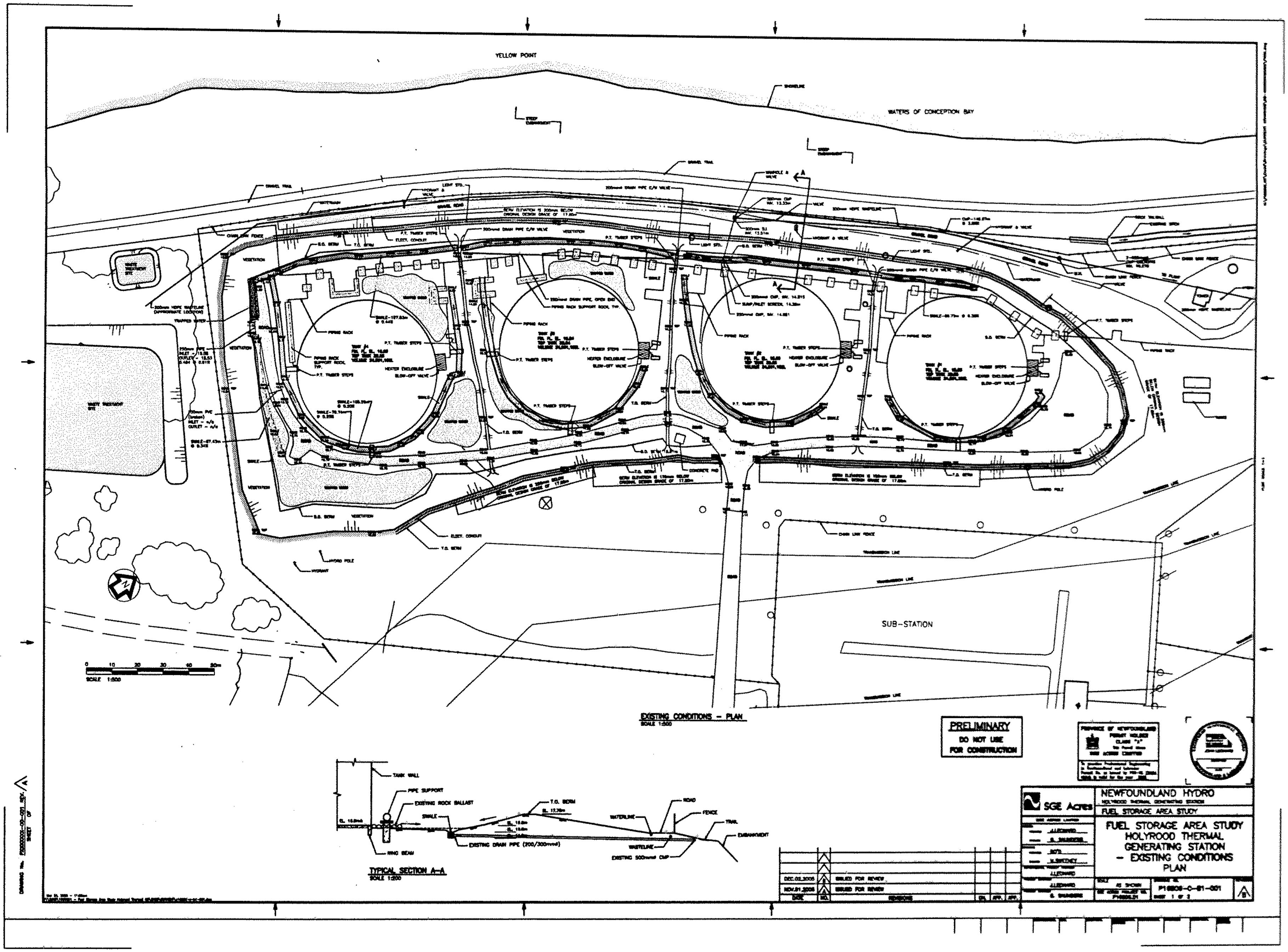
HOLYROOD GENERATING STATION TANK FARM

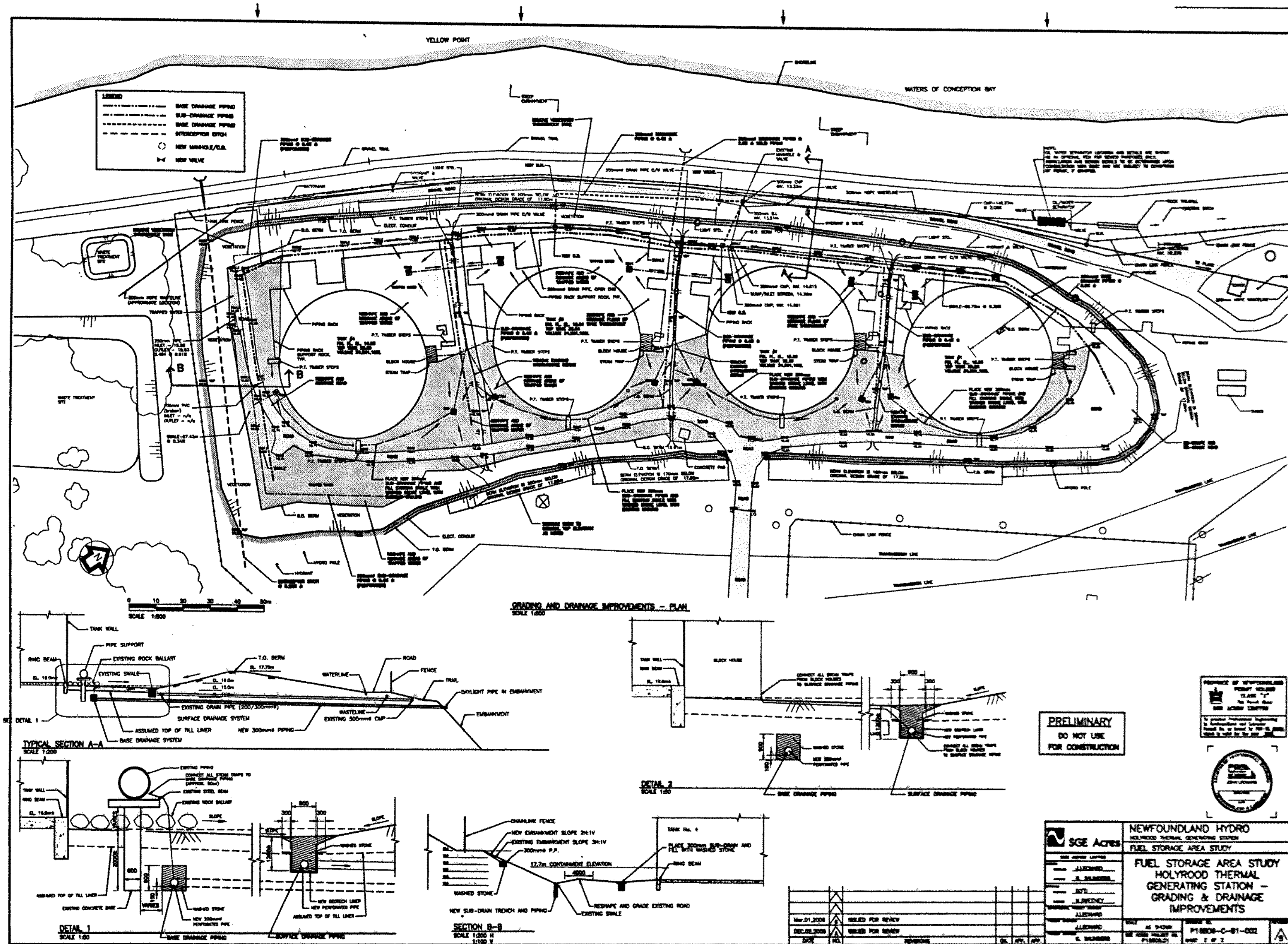
Capital Works Implementation Plan

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**

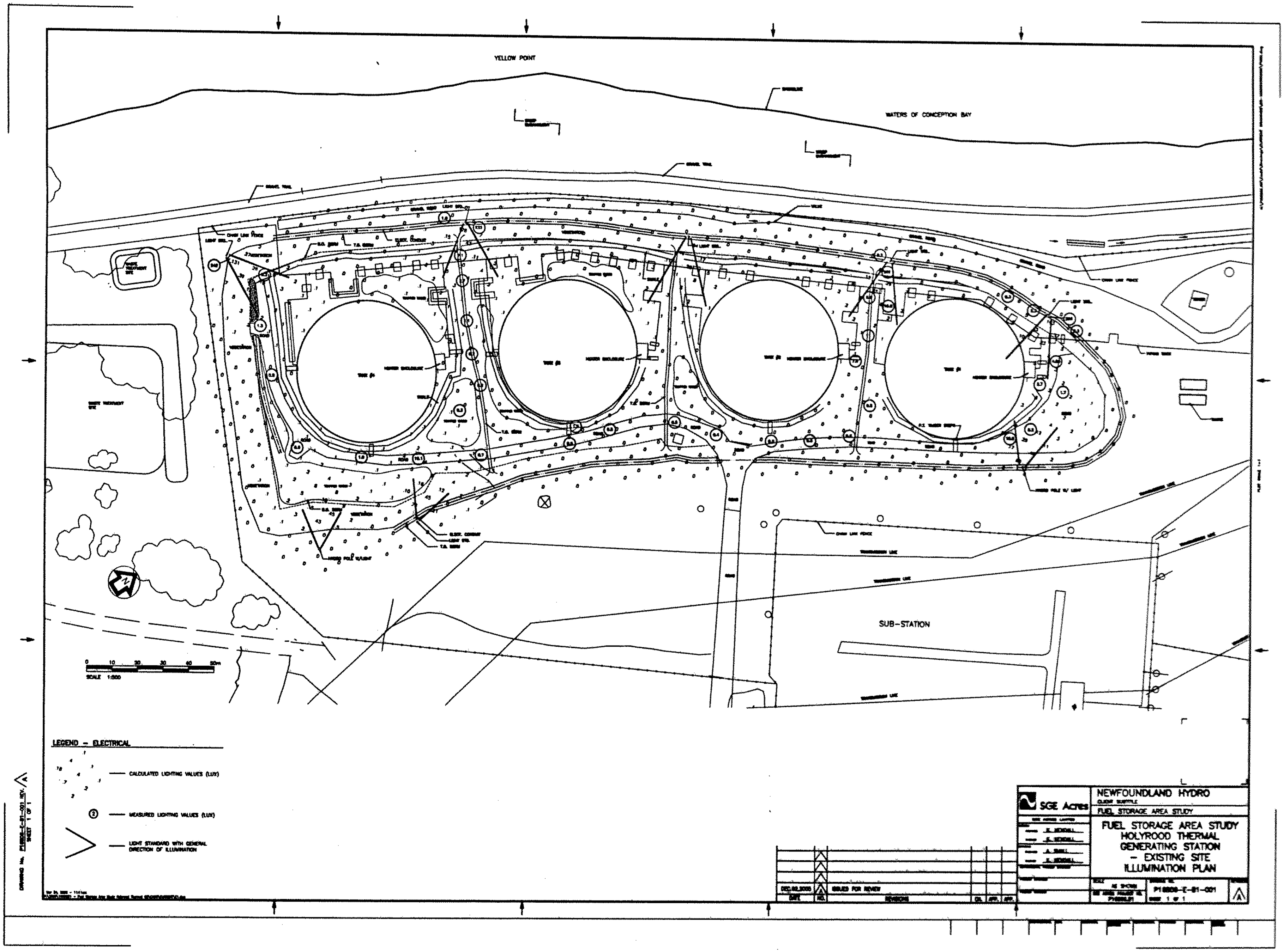
Item	Description	Total	Priority	Implementation Year				
				2007	2008	2009	2010	2011
3	**Tanks**							
3.1	**Tank 1**							
0.1	Replace Roof Plate	$756,400	Low				$6,200	$750,200
0.2	Roof Coating	$125,000	Low				$2,500	$122,500
0.3	Roof Rafters	$200,000	Low				$4,000	$196,000
0.4	Tank Cleaning	$280,000	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


YELLOW POINT
WATERS OF CONCEPTION BAY
SUB-STATION
EXISTING CONDITIONS - PLAN
SCALE 1:500
PRELIMINARY
DO NOT USE
FOR CONSTRUCTION
TYPICAL SECTION A-A
SCALE 1:200
TANK WALL
PIPE SUPPORT
EXISTING ROCK BALLAST
SWALE
RING BEAM
T.O. BERM
WATERLINE
ROAD
FENCE
TRAIL
EMBANKMENT
WASTELINE
EXISTING DRAIN PIPE (200/300mmØ)
PIPING RACK
P.T. TIMBER STEPS
HEATER ENCLOSURE
BLOW-OFF VALVE
WASTE TREATMENT SITE
SCALE 1:500
SGE Acres
NEWFOUNDLAND HYDRO
FUEL STORAGE AREA STUDY
FUEL STORAGE AREA STUDY
HOLYROOD THERMAL
GENERATING STATION
- EXISTING CONDITIONS
PLAN
AS SHOWN
DEC.02.2005
ISSUED FOR REVIEW
NOV.01.2005
ISSUED FOR REVIEW
REVISIONS



YELLOW POINT
WATERS OF CONCEPTION BAY
SHORELINE
LEGEND
BASE DRAINAGE PIPING
SUB-DRAINAGE PIPING
BASE DRAINAGE PIPING
INTERCEPTOR DITCH
NEW MANHOLE/C.B.
NEW VALVE
GRADING AND DRAINAGE IMPROVEMENTS - PLAN
SCALE 1:800
TYPICAL SECTION A-A
SCALE 1:200
TANK WALL
PIPE SUPPORT
RING BEAM
EXISTING ROCK BALLAST
EXISTING SWALE
T.O. BERM
WATERLINE
ROAD
FENCE
TRAIL
DAYLIGHT PIPE IN EMBANKMENT
EMBANKMENT
EXISTING DRAIN PIPE (200/300mmø)
SURFACE DRAINAGE SYSTEM
ASSUMED TOP OF TILL LINER
BASE DRAINAGE SYSTEM
NEW 300mmø PIPING
WASTELINE
EXISTING 500mmø CMP
DETAIL 1
SCALE 1:50
BASE DRAINAGE PIPING
SURFACE DRAINAGE PIPING
WASHED STONE
SECTION B-B
SCALE 1:200 H
1:100 V
CHAINLINK FENCE
NEW EMBANKMENT SLOPE 2H:1V
EXISTING EMBANKMENT SLOPE 3H:1V
17.7m CONTAINMENT ELEVATION
NEW SUB-DRAIN TRENCH AND PIPING
RESHAPE AND GRADE EXISTING ROAD
EXISTING SWALE
TANK No. 4
PLACE 300mm SUB-DRAIN AND FILL WITH WASHED STONE
RING BEAM
DETAIL 2
SCALE 1:50
BLOCK HOUSE
PRELIMINARY
DO NOT USE
FOR CONSTRUCTION
SGE Acres
NEWFOUNDLAND HYDRO
HOLYROOD THERMAL GENERATING STATION
FUEL STORAGE AREA STUDY
FUEL STORAGE AREA STUDY
HOLYROOD THERMAL
GENERATING STATION -
GRADING & DRAINAGE
IMPROVEMENTS
Mar.01,2006
ISSUED FOR REVIEW
DEC.02,2005
ISSUED FOR REVIEW
DATE
NO.
REVISIONS
AS SHOWN
P16808-C-81-002



YELLOW POINT
WATERS OF CONCEPTION BAY
SUB-STATION
TANK #1
TANK #2
TANK #3
TANK #4
HEATER ENCLOSURE
SCALE 1:500
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LEGEND - ELECTRICAL
CALCULATED LIGHTING VALUES (LUX)
MEASURED LIGHTING VALUES (LUX)
LIGHT STANDARD WITH GENERAL DIRECTION OF ILLUMINATION
SGE Acres
NEWFOUNDLAND HYDRO
FUEL STORAGE AREA STUDY
FUEL STORAGE AREA STUDY
HOLYROOD THERMAL
GENERATING STATION
- EXISTING SITE
ILLUMINATION PLAN
AS SHOWN
P16808-E-81-001
SHEET 1 OF 1
ISSUED FOR REVIEW
DATE
NO.
REVISIONS

Tab 3

GOVERNMENT OF
NEWFOUNDLAND AND LABRADOR
Department of Environment and Conservation

CERTIFICATE OF APPROVAL

Pursuant to the Environmental Protection Act, SNL 2002 c E-14.2 Section 83

Issue Date: ***February 2, 2006*** Approval No. AA06-025458

Expiration: ***February 2, 2011*** File No. 716.008

Proponent: **Newfoundland and Labrador Hydro**
P.O. Box 29
Holyrood, NL
A0A 2R0

Attention: Mr. Wayne Rice, Environment and Performance Manager

Re: **Holyrood Thermal Generating Station**

Approval is hereby given for: the operation of a thermal generating station, including power house, waste water treatment plant, hazardous waste landfill and associated works located at Holyrood, NL.

This certificate of approval does not release the proponent from the obligation to obtain appropriate approvals from other concerned provincial, federal and municipal agencies. Nothing in this certificate of approval negates any regulatory requirement placed on the proponent. Where there is a conflict between conditions in this certificate of approval and a regulation, the condition in the regulation shall take precedence. Approval from the Department of Environment and Conservation shall be obtained prior to any significant change in the design, construction, installation, or operation of the facility, including any future expansion of the works. This certificate of approval shall not be sold, assigned, transferred, leased, mortgaged, sublet or otherwise alienated by the proponent without obtaining prior approval from the Minister.

This certificate of approval is subject to the terms and conditions as contained in Appendix 'A' attached hereto, as may be revised from time to time by the Department. Failure to comply with any of the terms and conditions may render this certificate of approval null and void, may require the proponent to cease all activities associated with this certificate of approval, may place the proponent and its agent(s) in violation of the *Environmental Protection Act*, and will make the proponent responsible for taking such remedial measures as may be prescribed by the Department. The Department reserves the right to add, delete or modify conditions to correct errors in the certificate of approval or to address significant environmental or health concerns.

for **MINISTER**

APPENDIX "A"

TERMS AND CONDITIONS FOR APPROVAL No. AA06-025458
February 2, 2006

General

1. This Certificate of Approval is for: the operation of a thermal generating station, including power house, waste water treatment plant, hazardous waste landfill and associated works located at Holyrood, NL. Future modification or expansion may require an amendment to this Approval or a separate Approval.

2. Any inquires concerning this approval shall be directed to the St. John's office of the Pollution Prevention Division (telephone: (709) 729-2555; or facsimile: (709) 729-6969).

3. In this Certificate of Approval:

   - **accredited** means the formal recognition of the competence of a laboratory to carry out specific functions;

   - **acutely lethal** means that the effluent at 100% concentration kills more than 50% of the rainbow trout subjected to it during a 96-hour period, when tested in accordance with the ALT;

   - **Administrative Boundary** means the boundary surrounding the thermal generating station outside of which the ambient air quality standards, outlined in Schedule A of the ***Air Pollution Control Regulations, 2004***, apply;

   - **air contaminant** means dust, fumes, mist, smoke, other particulate matter, vapour, gas, odorous substances or a combination of them in air which may impair the quality of the natural environment for any use that can be made of it, cause harm or discomfort to a person, adversely affect the health or impair the safety of a person or cause injury or damage to property or to plant or animal life;

   - **ALT (acute lethality test)** means a test conducted as per Environment Canada's Environmental Protection Series reference method EPS/1/RM-13 Section 5 or 6;

   - **blanketed** means to cover a vessel with a lid that is specifically designed to contain vapours;

   - **BOD_5** means biochemical oxygen demand (5 day test);

   - **CEMS** means the continuous emissions monitoring system used to measure gaseous releases of SO_2, NO_X, CO_2, CO and O_2 from each boiler;

- **CO** means carbon monoxide;

- **CO_2** means carbon dioxide;

- **Department** means the Department of Environment and Conservation, and its successors;

- **Director** means the Director of the Pollution Prevention Division of the Department;

- **discharge criteria** means the maximum allowable levels for the parameters listed in Table 3;

- **effluent** means waste water resulting from the thermal generating station operations, including process water, boiler blowdown water, wash-down water, cooling water and leachate from the landfill;

- **grab sample** means a quantity of undiluted effluent collected at any given time;

- **hazardous waste** means a product, substance or organism that is intended for disposal or recycling, including storage prior to disposal or recycling, and that:
(a) is listed in Schedule III of the *Export and Import of Hazardous Waste Regulations under the Canadian Environmental Protection Act, 1999*;
(b) is included in any of Classes 2 to 6, and 8 and 9 of the *Transportation of Dangerous Goods Regulations* under the *Transportation of Dangerous Goods Act, 1992*; or
(c) exhibits a hazard classification of a gas, a flammable liquid, an oxidizer, or a substance that is dangerously reactive, toxic, infectious, corrosive or environmentally hazardous;

- **HYDRO** means Newfoundland and Labrador Hydro;

- **Landfill Operations Manual** means the ***HTGS Procedures Manual for the Controlled Waste Landfill*** (most recent version);

- **licenced** means has a Certificate of Approval issued by the Minister to conduct an activity;

- **liquid waste** is defined by the *Slump Test* (Canadian Standards Association test method A23.2-5C for determining the slump of concrete). The liquid waste slump test involves placing the waste in a 30 cm open inverted cone. The cone is removed and the immediate decrease (slump) in height of the waste material is measured. If the material slumps such that the original height is reduced by 15 cm or more, the waste is considered liquid;

- **leachate holding pond** means the detention pond for leachate control prior to transfer to the on-site waste water treatment plant;

- **malfunction** means any sudden, infrequent and not reasonably preventable failure of air pollution control equipment, waste water treatment equipment, process equipment, or a process to operate in a normal or usual manner. Failures caused in part by poor maintenance or careless operation are not malfunctions;

- **Minister** means the Minister of the Department;

- **NO_x** means oxides of nitrogen;

- **NO_2** means nitrogen dioxide;

- **O_2** means oxygen;

- **on-scene commander** means the person designated to co-ordinate and direct pollution control efforts at the scene of an existing spill of a toxic or hazardous material;

- **PCBs** means polychlorinated biphenyls;

- **PM_{10}** means particulate matter with a diameter of 10 μm or less;

- **$PM_{2.5}$** means particulate matter with a diameter of 2.5μm or less;

- **proficiency testing** means the use of inter-laboratory comparisons to determine the performance of individual laboratories for specific tests or measurements;

- **QA/QC** means Quality Assurance/Quality Control;

- **register(ed)**, in the context of storage tanks, means that information regarding the storage tank system has been submitted to a Government Service Centre office and a registration number has been assigned to the storage tank system. In the context of source testing, registered means source testing results that have been submitted to and approved by the department in accordance with the *Stack Emission Testing Guidance Document* (GD-PPD-016.1);

- **regulated substance** means a substance subject to discharge limit(s) under the *Environmental Control Water and Sewage Regulations, 2003*;

- **SO_2** means sulfur dioxide;

- **SOP** means Standard Operating Procedure;

- **spill or spillage** means a loss of gasoline or associated product in excess of 70 litres from a storage tank system, pipeline, tank vessel or vehicle, or of any volume of a regulated substance, onto or into soil or a body of water;

- **storage tank system** means a tank and all vent, fill and withdrawal piping associated with it installed in a fixed location and includes a temporary arrangement;

- **TDS** means total dissolved solids;

- **TPH** means total petroleum hydrocarbons as measured by the Atlantic PIRI method;

- **TSP** means total suspended particulate with diameters less than 100μm. For the purposes of this approval, TSP shall be measured using a high volume TSP sampler;

- **TSS** means total suspended solids;

- **used lubricating oil** means lubricating oil that as a result of its use, storage or handling, is altered so that it is no longer suitable for its intended purpose but is suitable for refining or other permitted uses;

- **used oil** means a used lubricating oil or waste oil;

- **waste oil** means an oil that as a result of contamination by any means or by its use, is altered so that it is no longer suitable for its intended purpose; and

- **waste water treatment plant** means HYDRO's treatment plant for waste water streams resulting from periodic cleaning of boiler fireside equipment, and includes the periodic basin, the batch reactor, filter press and all associated works.

4. All necessary measures shall be taken to ensure compliance with all applicable acts, regulations, policies and guidelines, including the following, or their successors:

   - *Environmental Protection Act;*
   - *Water Resources Act;*
   - *Air Pollution Control Regulations, 2004;*
   - *Environmental Control Water and Sewage Regulations, 2003;*
   - *Storage and Handling of Gasoline and Associated Products Regulations, 2003;*
   - *Halocarbon Regulations;*
   - *Used Oil Control Regulations;*
   - *Storage of PCB Waste Regulations, 2003;*
   - *Ambient Air Monitoring Policy Directive;*
   - *Accredited and Certified Laboratory Policy;*
   - *Compliance Determination Guidance Document;*
   - *Stack Emission Testing Guidance Document; and*
   - *Plume Dispersion Modelling Guidance Document.*

   This Approval provides terms and conditions to satisfy various requirements of the above listed acts, regulations, Departmental policies and guidelines. If it appears that all of the pertinent requirements of these acts, regulations, policies and guidelines are not being met, then a further review of the thermal generating station shall be conducted, and suitable pollution control measures may be required by the Minister.

5. All reasonable efforts shall be taken to minimize the impact of the thermal generating station on the environment. Such efforts include minimizing the area disturbed by the thermal generating station, minimizing air or water pollution, finding alternative uses, acceptable to the Director, for waste or rejected materials, and considering the requirement for the eventual rehabilitation of disturbed areas when planning the development of any area on the thermal generating station property.

6. HYDRO shall provide to the Department, within a reasonable time, any information, records, reports or access to data requested or specified by the Department.

7. HYDRO shall keep all records or other documents required by this Approval at the thermal generating station location for a period of not less than three (3) years, beginning the day they were made. These records shall be made available for review by Departmental representatives when requested.

8. Should HYDRO wish to deviate in any way from the terms and conditions of this Certificate of Approval, a written request detailing the proposed deviation shall be made to the Minister. HYDRO shall comply with the most current terms and conditions until the Minister has authorized otherwise. In the case of meeting a deadline requirement, the request shall be made 60 days ahead of the applicable date as specified in this Approval or elsewhere by the Department.

Waste Management

9. All waste generated at the thermal generating station is subject to compliance with the ***Environmental Protection Act***. All non-industrial waste shall be placed in closed containers and, on at least a weekly basis, removed from the site. If required, industrial waste shall be disposed of by a licenced operator. These wastes shall be disposed of at an authorized waste disposal site with the permission of the owner/operator of the site.

10. HYDRO shall submit a Waste Management Plan for their thermal generating station operation. With the goal of minimizing adverse effects on the environment, the Waste Management Plan shall: be comprehensive, including all operations within the thermal generating station; identify the types of waste materials (i.e. boiler ash, sewage, empty chemical packaging, etc.); provide general direction in dealing with the handling, storage, transport, treatment and disposal of waste materials; and incorporate the basic waste management principles of reduce, reuse, recycle, recover and residual disposal. An outline of the Plan shall be submitted to the Director for review by ***October 2, 2006***. The outline shall include a schedule of dates for preparation and implementation for each section of the Plan. The completed Plan shall then be submitted to the Director for review by ***February 2, 2007***. Every year the Waste Management Plan shall be reviewed and revised as necessary, accounting for expanding or alteration of activities. All proposed revisions shall be submitted to the Director for review. The Department will acknowledge receipt of the Plan and/or

revisions, and shall provide any review comments within a reasonable time frame.

11. HYDRO shall ensure that all volatile chemical and solvent wastes, if they can not be reused, are placed in suitable covered containers for disposal in a manner acceptable to the Department. Disposal of liquid wastes at waste disposal sites in the province is not considered an acceptable alternative.

12. Disposal of hazardous waste in a municipal or regional waste disposal site in this Province is prohibited. Transporters of hazardous waste shall have an approval issued by the Minister. Those generating hazardous waste shall have a waste generators number issued by the Director and shall also complete the required information outlined in the Waste Manifest Form.

Noise

13. HYDRO shall submit a Noise Management Plan with the goal of minimizing noise resulting from the thermal generating station operations. The Noise Management Plan shall be comprehensive, including all sources within the thermal generating station which generate noise in the surrounding environment, and shall provide direction in dealing with the noise levels. An outline of the plan shall be submitted to the Director by ***October 2, 2006***. The complete plan then shall be submitted to the Director for review by ***February 2, 2007***. Every year the Noise Management Plan shall be reviewed and revised as necessary. All proposed revisions shall be submitted to the Director for review. The Department will acknowledge receipt of the Plan and/or revisions, and shall provide any review comments within a reasonable time frame.

Chemical Operations

14. All chemical loading and blending shall be done inside the thermal generating station, with no chemical containers being opened outside. All vessels storing volatile chemicals or solvents shall be blanketed to eliminate vapour or odour releases.

Spill Prevention and Containment

15. Areas in which chemicals are stored shall have impermeable floors and dykes or curbs and shall not have a floor drain system, nor shall it discharge to the environment. Areas inside the dykes or curbs shall have an effective secondary containment capacity of at least **110%** of the chemical storage container capacity, in the case of a single container. If there is more than one storage container, the dyked area shall be able to retain no less than **110% of the capacity of the largest container or 100 % of the capacity of the largest container plus 10% of the aggregate capacity of all additional containers, whichever is greater.**

16. All on site storage of petroleum shall comply with the ***Storage and Handling of Gasoline***

and Associated Products Regulations, 2003, or its successor. Storage tank systems shall be registered with the Government Service Centre. All aboveground storage tanks shall be clearly and visibly labelled with their GAP registration numbers.

17. Where applicable, all tanks and fuel delivery systems shall be inspected to appropriate American Petroleum Institute or Underwriters' Laboratories of Canada standards, or any other standards acceptable to this Department. The required frequency of inspections may be changed at the discretion of the Director.

18. An inventory of all petroleum and chemical storage tanks shall be submitted to the Director for review by ***August 2, 2006***. This inventory shall include a plan showing location, registration and/or approval number (where applicable), identification number, material stored, capacity, tank material, tank type, year of manufacture, date of installation, date of last inspection, failure history, maintenance history, dyke capacity and date of next planned inspection. Every two (2) years, an update of any significant changes to the inventory shall be submitted to the Director.

Contingency Plan

19. A contingency plan for the operation of HYDRO's thermal generating station shall be submitted to the Director for review by ***August 2, 2006***. The contingency plan shall clearly describe the actions to be taken in the event of a spill of a toxic or hazardous material. It shall include, as a minimum: notification and alerting procedures; duties and responsibilities of the "on-scene commander" and other involved staff; spill control and clean-up procedures; restoration of the spill site; information on disposal of contaminants; and resource inventory. Copies of the plan shall be placed in convenient areas throughout the thermal generating station so that employees can easily refer to it when needed. HYDRO shall ensure that all employees are aware of the plan and understand the procedures and the reporting protocol to be followed in the event of an emergency. An annual response exercise is recommended for response personnel. Every year, as a minimum, the plan shall be reviewed and revised as necessary. Any proposed significant revisions shall be submitted to the Director for review. Changes which are not considered significant include minor variations in equipment or personnel characteristics which do not effect implementation of the plan.

20. Every time HYDRO implements the contingency plan, information shall be recorded for future reference. This will assist in reviewing and updating the plan. The record shall consist of all incidents with environmental implications, and include such details as: date; time of day; type of incident (i.e. liquid spill, gas leak, granular chemical spill, equipment malfunction, etc.); actions taken; problems encountered; and other relevant information that would aid in later review of the plan performance. A summary of all incident reports shall be submitted as per the ***Reporting*** section.

Site Decommissioning and Restoration Plan

21. A plan to restore areas disturbed by the thermal generating station shall be submitted to the Director for review at the time that closure of the thermal generating station is determined. For guidance on the preparation of the plan, refer to Appendix B. Wherever possible, the plan shall promote progressive reclamation of disturbed areas. HYDRO shall proceed through a phased environmental site assessment process to closure.

Bunker C

22. Each delivery of Bunker C shall be analysed for the parameters listed in Table 1. Analysis shall be on a representative sample of the Bunker C received.

Table 1: Fuel Analysis Program

Parameters			Frequency
A.P.I. Gravity @ 60 °F	Density (kg/m3 @ 15 °C)	Flash Point	**every batch delivered**
Pour Point	Viscosity cSt @ 51 °C	Viscosity SFS @ 122 °F	
Sulfur % by weight	BTU's per US Gallon	Ash % by weight	
Sediment % by weight	Water % by volume	Asphaltenes % by weight	
Aluminum	Nickel	Silicon	
Sodium	Vanadium		

23. HYDRO shall maintain, and submit to the Director as per the ***Reporting*** section, a record of all Bunker C received. The record shall include:
   - name of the supplier;
   - date and volume of Bunker C unloaded;
   - the certificate of analysis for each batch of Bunker C delivery received; and
   - the name of the laboratory where the analysis was performed.

24. HYDRO is permitted to accept and burn alternative fuel only with the written approval of the Department.

Used Oil

25. Used oil shall be retained in an approved tank or closed container, and disposed of by a company licenced for handling and disposal of used oil products.

26. An SOP for the handling and storage of used oil shall be submitted to the Director by ***August 2, 2006***. The SOP shall, as a minimum, detail procedures for the following:
   - storage and handling of used oil generated on-site; and
   - recording of volumes of used oil generated from each source.

Waste Water Flows and Treatment

27. The thermal generating station's once-through cooling water shall be obtained from Indian Pond, and shall be discharged directly to Conception Bay.

28. The thermal generating station's south-east floor drains shall be routed through an oil/water separator and then to Indian Pond through the storm water collection system;

29. The thermal generating station's south-west floor drains shall be routed through a grease trap and an oil/water separator and then to the cooling water discharge piping associated with Units # 1 & 2;

30. The thermal generating station's north-east and north-west floor drains shall be routed through a grease trap and an oil/water separator and then to a 900 m^3 equalization basin (continuous basin).

31. All oil/water separators shall be checked routinely to ensure they are working properly. A log of these checks shall be maintained.

32. Waste water streams resulting from daily operations, including raw water clarification, filter backwashes, boiler blowdown and other similar activities shall be directed to the continuous basin. Any flow or drainage from the continuous basin shall be discharged to Indian Pond.

33. Demineralizer regeneration waste water flows may be directed to the seal pit associated with Units # 1 & 2, during such times that at least one cooling water pump is active.

34. Waste water streams resulting from periodic events where water is used to clean boiler fireside equipment, including air preheater wash flows, fireside boiler wash flows and boiler acid wash flows, shall be directed to a 900 m^3 equalization basin (periodic basin). Any flow or drainage from the periodic basin shall be directed to the waste water treatment plant.

35. Any flow or drainage from the waste water treatment plant shall be discharged to the cooling water intakes for Units # 1 & 2.

36. Effluent from the dewatering of filter cake shall be re-cycled through the waste water treatment plant.

37. All solid waste generated from the waste water treatment plant operations shall be directed to the hazardous waste landfill.

Effluent Monitoring and Discharge

38. HYDRO shall perform an Effluent Monitoring Program as per Table 2.

Table 2: Effluent Monitoring Program					
Location	**Parameters**				**Frequency**
Batch Reactor	Aluminum Vanadium	Iron pH	Magnesium TSS	Nickel TPH	grab sample prior to each batch release †
	ALT				grab sample from each batch following new addition of waste water to the periodic basin
Continuous Basin outfall	Iron TSS	Nickel TPH	Vanadium	pH	weekly grab
	ALT				monthly grab
† grab samples for all parameters shall be taken from the batch reactor at the same time					

All results from the Effluent Monitoring Program shall be submitted to the Director as per the ***Reporting*** section.

39. Refer to Table 3 for the discharge criteria.

Table 3 - Effluent Discharge Criteria†	
Parameter	**Allowable Limits ***
Iron	10
Nickel	0.5
Vanadium	0.5
pH	5.5 - 9.0 pH units
TSS	30
TPH	15
† over background for metals and suspended solids * units are in mg/L unless otherwise indicated	

40. If effluent is determined to be acutely lethal for three consecutive ALTs, HYDRO shall implement a toxicity identification evaluation (TIE) to identify the toxin, and from this develop measures to prevent or reduce the toxin. The report, written as a result of these identification activities, shall be submitted to the Director for review, ***within 60 days*** of the third consecutive failed acutely lethal test result. After review of the report, the Director may

place additional requirements upon the proponent for treatment of effluent prior to discharge.

Water Chemistry Analysis

41. HYDRO shall perform a Water Chemistry Analysis Program every three (3) months, starting ***June, 2006***, as per Table 4.

Table 4 - Water Chemistry Analysis Program					
Location	**Parameters**				
1. Cooling water intake at Indian Pond (grab sample)	**General Parameters** - must include the following:				
	pH	TSS			
2. Cooling water outfall stream, prior to release into Conception Bay (grab sample) 3. Continuous Basin outfall stream, prior to release into Indian Pond (grab sample)	**Metals Scan** - must include the following:				
	aluminum antimony arsenic barium beryllium bismuth	boron cadmium chromium cobalt copper	iron lead manganese molybdenum mercury	nickel selenium silver strontium thallium	tin titanium uranium vanadium zinc

All results shall be submitted to the Director as per the ***Reporting*** section. The Water Chemistry Analysis Program may be discontinued after two (2) years of quarterly analysis are submitted to the Department, and the results are satisfactory.

Environmental Effects Monitoring

42. HYDRO shall conduct an Environmental Effects Monitoring study to monitor the impacts of the discharge of the cooling water, the continuous basin's water and the waste water treatment plant's treated water on Conception Bay. An outline of the study shall be submitted to the Director for review and approval by ***June 31, 2008.*** The results of the completed study shall be submitted to the Director for review by ***June 31, 2009***.

Hazardous Waste Landfill Operations

43. The hazardous waste landfill shall be operated in the manner described in the ***Landfill Operations Manual***. Any proposed revisions to the ***Landfill Operations Manual*** shall be submitted to the Director for review and approval prior to such revisions being made.

44. Only waste identified in Section 5.1 (Waste Characterization) of the ***Landfill Operations Manual*** shall be placed in the hazardous waste landfill. These include:

- bottom and fly ash;
- periodic basin sludge;
- continuous basin sludge;
- waste water treatment plant filtercake;
- raw-water treatment ion exchange resins; and
- clean-up from chemical spills.

In addition, Bunker C ash from institutions, such as hospitals, may be disposed of in space efficient containers in the hazardous waste landfill. HYDRO shall notify the Department prior to deposition of ash from sources other than from the thermal generating station.

45. Liquid waste shall not be disposed of in the landfill.

46. The Department reserves the right to require some form of pretreatment of waste before placement in the site.

47. HYDRO shall periodically review opportunities for reuse and/or recycling of the waste types disposed of in the site.

48. HYDRO shall maintain a landfill security fence with a sign affixed to the fence identifying the site as a hazardous waste containment system. This sign shall identify the owner of the landfill and a contact phone number. The sign and its placement shall be acceptable to the Department.

49. No activities shall occur within the fenced area of the landfill, except for the deposition of waste; extraction of leachate; or other maintenance requirements of the landfill cap or the landfill.

50. An annual inspection program shall be performed as per the ***Landfill Operations Manual***.

51. Leachate accumulated in each of the hazardous waste landfill collection systems, including the leachate holding pond, shall be removed as required so that leachate does not overflow the collection system.

52. Any flow or drainage from the leachate holding pond shall be directed to the periodic basin. Leachate shall not be discharged directly to the environment without prior authorization by the Department.

Hazardous Waste Landfill Monitoring

53. HYDRO shall perform an Environmental Monitoring Program as per section 7.12 (Environmental Monitoring) of the ***Landfill Operations Manual***. This shall include monitoring of:
    - groundwater quality and levels;
    - surface water quality;

- leachate leakage;
- liner integrity; and
- physical movement of the landfill.

54. HYDRO shall perform a Groundwater Monitoring Program as per Table 5. This monitoring program shall be performed throughout the operational life of the landfill, and during the 25 years following closure.

Table 5: Groundwater Monitoring Program

Location	Parameters				Frequency
Monitoring Wells: BH-1 BH-2 BH-3 BH-4 BH-5 BH-6 BH-7	Aluminum Vanadium	Iron	Magnesium	Nickel	**every four months**
Monitoring Wells: BH-1 BH-2 BH-3 BH-4 BH-5 BH-6 BH-7	Antimony Bismuth Chromium Mercury Selenium PCB's pH	Arsenic Cadmium Copper Molybdenum Silver VOC's	Barium Calcium Lead Phosphorus Sodium TSS	Beryllium Cobalt Manganese Potassium Zinc TDS	**annual**

55. HYDRO shall perform a Surface Water Monitoring Program as per Table 6. This monitoring program shall be performed throughout the operational life of the landfill, and during the 25 years following closure.

Table 6: Surface Water Monitoring Program

Location	Parameters			Frequency
3 locations from the upstream drainage ditch (i.e background) 3 locations from the downstream drainage ditch	Cadmium Lead Vanadium TSS	Chromium (total) Mercury pH VOCs	Iron Nickel TDS	**monthly (provided water is flowing in the ditches during the month)**

56. The total monthly flow:

- from the primary and secondary leachate collection systems;
- from the leachate holding pond to the periodic basin; and
- through the primary cell and holding pond leak detection manholes;

shall be accurately measured and recorded. This record and all results from the Groundwater and Surface Water Monitoring Programs shall be submitted to the Director as per the ***Reporting*** section.

57. HYDRO shall submit an annual Landfill Operating Report to the Director by ***February 28*** of the subsequent year. This report shall include:

- results of the Environmental Monitoring Program; and
- summaries of all materials placed in the landfill site including: waste characterization reports, volumes of waste deposited in the landfill, source(s) of the waste, identification of contaminants of concern, and copies of the hazardous waste manifest forms.

Ambient Air

58. HYDRO shall operate an ambient air monitoring program as per the conditions in this Approval and its amendments. Approval shall be obtained from the Director prior to purchase or installation of any monitoring equipment.

59. Locations and parameters to be monitored are outlined in Table 7.

Table 7 - Ambient Air Monitoring Program	
Site	**Parameter**
Butter Pot	$PM_{2.5}$, SO_2, NO_x, NO_2
Green Acres	TSP, $PM_{2.5}$, SO_2, NO_x, NO_2, Nickel*, Vanadium*
Indian Pond	TSP, $PM_{2.5}$, SO_2, NO_x, NO_2
Lawrence Pond	TSP, $PM_{2.5}$, SO_2, NO_x, NO_2
Lower Indian Pond Drive	TSP, $PM_{2.5}$, SO_2, NO_x, NO_2, Nickel*, Vanadium*
Main Gate	TSP, $PM_{2.5}$, Nickel*, Vanadium*
* Nickel and Vanadium analyses shall be performed on all TSP samples for these sites	

60. Ambient air monitoring shall be done in accordance with the ***Ambient Air Monitoring Policy Directive (PPD 98-01)***, its successors, or alternate methods approved by the Director.

61. Frequency of sampling of TSP shall coincide with the National Air Pollution Survey (NAPS) schedule. Sampling of all other parameters shall be continuous. All results from the Ambient Air Monitoring Program shall be submitted to the Director as per the ***Reporting*** section.

62. TSP shall be determined by the United States EPA Test Method: "Reference Method for the Determination of Suspended Particulate Matter in the Atmosphere (High Volume Method)" Section 2.2, 1983, and by a method indicated in United States EPA 40 CFR 50, Appendix J, "Reference Method for the Determination of Particulate Matter as PM_{10} in the Atmosphere (High Volume PM_{10} Sampler Method)," or alternate method approved by the Director.

63. SO_2 shall be determined by the United States EPA Test Method: "Reference Method for the Determination of Sulfur Dioxide in the Atmosphere (Fluorescence)" Section 2.9, 1982, or alternate method approved by the Director.

64. NOx (as NO_2) shall be determined by the United States EPA Test Method: "Reference Method for the Determination of Nitrogen Dioxide in the Atmosphere (Chemiluminescence)" Section 2.3, February 2002, or alternate method approved by the Director.

65. Automated $PM_{2.5}$ monitors shall determine $PM_{2.5}$ by a method indicated in United States EPA 40 CFR 50, Appendix L, "Reference Method for the Determination of Fine Particulate Matter as $PM_{2.5}$ in the Atmosphere," or alternate method approved by the Director. Installation and operation of these monitors shall comply with United States EPA Quality Assurance Guidance Document 2.12 "Monitoring $PM_{2.5}$ in Ambient Air Using Designated Reference or Class 1 Equivalent Methods." Automated monitors for $PM_{2.5}$ and PM_{10} shall be approved as United States EPA designated equivalent methods for PM_{10} in ambient air, and must be acceptable to the Director.

66. HYDRO shall operate and maintain a meteorological station at Green Acres site in accordance with the guidelines specified in the United States EPA document "Meteorological Monitoring Guidance for Regulatory Modeling Applications," EPA-454/R-99-005, February 2000, or its successors. Parameters to be measured and recorded shall include: wind speed, wind direction, ambient air temperature, dew point, solar radiation, barometric pressure, cloud height and precipitation. All results from this station shall be submitted in an acceptable digital format annually or as otherwise specified by the Department, as per the ***Reporting*** section.

67. The data loggers for SO_2, NOx and $PM_{2.5}$ shall be Campbell Scientific array-based data loggers, or alternates approved by the Director, with battery backup of data. The Green Acres data logger shall have enough differential input channels to allow input of meteorological station data. All dataloggers shall be remotely programmable and compatible with current Departmental standards for access to data for monthly Quality Assurance, and for scheduled access for data download.

68. All analysers shall be operated and maintained in accordance with United States EPA "List of Designated Reference and Equivalent Methods" issued October 9, 2003, or its successors.

Continuous Opacity Monitoring System

69. Opacity of emissions from each boiler shall be continuously measured and recorded using a Continuous Opacity Monitoring System (COMS) that meets all the requirements of *Performance Specification 1 (PS-1) - Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources,* of the United States *Code of Federal Regulations - 40 CFR Part 60, Appendix B.* Minimum QA/QC requirements are specified to assess the quality of COMS performance. Daily zero and span checks, quarterly performance audits, and annual zero alignment checks are required to assure the proper functioning of the COMS and the accuracy of the COMS data. These shall be recorded in a written log and a copy made available on request.

70. The United States EPA Federal Register *Test Method 203 - Determination of the Opacity of Emissions from Stationary Sources by Continuous Opacity Monitoring Systems* shall be used to determine compliance with the ***Air Pollution Control Regulations, 2004***, or its successor.

71. Monthly opacity data reports, in digital format, shall be submitted in the form of six minute arithmetic averages of instantaneous readings, as per the ***Reporting*** section. Each six minute average data point shall be identified by date, time and average percent opacity.

Continuous Emissions Monitoring System

72. By ***August 2, 2006***, HYDRO shall submit to the Director a plan for the automated CEMS to meet the requirements of Environment Canada's 1993 Report *Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation (EPS 1/PG/7)*, or its successor. The plan shall identify the proposed actions to be taken by HYDRO and shall include the time-lines for completion. Upon review of the plan and in consultation with HYDRO, the Director will establish a reasonable deadline for completion of activities necessary for the CEMS to meet the requirements of *EPS 1/PG/7*, or its successor. Notwithstanding this, application of specific requirements of *EPS 1/PG/7* to the CEMS may be modified subject to approval by the Director.

73. Monthly CEM data reports containing one-hour arithmetic averages of emission rates of SO_2, NO_X, NO_2, CO_2, CO and O_2 (all expressed in ppmv) shall be submitted in digital format, as per the ***Reporting*** section.

Administrative Boundary

74. Under this approval the Administrative Boundary shall be established as the land boundary of the thermal generating station property, as indicated on the land boundary map forwarded to the Department on ***December 7, 2005***.

Stack Emissions Testing and Dispersion Modelling

75. Stack emissions testing shall be done in accordance with the ***Source Emission Testing Guidance Document (GD-PPD-016)***. Dispersion Modeling shall be done in accordance with the ***Plume Dispersion Modeling Guidance Document (GD-PPD-019)***. Determination of frequency of stack emissions testing and dispersion modeling shall be done in accordance with the ***Compliance Determination Guidance Document (GD-PPD-009.02)***.

76. HYDRO shall be required to complete stack emissions testing once every four years if it has been shown, via a registered dispersion model, that the thermal generating station is in compliance with this Approval. If it has been shown, via a registered dispersion model, that the thermal generating station is not in compliance with section 3(2) and Schedule A of the ***Air Pollution Control Regulations, 2004***, then the thermal generating station shall complete stack emissions testing every two years. Plume dispersion modeling results shall be submitted to the Department within ***120 days*** of completion of the stack emissions testing.

Annual Air Emissions Reporting

77. HYDRO shall submit an annual Air Emission Report to the Director by ***February 28*** of the subsequent year. This report shall include:

- total fuel consumption;
- the weighted average sulphur content of the fuel;
- the fuel specific gravity;
- the estimated, or, if available, the monitored annual emissions of the following flue gas constituents: SO_2, NO_X, CO_2, CO and particulate; and
- the actual calculations including factors, formulae and/or assumptions used.

Analysis and QA/QC

78. Unless otherwise stated herein, all solids and liquids analysis performed pursuant to this Approval shall be done by either a contracted commercial laboratory or an in-house laboratory. Contracted commercial laboratories shall have a recognized form of accreditation. In-house laboratories have the option of either obtaining accreditation or submitting to an annual inspection by a representative of the Department, for which HYDRO shall be billed for each laboratory inspection in accordance with Schedule 1 of the ***Accredited and Certified Laboratory Policy (GD: PP2001-01)***. Recommendations of the Director stemming from the annual inspections shall be addressed within 6 months, otherwise further analytical results shall not be accepted by the Director.

79. If HYDRO wish to perform in-house laboratory testing and submit to an annual inspection by the Department then a recognized form of proficiency testing recognition shall be obtained for compliance parameters for which this recognition exists. The compliance

parameters are listed in the ***Effluent and Monitoring*** section. If using a commercial laboratory, HYDRO shall contact that commercial laboratory to determine and to implement the sampling and transportation QA/QC requirements for those activities.

80. The exact location of each sampling point shall remain consistent over the life of the monitoring programs, unless otherwise approved by the Director.

81. HYDRO shall bear all expenses incurred in carrying out the environmental monitoring and analysis required under the conditions of this Approval.

Monitoring Alteration

82. The Director has the authority to alter monitoring programs or require additional testing at any time when:

- pollutants might be released to the surrounding environment without being detected;
- an adverse environmental effect may occur; or
- it is no longer necessary to maintain the current frequency of sampling and/or the monitoring of parameters at a particular sampling station.

83. HYDRO may, at any time, request that monitoring program or requirements of this Approval be altered by:

- requesting the change in writing to the Director; and;
- providing sufficient justification, as determined by the Director.

The requirements of this Approval shall remain in effect until altered, in writing, by the Director.

Reporting

84. Monthly reports containing the environmental compliance monitoring and sampling information required in this Approval, as summarized in Table 8, shall be received by the Director, in hardcopy and digital formats (e-mail, diskette or CD), within 30 calendar days of the reporting month. A hardcopy of all related laboratory reports shall be submitted to the Director with the monthly report. The digital copy, if e-mailed, shall be sent to the following address: <<statenv@gov.nl.ca>>

Table 8 - Monthly Reporting Requirements	
Section	**Condition(s)**
Bunker C	22
Effluent Monitoring and Discharge	38
Water Chemistry Analysis *	41
Hazardous Waste Landfill Monitoring	54, 55
Ambient Air	59, 66
Continuous Opacity Monitoring System	71
Continuous Emissions Monitoring System	73
* to be included for the following reporting months; January, April, July and October	

85. All incidents of:

- *Contingency Plan* implementation; or
- non-conformance of any condition within this approval; or
- spillage or leakage of a regulated substance; or
- whenever discharge criteria is, or is suspected to be, exceeded; or
- verbal/written complaints of an environmental nature from the public received by HYDRO related to the thermal generating station, whether or not they are received anonymously;

shall be immediately reported, within one working day, to a person, message manager or facsimile machine as follows:

- contact this Department (St. John's office) by phoning (709) 729-2556, or faxing (709) 729-6969.

A written report including a detailed description of the incident, summary of contributing factors, and an action plan to prevent future incidents of a similar nature, shall be submitted to the Director. The action plan shall include a description of actions already taken and future actions to be implemented, and shall be submitted within two weeks from the date of the initial incident. The address for written report submission is:

Director, Pollution Prevention Division
Department of Environment and Conservation
P.O. Box 8700
St, John's, NL
A1B 4J6
Telephone: (709) 729-2556
Facsimile: (709) 729-6969

86. Any spillage or leakage of gasoline or associated product shall be reported immediately through the Canadian Coast Guard at 1-(709)-772-2083.

Liaison Committee

87. The Department recognizes the benefits, and at times the necessity, of accurate, unbiased communication between the public and industrial operations which have an impact on the properties and residents in the area. Regular meetings of the Liaison Committee, comprised of representatives of HYDRO, the Department and independent members of the general population of Holyrood and Conception Bay South, shall be maintained so as to provide a clear conduit of communication between concerned citizens and HYDRO.

Expiration

88. This Certificate of Approval expires ***February 2, 2011.***

89. Should HYDRO wish to continue to operate the thermal generating station beyond this expiry date, a written request shall be submitted, by ***August 2, 2010***, to the Director for the renewal of this Approval.

APPENDIX B

Industrial Site Decommissioning and Restoration Plan Guidelines

As part of the Department of Environment and Conservation's ongoing commitment to minimize the residual impact of industrial activities on the environment of the province, the Department requires that HYDRO develop a decommissioning and restoration plan for the thermal generating station at Holyrood and its associated property. The guidelines listed below are intended to provide some general guidance as to the expectations of the Department with regard to the development of a decommissioning and restoration plan, and to identify areas that are of particular concern or interest. The points presented are for consideration, and are open to interpretation and discussion.

Decommissioning and restoration plans are intended to present the scope of activities that a company shall undertake at the time of final closure and/or decommissioning of the industrial properties. Where it is useful and practical to do so the company is encouraged to begin undertaking some of the activities outlined in the plan prior to final closure and decommissioning. The objectives of the restoration work to be undertaken can be summarized as follows:

- to ensure that abandoned industrial facilities do not endanger public health or safety;
- to prevent progressive degradation and to enhance the natural recovery of areas affected by industrial activities;
- to ensure that industrial facilities and associated wastes are abandoned in a manner that will minimize the requirement for long term maintenance and monitoring;
- to mitigate, and if possible prevent, the continued loadings of contaminants and wastes to the environment. The primary objective shall be to prevent the release of contaminants into the environment. Where prevention is not practical due to technical or economic limitations then activities intended to mitigate the consequence of such a release of contaminants shall become the objective of restoration work;
- to return affected areas to a state compatible with the original undisturbed condition, giving due consideration to practical factors including economics, aesthetics, future productivity and future use; and
- to plan new facilities so as to facilitate eventual rehabilitation.

The decommissioning and restoration plan should:

- identify areas of known historical or current contamination;
- identify past or existing operational procedures and waste management practices that have, or may have, resulted in site contamination;
- highlight the issues or components to be addressed;
- identify operational procedures and waste management practices that can prevent or reduce site contamination;
- consider future land use, regulatory concerns and public concerns;
- enable estimation of the resources and time frame required to decommission the facility and restore the site to a condition acceptable to the Department;
- enable financial planning to ensure the necessary funds for decommissioning and restoration are set aside during the operational life of the facility, and;
- include arrangements for appropriate project management to ensure successful completion of the decommissioning and restoration program.

cc: Mr. Kevin Power, P.Eng. - Head
Environmental Protection Section
Environment Canada
6 Bruce Street
Donovans Industrial Park
Mount Pearl, NL
A1N 4T3

Mr. Kevin King - Regional Manager
Government Service Centre (GSC)
5 Mews Place
P. 0. Box 8700
St. John's, NL
AlB 4J6

Mr. Terry French, MHA
5th Floor - East Block
Government Members Office
Confederation Building
St. John's, NL

Mr. Scott Devereaux - Chief Administrative Officer / Town Clerk
Town of Holyrood
P.O. Box 100
Holyrood, NL

Ms. Gail Pomroy - Acting Town Clerk
Town of Conception Bay South
P.O. Box 280
Conception Bay South, NL
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Tab 4

NEWFOUNDLAND AND LABRADOR HYDRO

STATIONARY BATTERY REPLACEMENT PROGRAM

NEWFOUNDLAND AND LABRADOR HYDRO

JUNE 20, 2007

Table of Contents

INTRODUCTION

This report summarizes Newfoundland and Labrador Hydro's (Hydro's) Stationary Battery Replacement Program. This is an ongoing program to replace stationary battery systems, which are used by equipment located in generating and terminal stations as well as telecommunications microwave sites.

This report includes background information relating to the Stationary Battery Replacement Program and provides discussions of Hydro's operating experience in this area. A schedule of the equipment being replaced under the program is also presented.

BACKGROUND

Stationary batteries are used to provide power to telecommunications, protection and control, and switching equipment. They are used so that the equipment can still be operated during a power outage. The stationary battery provides storage of electricity, so that even if AC power is lost for a period of time, equipment will continue to function and Hydro can still operate the station, 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. Each cell has rectangular plates of lead-calcium 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 20 years. If an individual cell fails, the battery continues to operate, although at diminished capacity. There are disadvantages as well for instance, flooded cell batteries can emit small amounts of hydrogen gas during charging, so battery room ventilation is required. Regular maintenance is required to ensure the battery electrolyte does not deplete during operation, and failure of a jar can cause 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 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, reducing the chance of spill and eliminating off-gassing of hydrogen. Unfortunately, once in operation they soon demonstrated several significant disadvantages. In practice, VRLA batteries have frequently demonstrated less than 10 years of service life. They can experience a condition known as “thermal runaway” and have been known to heat up and explode. 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 when required to operate. For these reasons, many users are moving back to flooded-cell batteries.

Figure 2. VRLA battery (Hind's Lake)

There are also two applications for batteries – telecommunications and station service. The voltage of telecommunications batteries is usually 48V DC. These batteries are typically rated at higher capacity 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, but are normally replaced at the same time as flooded cell batteries.

COST-BENEFIT ANALYSIS – FLOODED VS. VRLA BATTERIES

A brief cost-benefit analysis demonstrates that flooded cell batteries are the most cost-effective option. Details of the analysis are shown in Appendix B.

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;
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. As shown in Appendix B, the flooded cell batteries are the preferred option with a net benefit of almost $19000 per battery. In some instances, VRLA batteries are still required when space or ventilation considerations preclude the use of flooded cell.

PROJECT SCOPE

The batteries being replaced under this program for 2008 are both VRLA and flooded cell, and are shown in Table 1.

Location	**Type**	**Voltage**	**Install Date**
Buchans	VRLA	48V	1999
Stony Brook	VRLA	48V	1999
Western Avalon	VRLA	48V	1999
Paradise River	Flooded	48V	1988
Springdale	Flooded	125V	1988
Doyles	VRLA	125V	1999
English Harbour W.	VRLA	125V	1998

Table 1. Battery replacements

The chargers being replaced are shown in Table 2.

Location	**Install date**
Stephenville	1974
Oxen Pond	1984
Paradise River	1988

Table 2. Charger replacements

The batteries and chargers being replaced under this program for the years 2008 – 2012 inclusive are shown in Appendix A – Battery Replacement Five-Year Schedule. This plan is subject to modification if conditions warrant the early replacement of a system, or if a system is showing lower than expected deterioration.

OPERATING EXPERIENCE

Batteries are typically inspected annually and tested as required. More frequent monitoring and testing may be performed if deterioration is noticed.

Flooded cell batteries experience an average life of 18-20 years; VRLA batteries, 7-10 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 recommends replacement of a battery at the earliest possible opportunity if the capacity has fallen to 80% of its rated capacity.

Based on age alone, the batteries being replaced are nearing the end of their useful lives. Capacity testing of some of the batteries demonstrates the need for timely replacement. The Buchans and Stony Brook batteries were both tested in August 2004 and passed at 84% and 94% of rated capacity respectively. The Western Avalon battery bank was tested in February 2005 and passed at 89% of rated capacity. These tests were conducted at 50% of the expected life of the batteries, and show significant deterioration already underway. Capacity tests are not available for the remaining batteries.

Conductance testing, which reflects the internal capacity of the battery to conduct electricity, can be used to extrapolate the battery's capacity, based on information supplied by the manufacturer. Conductance testing of the Paradise River battery performed in March 2007 shows that the battery capacity is well below 80% capacity.

CONCLUSION

Hydro's Battery Replacement Program ensures that batteries are replaced in a timely fashion. Batteries are a required part 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.

APPENDIX A - BATTERY REPLACEMENT FIVE- YEAR SCHEDULE

2008

Battery Replacements

Location	Type	Voltage	Install Date	Manufacturer
Buchans (BUC)	VRLA	48V	1999	Yuasa
Stony Brook (STB)	VRLA	48V	1999	Yuasa
Western Avalon (WAV)	VRLA	48V	1999	Yuasa
Paradise River (PRV)	Flooded	48V	1988	C&D
Doyles (DLS)	VRLA	125V	1999	C&D
English Harbour West (EHW)	VRLA	125V	1997	MTI Networks

Charger Replacements

Location	Battery Voltage	Capacity	Install Date	Manufacturer
Paradise River (PRV)	48V	50A	1988	Staticon
Oxen Pond (OPD)	125V	30A	1984	Staticon
Stephenville (SVL GT CHG 1)	125V	81A	1974	Powertronic

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	1990	C&D
Long Harbour (LHR)	Flooded	125V	1991	Exide C

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 Can Power Systems
Holyrood TS (HRD)	125V	30A	1985	Saft Nife
Hardwoods (HWD GT CHG 1)	125V	150A	1977	Cigentic

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

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

None Scheduled

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

APPENDIX B - FLOODED VS. VRLA COST-BENEFIT ANALYSIS DETAILS

Battery Replacement

Alternative Comparison

Cumulative Net Present Value

To The Year

2027

Alternatives	Cumulative Net Present Value (CPW)	CPW Difference between Alternative and the Least Cost Alternative
Flooded Cell Battery	48,400	0
VRLA Battery	67,299	18,899

Tab 5

WOOD POLE LINE MANAGEMENT PROGRAM
PROGRESS REPORT

2006 INSPECTION PROGRAM

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

MAY 1, 2007

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1 BACKGROUND

Hydro maintains approximately 2400 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, with the maximum age being 41 years. Almost two-thirds of transmission pole plant assets fall into two age categories; approximately 34% are at or over 30 years, and another 31% are 20 to 30 years old. The remaining asset age is less than 20 years old.

Historically, 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. It is well known in the industry that poles become susceptible to fungi and/or insect attack as the preservative levels deplete.

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 what was 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 program as a pilot study in 2003. It was recommended, that the program continue as a long-term asset management and life extension program. The program was presented to the Board of Commissioners of Public Utilities in October 2004 as part of Hydro's ongoing capital program 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 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 found that the project was justified and prudent and approved the expenditures as submitted in the 2005 Capital Budget. (Ref; Board Order P.U. 53(2004).

As part of its 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 THE PROGRAM

The Wood Pole Line Management (WPLM) program is a condition-based program, which uses the basic Reliability Centered Maintenance principles and strategies. Under the program, line inspection data in each year is analyzed by and appropriate recommendations 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 pole before the integrity of the structures is jeopardized. If the deterioration of the structure is not detected early enough then the reliability of the structure will affect the reliability off the line and the system as a whole. It may also create safety issues and hazards for the Hydro personnel and for the general public.

3 UPDATE OF 2006 WORK

The first objective of the 2006 program was to inspect, test and treat at least 3100 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. The following table summarizes the inspection accomplishments for 2006.

Regions	Line Name	Year In Service	Voltage Level	Target Number of Poles Inspected	Actual Poles Inspected	%	Inspection rate (poles per week)
Eastern	TL 212	1966	230kV	110	267	243%	
	TL 218	1983	230kV	112	75	67%	
	TL 219	1990	138kV	210	74	35%	
Central	TL 210	1969	138kV	152	200	132%	
	TL 223	1966	138kV	88	86	98%	
	TL 232	1981	230kV	189	187	99%	
	TL 251	1981	69kV	145	152	105%	
	TL 252	1981	69kV	163	144	88%	
	TL 253	1982	69kV	47	0	0%	
Western	TL 250	1987	138kV	321	405	126%	
Northern	TL 226	1970	69kV	179	245	137%	
	TL 239	1982	138kV	394	405	103%	
	TL 241	1983	138kV	163	157	96%	
	TL 244	1983	138kV	69	86	125%	
Labrador	TL 240	1976	138kV	792	497	63%	
Total				3134	2980	95%	

Overall, the total number of poles inspected was within 5% of the target value. Although individual lines may display larger differences the overall total for each region was within this five percent margin. The only area which showed a large difference in the actual number of poles inspected was Labrador

The inspection program in Labrador was hampered by difficulties in acquiring lineworkers, and equipment failures. Steps are currently being undertaken to incorporate these on-going problems into the future planning. This includes targeting a lower number of poles per year and utilizing the line crews in Churchill Falls to assist in the inspection process to ensure that this region maintains the inspection schedule.

As in 2006, the data collectors were used exclusively to collect the pole information, with paper forms for emergency purposes only. This continued to be very successful. In a couple of cases, temporary unit failure created the requirement to have data collected on paper forms for a couple of days. This data was then entered into the data collector when the opportunity arose, and when it would not interfere with inspection.

Another objective was the replacement of defective components identified in 2005 inspections. Hydro crews replaced 75 poles, numerous crossarms, and many smaller components, during the year, as identified in the spring of 2006.

4 CONCLUSION

In conclusion, the major objectives for the 2006 program were achieved, with the exception of a few points detailed above. The budget estimate of $2.3M 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.

2007 Work Plans

The proposed inspection and treatment work for 2007 is shown summarized in the following table.

Regions	Line Name	Year In Service	Voltage Levels	Number of Poles to be Inspected	Remarks
Eastern	TL 212	1966	138kV	57	
	TL 218	1983	230kV	125	
	TL 219	1990	138kV	200	
Central	TL 232	1981	230kV	189	
	TL 251	1981	69kV	290	
	TL 252	1981	69kV	326	
	TL 253	1982	69kV	47	
Western	TL 250	1987	138kV	321	
Northern	TL 229	1976	69kV	108	
	TL 239	1982	138kV	225	
	TL 241	1983	138kV	249	
	TL 244	1983	138kV	100	
	TL 257	1970	69kV	118	
Labrador	TL 240	1976	138kV	792	
Total				3147	

In addition to the inspections, refurbishment based on the 2006 inspection program will begin during the summer months and continue into the fall. The will include the replacement of approximately 100 poles and other components such as crossarms, crossbraces etc.

Additional work on the electronic database will continue in 2007. This includes the development of an improved method of analyzing the inspection results from the field as well as an automated process to update the records for refurbishment work that has been completed.

Attached, for additional general information is an inspection sheet for TL 250. This is presented here simply as a typical example of the type of information that is collected for each of the lines. It is provided to give an extra measure of information and understanding of the type and content of information that is being processed in this program.

Tab 6

TRANSMISSION LINE EQUIPMENT

OFF-LOADING SITES

REGISTERED PROFESSIONAL ENGINEER
D. A. RENDELL
SIGNATURE
2007-04-17
PROVINCE OF NEWFOUNDLAND

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

JUNE, 2007

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1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) is responsible for the maintenance of hundreds of kilometers of transmission lines throughout the province. There are many government approved trails along the highways that transmission crews use to access the transmission lines. Gaining access to many of these trails from the highway is often very difficult and sometimes dangerous.

Hydro is proposing to construct new earthen ramps as a means of providing improved access to transmission line trails. Completion of this project will improve the safety and efficiency of transmission crews during roadside off-loading operations. These off-loading sites will be used for both general and emergency access. As part of this project, Hydro will also enhance existing sites along several highways to an acceptable safety standard.

2 CURRENT PRACTICE

Transmission crews have struggled for many years with what can only be described as unsafe conditions when unloading off-road vehicles from trucks and trailers. Narrow shoulders and steep embankments, especially along our secondary highways, along with the ever increasing traffic volumes and speeds have made for dangerous situations. At many locations, traffic lanes have to be blocked off to unload the equipment.

The construction and upgrading of these access areas will permit the safe off-loading of equipment required for maintenance of transmission lines.

The current situation is an inefficient use of line maintenance crews' time. After off-loading their off-highway vehicles from truck or trailers, the crew must travel long distances (up to 3 kilometers) to safely and legally park their vehicles. This process is time consuming and requires additional personnel for traffic control and return transportation to the work site. In areas where access to an approved trail is not possible, crews are required to travel long distances along transmission line right-of-ways to gain access to work locations.

Appendix A provides several photographs which illustrate hazardous roadside off-loading sites.

3 PROJECT DESCRIPTION

It is estimated that there are approximately 100 roadside locations that require either construction of new earthen ramps or improvements to existing access sites. These areas are located on the Bay d'Espoir, Burin Peninsula, Buchans, Springdale, Hampton, Jackson's Arm, Howley, and Burgeo highways.

Ramp Construction
New ramps and upgrading of existing off-loading sites will consist of grubbing, excavation of unsuitable material, and supply, placement and compaction of granular and Class "A" backfill. Supply and installation of culverts, guard rails and signage will also be required based on site-specific conditions. Sketches are provided in Appendix B.

Occupation by Others
Most of the off-loading sites will be in locations not useful to the general public. In all cases, however, "no parking" signs will be erected. Any motorist who disregards the signs will be required to remove their vehicles to ensure the work of Hydro maintenance crews is not impeded.

Snow Clearing
It is not Hydro's intention to keep all of these access sites open in the winter. Snow will be cleared on an "as-needed" basis utilizing the closest available contractor.

Department of Transportation and Works
Hydro has consulted with the Provincial Department of Transportation and Works (DTW) regarding the planned construction of roadside off-loading ramps. DTW was informed that Hydro proposes to select the sites on a priority basis. Hydro considers the most critical sites to be those along the secondary roads with the narrowest shoulders and steepest embankments. DTW has informed Hydro that the construction of off-loading ramps will be permitted on a case-by-case basis.

Each local office of DTW has responsibility for secondary roads in their areas. The local DTW offices will be contacted for approval prior to commencement of the work. Each site will be mapped and items such as sight distances will be considered. Any highway classified as a "Protected Road" will require an additional permit from Government Services. Hydro will communicate with DTW before and during the work and will comply with all regulations and seek all approvals necessary.

4 JUSTIFICATION

Off-loading sites are required to provide safe working conditions for Hydro personnel, and to safeguard the public.

Safety

Workplace safety and public safety is the predominant reason for construction of the off-loading ramps. Hydro is committed to ensuring our customers, our employees, and the public are protected against the hazards of our facilities and our operations.

The current process for roadside off-loading heavy equipment constitutes a hazardous operation. This is particularly so during adverse weather conditions such as fog, snow, rain, or sleet which reduces visibility in high traffic areas. Construction of the ramps will increase the level of safety associated with this operation. The potential of vehicular incidents will be reduced, resulting in safer working conditions for our employees and less danger for the motoring public.

Efficiency

The current off-loading operation is a time intensive process. Diligent job planning and work methods often require the partial or complete closure of a highway lane. This may involve use of signage, flagpersons, or other precautionary measures depending on the site-specific conditions. The new ramps will eliminate the need for lane closures, resulting in increased functionality and improved workcrew efficiency. Eliminating the requirement for closed lanes on public roads, especially on highways, will reduce the danger created for the public.

Reliability

In addition to normal/planned operations by maintenance crews, the off-loading ramps will be used during unplanned outage situations. The installation of these sites will permit faster mobilization and shorter response time during forced outage situations, thus reducing customer outage time.

5-Year Strategy

Hydro proposes to execute the work as a multi-year project. It is planned to construct approximately 20 sites per year for the next five years. Sites will be selected on a priority basis, with the highest hazard areas addressed first. Scheduling will also be optimized so as to reduce mobilization and construction costs.

Table 1 displays the number of and location of the ramps to be constructed in the five year plan. Map locations are provided in Appendix C.

Table 1
Location of Proposed Roadside Ramp Sites

Highway	2007	2008	2009	2010	2011
Burin Peninsula		20		20	9
Bay d'Espoir					1
Buchans	8				
Springdale					1
Hampden					5
Jackson's Arm			15		
Howley					4
Burgeo	12		5		
Total Sites	**20**	**20**	**20**	**20**	**20**

<u>Future Maintenance</u>

The off-loading ramps will be constructed such that the required future maintenance will be minimal. Culverts and guard rails should last at least twenty-five years.

5 INDUSTRY STANDARD

Hydro has contacted other utilities across Canada regarding this safety issue. The utilities were asked if they encounter similar off-loading challenges, and how they have addressed such situations. A summary of responses is presented in Table 2.

Table 2 - Survey of Canadian Utilities

Utility	Comments
Nova Scotia Power	• pull-offs and ramps have been built as temporary measures • would prefer to leave in-place for future use, but not permitted
New Brunswick Power	• traffic control procedures (i.e. flag persons, traffic cones) are utilized in cases where roadside shoulders are wide enough • in other cases, equipment is unloaded at the closest available unused property culvert (staff are then required to drive the equipment up the side of the roadway to the site) • some cases involving infilling of roadside ditches (requires approvals from DOT to perform this work)
Hydro-Quebec	• similar situations in which shoulders are too narrow • solution is to prepare a pad in the adjacent land in the right-of-way • This may involve the following measures; - installation of a culvert or a small bridge - compensation to the land owner - installation of barriers
Hydro One (Ontario)	• similar types of equipment and highways/roads with varying shoulder • similar situations whereby vehicles are only partially parked outside traffic lanes • Ontario Ministry of Transportation requires the preparation of Traffic Control Plans to ensure the safety of workers
Manitoba Hydro	• not a problem in Manitoba • highways have fairly wide shoulders • lots of access roads, approaches to fields and other opportunities to exit highways • familiar with Newfoundland's road system and can appreciate the issue

A synopsis of the responses from various utilities suggests that narrow shoulders present similar problems in other jurisdictions. However, there does not appear to be a widely accepted industry standard for dealing with safe and efficient off-loading operations. Standard procedures in other provinces typically involve some combination of traffic control and construction of pads/ramps. In some cases, access to private property is required.

6 RECOMMENDATIONS

It is recommended that Hydro construct permanent off-loading ramps at appropriate roadside sites. Construction of these ramps will significantly improve workplace and public safety, as well as operational efficiencies during off-loading of heavy equipment along the provinces highways. Execution of this project demonstrates Hydro's continued commitment to employee and public safety.

Appendix A

Photos

Truck is parked on a narrow highway shoulder causing partial obstruction to traffic. Note pylons placed in the adjacent traffic lane.

This section of the highway shows a steep-sloped roadside embankment, making offloading at this location very difficult. In this case, the excavator was offloaded at a separate location and traveled to the transmission site.

Vehicles are unable to move off the paved driving surface while attempting to park on the shoulder.

Vehicle is partially parked in the traffic lane, causing a potential sight obstruction for motorists approaching a turn in the highway.

This highway location shows a very narrow shoulder (less than 0.5 m). Roadside vehicles which may be parked at this location would pose a hazard for on-coming traffic.

This offloading site at the crest of a hill shows a short site distance for on-coming traffic.

Offloading equipment is causing partial lane closure in traffic lane.

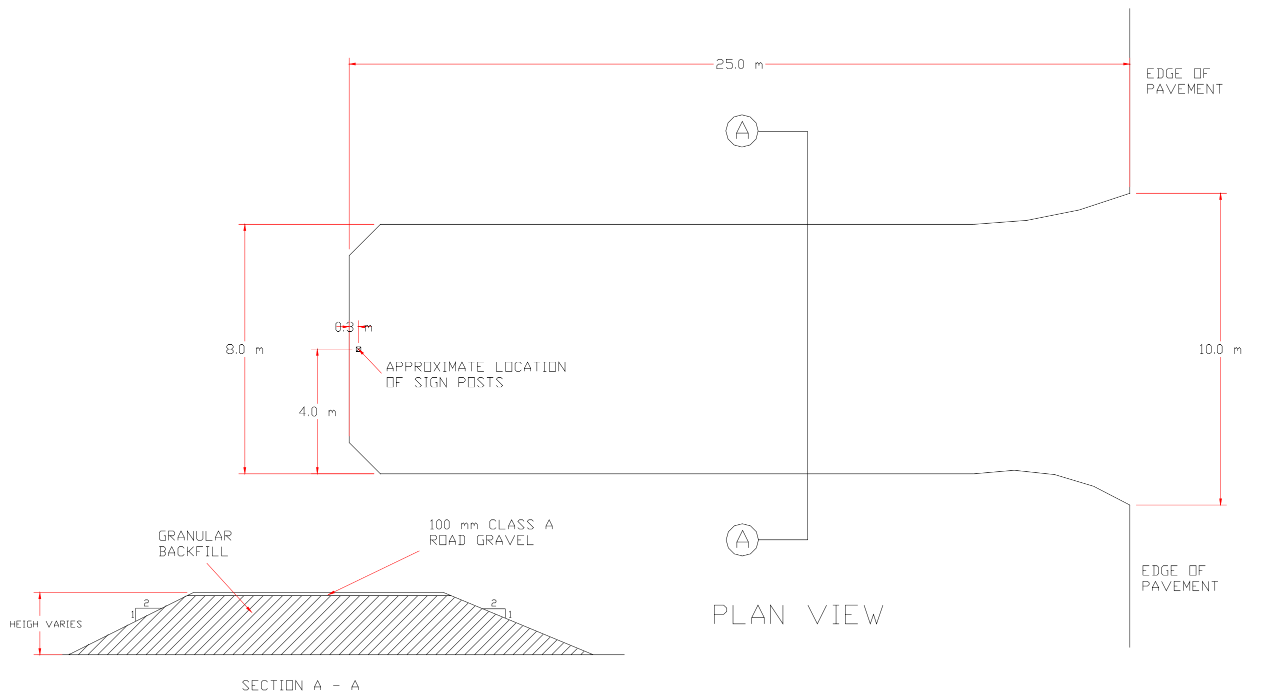
Motorists are diverted into the oncoming highway lane due to partial lane closure.

Photo shows transmission equipment being offloaded at roadside. Note pylons in traffic lane.

Transmission equipment descending a steep highway shoulder

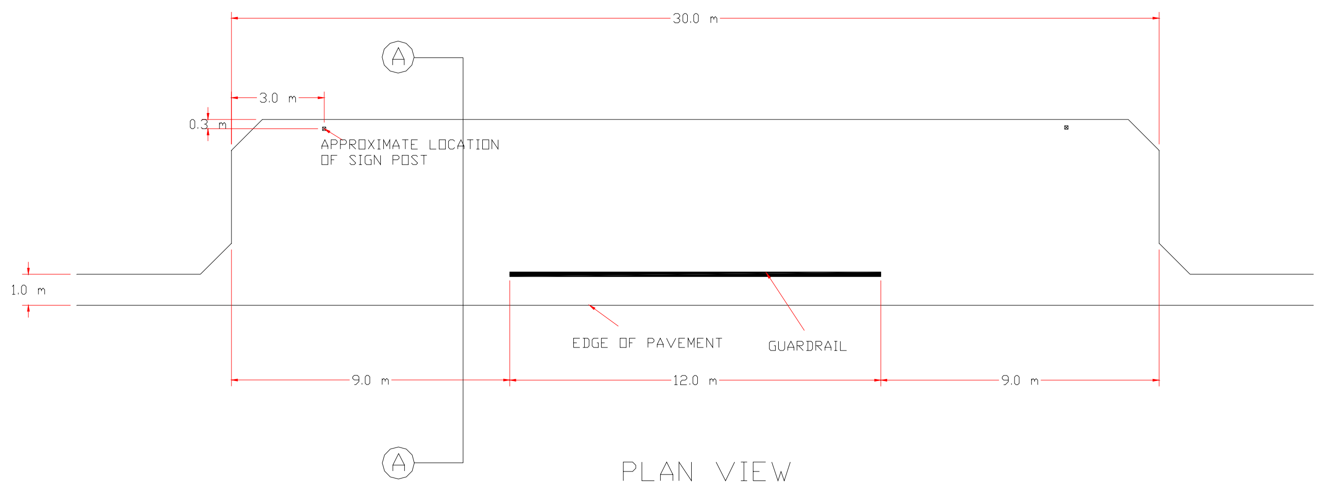
Appendix B

Sketches

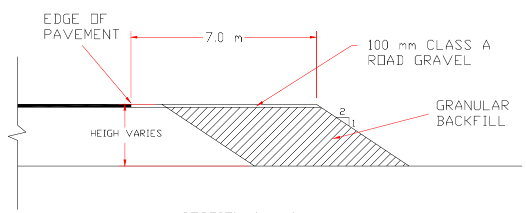


ALL DIMENSIONS ARE IN METERS

HYDRO	NEWFOUNDLAND AND LABRADOR HYDRO	
SCALE : NTS	BACK-IN RAMP	DATE : 06 04 20
DRAWN : D.R.		W.O.NO.
CHECKED		DWG.NO. SKETCH 2 — REV. 1
APPROVED		



PLAN VIEW



SECTION A - A

ALL DIMENSIONS ARE IN METERS

HYDRO

NEWFOUNDLAND AND LABRADOR HYDRO

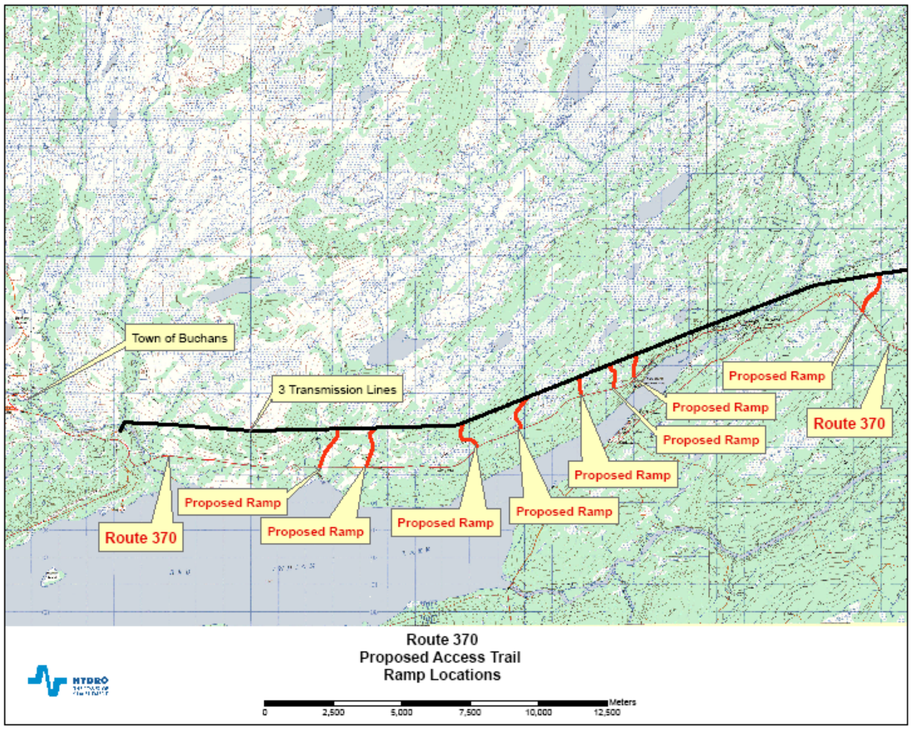
SCALE : NTS
DRAWN : D.R.
CHECKED
APPROVED

SIDE RAMP

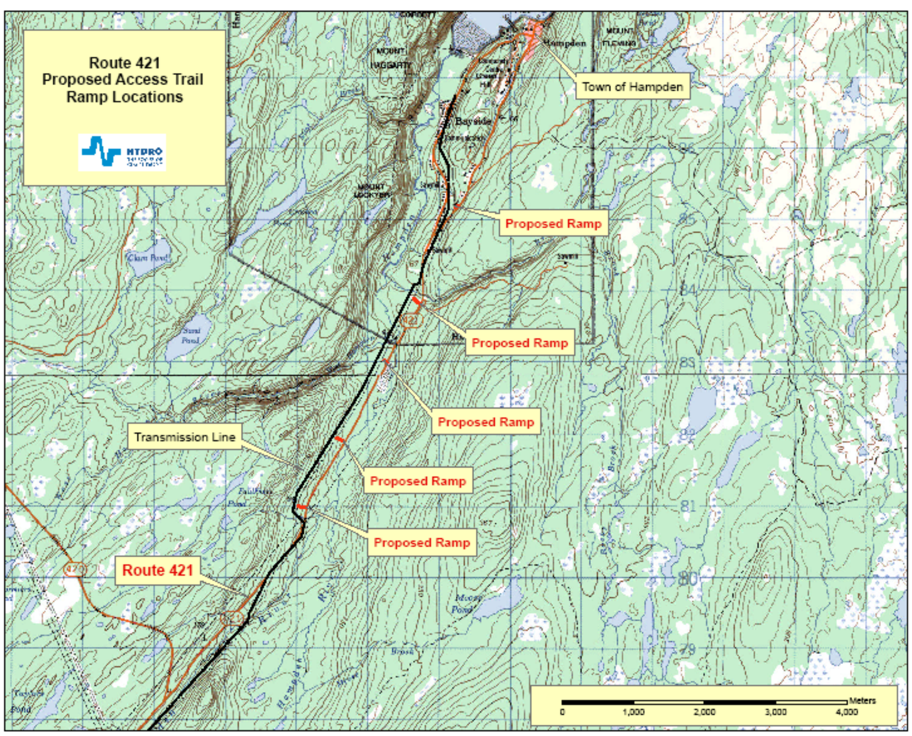
DATE : 06 04 20
W.O.NO.
DWG.NO. SKETCH 1
REV. 0

Appendix C

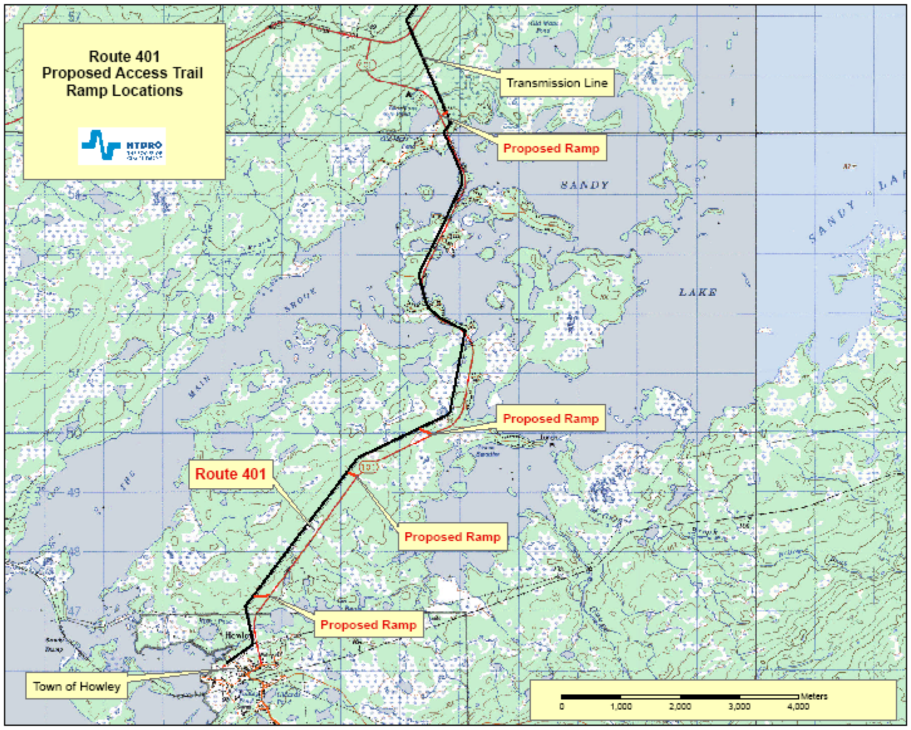
Maps



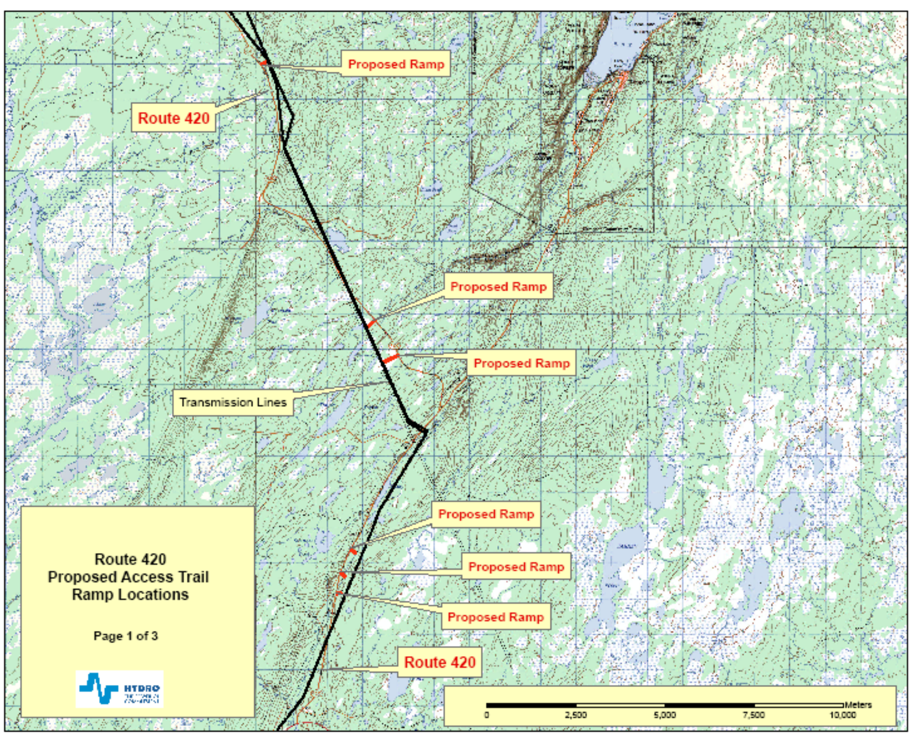
Transmission Lines TL 205, TL 232, TL 264 - along Buchans Highway



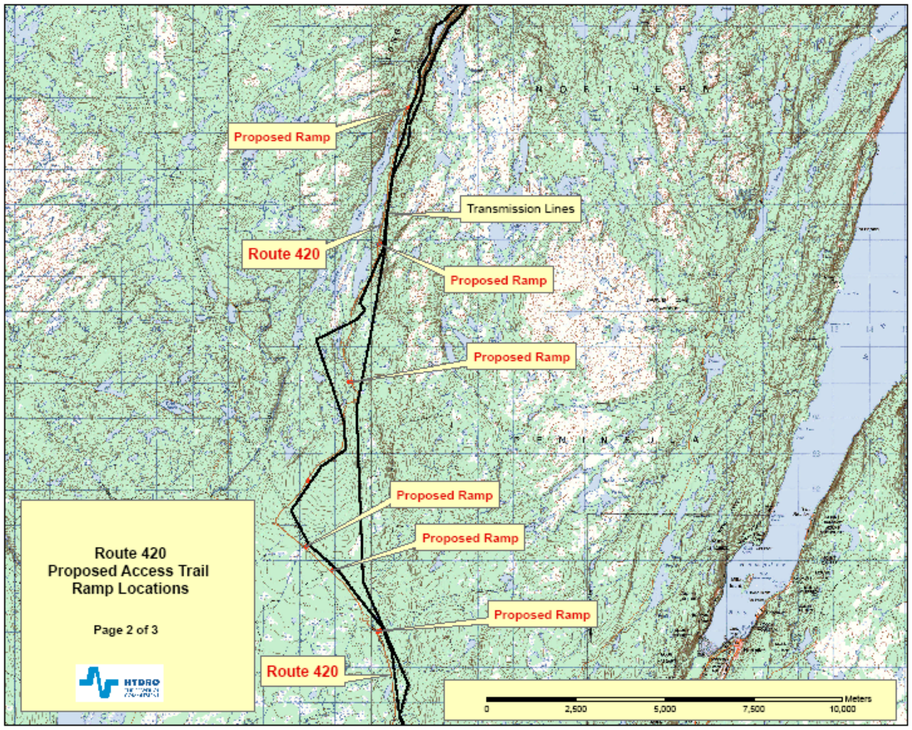
Transmission Line TL 251 - along Hampden Highway



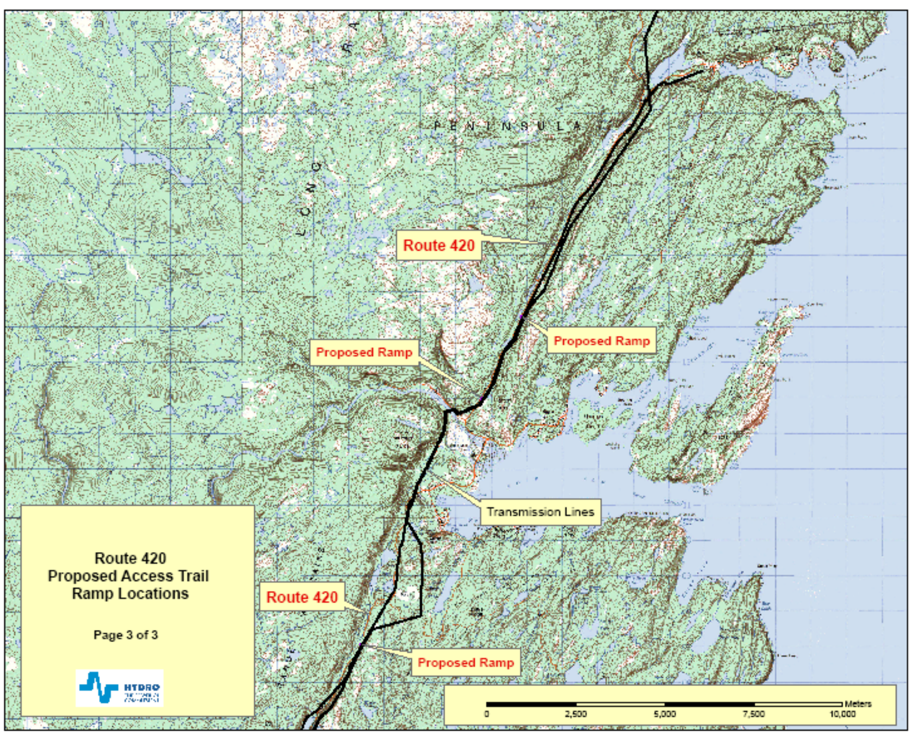
Transmission Line TL 251 - along Howley Highway



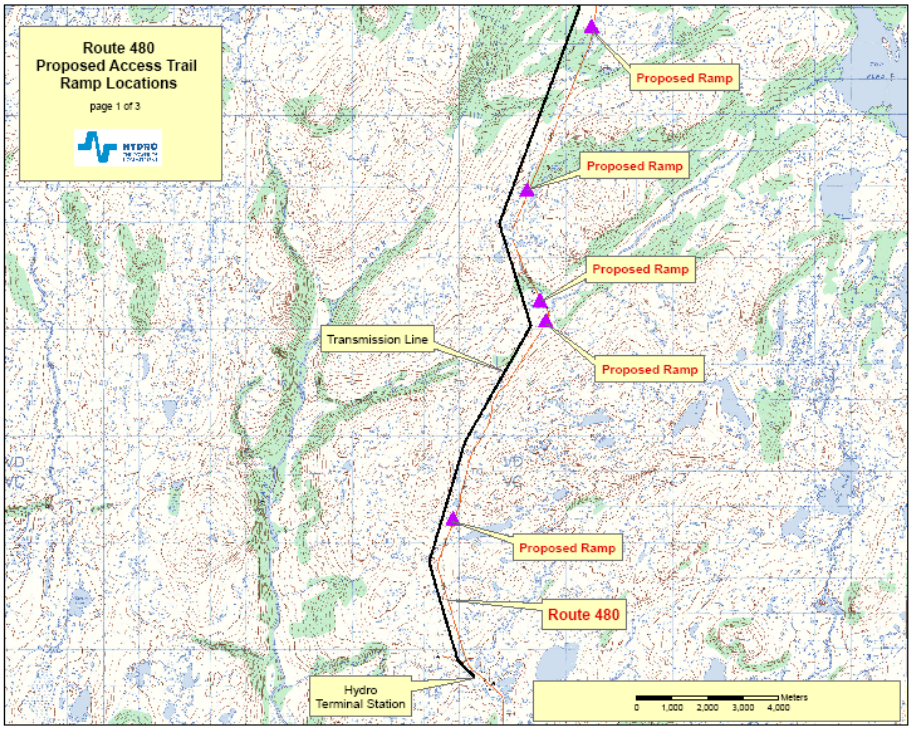
Transmission Line TL 252 - along Jackson's Arm Highway



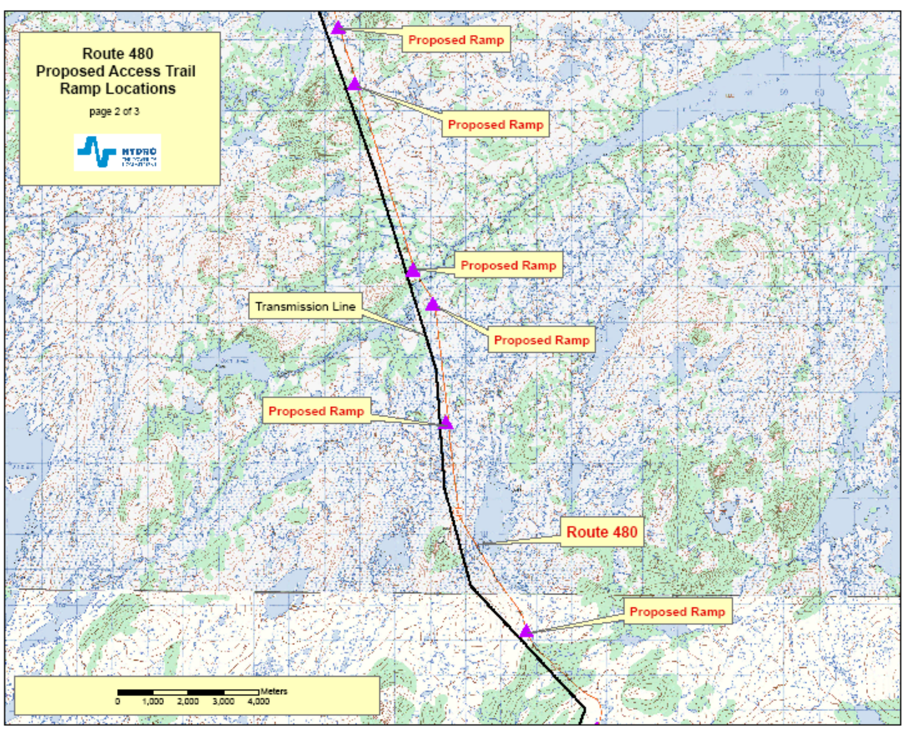
Transmission Line TL 252 - along Jackson's Arm Highway



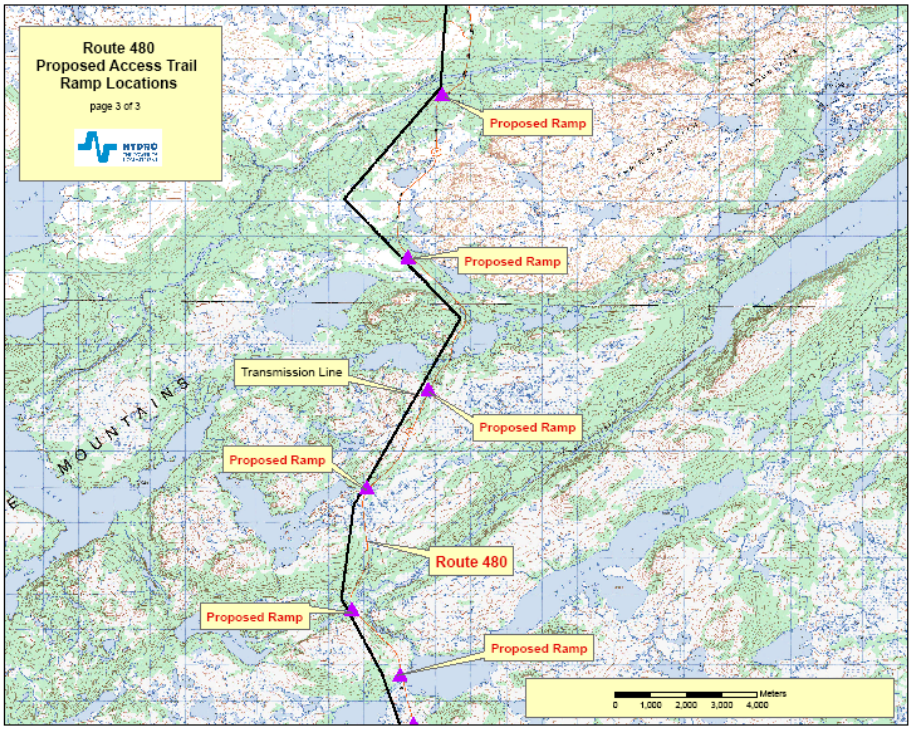
Transmission Line TL 252 - along Jackson's Arm Highway



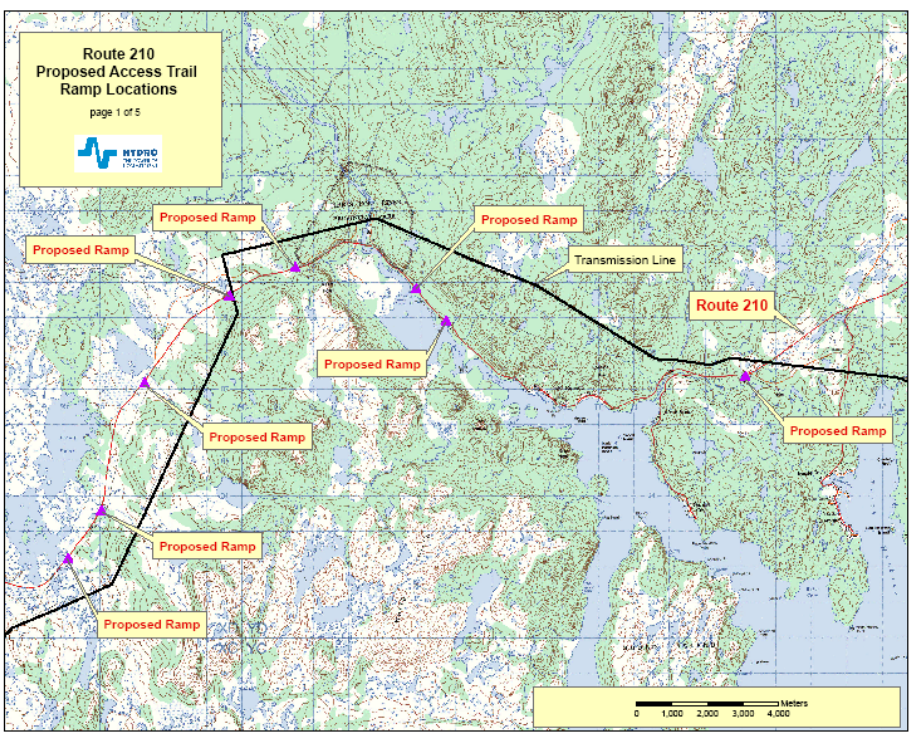
Transmission Line TL 250 - along Burgeo Highway



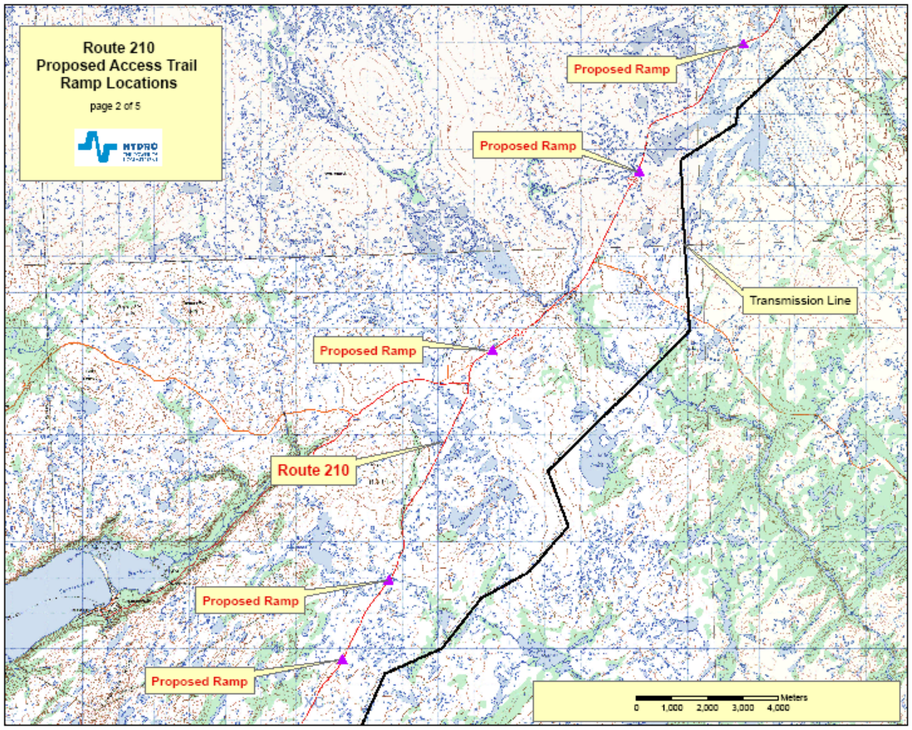
Transmission Line TL 250 - along Burgeo Highway



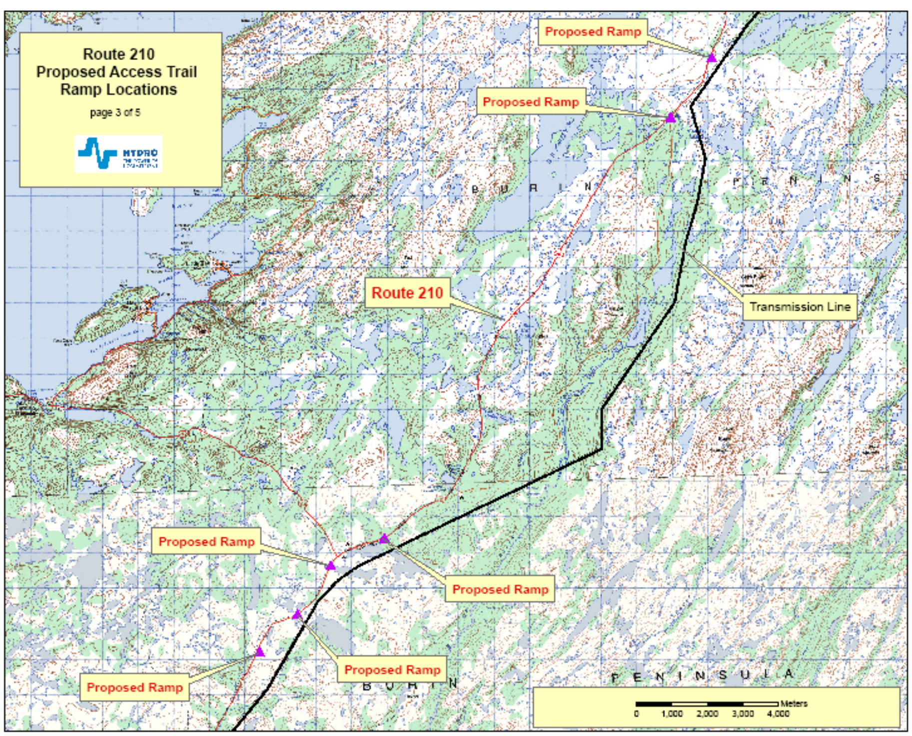
Transmission Line TL 250 - along Burgeo Highway



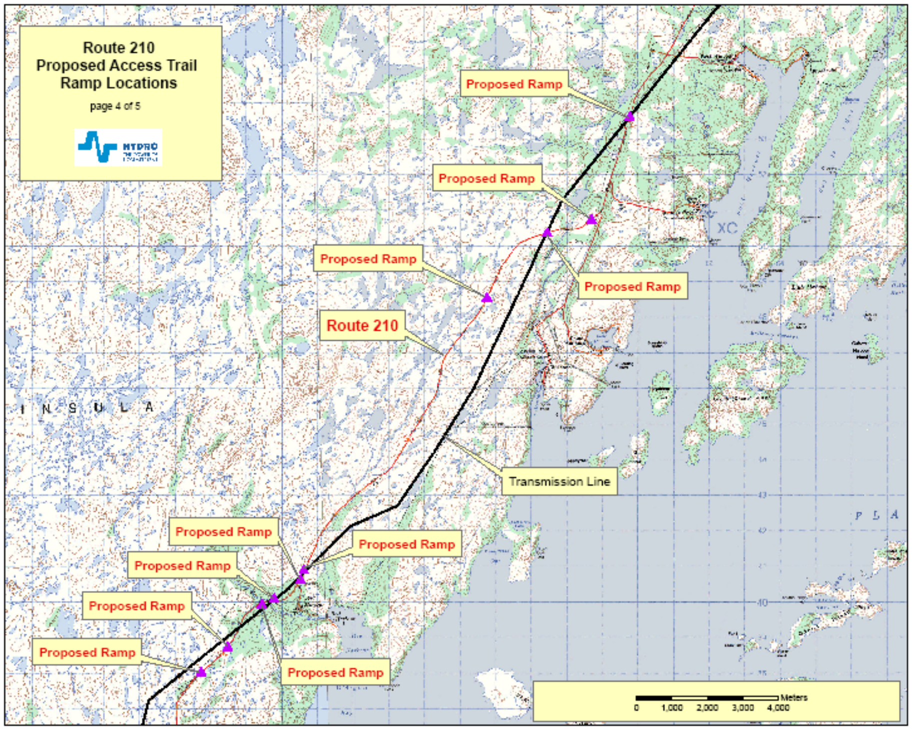
Transmission Lines TL 212, TL 219 - along Burin Peninsula Highway



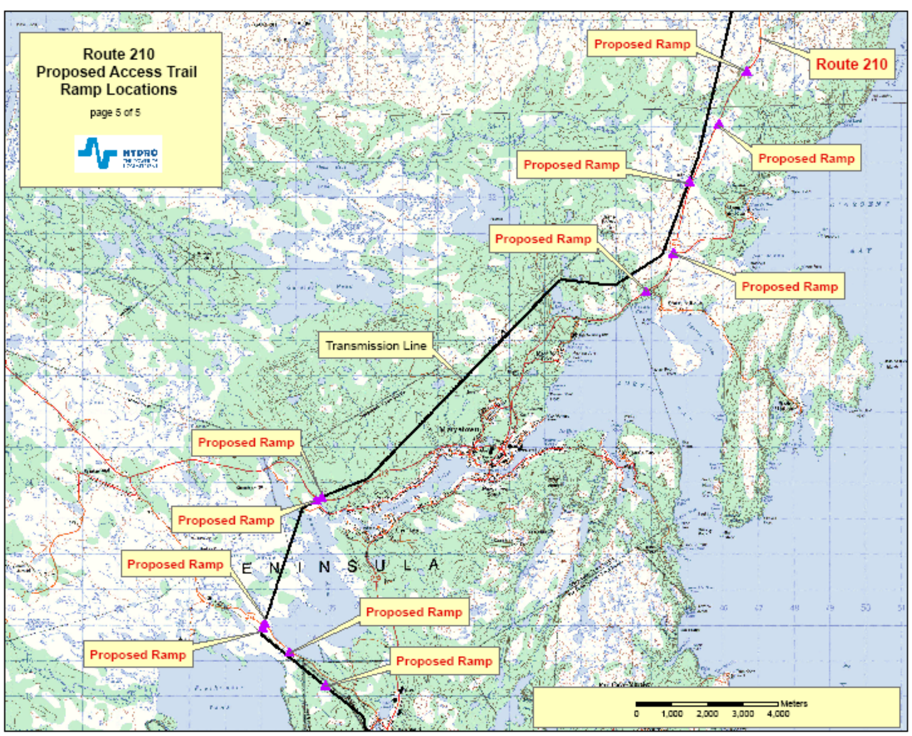
Transmission Lines TL 212, TL 219 - along Burin Peninsula Highway



Transmission Lines TL 212, TL 219 - along Burin Peninsula Highway



Transmission Lines TL 212, TL 219 - along Burin Peninsula Highway



Transmission Lines TL 212, TL 219 - along Burin Peninsula Highway

Tab 7

Tab 7

HAPPY VALLEY/GOOSE BAY

INVESTIGATION OF OPTIONS

FOR

OFFICE, WAREHOUSE AND LINE DEPOT FACILITIES

REGISTERED PROFESSIONAL ENGINEER
G. W. Lundrigan
G W Lundrigan
SIGNATURE
July 11, 2007
DATE
PROVINCE OF NEWFOUNDLAND

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

JULY 11, 2007

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1. Purpose of Report

The purpose of this report is to present the results of the investigation of the various options to provide office, warehouse and line depot facilities for TRO Operations at Happy Valley/Goose Bay, (HVGB) Labrador.

The need to identify and compare options took on a sense of urgency when:

- A need to up-grade the existing warehouse facilities was identified and was then budgeted for 2006.
- There was an impending expiration of the office facilities' lease, since renewed on a yearly basis, in September 2005.

Hydro needed to ensure that the consequences of any course of action taken were understood and that the most economical and practical solution, within the operational philosophy of the Company, was the one selected.

2. Existing Facilities

2.1 General

Hydro occupies four major facilities in Happy Valley/Goose Bay (HVGB). They are a leased office building, a combination warehouse/line depot/storage yard (WHLDB), a standby diesel plant/maintenance shop/storage yard facility (North Plant) and a Gas Turbine Generating Station/Terminal Station.

2.2 Leased Office Building

Hydro presently is the lone tenant and leases the entire area of a 370m^2 building located on Royal Street, Happy Valley. This serves as the central office for the Labrador area which extends from Black Tickle in Southern Labrador to Nain in Northern Labrador and also includes HVGB, Labrador City and Wabush.

This wood framed metal-sided one story building is occupied by Operations' supervisory, administrative and technical personnel.

It is located immediately adjacent to Hydro's Hunt Street property, which is the site of the existing WHLDB. The office building's parking lot is unpaved.

2.3 Warehouse, Line Depot and Storage Yard (WHLDB)

The warehouse and line depot occupies a 460 m^2 pre-engineered metal building fronting on Hunt Street. A fenced yard on which the building is located extends the complete distance between Hunt and Royal Streets. The fenced yard abuts the property on which the rented office building is located.

The total property measures approximately 70 m by 116 m with approximately 70 m frontages on both Royal and Hunt Streets.

2.3.1 Warehouse

The warehouse occupies an area approximately 290 m^2. Supply Chain confirms this is adequate size.

2.3.2 Line Depot

The line depot occupies an area approximately 170 m^2. Operations confirm this is adequate size.

2.3.3 Storage Yard

The storage yard area presently being used is approximately 5000 m^2 although the total area of Hydro's property, including that occupied by the WHLDB (460 m^2), the substation (143 m^2) and a strip of land between the fence and Royal Street (900 m^2) is approximately 8120 m^2. The yard space is utilized to store equipment such as transformers and line hardware either directly on the ground or on elevated ramps. Distribution and transmission line poles are stored at the North Plant yard.

2.4 North Plant and Associated Facilities

The North Plant is located on a 1.348-hectare site on Ottawa Street on the former Canadian Forces Base in Goose Bay. It consists of a diesel generating plant, electrical/mechanical maintenance shop, substation and a fenced storage yard. This facility was transferred from Public Works Canada to Hydro in 1977.

2.5 Gas Turbine Generating Plant and Terminal Station

The Gas Turbine Generating Plant (GTGP) and Terminal Station associated with transmission line TL 240 from Churchill Falls is situated on a 13.24-hectare site located at the junction of the Hamilton River Road and Provincial Highway Route 500 (to Churchill Falls).

3. Existing Facilities Conditions

3.1 Leased Office Building

The existing rental office building is one story and is of wood framed construction with metal siding. The building is approximately 12 years old and needs significant upgrades to put it in a condition for long term continued use. Happy Valley Goose Bay personnel have reported a number of operating deficiencies and a lack of maintenance by the owner during the tenancy period. Inoperable windows, significant downtime for the air conditioning system, flooding of the parking area during spring thaw and unpleasant odors are some of the complaints. The building does not have a basement and has a wooden joist floor, which is susceptible to rot as a result of poor ventilation. An outside structural engineer hired by Hydro to assess the building condition concluded that "the building is of lower end quality".

In 2005, in response to the office staff's complaints with respect to unpleasant odors, a consultant was hired to complete an air quality and mould assessment. High concentrations of mould were found in the building's crawl space and in a localized area in the office area. Although the mould was removed and measures were taken to prevent its reoccurrence there is a concern as to whether all was discovered or that, in spite of preventive measures, it may reoccur. If mould was again discovered it could, due to safety and health concerns, lead to costly cleanup and repairs. Although the owner of the building would be responsible for this work Hydro staff may need to move to temporary facilities while the work was being completed.

3.2 Warehouse, Line Depot and Storage Yard (WHLDB)

The existing WHLDB is a pre-engineered metal building with a total area of 460m^2. Approximately 290m^2 of area is dedicated to warehouse and the remaining 170m^2 is dedicated to the line depot. It was built in 1961 and was originally utilized as a power plant and housed diesel generating units until 1977. Operations and Supply Chain have confirmed the floor areas allocated to both the warehouse and line depot are adequate, but that the facility, especially the warehouse area, is in need of major upgrading. The building is structurally sound and new shingled roofs were installed on both the warehouse and the line depot in the mid nineties. This together with the removal of asbestos wall and ceiling panels, in the line depot area only, and some interior partition construction is the extent of upgrading that has been completed over the years.

The line depot requires upgrading of the exterior metal siding, doors and windows and the electrical system, whereas the warehouse upgrading requirements are much more extensive. A list of upgrading requirements for the warehouse is as follows:

- the removal of asbestos sheathing from walls and ceiling;
- the removal of an overhead crane;
- the complete removal of the existing electrical system and the re-installation of a new system to meet applicable codes;
- the relocation of interior partition to allow a more efficient utilization of space;
- the construction of insulated walls and ceiling within the warehouse space;
- the replacement of overhead doors;
- the removal of existing windows (openings to be covered with new siding);
- the replacement of all exterior metal siding; and
- the supply and installation of additional shelving.

The Town Council has advised Hydro that the warehouse/line depot building is a “permitted” use in the area. Should this building suffer damage to an extent greater than 50% of its replacement value Hydro would not be permitted to repair it or reconstruct a “similar use” building on this site.

A Phase I Environmental Site Assessment (ESA) identified that the WHLDB was originally operated as a diesel generating plant which had its fuel stored in underground storage tanks. The storage yard has been used to store creosote and penta treated distribution line poles and cross arms as well as PCB filled distribution transformers.

The Phase 1 ESA recommends that a Phase II ESA be completed. We believe that, given the past operating procedures, a Phase II ESA will identify extensive soil contamination and possible groundwater contamination. Depending on the type of contaminant we feel the cleanup effort could be significant and time consuming. Long term monitoring requirements may dictate that no new buildings be erected on this site.

3.3 North Plant Site

This site contains a standby diesel plant with its associated fuel storage tanks and electrical distribution station located immediately adjacent to plant. Treated distribution line poles are presently stored in the yard.

A Phase I and II ESA identified the presence of petroleum hydrocarbon impacted soil and groundwater. As part of the remedial action for the property a human health risk assessment was conducted. The risk assessment concluded that the identified contamination poses no unacceptable risks under the existing conditions. At the time, the property was classified as a commercial site with limited exposure (4 hours/day, 250 days/year) with drinking water supplied by municipal services. Should changes in the site usage or significant construction take place it is recommended that the risk assessment be re-evaluated.

3.4 Gas Turbine Generating Plant and Terminal Station

This site is in an isolated area remote to the town services and is subject to security concerns. Difficult terrain conditions would necessitate backfilling of the site to a depth of six (6) to nine (9) meters in some areas. Anecdotal information indicates that there may be some contamination resulting from dumping during the period when the American Air Force Base was in operation.

4. Options Investigated

The options investigated were:

- To construct a new facility at one of Hydro's existing sites.
- To construct a new facility at a new site.
- Leasing

4.1 New Facility Construction at an Existing WHLDB Site

The concerns with respect to possible site contamination combined with zoning restrictions quickly led to the discounting of this site as a viable location for construction of a new facility.

4.2 New Facility Construction at North Plant Site

The concerns with respect to site contamination/remediation plus concerns with respect to location of an office facility adjacent to a diesel powerhouse with its associated noise and emission issues led to discounting this site as a viable location for a new facility.

4.3 New Facility Construction at Gas Turbine Generating Plant and Terminal Station

The major concerns which led to this site being discounted as a viable location are:

- An estimated cost of $500,000 to complete the initial site development
- Remoteness from town services and security issues
- Possible contamination from dumping by previous users

4.4 New Facility Construction at New Location

Consultation with the Town Council indicates that since there are already areas in the town zoned to permit the construction of suitable facilities, they would not consider rezoning any other locations. Considering this restriction there were only two suitable locations identified. One site was located in the Burnwood Industrial Park and the other was located on the corner of Tenth and Bloomfield. The Burnwood Industrial Park site is a green site, the Tenth and Bloomfield one is not and since there are no other offsetting conditions, the Burnwood Industrial Park site is the more desirable.

4.5 Leasing

A review did not identify any existing suitable facilities in the Happy Valley/Goose Bay area.

5. Recommendations

Engineering Services recommends that a new facility be constructed at a new location. Design would commence in January 2008. A contract would be awarded for construction to start during the summer of 2008 with an in-service date of June 30, 2009.

The construction tender would contain provisions to allow a contractor the option of building and leasing an equivalent facility.

PHOTOGRAPHS

Photographs

Photo 1 Leased Office Building – Royal Street

Photo 2 Existing Facilities at Royal and Hunt Streets Showing Rented Office Building to the Left with Several Equipment Storage Ramps and a Section of the Line Depot Building in Background.

Photo 3 Warehouse/Line Depot Building at Hunt Street Entrance to Storage Yard.

Photo 4 Warehouse/Line Depot Building---Looking Southeast Along Hunt Street Showing Condition of Siding and Doors.

Photo 5 West side of Warehouse Section of Building Showing Condition of Doors and Windows.

Photo 6 West side of Warehouse Section of Building Showing Condition of Windows and Siding.

Photo 7 North Side of Line Depot Section of Building from Hunt Street.

Photo 8 East Side of Warehouse Section of Building Showing Condition of Windows and Siding.

Photo 9 East Side of Warehouse Section of Building Showing Condition of Siding.

Photo 10 South End of Warehouse Section of Building showing Condition of Siding, Windows and Doors.

Photo 11 Storage Yard with Equipment Storage Ramps to the Left and Right ---Looking North.

Photo 12 Interior of Line Depot Building Showing Electrical Panel Congestion

Photo 13 Interior of Line Depot Building Showing Electrical Panel Congestion on same Wall as Photo 11.

Photo 14 Interior of Warehouse showing General Clutter, Overhead Crane and Asbestos Sheeting in End Wall.

Photo 15 Interior of Warehouse---Note the Excessive Height of Building.

Photo 16 Interior View of Warehouse---Note Electrical Wiring on Beams at Left.

Tab 8

PROTECTION CODE MANAGEMENT SOFTWARE FOR HOLYROOD

NEWFOUNDLAND AND LABRADOR HYDRO

JULY 5, 2007

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1 INTRODUCTION

One of the main objectives of Newfoundland and Labrador Hydro is the creation of a safe work environment in which hazards can either be eliminated or controlled. The work protection code was developed to achieve this goal. It consists of important principles which, when combined with safe work practices, provide workers with a safe work area. It is imperative that these principles be adhered to throughout the corporation to achieve our goal of ensuring a safe work area.

The proposed system is a web based software tool designed to establish and maintain good plant configuration management for the safe and effective application of work protection. Hydro is pursuing this solution in order to enhance the level of compliance with work protection standards at Holyrood. Since 1998, throughout the corporation there have been 3,175 losses and near misses, of which 651 (20%) occurred in Holyrood. Given the importance of the work protection code in ensuring a safe work area, improvements are required.

The proposed system will provide an effective, consistent and standard means of creating work protection documentation, by ensuring adherence to work flow rules, tag management, and permit archiving. This tool will allow for capture and storage of plant knowledge which currently is undocumented, aligning with Hydro's ongoing succession planning goals.

Plant personnel will be tasked with creating a Master Equipment List (MEL) of approximately 5,000 field devices in a database to be used for creating work protection data. This will automate the generation of work permits which are required for every maintenance task at the Holyrood plant. All shift operators will be trained to use the new tool to effectively and consistently issue approximately five to ten work permits per day, with up to 150 devices per permit.

The project costs include the hardware and software necessary for automation of the work protection code. The project is expected to begin in January 2008 and conclude in May of 2008.

2 PROJECT DEFINITION

The project is to implement a specialized software application for the automation and work flow of the work protection requirements in the Holyrood plant. The specialized software is being acquired from the Ontario Power Generation (OPG).

The system will provide the flexibility and capability for Holyrood to improve plant configuration, safety, accuracy and efficiency as it applies to Work Protection data and requirements. One of the main areas where accuracy and efficiency gains can be immediately realized is by using the system to align Holyrood's physical plant, paper process and electronic records.

Once the software is implemented the MEL will include all the devices that are located in the plant, and the position of these devices, for creation of safe work permits. Equipment labels can be generated directly through the system in a non-demand fashion that would manage and keep current the equipment identification.

This will assist the compliance process and improve existing issues of missing alphanumeric identifiers and inconsistent descriptions, as well as improve the application of the Work Permit System.

2.2 Objective

The system will provide an effective, efficient, consistent and standard means of creating work protection documentation. Creating electronic work protection forms will be helpful in preventing common operating errors, resulting in increased employee, contractor and public safety as well as plant availability.

2.3 Scope/Major Deliverables

The system is a critical web-based software tool designed to establish and maintain good plant configuration management for the safe and effective application of Work Protection.

2.4 Quality Specifications

Holyrood is pursuing this solution in order to enhance the current level of compliance with work protection standards at this site, with an increase in safety and overall effectiveness as the desired and anticipated outcome of implementing the system.

3 APPROACHES

3.1 Identify Alternatives

Option 1 – Do Nothing

Under this approach, Holyrood would continue using their present system and not achieve the full compliance with Work Protection standards for the site.

Option 2 – Develop an In-House System

Under this approach, Hydro would apply its knowledge of the Work Protection Code and apply this to building its own custom software. This approach would require a tremendous effort by Information Systems staff in the Energy Systems area, and is not considered a viable alternative.

Option 3 – Acquire available system

Under this approach, Hydro would acquire the Work Protection software from Ontario Power Generation and services that are available through Systemware Innovation Corporation for implementation, testing and training services.

3.2 Recommended Alternative

Of the three options identified, Option 3 (Acquire available system) represents the preferred approach. This specialized software has been installed in Nuclear Plants, Coal Burning Plants and Hydro Plants. As well, implementing Option 3 would allow Hydro to document all the equipment that is presently under the Holyrood system, giving them more concise reporting when creating work protection forms, thus preventing common operating errors, increasing personnel and public safety and plant availability.

4 BENEFITS AND COSTS

4.1 Benefits

Economic Benefits

- Safety - reduces chances for operating errors, which translates to less time spent analyzing errors.
- Standardization –provides a standard interface for the Work Protection activities for the Plant with proven stability. This results in lower maintenance and support costs.
- Efficiency –increases the efficiency of the generation and checking of work permits, relieving the operator workloads. This potentially translates to shorter outages as the software enables users to more quickly adapt to changes in plant status and configuration.

Non-Economic Benefits

- Regulatory – enables work protection and plant configuration management mandates to be satisfied and provides an audit trail for conformity.
- Accuracy – (can also be viewed as an Economic Benefit) the integrative capability of this system allows station users access to more complete and up-to-date information for decision making. Greater accuracy translates into:
  - Shorter outage times
  - Confidence in the alignment of the physical and paper
- Configuration Control – The unit operator, who has responsibility for all activities on the unit, has greater control of the unit configuration. This information is also available for efficient maintenance planning. This also provides the ability to better adapt to changes in the plant if configuration errors are uncovered during an outage.

4.2 Costs

Costs for Work Protection Code in Holyrood

-	License costs for one site – Holyrood	$100,000
-	Materials (Equip, Travel, Consumables)	79,000
-	Implementation, Testing and Training	213,000
-	Internal Labour	130,000
-	Support 5 x 8 (9:00 am – 5: 00 pm ET) 1 year	47,000
-	Contingency	56,900
-	Corporate O/H & Escalation	52,200
TOTAL		**$678,100**

Tab 9

IMPLEMENTATION OF A SHORT TERM WATER MANAGEMENT DECISION SUPPORT SYSTEM FOR NEWFOUNDLAND AND LABRADOR HYDRO

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

JULY 2007

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EXECUTIVE SUMMARY

Hydro currently uses the LT Vista decision support systems (DSS) for guidance in determination of the appropriate mixture of generation from hydroelectric and thermal sources. Hydro also uses unit commitment and economic dispatch tools to optimize real-time production. While Hydro uses sophisticated tools for long term and real-time water management, short term water management decisions are performed using a combination of spreadsheets and professional judgment.

An assessment of the potential savings in thermal production resulting from improved hydraulic unit dispatch was conducted by Synexus Global Incorporated in 2006. The assessment concluded that based upon 2005 actual experience (a slightly higher than average inflow year) there is a theoretical improvement of 29 GWh in hydroelectric yield (between 0.6% and 0.7% of the annual hydraulic production) when short term operations are optimized via a DSS.

The total cost of acquiring and implementing a short term water management DSS is expected to be $651,000. Based upon a typical Holyrood conversion factor of 630 kWh/bbl, a conservative estimate of the annual capture of savings, and fuel price projections contained in Hydro's spring 2007 long term fuel price forecast, the DSS will fully recover its costs in slightly over 3 ½ years. A sensitivity analysis was conducted relative to fuel prices to determine the impact of a low fuel price projection on project economics. The project was found to be relatively insensitive to fuel price, with the fuel price reduction moving the payback period out to 6 years

Under the proposed project, Hydro would acquire a short term water management DSS that would generate inflow forecasts and assist in translating long term reservoir and thermal dispatch guidance into daily and hourly schedules. The system would be integrated with Hydro's LT Vista decision support system, and closely integrated with, though not dependent on, Hydro's new Energy Management System.

In addition to the direct avoided fuel costs, the system will provide Hydro with a powerful analytical tool that can be used in a variety of arenas, including maintenance planning and generation operation scenario analysis

Implementing a short term water management decision support system will provide Hydro with powerful tools to help in its efforts to provide least cost electricity and reduce its environmental impact.

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) operates nine major reservoirs in three river systems. Combined these reservoirs represent virtually all hydraulic storage for the operation of Hydro's Island Interconnected system.

Hydro currently uses the LT Vista decision support systems for guidance in determination of the appropriate mixture of generation from hydroelectric and thermal sources. The system also provides weekly guidance on optimum water releases from each reservoir. Hydro also operates unit commitment and economic dispatch tools to optimize real-time system production. None of these systems, however, provides information on the optimum allocation of water releases and generation amongst units within the week, effectively bridging the gap between the long term guidance and the real time dispatch.

The purpose of this project is to acquire, install, and operate a decision support system, and all necessary support subsystems, that will use the long term guidance provided by LT Vista, and produce daily and hourly generation dispatch as well as guidance for optimum reservoir releases. While the project will complement operation of Hydro's new Energy Management System (EMS), the project is not tied to the operation or future of the EMS.

This report documents the basis for justifying and implementing such a short term water management decision support system, and provides a summary of the benefits that can be expected as a result of the implementation.

1.1 Background

In 2006 Hydro engaged Synexus Global Incorporated (SGI) to review its water management practices to determine how well Hydro, and in particular System

Operations, managed Hydro's hydraulic generation via its water management practices and decision making framework. The scope of work entailed a review of current practice, and an evaluation of the potential for improvement.

Arising from the assessment, the following key findings were highlighted:

- Hydro currently performs its long term water management activity using a sophisticated optimization tool (LT Vista) in conjunction with several support spreadsheets and professional judgment.

- Hydro currently translates the long term guidance (one week out to 3½ years) into a weekly schedule based upon a spreadsheet and professional judgment.

- Opportunity exists to implement short term (hourly and daily) modeling software that can assist in improving unit dispatch and water release decisions. Improved decision-making can translate into improved hydraulic conversion factors (output per unit of input). This in turn translates into a reduction in the requirement for thermal production at Holyrood.

- Though covered in the scope of a separate budget proposal, addition of meteorological observation sites can improve inflow forecasting accuracy and capability.

- SGI identified the potential of an additional 29 GWh of hydraulic yield for 2005 test year data arising as the result of implementing improved inflow forecasting and short term water management optimization. The theoretical improvement represented an increase of between 0.6% and 0.7% of the annual hydraulic production for 2005.

- Based upon a conservative estimation of potential reduction in thermal production, Hydro should give consideration to implementing a water management decision support system.

1.2 Project Deliverables and Scope

The major deliverable of this project is a decision support system that provides:

- A model whose optimization objective is the minimization of the cost of generation and maximization of the value of reservoir releases while meeting all physical and operational constraints imposed on the hydraulic system operations.

- A model that operates within Hydro's daily and weekly planning horizon.

- A model that includes inflow forecasting which integrates short term optimization with long term water management activities, and is based upon the National Weather Service River Forecast Model (NWSRFM) formulation.

The project also includes all necessary model testing and calibration, all necessary computer hardware required to effectively operate the system, and training

The scope of the project is limited to establishment of the toolset as noted above, and does not extend to the development of any generation operating policies, targets, and performance measures which may arise as a result of implementing the project

2 ALTERNATIVES

In light of the results of the SGI report, a number of options were considered for addressing the potential for reducing thermal production by improving overall hydraulic conversion factor. Three options for consideration were:

Option 1 – Do Nothing

Under this approach, Hydro would continue to operate the existing long term optimization and spreadsheets to determine water release and generation dispatch. This approach would forgo any opportunity accessing the potential increased yield identified by SGI.

Option 2 – Develop an In-House System

Under this approach, Hydro would apply its considerable knowledge of its physical system and assets to the development of its own water management DSS. This approach would require that Hydro develop or acquire the necessary expertise in hydraulic system optimization to integrate with its system knowledge. This represents a sizeable investment in technological development, and goes against Hydro's approach of avoiding software development if suitable products can be purchased on the market.

Option 3 – Acquire Available System

Under this approach, Hydro would acquire one of the existing water management DSS products currently available in the marketplace. Though water management systems are a niche market, there are several possible candidates that can address the opportunities identified in the SGI report.

Of the three options identified, Option 2 (Develop an In-House System) was discounted. Accordingly, the only two options given further consideration were the Status Quo option and the Acquire Available System option.

3 ANALYSIS

The economic justification for implementing the sort term water management decision support system is based upon the comparison of expected increases in hydraulic production as a result of implementing the system compared to the capital and operating costs of the system. In effect, the justification is the comparison of options 1 and 3 as described in Section 2.

3.1 Methodology and Assumptions

To conduct the analysis, the following methodology and assumptions were used.

- Establish a benefits stream arising from expected increased hydroelectric yield arising from implementation of the decision support system. Benefits are dependent upon a number of factors, including type of hydraulic year (low inflow or high inflow year), system constraints, and forecast accuracy. Accordingly it is unlikely that the same benefits would accrue each year. A conservative estimate of annual savings over the study life was generated to reflect limitations in accessing the full potential for the above reasons, as well as to reflect a learning curve in applying a sophisticated water management tool. Table 1 in Appendix A summarizes assumed annual capture of benefits.

- Establish the cost stream for the acquisition, implementation and operation of the decision support system. Capital cost estimates were developed based upon budgetary pricing provided by SGI. Table 2 in Appendix A summarizes the cost information used in the analysis.

- Determine the annual equivalent amount of energy avoided at Holyrood as a result of the expected additional hydroelectric yield produced by implementing the decision support system. It was assumed that all hydroelectric production increases directly offset Holyrood production.

- Determine the value of energy reductions at Holyrood. This determination was made assuming a 630 kWh/bbl conversion factor for Holyrood, and Hydro's spring 2007 fuel price forecast. Table 3 in Appendix A provides the annual fuel prices used in the analysis.

- Determine the cumulative net present value of the status quo option over the study life and compare to the cumulative net present value of the proposed alternative (Option 3 in Section 2).

It is likely that should the decision support system be implemented, it would become a permanent part of Hydro's operating toolset. However, for the purposes of the analysis, a study life of 10 years was assumed.

A discount rate of 7% was assumed, and cash flow for the decision support system was assumed to commence in 2008.

3.2 Results

The above costs and benefits were discounted to January 2007. Figure 1 summarizes the results of the comparison. As can be seen, avoided fuel costs that arise as a result of implementing the decision support fully pay for the cost of the system in slightly over 3 ½ years. The net present value of the decision support system over the ten year study horizon was $1.8 million. Table 4 of Appendix A details the results of the analysis.

3.3 Sensitivity Analysis

A sensitivity analysis was conducted to test how project economics fared in light of a significant change to the key project variable – fuel costs. To test the sensitivity, a low fuel price forecast was developed and applied to the original assumptions and analysis. The low fuel price sensitivity is provided in Table 3 in Appendix A.

The result of the analysis was an extension of the payback period for the project, from 3 ½ years to 6 years. The total net present value over the ten year study horizon dropped to $474,000 when the lower fuel price forecast is used. Results are detailed in Table 4 of Appendix A.

Figure 1 shows the results of the analysis for both the base case and sensitivity.

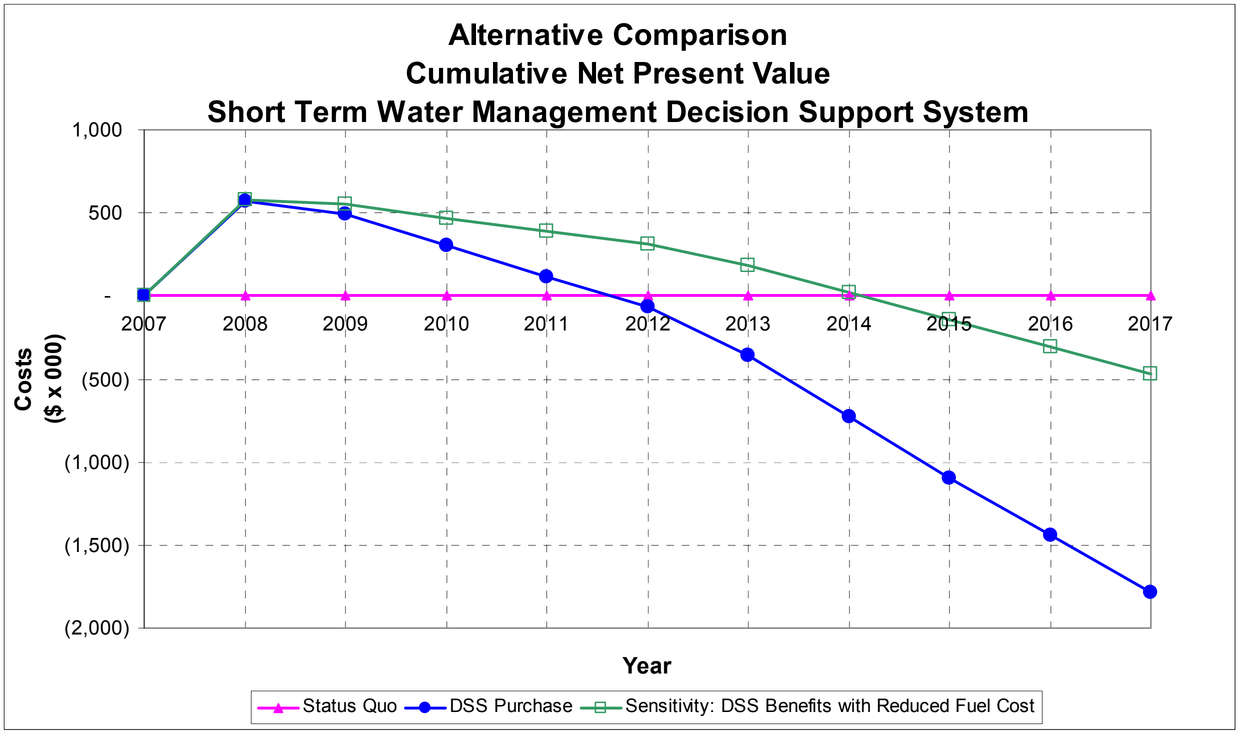

Figure 1. Cumulative Net Present Worth Comparisons

3.4 Discussion

The implementation of the decision support system yields favourable economic results, even in the event of lower than expected fuel prices. In evaluating the project, additional issues should be considered.

First, the reduction of production at Holyrood not only reduces fuel costs, but also avoids emissions. Based upon the benefits stream outlined in Table 1, annual SO2 emissions would be reduced between 8 and 30 metric tonnes, averaging approximately 20 tonnes per year. Likewise, CO2 emissions would be reduced by between 1163 and 4652 metric tonnes per year, averaging about 3000 metric tonnes in reduction per year[1].

[1] Based upon Holyrood emission rates of 5.329 g/kWh SO_2 and 0.802 kg/kWh CO_2

Second, the decision support system will provide a number of tangible and intangible benefits, including:

- Improved inflow forecasting leading to improved short-term decision making in the areas of granting unit maintenance outages and evaluating the priority of the activities that impinge upon water management.

- Providing the information necessary for further integrating water management activities into the capabilities of Hydro's new Energy Management System.

- Hydro will acquire a powerful analytical tool that can, in addition to supporting ongoing operation dispatch decisions, provide a means of assessing the impacts of various maintenance outage scenarios as well as impacts of new generation sources (such as Island Pond, Portland Creek, or further non-dispatchable generation sources such as wind turbine generation).

- Hydro will be able to embody in a model some aspects of the operating and system knowledge that has been accumulated over the years, guarding the information against loss through personnel moves or attrition.

- As new projects such as Portland Creek or Island Pond are introduced into the system, hourly dispatch decisions become far more complex, making this type of tool essential to operational decision-making. Having a short term water management DSS in place with operating experience will assist in the smooth transition to a more complex system. Likewise, the DSS has application for a Labrador infeed when market prices may become part of the decision-making framework. Similar benefits would also be expected with the addition of different thermal resources

Finally, it must be noted that the improvements in conversion factor will be spread across the system, resulting in some units experiencing poorer conversion factor performance in favour of overall system conversion factor performance improvement. Changes in conversion factor and overall energy improvement will be present, though small (less than 1%). Accordingly, measurement of annual changes may be difficult, and impossible to disaggregate from the impacts of other improvement activities and events.

4 RECOMMENDATIONS AND CONCLUSIONS

Hydro does not currently possess a DSS to translate long term water management guidance into weekly dispatch decisions. An assessment of the potential savings in thermal production resulting from improved hydraulic unit dispatch was conducted by Synexus Global Incorporated in 2006. The assessment concluded that there is opportunity to improve annual hydroelectric yield by between 0.6% and 0.7%, which in turn directly offsets thermal production from Holyrood.

Based upon Hydro's spring fuel price forecast and a 630 kWh/barrel conversion factor at Holyrood, the savings arising from implementation of the DSS fully recover the budgeted project cost of $651,000 in slightly over 3 ½ years. If fuel prices fall and stay low, the viability of the project is not jeopardized, as the payback period extends to about 6 years.

In addition to the direct avoided fuel costs, additional hydroelectric yield will also result in avoided emissions at Holyrood, reducing SO_2 emissions by roughly 20 metric tonnes per year, and reducing CO_2 emissions by roughly 3000 metric tonnes per year. The project will also provide Hydro with a powerful analytical tool that can be used in a variety of arenas, including maintenance planning and generation operation scenario analysis.

It s recommended that Hydro seek approval for acquiring and implementing the proposed project.

APPENDIX A

Table 1. Annual Benefits Capture Assumptions

Analysis Year	Potential Capture per SGI Report[2]		Assumed Capture	
	(% of Annual Theoretical Maximum)[3]	(GWh)	(% of Annual Theoretical Maximum)	(GWh)
1	40	11	0	0.0
2	40	11	5	1.5
3	40	11	10	2.9
4	40	11	10	2.9
5	40	11	10	2.9
6	40	11	15	4.4
7	40	11	20	5.8
8	40	11	20	5.8
9	40	11	20	5.8
10	40	11	20	5.8

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[2] Assessment of Hydraulic Resource Management Tools and Practices, Synexus Global Incorporated, February 2007, p. 4-15.

[3] *Ibid*, p. 10-5.

APPENDIX A – Cont'd

Table 2. DSS Capital and Operating Costs

Decision Support Software:	$500,000
Ancillary Software Acquisitions	$3,500
Hardware Purchases	$6,500
Internal Labour and Project Management	$23,000
Training	$12,000
Corp Overhead, Escalation and AFUDC	$51,700
Contingency	$54,500
Total	$651,200

Annual support and maintenance fees assumed to $50,000 (10% of acquisition cost). Note that all amounts are quoted in Canadian dollars.

APPENDIX A – Cont'd

Table 3. Fuel Price Forecast

Year	Base Case Fuel Price ($/bbl)	Sensitivity Low Fuel Price ($/bbl)
2007	50.50	43.80
2008	54.65	36.45
2009	61.10	34.60
2010	64.75	34.60
2011	68.45	35.05
2012	71.50	36.25
2013	73.40	36.90
2014	75.50	36.35
2015	78.05	37.35
2016	80.45	40.85
2017	82.80	43.15

APPENDIX A – Cont'd

Table 4. Analysis Results

Year	Base Case Cost (Benefit)		Sensitivity: Low Fuel Price Cost (Benefit)	
	Present Worth ($ x 000)	Cumulative Present Worth ($ x 000)	Present Worth ($ x 000)	Cumulative Present Worth ($ x 000)
2007	0	0	0	0
2008	569	569	575	575
2009	-74	495	-24	551
2010	-189	306	-83	468
2011	-189	117	-79	389
2012	-186	-69	-78	311
2013	-285	-354	-128	183
2014	-375	-729	-166	17
2015	-364	-1093	-160	-143
2016	-351	-1444	-166	-309
2017	-338	-1782	-165	-474

All costs discounted to January 2007.

Costs and benefits are relative to continued operation without optimization (Option 1 – Status Quo Case).

Tab 10

Implementation of Optimum Power Flow in the Reduction of Transmission Losses

HYDRO
THE POWER OF COMMITMENT

Newfoundland And Labrador Hydro

July 10, 2007

Table of Contents

SUMMARY

Optimal Power Flow (OPF) is an operational support system that will be used in a real time environment. The software recommends the control actions to be performed by operating staff in order to position the power system to minimize transmission losses and avoid transmission constraint violations. In this way the total amount of generation required to meet the same load is reduced and a lower operating cost will result. OPF minimizes losses by increasing the system voltages within specified limits.

The benefits of using OPF for Hydro are mainly in the areas of increased security and reduced transmission network losses. Based on past testing, the magnitude of loss savings is expected to be within the sources of measurement error. As a result, it will be difficult to measure the benefit. However, based upon sound theory and widespread industry practice, raising the transmission network voltage profile translates into reduced losses. While increased power system security is likely as a result of OPF implementation, the focus of this report and analysis has been on the economic impacts of OPF actions on system losses.

Two options were considered in this report - to implement OPF or to maintain the status quo, in which OPF is not used. If OPF is not implemented then losses will continue to be incurred at the same rate as they have been historically, at approximately 3% of system generation. If OPF is implemented the decrease in losses is estimated, on average, to be 1 MW over an hour. This reduction was assumed to directly offset production at Holyrood. Over the course of 10 years the cost benefit analysis showed a cumulative net present value of $3.3 million.

A sensitivity analysis was performed based on a low price fuel scenario. This analysis showed that the effect on the economic feasibility of the project was

minimal. In this case, the cost benefit analysis showed a cumulative net present value of $ 1.6 million over the course of 10 years.

In the event of a contingency, such as a major line outage or a generator trip, severe voltage and flow violations may occur. A more refined set of device limits needs to be developed that recognizes the impact of contingencies to a greater extent. Training in use of contingency analysis is also required, so that operators are aware of potential violations and may eliminate them before they occur. Accordingly, a research component has been added to the project cost in an effort to alleviate these risks.

Based upon the analysis of implementing OPF, it is recommended that Hydro proceed with acquiring and implementing OPF.

1 INTRODUCTION

1.1 Background

It is estimated that transmission system losses account for approximately 3.2% of the total generation. Appendix 4: 2005 Loss Summary shows the calculation for the year 2005. If this value could be reduced by even a small amount to 3.1%, then significant cost savings could be obtained. The purpose of this report is to evaluate the costs and benefits of implementing Optimum Power Flow (OPF) software.

Optimum Power Flow (OPF) is a widely used software application that addresses system loss issues. OPF will recommend the generator voltages and transformer tap settings that the power system operator should use in order to minimize losses and maintain system security. Losses are minimized by increasing the system voltages within specified limits.

Hydro has recently replaced the Harris M900 Energy Control system with the Open System International Monarch system. On the Harris M9000 system OPF was only used for study activity. A previous study on the Harris M9000 system has indicated an approximate loss reduction of 1.7 MW for each hour that the Optimum Power Flow (OPF) method was used[1]. The study concluded that loss reductions through application of OPF was technically feasible.

The main objective of the project is to minimize losses in the transmission system while at the same time avoiding system security constraint violations under various contingencies using OPF software. Contingency violations give an indication of the number and severity of violations that would occur in the event of predefined system events, such as the loss of a major transmission line. When using OPF it was noted that the number of violations generally increased but the

[1] OPF Data July 6, 2002, System Operations, Newfoundland and Labrador Hydro, July 6th, 2002, p. 34

violations were, on average, no more than 1% above the maximum limits. Selection of optimum bus and line flow limits is crucial to the success of OPF. Bus voltage limits should be high enough to give reasonable loss reduction capability. However, in implementing OPF recommendation in the real-time system, operators need to be made aware of any significant increase in contingency violations. How to best accomplish this will require additional research and effort, which has been reflected in the project proposal.

1.2 Project Deliverables and Scope

The major deliverable of this project is an OPF software system that will integrate with Hydro's new Energy Management System.

Vendor activities will include:

- Supplying the optimum power flow software. This software will normally operate in a real time environment and provide the user with the system settings (voltages, MVars and MWs) required to obtain minimum system losses within the constraints of the power system elements.

- Performing initial setup, configuration, tuning and testing of the software. This will include, but is not limited to, user training, software setup, and validation of software performance. The vendor will collaborate with Hydro to determine appropriate device limits so that contingency violations are minimized.

Hydro activities will include:

- Creation and validation of calculations required for evaluation of OPF (e.g. losses and system generation).

- Validation of loss reduction and maintenance of the system components, when it has been installed and verified by the vendor.

- Establish voltage monitoring and generate messages if system voltages are moving away from the OPF recommended values.

Also included under the scope of this project is a block of engineering research time devoted to establishing OPF constraints necessary to ensure contingency conditions during OPF do not jeopardize system security.

2 ALTERNATIVES

Developing OPF software to run in conjunction with an Energy Management System (EMS) requires access to proprietary programming code in addition to expertise in OPF algorithm development. Hence, OPF software is most often developed by EMS vendors to closely integrate with pre-existing applications used for EMS real-time operations. Consequently, developing an in-house OPF tool was ruled out as a viable option.

As a result only two alternatives were investigated:

1. Implement OPF: This involves the purchase and implementation of the optimum power flow software.

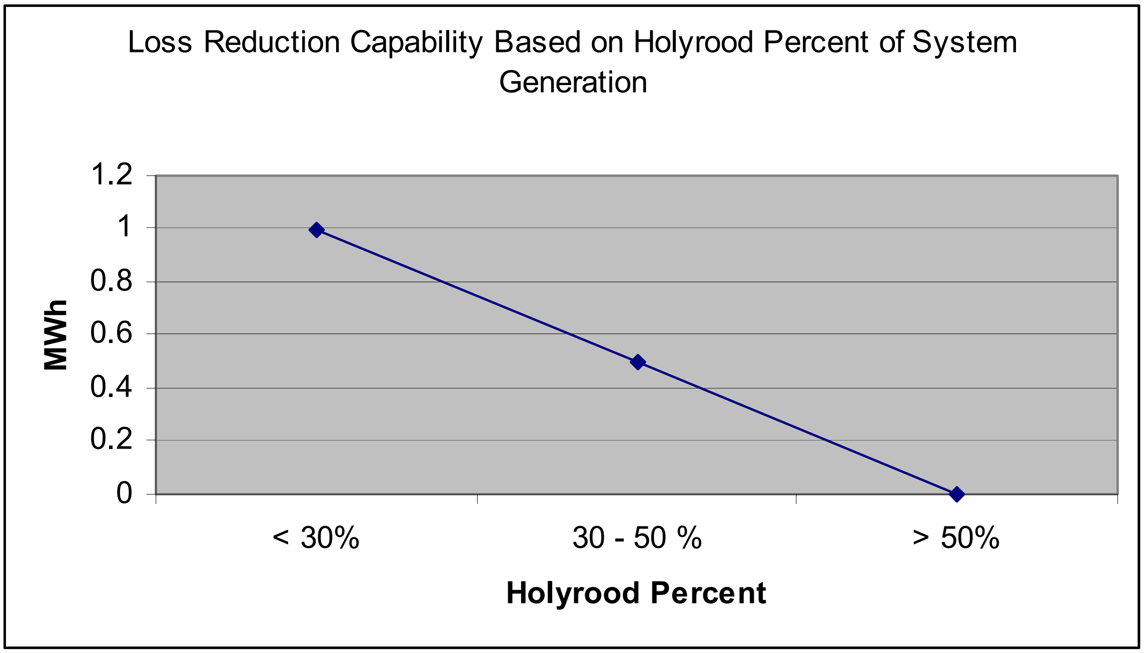
2. Do Not Implement OPF: Leave things as they stand and do not implement the OPF software.

3 ANALYSIS

3.1 OPF Option Methodology

Testing of OPF on the previous Harris M9000 Energy Control System showed a comparative loss reduction in the range of 0.8 to 1.7 MWh per hour. This is based on a series of five tests conducted at various system loads, from 750 to 1000 MWh. The method used to obtain the loss reduction estimates consisted of implementing the recommendations of OPF and then comparing losses to those obtained under similar system conditions, when OPF was not implemented. Because of the variable nature of the power system, the estimated loss reductions may not apply for all system conditions. Taking into account the requirement to minimize post-contingency violations, a more conservative estimate of 0.5 to 1.0 MWh reduction was used. For this smaller reduction, OPF control recommendations would be less aggressive, resulting in fewer and less severe contingency violations.

The results of the 2002 testing showed that OPF had the greatest effect on loss reduction when the Holyrood plant generation was at a minimum and the total system generation was greater than approximately 600 MW. When the Holyrood generation is high, the major load concentrations (the Avalon Peninsula) are close to a major generating source and losses are less than when the generation source is hydraulic. When Holyrood generation is low and the majority of the generation is supplied from hydraulic sources, transmission line losses are greatest. When the Holyrood generation is greater than approximately 50% of the system generation, the loss reduction obtained from OPF is minimal. The highest estimate of loss reduction (1.7 MWh) was obtained when Holyrood generation was at 25% of system generation. Thus, whenever the Holyrood production is between 0 and 50% of the system generation, potential for significant transmission line loss reduction exists.



In estimating the expected loss reduction, it was necessary to look at the amount of time these conditions existed on the system in a typical year. The year selected was 2005. The year 2005 was more representative of current conditions and conditions in the foreseeable future, since a large block of load was removed from the system at this time – approximately 70 MW of load at Abitibi Consolidated Incorporated in Stephenville. Appendix 4 tabulates the number of hours that Holyrood generation is at a given percentage of total system generation. When Holyrood output was 0 to 30% of system generation then an OPF loss reduction estimate of 1 MWh was assumed. When Holyrood output was 30 to 50% of system generation then an OPF loss reduction estimate of 0.5 MWh was assumed. When Holyrood output was greater than 50% of system generation then no OPF loss reduction was assumed. The number of hours that Holyrood output was in each range was multiplied by the corresponding MWh value to obtain the total savings.

Because of the manual process required to implement the settings recommended by OPF and continually changing system conditions, the OPF settings in use at a particular instant may not always result in the maximum benefit. Based on an assumption of 6 to 7 changes in settings per day, there may be 7-8 hours during the day that the maximum loss reduction is not being obtained. As a result, the total loss reduction estimate has been reduced by a factor of one third.

3.2 Assumptions

In analyzing the costs and benefits of acquiring and implementing OPF, the following assumptions were made:

- The size of the system and hence transmission line losses are assumed to be constant over the course of the cost-benefit period. As the size of the system grows, total losses would be expected to increase.

- An OPF tool must be integrated with the current real-time EMS. Accordingly, the analysis time horizon was set to 10 years, the expected life of the EMS.

- A corporate discount rate of 7.0 % was used.

- OPF would be purchased in January of 2008 and would be commissioned in May of 2008. Loss reductions are assumed to commence as of May, 2008.

- All loss reductions directly offset production from Holyrood.

- Avoided production at Holyrood is translated into avoided fuel consumption using a 630 kWh/bbl net conversion factor.

- Avoided fuel costs are derived using Hydro's spring 2007 fuel price forecast (see Appendix 1).

3.3 Results

Hydro estimates currently indicate transmission line energy losses of 3.2%. The estimated cost of transmission line energy losses for 2005 was $18.4 million (based on 2008 fuel price of $54.65).

Estimated savings:

% of Generation Contributed by Holyrood	MWh Loss Reduction	# Hours	$ Savings
Between 0% and 30%	1	6,768	$ 391,000
Between 30% and 50%	0.5	536	$ 16,000
Greater Than 50%	0	121	$ 0
System Generation < 600 MW	0	752	$ 0
Total		**8,177**	$ 407,000

If OPF had been implemented in 2005 then the estimated transmission line energy losses would be reduced to 3.1%. The estimated total cost of the losses would be reduced to $18.0 million. This represents a total saving of $407,000.

The in-service project cost is $215,709. This includes the purchase and installation of the software, project management cost, training, corporate overhead, escalation, AFUDC and contingency. An estimate of these costs is given in Appendix 3.

The cost benefit results for this case are shown in Appendix 2. This analysis shows a net present value of $3.3 million over a 10 year period.

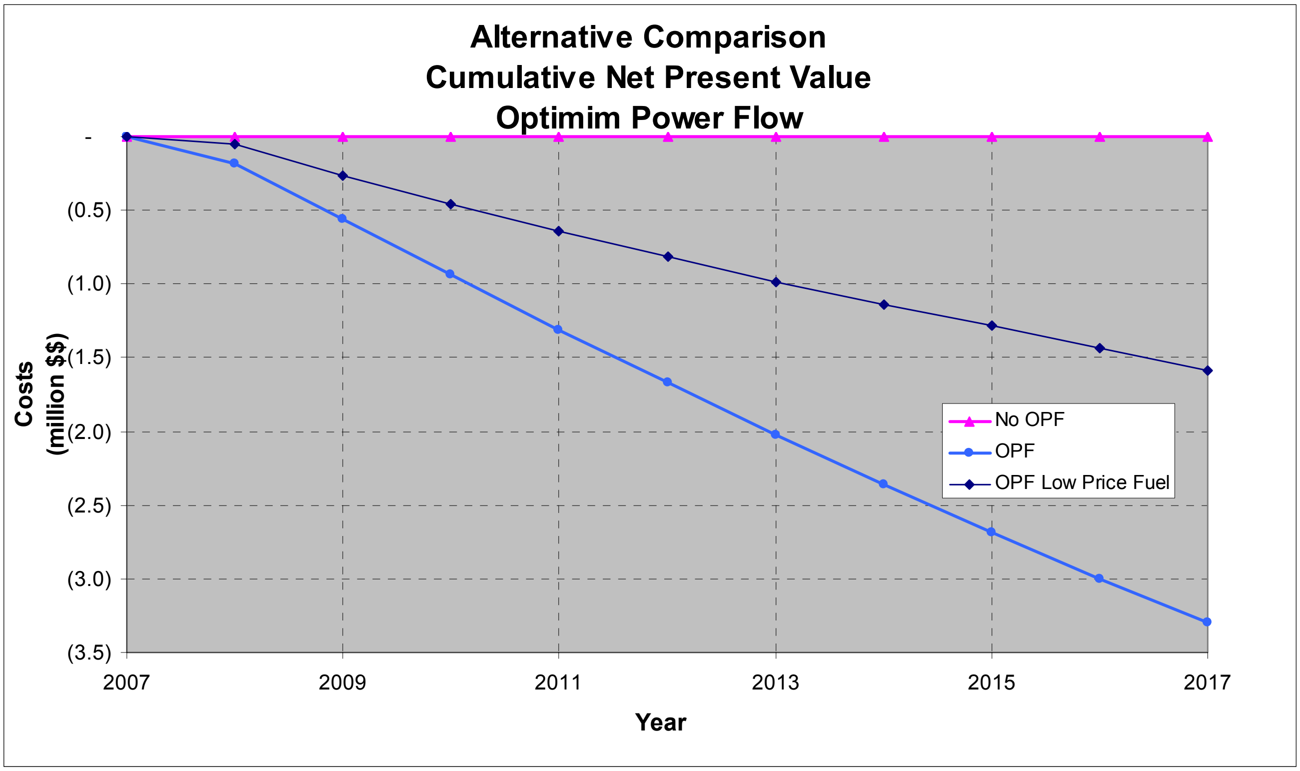
3.4 Sensitivity Analysis

A sensitivity analysis was conducted using a low fuel price forecast. See Appendix 1: NLH Residual Fuel Reference for fuel price information. The cost benefit results for this case are shown in Appendix 2. The total net present value of the project over the ten year period dropped from $3.3 million to $1.6 million.

The following table and graph show the results of the cost benefit analysis.

Optimum Power Flow
Alternative Comparison
Cumulative Net Present Value
To The Year
2017

Alternatives	Cumulative Net Present Value (CPW)	CPW Difference between Alternative and the Least Cost Alternative
Alternative # 1 OPF	(3,299,172)	0
No OPF		
OPF With Low Price Fuel Forecast	(1,590,682)	1,708,490



3.5 Discussion

The analysis demonstrates that the costs associated with implementing an OPF system are vastly outweighed by the expected benefits. The initial capital cost of the tool is expected to be fully recovered through avoided Holyrood fuel costs within the first 12 months following commissioning, even with a low fuel price forecast.

In reviewing the justification for proceeding with the project, the following issues should be noted:

- In this analysis, system generation values less than 600 MW were omitted. At low generation levels, voltage stability is the main objective and System Operations wishes to minimize changes to system voltages.

- The estimated energy savings are small compared to the system measurement error (± 5%). As a result it is difficult to quantify real time savings due to implementation of OPF. However, OPF is based on the principal that an increase in voltage results in a reduction of losses and from the physics of static electrical systems, a reduction in losses is a known result of increased voltage.

- OPF can be used in a real-time environment or in an off-line simulation environment (study mode). Study mode would normally be used to investigate actions that would be required to reduce losses for a change in the system, for example, a change load level.

- This project also has a positive environmental impact. A reduction in emissions will result since this project has the potential to displace 1.0 MWh per hour of Holyrood generation for each hour that OPF is used.

4. RECOMMENDATIONS AND CONCLUSIONS

Implementation of OPF on Hydro's Energy Management System is expected to yield ongoing savings in system losses. These savings more than offset the cost of acquisition, and will enable Hydro to further pursue its objective of providing least cost electrical power with due consideration for the environment.

Because of the relatively small MWh savings obtained during our testing, it is difficult to quantify the real time savings due to implementation of OPF. A saving of 1 MWh is well within the existing system measurement error (± 5%). However, OPF achieves a reduction in losses by increasing system voltages, which is a verifiable result for any static electrical system.

Accordingly, it is recommended that Hydro purchase and implement OPF.

APPENDICES

Appendix 1: NLH Residual Fuel Reference

Year	Reference	Low Fuel
	(Nominal Dollars)	(Nominal Dollars)
	#6 1.0%s	#6 1.0%s
	($Cdn/bbl)	($Cdn/bbl)
2007	50.50	43.80
2008	54.65	36.45
2009	61.10	34.60
2010	64.75	34.60
2011	68.45	35.05
2012	71.50	36.25
2013	73.40	36.90
2014	75.50	36.35
2015	78.05	37.35
2016	80.45	40.85
2017	82.80	43.15

Appendix 2: Cost - Benefit Analysis Results

Year	OPF Option				Sensitivity: OPF Option With Low Fuel Price Forecast			
	Costs	**Benefit**	**P.W. January 2008**	**Cumulative Present Worth**	**Costs**	**Benefit**	**P.W. January 2008**	**Cumulative Present Worth**
2007	-	-	-	-	-	-	-	-
2008	215,709	406,897	178,680	178,680	215,709	271,389	52,037	52,037
2009	19,640	454,920	380,191	558,871	19,640	257,614	207,856	259,893
2010	20,092	482,096	377,133	936,004	20,092	257,614	193,889	453,783
2011	20,554	509,645	373,125	1,309,130	20,554	260,965	183,409	637,191
2012	21,067	532,353	364,540	1,673,669	21,067	269,899	177,414	814,605
2013	21,594	546,500	349,767	2,023,436	21,594	274,739	168,681	983,286
2014	22,134	562,135	336,286	2,359,722	22,134	270,644	154,760	1,138,046
2015	22,687	581,121	325,014	2,684,736	22,687	278,090	148,646	1,286,692
2016	23,255	598,991	313,162	2,997,898	23,255	304,149	152,788	1,439,480
2017	23,836	616,488	301,274	3,299,172	23,836	321,273	151,202	1,590,682

Appendix 3: Cost Estimate

Item	Total Cost
Purchase and Install Contract	$157,448
Escalation	$4,100
Project Management	$23,961
AFUDC	$12,000
Contingency	$18,200
Total	$215,709

Appendix 4: 2005 Loss Summary

The following table gives a monthly breakdown of system generation and system losses in MWh for each category of Holyrood operation in the range of 0% to 70% of system generation. A summary table then sums the monthly totals to give the year results.

Jan-05							
%HRD/System Generation	Avg. Loss MWh	Avg %HRD	Avg HRD MWh	Avg S.G. MWh	#Hours	Total MWH Loss	Total MWH System Generation
`0-10 %					0	0	0
`10-20 %	44.81	19.23	207.11	1077.95	19.00	851.30	20480.98
`20-30 %	37.90	25.92	277.11	1063.84	199.00	7541.64	211704.47
`30-40 %	31.21	34.48	375.13	1092.36	394.00	12295.47	430390.17
`40-50 %	18.40	44.19	384.20	871.96	124.00	2281.72	108122.47
`50-60 %	17.50	51.50	396.88	771.23	8.00	139.96	6169.84
`60-70 %					0.00	0.00	0.00
					744.00	23110.10	776867.92
Feb-05							
%HRD/System Generation	Avg. Loss MWh	Avg %HRD	Avg HRD MWh	Avg S.G. MWh	#Hours	Total MWH Loss	Total MWH System Generation
`0-10 %					0.00	0.00	0.00
`10-20 %					0.00	0.00	0.00
`20-30 %	36.05	27.80	297.29	1070.41	99.00	3568.78	105970.62
`30-40 %	28.23	34.81	355.38	1022.19	264.00	7451.42	269857.41
`40-50 %	21.03	44.04	420.44	958.02	231.00	4857.42	221301.60
`50-60 %	17.38	53.38	423.32	793.56	76.00	1320.59	60310.57
`60-70 %	17.77	60.74	442.00	727.78	2.00	35.53	1455.55
					672.00	17233.75	658895.74
Mar-05							
%HRD/System Generation	Avg. Loss MWh	Avg %HRD	Avg HRD MWh	Avg S.G. MWh	#Hours	Total MWH Loss	Total MWH System Generation
0-10 %					0.00	0.00	0.00
`10-20 %					0.00	0.00	0.00
`20-30 %	32.60	27.16	275.40	1016.01	99.00	3227.52	100585.18
`30-40 %	24.24	35.23	331.14	940.79	404.00	9794.62	380080.55
`40-50 %	19.42	43.57	390.32	896.10	206.00	4000.75	184596.36
`50-60 %	18.06	54.17	451.97	834.76	35.00	632.17	29216.75
`60-70 %					0.00	0.00	0.00
					744.00	17655.05	694478.83

Apr-05							
%HRD/System Generation	Avg. Loss MWh	Avg %HRD	Avg HRD MWh	Avg S.G. MWh	#Hours	Total MWH Loss	Total MWH System Generation
`0-10 %	34.33	8.27	66.82	810.47	14.00	480.67	11346.55
`10-20 %	29.15	16.15	132.16	819.64	380.00	11078.77	311463.58
`20-30 %	20.58	23.30	174.62	744.69	340.00	6996.03	253194.85
`30-40 %	18.00	30.84	232.00	753.09	10.00	179.98	7530.95
`40-50 %					0.00	0.00	0.00
`50-60 %					0.00	0.00	0.00
`60-70 %					0.00	0.00	0.00
					744.00	18735.45	583535.93
May-05							
%HRD/System Generation	Avg. Loss MWh	Avg %HRD	Avg HRD MWh	Avg S.G. MWh	#Hours	Total MWH Loss	Total MWH System Generation
`0-10 %	32.39	1.81	12.28	673.36	619.00	20047.60	416812.86
`10-20 %	22.15	13.19	88.66	661.50	77.00	1705.58	50935.24
`20-30 %	14.48	23.33	144.73	625.03	24.00	347.57	15000.72
`30-40 %					0.00	0.00	0.00
`40-50 %					0.00	0.00	0.00
`50-60 %					0.00	0.00	0.00
`60-70 %					0.00	0.00	0.00
					720.00	22100.75	482748.82
Jun-05							
%HRD/System Generation	Avg. Loss MWh	Avg %HRD	Avg HRD MWh	Avg S.G. MWh	#Hours	Total MWH Loss	Total MWH System Generation
`0-10 %	27.77	0.04	0.24	616.68	642.00	17830.14	395907.16
`10-20 %	18.15	18.41	118.68	643.68	31.00	562.53	19953.95
`20-30 %	13.54	22.43	123.65	557.39	47.00	636.41	26197.12
`30-40 %					0.00	0.00	0.00
`40-50 %					0.00	0.00	0.00
`50-60 %					0.00	0.00	0.00
`60-70 %					0.00	0.00	0.00
					720.00	19029.09	442058.23
Jul-05							
%HRD/System Generation	Avg. Loss MWh	Avg %HRD	Avg HRD MWh	Avg S.G. MWh	#Hours	Total MWH Loss	Total MWH System Generation
`0-10 %	24.66	0.94	5.77	604.19	79.00	1947.99	47731.32
`10-20 %	17.17	18.48	120.33	651.79	263.00	4515.21	171421.40
`20-30 %	12.15	22.21	117.19	531.34	362.00	4398.41	192346.27
`30-40 %					0.00	0.00	0.00
`40-50 %					0.00	0.00	0.00
`50-60 %					0.00	0.00	0.00
`60-70 %					0.00	0.00	0.00
					704.00	10861.61	411498.99

Aug-05							
%HRD/System Generation	Avg. Loss MWh	Avg %HRD	Avg HRD MWh	Avg S.G. MWh	#Hours	Total MWH Loss	Total MWH System Generation
`0-10 %	23.20	0.22	1.36	586.59	380.00	8814.49	222905.73
`10-20 %	16.66	16.43	100.86	617.19	285.00	4747.30	175899.83
`20-30 %	10.15	21.35	101.78	477.19	79.00	802.02	37698.11
`30-40 %					0.00	0.00	0.00
`40-50 %					0.00	0.00	0.00
`50-60 %					0.00	0.00	0.00
`60-70 %					0.00	0.00	0.00
					744.00	14363.82	436503.67
Sep-05							
%HRD/System Generation	Avg. Loss MWh	Avg %HRD	Avg HRD MWh	Avg S.G. MWh	#Hours	Total MWH Loss	Total MWH System Generation
`0-10 %	21.43	2.83	18.88	572.97	74.00	1585.46	42400.10
`10-20 %	18.24	14.89	94.53	642.41	597.00	10886.92	383519.21
`20-30 %	10.28	21.01	100.42	478.18	73.00	750.53	34906.84
`30-40 %					0.00	0.00	0.00
`40-50 %					0.00	0.00	0.00
`50-60 %					0.00	0.00	0.00
`60-70 %					0.00	0.00	0.00
					744.00	13222.91	460826.15
Oct-05							
%HRD/System Generation	Avg. Loss MWh	Avg %HRD	Avg HRD MWh	Avg S.G. MWh	#Hours	Total MWH Loss	Total MWH System Generation
`0-10 %	21.72	7.12	43.26	613.30	20.00	434.39	12265.99
`10-20 %	22.06	14.84	101.36	695.99	307.00	6772.38	213667.76
`20-30 %	20.27	24.82	179.16	725.08	271.00	5493.14	196497.71
`30-40 %	11.48	32.90	181.58	552.94	123.00	1411.80	68011.24
`40-50 %					0.00	0.00	0.00
`50-60 %					0.00	0.00	0.00
`60-70 %					0.00	0.00	0.00
					721.00	14111.72	490442.68
Nov-05							
%HRD/System Generation	Avg. Loss MWh	Avg %HRD	Avg HRD MWh	Avg S.G. MWh	#Hours	Total MWH Loss	Total MWH System Generation
`0-10 %					0.00	0.00	0.00
`10-20 %	32.09	16.46	131.08	797.80	214.00	6866.37	170730.12
`20-30 %	21.21	24.19	172.85	723.57	467.00	9906.41	337907.28
`30-40 %	11.79	31.69	178.00	563.19	63.00	742.53	35481.00
`40-50 %					0.00	0.00	0.00
`50-60 %					0.00	0.00	0.00
`60-70 %					0.00	0.00	0.00
					744.00	17515.32	544118.40

Dec-05							
%HRD/System Generation	Avg. Loss MWh	Avg %HRD	Avg HRD MWh	Avg S.G. MWh	#Hours	Total MWH Loss	Total MWH System Generation
`0-10 %					0.00	0.00	0.00
`10-20 %	37.76	15.68	135.50	870.09	526.00	19862.26	457669.32
`20-30 %	26.04	23.10	177.64	770.42	181.00	4713.01	139446.87
`30-40 %	10.39	32.99	183.50	556.84	5.00	51.93	2784.21
`40-50 %					0.00	0.00	0.00
`50-60 %					0.00	0.00	0.00
`60-70 %					0.00	0.00	0.00
					712.00	24627.20	599900.39

Total Losses for 2005								
		Actual	Avg.	Avg	Avg	Total		Avg
%HRD/System Generation	Avg. Loss	MWH Loss	%HRD	HRD MWh	System Gen	MWh System Generation	#Hours	% Loss
`0-10 %	26.50	51140.75	3.03	21.23	639.65	1149369.71	1828.00	0.0414
`10-20 %	25.82	67848.64	16.38	123.03	747.80	1975741.38	2699.00	0.0345
`20-30 %	21.27	48381.49	23.89	178.49	731.93	1651456.03	2241.00	0.0291
`30-40 %	19.33	31927.75	33.28	262.39	783.06	1194135.51	1263.00	0.0247
`40-50 %	19.62	11139.89	43.93	398.32	908.69	514020.43	561.00	0.0216
`50-60 %	17.64	2092.72	53.02	424.06	799.85	95697.15	119.00	0.0221
`60-70 %	17.77	35.53	60.74	442.00	727.78	1455.55	2.00	0.0244
Totals		212566.77				6581875.77	8713.00	0.0283
Cost								

From this total the percentage transmission losses of system generation are calculated as follows:

Actual MWh Loss/MWh System Generation = 212566.77/6581875.77 *100% = 3.2%

Adjusted Losses

%HRD/System Generation	MWh No OPF	MWh OPF	MWh Diff	Cost Savings	Adjusted for 2/3 Duty Cycle
`0-10 %	51140.75	49312.75	1828.00	146530.16	97691.66
`10-20 %	67848.64	65149.64	2699.00	216348.41	144239.49
`20-30 %	48381.49	46140.49	2241.00	179635.71	119763.13
`30-40 %	31927.75	31296.25	631.50	50620.24	33748.51
`40-50 %	11139.89	10859.39	280.50	22484.52	14990.43
`50-60 %	2092.72	2092.72	0.00	0.00	0.00
`60-70 %	35.53	35.53	0.00	0.00	0.00
Totals	212566.77	204886.77	7680.00	615619.05	410433.22
Cost	18439323.78	17773114.25			

Loss Reduction Estimates For 2008 - With Contingency Buffer – 2008 Fuel Price $54.65					
	MWH Loss Reduc	#Hrs*	Total MWH	$ Saving	With 2/3 Factor
HRD<30%	1.00	6768.00	6768.00	587097.14	391398.10
HRD Between 30 and 50 %	0.50	1072.00	536.00	23247.94	15498.62
HRD >50%	0.00	121.00	0.00	0.00	0.00
Unavailable	0.00	752.00	0.00	0.00	0.00
Total		8713.00	7304.00	610345.08	406896.72

* Number of hours for 30-50% category was reduced from 1824 to 1072 to account for the 752 hours in which the system generation was less than 600 MW or data was unavailable.

Tab 11

REPLACEMENT OF CUSTOMER SERVICES BILLING AND OUTAGE INFORMATION SYSTEM

NEWFOUNDLAND AND LABRADOR HYDRO

JUNE 7, 2007

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1 EXECUTIVE SUMMARY

In 2003, Newfoundland and Labrador Hydro (Hydro) contracted with Aliant Inc. to provide a Customer Services Billing and Outage Information System that would be available to customers 24 hours per day, seven days a week, and would allow self-serve information retrieval. The system supplied by Aliant is known as Multi-Channel Application Service (MCAS), and is available to customers via a touch-tone telephone interface and an Internet interface. Aliant has notified Hydro that this system will be taken out of service in 2008.

To determine the most cost-effective solution, Hydro contacted several equipment vendors to obtain the cost of a replacement system. At the time of writing this document, only one vendor has responded. In addition, Aliant has indicated that they are now intending to replace the system with another service; no details or costs on the proposed replacement are forthcoming at this time.

Three options were considered for the MCAS replacement:

- Do nothing;
- Stand-alone solution, owned and operated by Hydro; and
- Leased system.

The first alternative is unacceptable, as customers are accustomed to the existing level of service. The cost-benefit analysis of the two acceptable solutions determined that a Hydro-owned system has a net benefit of approximately $315,000, based on currently available information. In order to ultimately ensure the least cost solution that meets functional requirements is obtained, this system will be publicly tendered.

2 BACKGROUND

2.1. Overview

Prior to 2003, all Hydro's customer billing and power outage inquires were administered by Customer Service Representatives (CSRs) during regular working hours. After hours, the Energy Control Center (ECC) provided customers with power outage information only. Hydro currently operates a Customer Services Billing and Outage Information System (the System) that is available to customers 24 hours per day, seven days a week, and provides self-serve information retrieval. The System was designed to minimize the involvement of the CSRs and ECC operators in relatively mundane tasks such as providing customers with account balances, payment due dates, power outage duration, anticipated power outage restoration times, and so on. The System consists of an Internet application and an Interactive Voice Response (IVR) application that provides the following:

- Customer access to account information;
- Customer access to power outage messaging;
- Meter Reader access to account information;
- Limited statistical reporting;
- Emergency call re-routing by telephone exchange; and
- Automated Power Outage Messaging.

To provide this service, Hydro utilizes the MCAS application, which is owned and operated by Aliant but which will be discontinued in 2008. The purpose of this project is to replace MCAS with the least cost alternative that provides, as a minimum, the same functionality as the Aliant MCAS system.

2.2. Operating Experience

Since implementation in 2003, the MCAS IVR component has successfully answered on average approximately 60,000 billing and power outage enquiries per year. At the time of its implementation, Hydro paid Aliant $170,000 (2003 dollars) to cover the cost of customization of MCAS to Hydro's requirements.

Hydro is billed for facilities and usage. These costs include the telecommunications facilities from Hydro to the MCAS system, as well as per use charges for each inquiry. Operating costs today average $50,000/year.

All changes to the existing system must be performed by Aliant. Since the system was installed in 2003, one change was requested. The scope of the change consisted of functional changes to provide customers with more information on outages, and to provide administrators with better tools to administer information related to power outages. This was completed in 2006 at a cost of $21,000.

On September 22, 2006 Aliant Inc. issued Hydro a "Notice of Discontinuation of Multi-Channel Application Service". The notice identified October 21, 2008 as the MCAS End-Of-Life date. In addition, Aliant Inc. informed Hydro that no further service enhancements would be performed after December 31, 2006, and that Aliant had no future plans of providing a replacement system.

3 ALTERNATIVES

Three alternatives were considered for the replacement of MCAS:

- Do nothing;
- Stand-alone solution, owned and operated by Hydro; and
- Leased system.

The do nothing approach is unacceptable. The Customer Services department relies on this system to provide accurate and timely information to customers. Customers expect account information to be available after working hours, and they expect the Internet to be a source of this information. They also expect to be able to report, and obtain information on, power outages regardless of when they occur. Failure to replace the system will cause these capabilities to be lost.

In an effort to obtain accurate costs for a stand-alone solution, three manufacturers were contacted. Only one responded with a cost estimate; however, because this is for a system that is an extension of the existing PBX, as opposed to the complete replacement that would be required if another manufacturer were to be chosen, it is also likely the least cost. This estimate is used herein.

There may be leased services available as well. Aliant has verbally indicated that they now intend to offer a replacement for MCAS; however, details and costs are not available at this time. Other service providers also exist, but their desire and ability to provide service is unknown at this time. Leased options will be addressed during tendering.

4 PROJECT DESCRIPTION

4.1. Objective

This project's objective is to implement a replacement Billing and Outage Information System. This System will provide Hydro with the required infrastructure to provide the services described in Section 2 above; that is, to provide the least-cost solution for Hydro to achieve the following outcomes:

- Enable Hydro customers to securely obtain personal billing information via an Internet browser or touch-tone telephone;
- Enable Hydro customers to obtain power outage information via an Internet browser or touch-tone telephone;
- Enable Hydro customers to report a power outage via an Internet browser or touch-tone telephone;
- Enable Hydro meter readers to securely obtain billing information for accounts via an Internet browser or touch-tone telephone;
- Enable Hydro administrators to add, modify, and delete system users via an

Internet browser;

- Enable Hydro administrators to update outage information via an Internet browser or touch-tone telephone;
- Create a data repository to provide account information around the clock, even when the corporate customer information database is offline.

4.2. Project Scope

This project as estimated assumes that a new System will be implemented using Hydro's existing Private Branch Exchange (PBX) located at Hydro Place as a base platform, upon which the System will reside. Other options may exist; for instance, it may be more cost-effective to replace the PBX entirely. Because information regarding complete replacement is not available at this time, this will be addressed during tendering. Best information at this time indicates that the upgrade is the most realistic option.

The project can be considered to consist of three major components:

- PBX upgrade;
- IVR or touch-tone telephone integration; and
- Web interface integration.

The PBX upgrade is a prerequisite to implementing the System, if Hydro's existing PBX is used. It involves a hardware and software upgrade to the Hydro Place PBX in order to bring it to a current version. This upgrade has already been identified and planned by Telecontrol Engineering as a required upgrade, with a separate capital budget proposal identified for 2009 to accomplish this. If the System is implemented using the existing PBX, the proposed upgrade will not be required in 2009.

The IVR component will be implemented by a contractor and will consist of new equipment installation, software to permit integration with the upgraded PBX, and custom software development to establish the IVR call hierarchy. In addition to maintaining the present touch-tone telephone feature set, the new IVR will incorporate new features, such as customizable statistical reports for Hydro analysis, and speech recognition for customers.

The final component, the web interface, involves creating a new graphical user interface to allow customers to access billing and outage information via the Internet. Like the IVR component, the web interface will maintain the same feature set as the existing System, with the addition of some new features. These new features will include more flexible and more comprehensive reports for usage data, maintaining a history of power outages, and providing customers with historical account information.

5 COST BENEFIT ANALYSIS

In determining the most cost-effective solution, the estimate for a Hydro-owned System was compared to a projected cost for a leased solution. The leased system estimate is based on the cost of, and experience with, the existing MCAS system, since no other leased costs are available at this time.

In developing a leased service estimate, the following assumptions were used:

- Internal forces will be used to answer customer enquiries;
- As with MCAS, the life of a leased solution will be five years, after which time a total replacement will be required;
- Costs for the leased solution are estimated to be the same as those for MCAS, converted to present day dollars;
- One enhancement will be required half way through the life of a leased solution, at the same cost incurred by Hydro in 2006 for an enhancement of MCAS, converted to present day dollars;
- Because internal labour costs were not available for the original MCAS installation, internal costs are estimated for the leased solution;

- Reoccurring operating costs for a leased service are based on current costs for MCAS.

In the estimate for the owned System, the following assumptions were used:

- Internal forces will be used to answer customer enquiries;
- The life of the System will be ten years. This is comparable to existing telephone systems owned by Hydro; in fact, it may be conservative;
- The operating cost to maintain the system will be two weeks manpower for one technologist per year, at an estimated cost of $3,400/year (2007 dollars);
- Two enhancements are assumed to be required over the life of the product. Because these are done with internal forces, it is anticipated that the cost will be lower than for a leased system. One week for a design engineer and four weeks for a design programmer are assumed per enhancement, at a cost of $9,200 (2007 dollars).

The results of the analysis are contained in Appendix A. As shown, the owned system is the less expensive alternative. Over a ten year life, the estimated net benefit is over $315,000.

5.1. Qualitative Analysis

Alternative #1, the Hydro owned and operated System, will provide the necessary functional requirement of the existing Customer Services Billing and Outage Information System. This system will also provide Hydro with:

- Flexibility for implementing changes as identified by system users;
- Flexibility for integration with present or new systems, such as Automatic Meter Reading (AMR); and
- In-house technical resources for troubleshooting issues and developing enhancements.

The second alternative, a leased System, would be similar to the existing MCAS system. A leased system would provide the required functionality, but past experience has shown the following limitations:

- Difficulties or long delays with implementing changes and resolving maintenance issues;
- High costs associated with implementing changes;
- Unpredictability for the continuation of service;
- No control over recurring costs.

6 CONCLUSION

Preliminary analysis shows that the Hydro-owned System described in this document is the least cost solution for providing the Billing and Customer Outage System for Hydro. In order to ensure that all avenues are explored, other alternatives will be requested during tendering, and the least cost solution chosen at that time.

Appendix A
Cost Benefit Analysis

JECT COST / BENEFIT ANALYSIS TEMPLATE
mer Services System
o Owned
NLH Owned

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2008
Number of Years in Study	10
Discount Rate	7.0%
Total In-service Project Cost	$ 949,000
In-service Year	2008
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 *PBX Upgrade* $**	**Benefit 2 *(specify)* $**	**NET $**	**P.W. January 2008**	**Cumulative Present Worth**
0	2007	-		-	-	-	-	-	-	-	-
1	2008	3,482		-	-	952,482	-	-	952,482	890,170	890,170
2	2009	3,565		-	-	3,565	(329,000)	-	(325,435)	(284,247)	605,922
3	2010	3,647		-	-	3,647	-	-	3,647	2,977	608,899
4	2011	13,827		-	-	13,827	-	-	13,827	10,548	619,448
5	2012	3,824		-	-	3,824	-	-	3,824	2,727	622,175
6	2013	3,920		-	-	3,920	-	-	3,920	2,612	624,787
7	2014	4,018		-	-	4,018	-	-	4,018	2,502	627,289
8	2015	4,118		-	-	4,118	-	-	4,118	2,397	629,686
9	2016	15,644		-	-	15,644	-	-	15,644	8,509	638,195
10	2017	4,327		-	-	4,327	-	-	4,327	2,200	640,394
						-			-	-	-
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Assumptions & Notes:
1. Costs based on estimate obtained from Nortel, 2007.
2. 10 year ife assumed, with no upgrades required.
3. Benefit in 2009 is obtained from no longer needing upgrade of PBX, currently planned for that year.

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Customer Services System

Leased System

Leased System

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2008
Number of Years in Study	10
Discount Rate	7.0%
Total In-service Project Cost	$ 310,000
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	$ -
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 310,000
Replacement Year (if applicable)	2013
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	2007	-		-	-	-	-	-	-	-	-
1	2008	55,501		-	-	365,501	-	-	365,501	341,590	341,590
2	2009	56,833		-	-	56,833	-	-	56,833	49,640	391,230
3	2010	58,140		-	-	58,140	-	-	58,140	47,460	438,689
4	2011	59,477		-	23,298	82,775	-	-	82,775	63,149	501,838
5	2012	60,964		-	-	60,964	-	-	60,964	43,467	545,304
6	2013	62,488		-	-	372,488	-	-	372,488	248,205	793,509
7	2014	64,050		-	-	64,050	-	-	64,050	39,887	833,396
8	2015	65,652		-	-	65,652	-	-	65,652	38,210	871,606
9	2016	67,293		-	25,471	92,764	-	-	92,764	50,458	922,064
10	2017	68,975		-	-	68,975	-	-	68,975	35,064	957,127
						-			-	-	-
						-			-	-	-
						-			-	-	-
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Assumptions & Notes:

1. All costs based on cost of existing MCAS system.
2. The leased system is assumed to have a 5 year life, at which time it must be replaced, based on experience with existing system.
3. Two upgrades are assumed, in 2011 and 2016. Costs ar based on cost for upgrading existing system in 2006.

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Customer Services System

Alternative Comparison

Cumulative Net Present Value

To The Year

2017

Alternatives	Cumulative Net Present Value (CPW)	CPW Difference between Alternative and the Least Cost Alternative
Hydro Owned	640,394	0
Leased System	957,127	316,733

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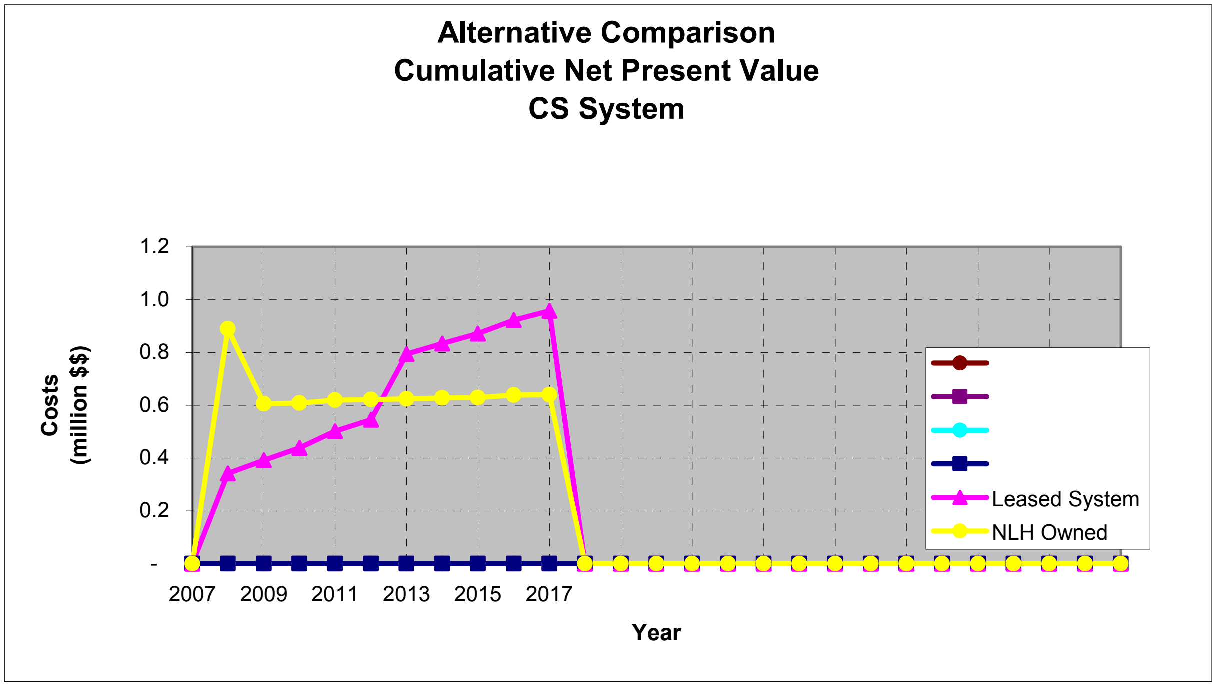
Alternative Comparison
Cumulative Net Present Value
CS System
Costs (million $$)
1.2
1.0
0.8
0.6
0.4
0.2
-
2007
2009
2011
2013
2015
2017
Year
Leased System
NLH Owned

Tab 12

CHANGE ISLANDS RECLOSERS

REMOTE CONTROL ANALYSIS

NEWFOUNDLAND AND LABRADOR HYDRO

JUNE 5, 2007

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1 INTRODUCTION

The purpose of this project is to provide remote control from the Energy Control Center (ECC), located at Hydro Place in St John's, to the two reclosers FH1-R1 and FH1- R2 located on the southern tip of Change Islands. These two reclosers form part of the Farewell Head Distribution System that supplies electricity to 1750 residential and commercial customers on Fogo Island and Change Islands. FH1-R1 protects and controls the power supply to Change Islands and FH1-R2 protects and controls the supply to Fogo Island. This upgrade will improve service to the customers and increase reliability of the distribution system.

2 BACKGROUND

Overview

The Farewell Head Distribution system consists of a terminal station at Farewell Head, a submarine cable between Farewell Head and Change Islands, a distribution system on Change Islands, a second submarine cable between Change Islands and Fogo Island and the distribution system on Fogo Island. The two reclosers that will be remote controlled are located on the southern tip of Change Islands. One recloser controls power to the Change Islands distribution system, while the second controls power from Change Islands over the submarine cable and into the Fogo Island distribution system.

Operating Experience

The Farewell Head distribution reliability statistics are shown in the following table.

Farewell Head Distribution System Reliability Performance

Farewell Head System		
	SAIFI	**SAIDI**
2001	3.95	6.79
2002	10.49	36.75
2003	11.37	28.99
2004	6.27	22.77
2005	6.86	17.55
2006	2.57	6.41
Farewell Head 2002-2006 Average	7.52	22.51
NLH 2002-2006 Average	6.88	10.7
CEA 2006	2.54	7.88
CEA 2002-2006 Average	2.36	6.43

The 5-year (2002-2006) System Average Interruption Frequency Index (SAIFI) of 7.52 is comparable to the NLH average of 6.88, but the System Average Interruption Duration Index (SAIDI) index is 22.5, which is over 2 times the NLH average of 10.7, and 3.5 times the Canadian Electrical Association (CEA) 5-year average (2002-2006) of 6.43. The high duration index is caused by a combination of repair time and repair crew travel time. The outages causes are mainly weather related events, such as lightning during the summer months and a combination of high winds, snow, freezing rain and sea icing conditions in the winter months.

The two reclosers located on Change Islands operate when faults are detected by the protection relays on the distribution systems of either Change Islands or Fogo Island, to protect the equipment from serious damage. Reclosers are used so that the electricity supply can be automatically switched back in after they operate. When a fault causes the recloser to open and disconnect electricity to the load, it will automatically try to reconnect three times in sequence. This permits the customers to be quickly reconnected to the electricity supply without human intervention, if there is a temporary fault, such as a tree branch falling across the line or a lightning strike to the line. If the fault has not cleared once the third automatic attempt is made, the recloser enters a locked state that can only be reset through manual intervention.

Up until the fall of 2003, there was a part-time employee on Change Islands who operated the reclosers on Change Islands and did line worker duties. This employee retired in the fall of 2004 and attempts to hire a replacement have been unsuccessful. Currently there are three full-time line crew personnel stationed on Fogo Island. These crew members are responsible for both the Fogo Island and Change Islands distribution systems. They must travel by ferry to access the Change Islands distribution system and the two reclosers, FH1-R1 and FH1-R2, on Change Islands.

During winter storms and high wind conditions, the reclosers often operate when conductors on the high voltage distribution lines come in close proximity to each other. Under these conditions if the reclosers become locked an extended customer outage will occur because such severe weather usually restricts travel by ferry or helicopter.

Extended outages can also occur at night, when the ferry is not operating and helicopters cannot fly, and during the spring when sea ice can block the ferry route and wind, fog or low cloud may prevent helicopters from flying.

During normal ferry operations, delays in restoring power are experienced due to the regular ferry schedule. The crew located at Fogo must wait for the ferry to pick them up and travel to Change Islands to operate the recloser. The normal round trip to Change Islands takes 2.5-3 hours.

Justification

This project will result in reduction of the extended duration of outages to customers where the line crew does not have to travel to Change Islands to facilitate repairs. There have been 12 incidents since the beginning of 2000 when the Change Islands reclosers locked out requiring local intervention. The duration of the resultant customer outages varied from 1 hour to 27 hours. The shorter duration outages in the range of 1 to 12 hours occurred prior to the retirement of the Change Islands employee. Since the retirement, the durations have been in a range of 4 to 27 hours. Refer to appendix A2 for a listing of customer outage incidents involving FH1-R1 and FH-R2 in the past 7 years.

Remote control of reclosers FH1-R1 and FH1-R2 will improve outage duration times down to potentially minutes for momentary faults. It takes at a minimum 1 to 3 hours and potentially days, to travel to Change Islands by ferry to close either recloser. This project will provide remote control to ECC for both of these reclosers and reduce the outage time for certain events to minutes.

3 PROJECT DESCRIPTION

Description

This project will install a private radio system between Farewell Head Terminal Station and both Changes Islands Reclosers FH1-R1 and FH1- R2. The reclosers' communications interface will be upgraded so that they will have the ability to communicate with the existing SCADA System at Farewell Head TS via the new radio link. Then leveraging the existing communications infrastructure into Farewell Head TS, remote control will be provided to the Energy Control Center in St John's.

Objectives

The objective of this project is to provide remote control for the Energy Control Center to both reclosers FH1-R1 and FH1-R2 on Change Islands.

Scope/Major Deliverables

The scope of the project includes the following:

- Engineering design, install and commission a Private Radio System between Farewell Head TS and Change Islands;
- Add SCADA controls and indication to the Farewell Head TS Remote Terminal Unit(RTU) for the two reclosers on Change islands and communicate via the new radio link;
- Upgrade recloser controls with a new communications and controls interface.
- Add and commission new SCADA controls and indications to the Energy Management System

Stakeholders

The primary stakeholders of the Project are System Operations (Energy Control Center), Customers of Change and Fogo Islands, Regulated Operations (Network Services and TRO) and Engineering Services (Telecontrol and P&C).

Dependencies

The following dependencies have been identified for this Project:

- Weather –work is planned for completion during the summer months, although access to the remote sites is dependent on good weather;
- Line outages – either planned or forced, proceeding with the work would be highly dependent on line outages.

Assumptions and Constraints

The following assumptions have been made regarding this Project:

- New radio will operate as predicted using existing radio design software;
- Approval by Industry Canada for radio licences for VHF or UHF radios between ;
- NLH Recourses will be available for installation and commissioning of the new equipment;
- Support from the Energy Control Centre will be provided for the duration of the field commissioning activities;

The following constraints may affect the execution of this Project:

- Limit of 10-hour shift duration for unionized personnel.

4 FUNDING

Funding Requirements

The project will be funded with capital over a one-year period. The following table provides the detail of the budget estimate:

Cost Type	Budget Amount ($)
	Total
1110 – Labour	$58,800
1120 – Overtime	$7,600
1130 – Material	$74,700
1135 – Consultant	$0
1140 – Equipment Rental	$4,400
1145 – Travel	$12,700
1150 – Contract Work	$0
1160 – Corporate Overhead	$10,500
1175 – Contingency	$15,800
1165 – AFUDC	$3,600
Escalation	$5,900
Total:	$194,000

5 ALTERNATIVES

The only alternative is to leave the system as status quo and continue with manual operation of the Reclosers. This would result in no improvement of the existing SAIDI index for Change and Fogo Island customers.

6 COST/BENEFIT ANALYSIS

Quantitative Analysis - Cash Flows of Alternatives

None

Qualitative Analysis — Non-Financial Benefits and Costs

With respect to Alternative #1 that is Status Quo, the existing outage durations will be maintained, with no predicted improvement visible. The service provided to the 1750 customers would not be improved. The Energy Control Center will remain in the same capacity as they are now with no control.

- With respect to Alternative #2, that is to install the new radio system and extend supervisory control to Change Islands reclosers. Real reductions in outage duration for a portion of the outages to Change Islands and Fogo Island can be change reduced. For example, by having remote control, the Fogo Island line crew could have power restored back to Fogo Island immediately following the correction on any damage on Fogo Island, by communicating with ECC and having ECC operate the reclosers on Change Islands. This would save travel time as well as time spent on mobilization and troubleshooting any addition problems that could be present on the Fogo Island side.

7 CONCLUSION

The recommended alternative is to implement the new radio system and operate the reclosers remotely from ECC.

8 APPENDICES

A1: Customer Outage Incidents Fogo Island and Change Islands
A2: Capital Budget Proposal

A1: Customer Outage Incidents Fogo and Change Islands

The following is summary of the events since 2000 in which manual closing of FH1-R1 and FH1-R2 was required and where remote control could reduce customer outage times to minutes. Some of these events involved problems on Fogo Island but recloser FH1-R2 had to be closed on Change Island. This resulted in a multi-hour outage to the 1500 customers on Fogo Island that could be reduced to minutes if the remote control had been in place.

- May 3, 2000, recloser FH1-R2 tripped resulting in outage to 1520 customers on Fogo Island. The recloser was closed in 1.75 hours to restore customers.

- June 7, 2002, sectionalizer FH1-S1 failed on Fogo Island. Recloser FH1-R2 tripped and had to be closed on Change Island. The recloser was closed in 2 hours to restore 1520 customers.

- October 2, 2002, failure of the submarine cable which had to be switched to the spare cable on Change Island. Over 1744 customers experienced a 5 hours outage.

- October 21, 2002, recloser FH1-R2 tripped after a planned outage on transmission TL254 at Farewell Head Terminal Station. 1520 customers experienced a 2.5 hour outage.

- November 6, 2002, recloser FH1-R2 tripped due to lightning arrestor failure on L1. 1520 customers experienced a 2 hour outage.

- December 27, 2002, recloser FH1-R1 tripped. Recloser closed in 1 hour to restore the 219 customers on Change Island.

- December 27, 2002, recloser FH1-R1 tripped. All 219 customers on Change Islands experienced a 12 hours outage after there were problems in closing FH1-R2 and other issues at the submarine cable termination on Fogo Island.

- December 28, 2002, recloser FH1-R2 tripped due to lightning arrestor failure on L1. 1520 customers experienced a 6 hour outage.

- November 9, 2003, recloser FH1-R1 tripped after line 1 was damage during a storm. Repairs were made before the recloser could be closed. 227 customers experienced a 27 hour outage.

- April 16, 2004, recloser FH1-R1 tripped after line 1 was damage during a storm. Repairs were made before the recloser could be closed. 227 customers experienced a 19.5 hour outage.

- November 16, 2004, recloser FH1-R1 tripped after line 1 was damage during a storm. Repairs were completed before the recloser could be closed. 227 customers experienced a 27 hour outage.

- March 27, 2005, recloser FH1-R2 tripped due to failure of the submarine cable termination on Fogo Island on L1. 1500 customers experienced a 4 hour outage.

Tab 13

MICROWAVE ANTENNA

RADOME REPLACEMENT PROGRAM

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

MAY 29, 2007

Table of Contents

Introduction

This report presents the Newfoundland and Labrador Hydro (Hydro) Radome Replacement Program. This is an ongoing program to replace microwave radio radomes, the protective covers that enclose the delicate components of the microwave antennas in Hydro's microwave radio system.

This report includes background information relating to the Radome Replacement Program and provides discussions of Hydro's operating experience in this area. Descriptions of the scope and costs associated with the program are also presented.

Background

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;
- Operational and administrative voice systems.

Microwave radio signals are transmitted from one location to the next using parabolic antennas attached to towers. These towers are mounted up to heights of 120 m and range in diameter from 3 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 radomes. 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, cause 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.

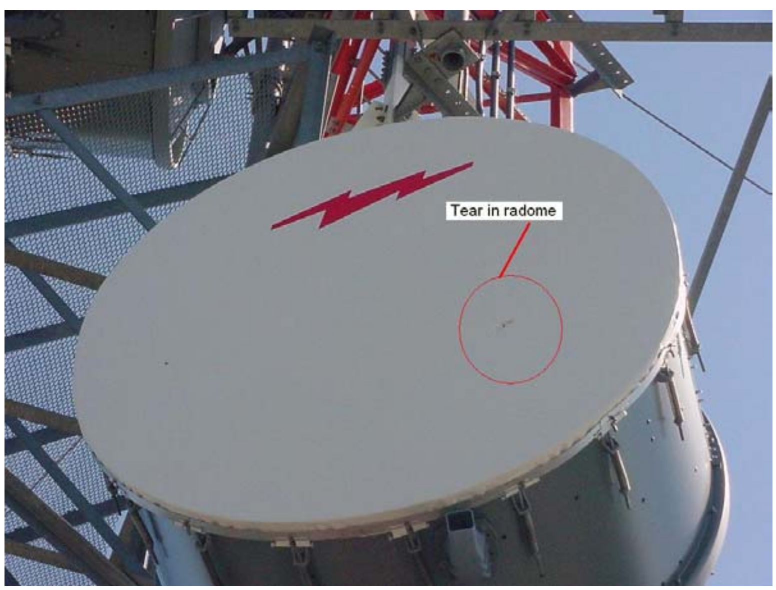

Figure 2. Tear in radome.

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.

Operating Experience

In the winter of 1996, Hydro suffered a significant and sustained outage to its communications network as a result of the failure of two separate radomes during a wind storm. Despite routine inspections, radomes at both Sandy Brook Hill Microwave Site and Mary March Hill Microwave Site were torn and the material of the shells became entangled in the antenna feed horns. As a result, the feed horns in both cases 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.

As a result of the costs and outage time associated with this incident, 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 a eight-year cycle.

One of the challenges associated with the development of the radome replacement schedule, however, was that many of Hydro's microwave sites were installed on the same year. For example, during the installation of the East Cost Microwave System in 2001, upwards of twenty antennas were installed. To avoid the financial challenge that would be created by replacing each of these radomes in the same year, it was decided by Hydro personnel 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 above. These radomes must be replaced as soon as the damage is identified to ensure that the integrity of the microwave system is maintained.

It should be noted that the cost of a microwave failure today would be far more significant than the incident of 1996. This is 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 fact, protection signals for seventeen of Hydro's critical 230 kV transmission lines are carried on the microwave network. As a result, failure of the microwave would cause the Energy Control Centre to lose control of the system stations and likely cause and/or extend customer outages.

Project Description

To reduce the probability of system outages that would result from radome failure, Hydro has initiated a radome replacement program for the microwave antennas of the corporate network - a network that has increased in size considerably since the expansion of 2001. Radomes are replaced at different sites throughout the network each year, depending on age and condition (the radome replacement schedule for 2008-2012 is provided in Appendix A). Historically, this project has been performed though the joint effort of an external contractor and internal forces that perform project management and provide technical support.

Summary

In summary, Newfoundland and Labrador Hydro's Radome Replacement Program is a necessary project that involves the replacement of the protective shells that enclose the delicate components of microwave antennas.

The radome replacement program proposed by Newfoundland and Labrador 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 represents a proactive approach to ensuring that the likelihood of failure of microwave antenna radomes is minimized.

Appendix A – Radome Replacement Schedule

2008 Radome Replacement

Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
GPH-div	SBH-div	2000	3.6m(12')	Andrew	HP12-71E
GPH	BDH	2000	2.4m(8')	Andrew	HP8-71D
SBH-main	GPH-main	2000	3.6m(12')	CW	DA12-71hp
SBH	STB	2000	1.8m(6')	CW	DA6-71hp
SBH-div	GPH-div	2004	3.6m(12')	Andrew	HP12-71E
SBH-div	MMH-div	2004	3.0m(10')	Andrew	HP10-71D
HLP	HLK	2000	2.4m(8')	CW	DA8-71hp
HLP	BGH	2000	2.4m(8')	CW	DA8-71hp
HLK	HLP	2000	1.8m(6')	CW	DA6-71hp

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

Section I

	2006 ($000)	2005 ($000)
Capital Assets	1,976,170	1,936,960
Less:		
Accumulated Depreciation	536,691	506,374
Contributions in Aid of Construction	93,713	84,627
Net Capital Assets	1,345,766	1,345,959
Balance Previous Year	1,345,959	1,353,339
Average Capital Assets	1,345,863	1,349,649
Working Capital	3,207	2,711
Fuel	24,886	21,506
Supplies Inventory	20,996	20,084
Average Deferred Charges	77,232	79,809
Average Rate Base	1,472,184	1,473,759