DELIVERED BY HAND

April 28, 2006

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

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies and Gentlemen:

Re: Newfoundland Power's 2007 Capital Budget Application

A. Enclosures

Enclosed are 15 copies of Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") 2007 Capital Budget Application (the "Application") and supporting materials in two volumes (the "Filing").

B. Budget Highlights

B.1 Rattling Brook Hydroelectric Plant

The Application seeks approval of 2007 capital expenditures totaling $62.2 million. The size of the 2007 capital budget, which is larger than the Company's recent capital budgets, is principally influenced by the proposed major refurbishment of the Company's largest hydroelectric generating plant at Rattling Brook (the "Rattling Brook Project"). The Rattling Brook Project is to be completed over 2 years, with the bulk of the work being done during the 2007 construction season.

The total proposed 2007 capital expenditure for the Rattling Brook Project is $18.8 million. The Application seeks only approval of the proposed 2007 expenditures. Approval of the remaining refurbishment work, consisting of upgrades to dam and spillway structures at an estimated cost of approximately $2.1 million, will be sought in the 2008 Capital Budget Application.

B.2 Substation Capital Budget

This year, as part of its ongoing effort to improve both the planning and presentation of its annual capital budgets, Newfoundland Power is introducing a modified approach to capital budgeting in the Substations budget category. Following a detailed review of its substations assets, the Company has developed a 10-year plan for the refurbishment and modernization of its substations. The plan is designed to complement the existing substation maintenance program, which also follows a 10-year cycle. The changes in the way Substations capital projects are planned and executed, and the resulting changes in the way the Substations capital budget is presented, are described in *2.1 Substation Strategic Plan*.

B.3 2007 Capital Budget Plan

The 2007 Capital Budget is somewhat unique in that a single Generation project, the Rattling Brook Project, constitutes approximately 30% of the total planned expenditure. Accordingly, the *2007 Capital Plan* included in the Filing contains an overview of the Company's capital management practices with special emphasis on Generation assets.

As indicated in Appendix A of the *2007 Capital Plan*, Newfoundland Power anticipates that, following the significant increase due to the Rattling Brook Project in 2007, the level of annual capital expenditure is expected to be relatively stable and consistent with recent historic levels of expenditure.

C. Description of the Filing

C.1 Timing of the Filing

This year Newfoundland Power is filing its capital budget application earlier than usual. The purpose of the early filing is to facilitate earlier consideration of the Application by the Board to accommodate the Company's orderly execution of the Rattling Brook Project.

The work to be completed on the Rattling Brook Project in 2007 includes the replacement of the existing woodstave penstock, the rehabilitation of the surge tank and replacement of the switchgear, main valves and governor controls. The procurement of much of the material required for this work involves long lead times. In order to meet the project schedule and have the plant in service for the 2007-2008 winter season, it will be necessary to commence the procurement of materials early in the 4th quarter of 2006. The Company therefore requests that the Board's review of the Application proceed with a view to the issuance of an order with respect to the Rattling Brook Project by early October.

The June 2005 Provisional Capital Budget Application Guidelines (the "Provisional Guidelines") set out general guidelines for the scheduling of the annual capital budget process. The Provisional Guidelines contemplate a capital budget process that extends approximately 4 months from beginning to end. By filing its capital budget on April 28th, Newfoundland Power is effectively requesting the Board make an order with respect to the Rattling Brook Project within approximately 5 months.

C.2 Organization of Materials

The information contained in the Filing is organized in 2 volumes. Volume 1 contains the bulk of the informational material, including the Application and Schedules and most of the more detailed supporting material. Volume 2 consists entirely of information related to the Rattling Brook Project.

Included with the Filing is the *Electrical System Handbook - Hydroelectric Generation*. The *Electrical System Handbook - Hydroelectric Generation* provides generic information on the infrastructure and equipment that comprises a typical small hydroelectric plant. It is intended to assist in understanding the engineering terminology associated with the material provided in the Filing concerning the Rattling Brook Project.

C.3 Compliance Matters

C.3.1 Board Orders

In Order No. P.U. 30 (2005) (the "2006 Capital Order"), the Board required specific information to be filed with the Application. The Filing complies with the requirements of the 2006 Capital Order.

In Order No. P.U. 35 (2003) (the "2004 Capital Order") required specific information, and in particular a 5-year capital plan, to be provided with the Application. The Filing complies with the requirements of the 2004 Capital Order.

In Order No. P.U. 19 (2003) (the "2003 Rate Order"), the Board required that evidence relating to deferred charges and a reconciliation of average rate base to invested capital be filed with the Application. The Filing complies with the requirements of the 2003 Rate Order.
The Filing contains the following specific reports:

1. *2007 Capital Budget Plan*: this is filed in compliance with the 2004 Capital Order;

2. *2006 Capital Expenditure Status Report*: this is filed in compliance with the 2006 Capital Order;

3. *Wesleyville Gas Turbine Refurbishment Update*: this is filed in compliance with the 2006 Capital Order; and

4. *Deferred Charges and Rate Base*: this is filed in compliance with the 2003 Rate Order.

C.3.2 The Provisional Guidelines

In the Provisional Guidelines, the Board outlined certain directions on how to define and categorize capital expenditures. Although compliance with the Provisional Guidelines necessarily requires the exercise of a degree of judgment, the Filing, in the Company's view, complies with the Provisional Guidelines while remaining reasonably consistent and comparable with past filings.

Section 3 of the *2007 Capital Budget Plan* provides a breakdown of the overall 2007 capital budget by definition, classification, costing method and materiality segmentation as described in the Provisional Guidelines.

D. Order Sought in the Application

In the Application**,** Newfoundland Power essentially seeks (i) approval of a 2007 capital budget in the amount of $62,166,000; and (ii) the fixing and determining of a 2005 rate base in the amount of $745,446,000.

E. Filing Details and Circulation

The Filing will be posted on the Company's website (www.newfoundlandpower.com) in the next few days. Copies of the Filing will be available for reviewing by interested parties at the Company's offices throughout its service territory.

The enclosed material has been provided in binders with appropriate tabbing. For convenience, additional materials such as Responses to Requests for Information will be provided on three-hole punched paper.

A PDF file of the Filing will be forwarded to the Board in due course.

A copy of the Filing has been forwarded directly to Mr. Geoffrey Young, Senior Legal Counsel of Newfoundland & Labrador Hydro and Mr. Thomas Johnson, the Consumer Advocate.

F. Concluding

We trust the foregoing and enclosed are found to be in order.

If you have any questions on the Filing, please contact us at your convenience.

Yours very truly,

Peter Alteen
Vice President, Regulatory Affairs
& General Counsel

Enclosures

c. Geoffrey Young
Newfoundland & Labrador Hydro

Thomas Johnson
O'Dea Earle Law Offices

Newfoundland Power Inc.
2007 Capital Budget Application
Filing Contents

Volume I

Application

Supporting Materials

Generation

Substations

Transmission

General Property

Information Systems

Deferred Charges

Newfoundland Power Inc.
2007 Capital Budget Application
Filing Contents

Volume II

Supporting Materials

Rattling Brook Hydro Plant Refurbishment

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:

(a) approving its 2007 Capital Budget of $62,166,000; and

(b) fixing and determining its average rate base for 2005 in the amount of $745,446,000

2007 Capital Budget Application

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:
(a) approving its 2007 Capital Budget of $62,166,000; and
(b) fixing and determining its average rate base for 2005 in the amount of $745,446,000

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

THE APPLICATION OF Newfoundland Power Inc. ("Newfoundland Power") **SAYS THAT:**

1. Newfoundland Power is a corporation duly organized and existing under the laws of the Province of Newfoundland and Labrador, is a public utility within the meaning of the Act, and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. Schedule A to this Application is a summary of Newfoundland Power's 2007 Capital Budget in the amount of $62,166,000 which includes an estimated amount of $1,500,000 in contributions in aid of construction that the Applicant intends to demand from its customers in 2007. All contributions to be recovered from customers shall be calculated in a manner approved by the Board.

3. Schedule B to this Application is a list of 2007 capital expenditures, by project, which comprise Newfoundland Power's 2007 Capital Budget.

4. Schedule C to this Application is an estimate of future required expenditures on improvements or additions to the property of Newfoundland Power that are included in the 2007 Capital Budget but will not be completed in 2007 or are included in multi-year projects.

5. The proposed expenditures as set out in Schedules A, B, and C to this Application are necessary for Newfoundland Power to continue to provide service and facilities which are reasonably safe and adequate and just and reasonable as required pursuant to Section 37 of the Act.

6. Schedule D to this Application shows Newfoundland Power's actual average rate base for 2005 of $745,446,000.

7. Communication with respect to this Application should be forwarded to the attention of Ian Kelly, Q.C. and Peter Alteen, Counsel to Newfoundland Power.

8. Newfoundland Power requests that the Board make an Order:

   (a) pursuant to Section 41 of the Act, approving Newfoundland Power's purchase and construction in 2007 of the improvements and additions to its property in the amount of $62,166,000 as set out in Schedules A and B to the Application; and

   (b) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2005 in the amount of $745,446,000 as set out in Schedule D to the Application.

DATED at St. John's, Newfoundland and Labrador, this 28th day of April, 2006.

NEWFOUNDLAND POWER INC.

Ian Kelly, Q.C. and Peter Alteen
Counsel to Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's, NL A1B 3P6

Telephone: (709) 737-5609
Telecopier: (709) 737-2974

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:
(a) approving its 2007 Capital Budget of $62,166,000; and
(b) fixing and determining its average rate base for 2005 in the amount of $745,446,000

AFFIDAVIT

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

1. That I am Vice-President, Engineering and Operations, of Newfoundland Power Inc.

2. To the best of my knowledge, information and belief, all matters, facts and things set out in this Application are true.

SWORN to before me at St. John's in the Province of Newfoundland and Labrador this 28th day of April, 2006, before me:

Barrister

Phonse Delaney

2007 CAPITAL BUDGET SUMMARY

Asset Class	Budget (000s)
1. Generation - Hydro	$ 19,188
2. Substations	3,968
3. Transmission	4,283
4. Distribution	24,103
5. General Property	1,310
6. Transportation	2,206
7. Telecommunications	101
8. Information Systems	3,457
9. Unforeseen Allowance	750
10. General Expenses Capitalized	2,800
Total	**$ 62,166**

2007 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
1. Generation- Hydro		
Rattling Brook Hydro Plant Refurbishment	$18,242	2
Facility Rehabilitation	946	4
Total – Generation - Hydro	**$19,188**	
2. Substations		
Substation Refurbishment and Modernization	$ 2,190	7
Replacements Due to In-Service Failures	1,200	9
Rattling Brook Substation Refurbishment	578	11
Total - Substations	**$ 3,968**	
3. Transmission		
Rebuild Transmission Lines	$ 4,283	14
Total - Transmission	**$ 4,283**	

1 Project descriptions can be found in Schedule B at the page indicated.

2007 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
4. Distribution		
Extensions	$ 6,815	17
Meters	1,100	19
Services	1,848	22
Street Lighting	1,288	25
Transformers	5,728	28
Reconstruction	3,077	30
Rebuild Distribution Lines	3,625	32
Relocate/Replace Distribution Lines for Third Parties	541	35
Interest During Construction	81	37
Total - Distribution	**$ 24,103**	
5. General Property		
Tools and Equipment	$ 600	40
Additions to Real Property	100	42
Energy Efficient HVAC System	610	44
Total - General Property	**$ 1,310**	
6. Transportation		
Purchase Vehicles and Aerial Devices	$ 2,206	47
Total - Transportation	**$ 2,206**	

[1] Project descriptions can be found in Schedule B at the page indicated.

2007 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
7. Telecommunications		
Replace/Upgrade Communications Equipment	$ 101	50
Total - Telecommunications	**$ 101**	
8. Information Systems		
Application Enhancements	$ 1,281	53
System Upgrades	689	55
Personal Computer Infrastructure	400	57
Shared Server Infrastructure	877	60
Microsoft Enterprise Agreement	210[2]	
Total – Information Systems	**$ 3,457**	
10. Unforeseen Allowance		
Allowance for Unforeseen Items	$ 750	63
Total – Unforeseen Allowance	**$ 750**	
11. General Expenses Capitalized		
General Expenses Capitalized	$ 2,800	65
Total – General Expenses Capitalized	**$ 2,800**	

[1] Project descriptions can be found in Schedule B at the page indicated.
[2] This is a multi-year project approved with the 2006 Capital Budget Application. Details found in Schedule A, page 5 of 5.

2007 CAPITAL PROJECTS: MULTI-YEAR

Capital Project	Approved	2006	2007	2008
Microsoft Enterprise Agreement[3]	Order No. P.U. 30 (2005)	$210,000	$210,000	$210,000

3 The scope, nature, and amount of this expenditure are consistent with the original approval.

GENERATION - HYDRO

Project Title: Rattling Brook Hydro Plant Refurbishment (Clustered)

Project Cost: $18,242,000

Project Description

This Generation Hydro project is a major refurbishment of the Company's Rattling Brook Hydroelectric Generating Plant. This refurbishment project will require major upgrades to the civil, electrical and mechanical systems of the plant in 2007. Many components require replacement or refurbishment including the woodstave penstock, surge tank, switchgear, generator controls and protection, governors and main valves.

Details on the proposed expenditures are included in ***Volume II*** *Rattling Brook Hydro Plant Refurbishment*.

This is a major plant refurbishment which involves a combination of inter-dependent and related components. This refurbishment will be completed in 2007 and is clustered with the Rattling Brook Substation Refurbishment project to minimize plant downtime and maximize efficiencies.

Justification

The Rattling Brook Hydroelectric Generating Plant is the largest generating plant operated by Newfoundland Power. It was commissioned in 1958 and, with the exception of some upgrades, remains in original condition. The normal annual plant production is approximately 69.8 GWh of energy, or about 16.6 per cent of Newfoundland Power's total hydroelectric generation.

Engineering assessments of the civil, mechanical and electrical systems have revealed a number of deficiencies. In particular, the civil engineering assessment, completed with the assistance of outside experts, has identified the necessity to replace the deteriorated penstock and refurbish the surge tank. Replacing the penstock with a larger diameter penstock will result in direct energy gains of 5.2 GWh using the same amount of water as is used today.

The plant's electrical systems are original equipment and have deteriorated with age. The electrical assessment identified issues with electrical protection, the plant's AC and DC systems, and the distribution and communications systems. Upgrades to these components will improve availability for generation and overall plant reliability.

The mechanical assessment identified that the main valves leak with pressure loss across the valves that is approximately three times more than a modern design butterfly valve. Pressure test results show that the replacement of the main valves will directly result in energy gains of 1 GWh.

A feasibility analysis of projected capital and operating expenditures for the Rattling Brook Hydroelectric Generating Plant has determined the levelized cost of energy from the plant over the next 50 years to be 2.9 cents per kilowatt-hour, which is significantly less than the cost of replacement energy at Holyrood. Furthermore, this project will supply an additional 6.2 GWh of energy to the Island Interconnected electrical system.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 to 2011. Anticipated expenditures relating to Rattling Brook's civil infrastructure are currently planned for 2008. These expenditures will be presented with the 2008 Capital Budget Application.

Table 1
Project Expenditures
(000s)

Cost Category	2007	2008	2009 - 2011	Total
Material	$15,968	-	-	-
Labour – Internal	370	-	-	-
Labour – Contract	99	-	-	-
Engineering	810	-	-	-
Other	995	-	-	-
Total	**$18,242**	**$2,080**	-	**$20,322**

Costing Methodology

The budget for this project is based on an engineering cost estimate.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project. While expenditures are planned for the future, only the 2007 portion is being presented for approval with the 2007 Capital Budget Application.

Project Title: **Facility Rehabilitation (Pooled)**

Project Cost: **$946,000**

Project Description

This Generation project is necessary for the replacement or rehabilitation of deteriorated plant components that have been identified through routine inspections, operating experience and engineering studies. Work will take place on various dam structures such as the Paddy's Pond Outlet Structure, the Horsechops West dam and the Bay Bulls Big Pond dam. The project includes expenditures necessary to improve the efficiency and reliability of various hydro plants or to replace plant due to in-service failures.

Details on 2007 proposed expenditures are included in ***1.1*** *2007 Facility Rehabilitation*.

The replacement or rehabilitation of deteriorated components at individual plants are not inter-dependent or related. However, all budget items included in this project are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Justification

The Company's 23 hydroelectric and six thermal plants range in age from 106 years old to two years old. These facilities provide energy to the Island interconnected electrical system. Maintaining these generating facilities reduces the need for additional, more expensive, generation. In many cases, these generating facilities provide local generation.

Replacement and rehabilitation projects are identified during ongoing inspections and maintenance activities. These projects are necessary for the continued operation of electric generation facilities in a safe, reliable and environmentally compliant manner.

The Company's hydro generation facilities produce a combined normal annual production of 419.6 GWh. The alternative to maintaining these facilities would be to retire them. Replacing the energy produced by these facilities by increasing production at Newfoundland and Labrador Hydro's Holyrood generation facility would require approximately 670,000 barrels of fuel annually. At oil prices of $36.85 per barrel, this translates into approximately $25 million in annual fuel savings.

All expenditures on individual hydroelectric plants, such as the replacement of dam structures, runners, or forebays, are justified on the basis of maintaining access to hydroelectric generation at a cost that is lower than the cost of replacement energy.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1

Project Expenditures (000s)

Cost Category	2007	2008	2009 - 2011	Total
Material	$803	-	-	-
Labour – Internal	62	-	-	-
Labour – Contract	-	-	-	-
Engineering	38	-	-	-
Other	43	-	-	-
Total	**$946**	**$1,858**	**$4,723**	**$7,527**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2

Expenditure History (000s)

Year	2002	2003	2004	2005	2006F
Total	**$2,031**	**$2,510**	**$1,909**	**$2,283**	**$996**

The budget estimate for this project is comprised of engineering estimates for the individual budget items and an assessment of historical expenditures for the remainder.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

SUBSTATIONS

Project Title: **Substations Refurbishment and Modernization (Pooled)**

Project Cost: **$2,190,000**

Project Description

This Substations project is a compilation of five formerly separate projects known as Rebuild Substations, Protection and Monitoring Upgrades, Distribution Feeder Remote Control, Reliability and Power Quality Improvements and Transformer Cooling Refurbishment. This project is necessary for the planned replacement of deteriorated and substandard substation infrastructure, such as bus structures, breakers, potential transformers, protective relaying and support structures, equipment foundations, switches and fencing.

A Substation Strategic Plan, which details the Company's ten-year strategy and 2007 proposed expenditures, are included in ***2.1*** *Substation Strategic Plan.*

The individual requirements for the replacement of substation infrastructure are not inter-dependent. However, they are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

This project is justified based on the need to maintain safe, reliable electrical service and ensure workplace safety by replacing deteriorated or substandard substation infrastructure.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1

Project Expenditures
(000s)

Cost Category	2007	2008	2009 – 2011	Total
Material	$871	-	-	-
Labour – Internal	517	-	-	-
Labour – Contract	93	-	-	-
Engineering	520	-	-	-
Other	189	-	-	-
Total	**$2,190**	**$3,865**	**$12,316**	**$18,371**

Costing Methodology

Table 2 shows the annual expenditures and unit costs for this project for the most recent five-year period.

Table 2

Expenditure History (000s)

	2002	**2003**	**2004**	**2005**	**2006F**
Rebuild Substations	$687	$399	$634	$722	$1,603
Protection and Monitoring Upgrades	116	448	57	80	423
Distribution Feeder Remote Control	1,092	1,165	1,179	1,025	779
Reliability and Power Quality Improvements	95	76	43	101	-
Transformer Cooling Refurbishment	-	-	255	144	-
Total	**$1,990**	**$2,088**	**$2,168**	**$2,072**	**$2,805**

The Company has 130 substations varying in age from five years to greater than 100 years. Infrastructure to be replaced was identified as a result of inspections, engineering studies and operating experience.

The budget for this project is comprised of engineering estimates for the cost of individual budget items.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Replacements Due to In-Service Failures (Pooled)**

Project Cost: **$1,200,000**

Project Description

This Substations project, formerly known as Replacement and Standby Substation Equipment, is necessary to replace substation equipment that is retired due to vandalism, storm damage, lightning strikes, electrical or mechanical failure, corrosion damage, technical obsolescence and failure during maintenance testing. Substation equipment that fails in-service requires immediate attention as it is essential to the integrity and reliability of the electrical supply to customers.

The individual requirements for substation equipment are not inter-dependent. However, they are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Details on 2007 proposed expenditures are included in ***2.2*** *2007 Replacements Due to In-Service Failures*.

Justification

This project is justified based on the need to maintain safe, reliable electrical service and ensure workplace safety by replacing deteriorated or substandard substation plant and equipment.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1

Project Expenditures
(000s)

Cost Category	2007	2008	2009 - 2011	Total
Material	$690	-	-	-
Labour – Internal	215	-	-	-
Labour – Contract	-	-	-	-
Engineering	190	-	-	-
Other	105	-	-	-
Total	**$1,200**	**$1,231**	**$3920**	**$6,351**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2

**Expenditure History
(000s)**

Year	**2002**	**2003**	**2004**	**2005**	**2006F**
Total	**$2,716**	**$1,159**	**$1,284**	**$1,194**	**$1,023**

The Company has 130 substations. The major equipment items comprising a substation include power transformers, circuit breakers, reclosers, voltage regulators, potential transformers and battery banks. In total, Newfoundland Power has in service approximately 190 power transformers, 400 circuit breakers, 200 reclosers, 360 voltage regulators, 220 potential transformers, 115 battery banks and 2,500 high voltage switches.

The need to replace equipment is determined on the basis of tests, inspections, in-service and imminent failures and operational history of the equipment. An adequate pool of spare equipment is necessary to enable the Company to quickly respond to in-service failure. The size of the pool is based on past experience and engineering judgement, as well as a consideration of the impact the loss of a particular apparatus would have on the electrical system.

The budget for this project is based on engineering cost estimates and an assessment of historical expenditures.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Rattling Brook Substation Refurbishment (Clustered)**

Project Cost: **$578,000**

Project Description

This substation project is proposed in conjunction with the major refurbishment of the Company's Rattling Brook Hydroelectric Generating Plant. This substation refurbishment project will increase the physical dimensions of the substation and will involve the upgrading of the low voltage bus and associated structures. In addition, a three phase station service transformer will be installed for the Rattling Brook plant.

Details on 2007 proposed expenditures are included in ***Volume II*** *Rattling Brook Hydro Plant Refurbishment*.

Justification

The existing substation is wood pole construction. The current 12.5 kV distribution bus has non-standard clearances, materials and hardware. The substation bus does not have adequate space to accommodate the addition of the three phase station service transformer. For these reasons the existing substation must be upgraded to current standards. As well, the substation site is too small to facilitate the installation of a portable substation for transformer maintenance or emergency situations and must be increased.

A feasibility analysis of projected capital and operating expenditure requirements for the complete Rattling Brook Hydroelectric Generating Plant has determined the levelized cost of energy from the plant over the next 50 years to be 2.9 cents per kilowatt-hour, which is significantly less than the cost of replacement energy.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007. There are no expenditures expected after 2007.

Table 1
Project Expenditures
(000s)

Cost Category	2007	2008	2009 - 2011	Total
Material	$288	-	-	-
Labour – Internal	89	-	-	-
Labour – Contract	-	-	-	-
Engineering	126	-	-	-
Other	75	-	-	-
Total	**$578**	**-**	**-**	**$578**

Costing Methodology

The budget for this project is based on engineering cost estimates.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

TRANSMISSION

Project Title: **Rebuild Transmission Lines (Pooled)**

Project Cost: **$4,283,000**

Project Description

This Transmission project involves:

1. The rebuilding of the Company's oldest, most deteriorated transmission lines on a priority basis in accordance with the program outlined in the report *Transmission Line Rebuild Strategy* filed with the 2006 Capital Budget Application ($2,568,000).

   Proposed transmission line rebuilding work will take place on sections of 43L, 110L and 20L. Details of the rebuilds can be found in ***3.1*** *Transmission Line Rebuild*.

2. The replacement of poles, crossarms, conductors, insulators and miscellaneous hardware due to deficiencies identified during inspections and engineering reviews or due to in-service and imminent failures ($1,565,000).

3. Work associated with the relocation of transmission lines at the request of third parties ($150,000).

Justification

Thirty per cent of the Company's 104 transmission lines are in excess of 40 years of age. Many of these lines are experiencing pole, crossarm, conductor, insulator and hardware deterioration. Replacement is required to maintain the strength and integrity of these lines.

This project is justified based on the need to replace deteriorated infrastructure in order to ensure the continued provision of safe, reliable electrical service.

The portion of this project related to relocations at the request of third parties is justified based on the need to accommodate the legitimate requirements of governments, other utility service providers and the public.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1

Project Expenditures (000s)

Cost Category	2007	2008	2009 - 2011	Total
Material	$1,430	-	-	-
Labour – Internal	575	-	-	-
Labour – Contract	1,818	-	-	-
Engineering	130	-	-	-
Other	330	-	-	-
Total	**$4,283**	**$5,056**	**$15,497**	**$24,836**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2

Expenditure History (000s)

Year	2002	2003	2004	2005	2006F
Total	**$3,089**	**$4,026**	**$2,061**	**$2,651**	**$4,060**

The budget estimates for rebuilding and upgrade projects are based on engineering cost estimates. The budget estimates for replacements and relocation projects are based on an assessment of historical expenditures.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

DISTRIBUTION

Project Title: **Extensions (Pooled)**

Project Cost: **$6,815,000**

Project Description

This Distribution project involves the construction of both primary and secondary distribution lines to connect new customers to the electrical distribution system. The project also includes upgrades to the capacity of existing lines to accommodate customers who increase their electrical load. The project includes labour, materials, and other costs to install poles, wires and related hardware.

Distribution line extensions and upgrades for new customers and for increased loads are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

This project is justified based on the need to address customers' new or additional service requirements.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1
Project Expenditures
(000s)

Cost Category	2007	2008	2009 - 2011	Total
Material	$2,199	-	-	-
Labour – Internal	1,630	-	-	-
Labour – Contract	2,109	-	-	-
Engineering	699	-	-	-
Other	178	-	-	-
Total	**$6,815**	**$6,772**	**$20,417**	**$34,004**

Costing Methodology

Table 2 shows the annual expenditures and unit costs for this project for the most recent five-year period, as well as a projected unit cost for 2007.

Table 2
Expenditure History and Unit Cost Projection

Year	**2002**	**2003**	**2004**	**2005**	**2006F**	**2007B**
Total Exp. (000s)	**$5,717**	**$6,586**	**$8,406**	**$7,962**	**$7,830**	**$6,815**
Adjusted Cost (000s)[1]	$6,534	$7,354	$9,111	$8,282	$7,830	-
New Customers	3,485	3,833	4,294	4,149	3,584	3,307
Unit Cost ($/cust.)[1]	$1,875	$1,919	$2,122	$1,996	$2,185	$2,061

[1] 2006 Dollars.

The project cost for the connection of new customers is calculated on the basis of historical data. Historical annual expenditures over the most recent five-year period, including the current year, expressed in current-year dollars ("Adjusted Cost") are divided by the number of new customers in each year to derive the annual extension cost per customer in current-year dollars ("Unit Cost"). The average of these unit costs, with unusually high and low data excluded, is modified by the GDP Deflator for Canada before being multiplied by the forecast number of new customers for the budget year to determine the budget estimate. The forecast number of new customers is derived from economic projections provided by independent agencies.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Meters (Pooled)**

Project Cost: **$1,100,000**

Project Description

This Distribution project includes the purchase and installation of meters for new customers and replacement meters for existing customers. Table 1 lists the meters required in 2007.

Table 1
2007 Proposed Meter Acquisition

Program	Number of Meters
Energy Only Domestic Meters	8,150
Other Energy Only and Demand Meters	1,044

The expenditures for individual meters are not interdependent. However, because the individual expenditure items are similar in nature and justification, they have been pooled for consideration as a single capital project.

Of the $1,100,000 cost for meters to be purchased in 2007, approximately $133,000 will be allocated to purchase meters with automated meter reading ("AMR") technology. AMR meters will be installed where it is determined that the higher cost is justified by the savings provided as per the *Metering Strategy* filed with the 2006 Capital Budget Application.

Justification

The purchase of new meters is necessary to accommodate customer growth and to replace deteriorated meters. Revenue metering of electrical service is regulated under the *Electricity and Gas Inspection Act (Canada)*. The additional cost associated with expenditures on AMR meters is justified on an economic basis.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 2 **Projected Expenditures** **(000s)**				
Cost Category	**2007**	**2008**	**2009 - 2011**	**Total**
Material	$902	-	-	-
Labour – Internal	154	-	-	-
Labour – Contract	44	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$1,100**	**$1,132**	**$3,797**	**$6,029**

Costing Methodology

Table 3 shows the annual expenditures for the most recent five-year period, as well as a projection for 2007.

Table 3 **Expenditure History and Budget Estimate**							
Year	**2002**	**2003**	**2004**	**2005**	**2006F**	**Avg**	**2007B**
Meter Requirements							
New Connections	3,485	3,833	4,294	4,149	3,584	-	3,307
GRO's/CSO's	2,270	1,455	8,544	12,399	13,817	-	2,944
Other	540	1,055	1,064	2,175	2,357	-	2,943
Total	6,295	6,343	13,902	18,723	19,758	-	9,194
Meter Costs							
Actual (000s)	$674	$595	$ 1,297	$1,342	$1,556	-	$1,100
Adjusted[1] (000s)	$755	$649	$1,376	$1,382	$1,556	-	-
Unit Cost[1]	$120	$102	$99	$74	$79	$95	$120

[1] 2006 dollars.

The budget estimate for Meters is calculated using the inflation adjusted average historical unit cost per installed meter multiplied by the expected number of meter installations. The expected number of meter installations is based on projected new customer connections, projected requirements to meet Industry Canada regulations and other requirements based on historical trends.

The quantity of meters for *new* customers is based on the Company's forecast of customer growth. The quantity for *replacement* purposes is determined using historical data for retired meters and sampling results from previous years. Sampling and replacement requirements are governed by Compliance Sampling Orders (CSOs) and Government Retest Orders (GROs) issued in accordance with regulations under the *Electricity and Gas Inspection Act (Canada)*.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Services (Pooled)**

Project Cost: **$1,848,000**

Project Description

This Distribution project involves the installation of service wires to connect new customers to the electrical distribution system. Service wires are low voltage wires that connect the customer's electrical service equipment to the utility's transformers. Also included in this project is the replacement of existing service wires due to deterioration, failure or damage, as well as the installation of larger wires to accommodate customers' additional load.

The proposed expenditures for new and replacement service wires are similar in nature. The expenditures are therefore pooled for consideration as a single capital project.

Justification

The *new* component of this project is justified based on the need to address customers' new service requirements. The *replacement* component is justified on the basis of the obligation to provide safe, reliable electrical service.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1
Project Expenditures
(000s)

Cost Category	2007	2008	2009 – 2011	Total
Material	$556	-	-	-
Labour – Internal	1,025	-	-	-
Labour – Contract	90	-	-	-
Engineering	155	-	-	-
Other	22	-	-	-
Total	**$1,848**	**$1,850**	**$5,650**	**$9,348**

Costing Methodology

Table 2 shows the annual expenditures and unit costs for *new* services for the most recent five-year period, as well as a projected unit cost for 2007.

Table 2

Expenditure History and Unit Cost Projection
New Services

Year	2002	2003	2004	2005	2006F	2007B
Total (000s)	**$ 1,293**	**$ 1,421**	**$ 1,659**	**$1,894**	**$1,465**	**$1,455**
Adjusted Cost (000s)[1]	$1,479	$1,591	$1,804	$1,974	$1,465	-
New Customers	3,485	3,833	4,294	4,149	3,584	3,307
Unit Cost ($/cust.)[1]	$424	$415	$420	$476	$409	$440

1 2006 dollars.

The project cost for the connection of new customers is calculated on the basis of historical data. For *new* services, historical annual expenditures over the most recent five-year period, including the current year, are converted to current-year dollars ("Adjusted Cost") and divided by the number of new customers in each year to derive the annual services cost per customer in current-year dollars ("Unit Cost"). The average of these unit costs, with unusually high and low data excluded, is modified by the GDP Deflator for Canada before being multiplied by the forecast number of new customers for the budget year to determine the budget estimate. The forecast number of new customers is derived from economic projections provided by independent agencies.

Table 3 shows the annual expenditures and unit costs for *replacement* services for the most recent five-year period, as well as a projected unit cost for 2007.

Table 3

Expenditure History and Average Cost Projection
Replacement Services
(000s)

Year	2002	2003	2004	2005	2006F	2007B
Total	**$550**	**$568**	**$349**	**$339**	**$384**	**$393**
Exclusions[1]	211	200	-	-	-	-
Adjusted Cost[2]	$388	$412	$380	$353	$384	-

1 Exclusions in the 2002 to 2003 period included program replacement of underground services in St. John's and program replacement of aerial services in Lark Harbour and Port aux Basques.

2 2006 dollars.

The process of estimating the budget requirement for *replacement* services is similar to that for *new* services, except the budget estimate is based on the historical average of the total cost of replacement services, as opposed to a unit cost. To ensure consistency from year to year, expenditures related to planned service replacement programs are excluded from the calculation of the historical average.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Street Lighting (Pooled)**

Project Cost: **$1,288,000**

Project Description

This Distribution project involves the installation of new lighting fixtures, the replacement of existing fixtures, and the provision of associated overhead and underground wiring. A street light fixture includes the light head complete with bulb, photocell and starter as well as the pole mounting bracket and other hardware. The project is driven by customer requests and historical levels of lighting fixtures requiring replacement.

The proposed expenditures for new and replacement street lights are similar in nature. The expenditures are therefore pooled for consideration as a single capital project.

Justification

The *new* component of this project is justified based on the need to address customers' new street light requirements. The *replacement* component is justified on the basis of the obligation to provide safe, reliable electrical service.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1
Project Expenditures
(000s)

Cost Category	2007	2008	2009 – 2011	Total
Material	$698	-	-	-
Labour – Internal	459	-	-	-
Labour – Contract	99	-	-	-
Engineering	19	-	-	-
Other	13	-	-	-
Total	**$1,288**	**$1,288**	**$3,922**	**$6,498**

Costing Methodology

Table 2 shows the annual expenditures and unit costs for *new* street lights for the most recent five-year period, as well as a projected unit cost for 2007.

Table 2

Expenditure History and Unit Cost Projection
New Street Lights

Year	**2002**	**2003**	**2004**	**2005**	**2006F**	**2007B**
Total (000s)	**$839**	**$892**	**$1,020**	**$1,363**	**$864**	**$861**
Exclusions[1] (000s)	-	-	-	$380	-	-
Adjusted Cost (000s)[2]	$953	$985	$1,095	$1,018	$864	-
New Customers	3,485	3,833	4,294	4,149	3,584	3,307
Unit Cost ($/cust.)[2]	$273	$257	$255	$245	$241	$260

1 Exclusions in 2005 reflect the unusually high quantity of new Street Lights installed for the City of St. John's.
2 2006 dollars.

The project cost for the connection of new customers is calculated on the basis of historical data. For *new* street lights, historical annual expenditures over the most recent five-year period, including the current year, expressed in current-year dollars ("Adjusted Cost") are divided by the number of new customers in each year to derive the annual street light cost per customer in current-year dollars ("Unit Cost"). The average of these unit costs, with unusually high and low data excluded, is modified by the GDP Deflator for Canada before being multiplied by the forecast number of new customers for the budget year to determine the budget estimate. The forecast number of new customers is derived from economic projections provided by independent agencies.

Table 3 shows the annual expenditures and unit costs for *replacement* street lights for the most recent five-year period, as well as a projected unit cost for 2007.

Table 3

Expenditure History and Average Cost Projection
Replacement Street Lights
(000s)

Year	**2002**	**2003**	**2004**	**2005**	**2006F**	**2007B**
Total	**$360**	**$395**	**$379**	**$489**	**$401**	**$427**
Exclusions[1]	-	-	-	70	-	-
Adjusted Cost[2]	$409	$436	$407	**$434**	$401	-

1 Exclusions in 2005 reflect the Company's program replacement of underground wiring for streetlights in the St. John's area at a cost of $70,000.
2 2006 dollars.

The process of estimating the budget requirement for *replacement* street lights is similar to that for *new* street lights, except the budget estimate is based on the historical average of the total cost of replacement street lights, as opposed to a unit cost. The estimate is based on historical annual expenditures for the replacement of damaged, deteriorated or failed street lights.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: Transformers (Pooled)

Project Cost: $5,728,000

Project Description

This Distribution project includes the cost of purchasing transformers for customer growth and the replacement or refurbishment of units that have deteriorated or failed.

Transformers requirements are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

This project is justified on the basis of the obligation to meet customers' electrical service requirements and the need to replace defective or worn out electrical equipment in order to maintain a safe, reliable electrical system.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1
Project Expenditures
(000s)

Cost Category	2007	2008	2009 – 2011	Total
Material	$5,728	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$5,728**	**$5,802**	**$17,971**	**$29,501**

Costing Methodology

Table 2 shows the annual expenditures for the most recent five-year period, as well as an estimate for 2007.

Table 2

Expenditure History and Budget Estimate
(000s)

Year	**2002**	**2003**	**2004**	**2005**	**2006F**	**2007B**
Total	**$5,194**	**$5,529**	**$5,449**	**$4,976**	**$5,540**	**$5,728**
Adjusted Cost[1]	$5,806	$5,995	$5,747	$5,100	$5,540	-

[1] 2006 Dollars.

The process of estimating the budget requirement for transformers is based on a historical average. Historical annual expenditures related to distribution transformers over the most recent five-year period, including the current year, expressed in current-year dollars ("Adjusted Cost") are modified by the GDP Deflator for Canada for the budget year to determine the budget estimate.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Reconstruction (Pooled)**

Project Cost: **$3,077,000**

Project Description

This Distribution project involves the replacement of deteriorated or damaged distribution structures and electrical equipment. This project is comprised of smaller unplanned projects that are identified during the budget year as a result of line inspections, or recognized during follow-up on operational problems, including power interruptions and customer trouble calls. This project consists of high priority projects that cannot be deferred to the next budget year.

Distribution Reconstruction requirements are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

This project differs from the Rebuild Distribution Lines project, which involves rebuilding sections of lines that are identified and planned in advance of the annual capital budget preparation.

Justification

This project is justified on the basis of the need to replace defective or deteriorated electrical equipment in order to maintain a safe, reliable electrical system.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1
Project Expenditures
(000s)

Cost Category	2007	2008	2009 – 2011	Total
Material	$728	-	-	-
Labour – Internal	1,239	-	-	-
Labour – Contract	694	-	-	-
Engineering	311	-	-	-
Other	105	-	-	-
Total	**$3,077**	**$3,155**	**$10,038**	**$16,270**

Costing Methodology

Table 2 shows the annual expenditures and costs in current dollars for the most recent five-year period, as well as the projected expenditure for 2007.

Table 2

Expenditure History and Budget Estimate (000s)

Year	**2002**	**2003**	**2004**	**2005**	**2006F**	**2007B**[1]
Total	**$2,878**	**$2,846**	**$2,420**	**$2,898**	**$2,878**	**$3,077**
Adjusted Cost[2]	$3,299	$3,189	$2,636	$3,023	$2,878	-

1 2007B amount reflects increased customer base.
2 2006 dollars.

The process of estimating the budget requirement for Reconstruction is based on a historical average. Historical annual expenditures related to unplanned repairs to distribution feeders over the most recent five-year period, including the current year, expressed in current-year dollars ("Adjusted Cost") are modified by the GDP Deflator for Canada for the budget year to determine the budget estimate.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Rebuild Distribution Lines (Pooled)**

Project Cost: **$3,625,000**

Project Description

This Distribution project involves the replacement of deteriorated distribution structures and electrical equipment that have been previously identified through ongoing line inspections, engineering reviews, or day to day operations.

Distribution rebuild projects are preventative capital maintenance projects which are either the complete rebuilding of deteriorated distribution lines or the selective replacement of various line components based on inspections or engineering reviews. These typically include the replacement of poles, crossarms, conductor, cutouts, surge/lightning arrestors, insulators and transformers.

The work for 2007 includes feeder improvements on 47 of the Company's 303 feeders, as well as the replacement of deteriorated padmount transformers.

While the various components of the project are not inter-dependent, they are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

This project is justified on the basis of maintaining a safe, reliable electrical system.

The Company has over 8,300 kilometres of distribution lines in service and has an obligation to maintain this plant in good condition to safeguard the public and its employees and to maintain reliable electrical service. The replacement of deteriorated distribution structures and equipment is an important element of this obligation.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1 **Project Expenditures** **(000s)**				
Cost Category	**2007**	**2008**	**2009 - 2011**	**Total**
Material	$1,750	-	-	-
Labour – Internal	1,468	-	-	-
Labour – Contract	208	-	-	-
Engineering	27	-	-	-
Other	172	-	-	-
Total	**$3,625**	**$3,702**	**$11,672**	**$18,999**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2 **Expenditure History** **(000s)**					
Year	**2002**	**2003**	**2004**	**2005**	**2006F**
Total	**$3,210**	**$3,351**	**$3,382**	**$3,545**	**$3,190**

Distribution feeders are inspected in accordance with Newfoundland Power's distribution inspection standards to identify:

a) Deficiencies that are a risk to public or employee safety, or that are likely to result in imminent failure of a structure or hardware;
b) Locations where lightning arrestors are required as per the *2003 Lightning Arrestor Review*;[1]
c) Locations where CP8080 and 2-piece insulators still exist. These insulators have a history of failure;[2]
d) Locations where current limiting fuses are required in accordance with the internal memo dated January 11, 2000;[3] and
e) Hardware for which a high risk of failure has been identified, such as automatic sleeves and porcelain cutouts.[4]

The budget estimate is based on engineering estimates of individual rebuild requirements.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

[1] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment B for further detail on lightning arrestor requirements.
[2] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment C for further detail on problem insulators.
[3] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment D for further detail on current limiting fuse requirements.
[4] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment E and Attachment F for further detail on automatic sleeves and porcelain cutouts.

Project Title: **Relocate/Replace Distribution Lines for Third Parties (Pooled)**

Project Cost: **$541,000**

Project Description

This Distribution project is necessary to accommodate third party requests for the relocation or replacement of distribution lines. The relocation or replacement of distribution lines results from (1) work initiated by municipal, provincial and federal governments, (2) work initiated by other utilities such as Aliant, Persona and Rogers Cable, or (3) requests from customers.

The Company's response to requests for relocation and replacement of distribution facilities by governments and other utility service providers is governed by the provisions of agreements in place with the requesting parties.

While the individual requirements are not inter-dependent, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Justification

This project is justified on the basis of the need to respond to legitimate requirements for plant relocations resulting from third party activities.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1
Project Expenditures
(000s)

Cost Category	2007	2008	2009 – 2011	Total
Material	$190	-	-	-
Labour – Internal	173	-	-	-
Labour – Contract	114	-	-	-
Engineering	55	-	-	-
Other	9	-	-	-
Total	**$541**	**$555**	**$1,766**	**$2,862**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2
Expenditure History
(000s)

Year	**2002**	**2003**	**2004**	**2005**	**2006F**
Total	**$390**	**$330**	**$440**	**$630**	**$1,640**
Adjusted Cost[1]	$447	$370	$479	$657	$1,640

[1] 2006 dollars.

The budget estimate is based on historical expenditures and specific project estimates for extraordinary requirements. Generally these expenditures are associated with a number of small projects that are not specifically identified at the time the budget is prepared. Historical annual expenditures related to distribution line relocations and replacements over the most recent five-year period, including the current year, expressed in current-year dollars ("Adjusted Cost") are modified by the GDP Deflator for Canada for the budget year to determine the budget estimate. To ensure consistency from year to year, expenditures related to past extraordinary requirements are excluded from the calculation.

Estimated contributions from customers and requesting parties associated with this project have been included in the contribution in aid of construction amount referred to in the Application.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Interest During Construction (Pooled)**

Project Cost: **$81,000**

Project Description

This Distribution project is an allowance for interest during construction that will be charged on distribution work orders with an estimated expenditure of less than $50,000 and a construction period in excess of three months.

Justification

The interest incurred during construction is justified on the same basis as the distribution work orders to which it relates.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1

Project Expenditures
(000s)

Cost Category	2007	2008	2009 – 2011	Total
Material	-	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	81	-	-	-
Total	**$81**	**$82**	**$254**	**$417**

Cost Methodology

Table 2 shows the annual expenditures for the most recent five-year period, as well as an estimate for 2007. The 2006 forecast amount and the 2007 budget amount are based on the average of the annual expenditures for the period 2002 to 2005.

Table 2 **Expenditure History and Budget Estimate** **(000s)**					
Year	**2002**	**2003**	**2004**	**2005**	**2006F**
Total	**$80**	**$74**	**$66**	**$73**	**$84**

The budget estimate for interest during construction is based on an estimated monthly average of total distribution work in progress of $1.0 million. The interest rate which is applied each month is dependent on the source of funds used to finance the capital expenditure and is calculated in accordance with Order No. P.U. 37 (1981).

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

GENERAL PROPERTY

Project Title: **Tools and Equipment (Pooled)**

Project Cost: **$600,000**

Project Description

This General Property project is required to add or replace tools and equipment used in providing safe, reliable electrical service. Users of tools and equipment include line staff, engineering technicians, engineers and electrical and mechanical tradespersons. The majority of these tools are used in normal day to day operations. As well, specialized tools and equipment are required to maintain, repair, diagnose or commission Company assets required to deliver service to customers.

Individual requirements for the addition or replacement of tools and equipment are not inter-dependent. However, the expenditure requirements are similar in nature and justification. They are therefore pooled for consideration as a single capital project.

All items within this project involve expenditures of less than $50,000. These items are consolidated into the following categories:

1. *Operations Tools and Equipment ($170,000)*: This is the replacement of tools and equipment used by line and field technical staff in the day to day operations of the Company. These tools are maintained on a regular basis. However, over time they degrade and wear out, especially hot line equipment which must meet rigorous safety requirements. Where appropriate, such tools will be replaced with battery and hydraulic alternatives to improve productivity and working conditions.

2. *Engineering Tools and Equipment ($380,000)*: This project includes engineering test equipment, tools and substation portable grounds used by electrical and mechanical maintenance personnel and engineering technicians. Engineering test equipment is required to perform system calibration, commissioning and testing of power system facilities and testing and analysis of associated data communications facilities.

3. *Office Furniture ($50,000)*: This project is the replacement of office furniture that has deteriorated. The Company has approximately 600 full time employees. The office furniture utilized by these employees deteriorates through normal use and must be replaced.

Justification

Suitable tools and equipment in good condition enable staff to perform work in a safe, effective and efficient manner.

Additional or replacement tools are purchased to either maintain or improve quality of work and overall operational efficiency.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1

Project Expenditures
(000s)

Cost Category	2007	2008	2009 - 2011	Total
Material	$600	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$600**	**$681**	**$1,972**	**$3,253**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2

Expenditure History
(000s)

Year	2002	2003	2004	2005	2006F
Total	**$378**	**$865**	**$570**	**$693**	**$679**

The project cost is based on an assessment of historical expenditures for the replacement of tools and equipment that become broken or worn out, and is adjusted for anticipated expenditure requirements for extraordinary items.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Additions to Real Property (Pooled)**

Project Cost: **$100,000**

Project Description

This General Property project is required to ensure the continued safe operation of Company facilities and workplaces. The Company has in excess of 20 office and other buildings. There is an ongoing requirement to upgrade or replace equipment and facilities at these buildings due to failure or normal deterioration. Past expenditures have included such items as emergency roof repairs and correcting major drainage problems.

The individual budget items are not inter-dependent. However, they are similar in nature and are therefore pooled for consideration as a single capital project.

Justification

This project is necessary to maintain buildings and support facilities and to operate them in a safe and efficient manner.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1
Project Expenditures
(000s)

Cost Category	2007	2008	2009 - 2011	Total
Material	$94	-	-	-
Labour – Internal	6	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$100**	**$227**	**$705**	**$1,032**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period, as well as a projected unit cost for 2006.

Table 2
Expenditure History
(000s)

Year	**2002**	**2003**	**2004**	**2005**	**2006F**
Total	**$337**	**$237**	**$336**	**$334**	**$175**
Exclusions	270	157	211	224	-
Adjusted Cost	$67	$80	$125	$100	$175

The budget for this project is calculated on the basis of historical data as well as engineering estimates for planned budget items as required. To ensure consistency from year to year, expenditures related to planned additions are excluded from the calculation. There are no planned budget items for 2007.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Energy Efficient HVAC System (Other)**

Project Cost: **$610,000**

Project Description

This General Property project consists of the replacement of the heating, ventilation and air conditioning system ("HVAC system") in the basement and on the first floor of the Kenmount Road office building. The replacement HVAC system will be energy efficient.

Details on 2007 proposed expenditures are outlined in ***4.1*** *Kenmount Road Office Building HVAC System Replacement.*

Justification

This project is necessary to address high operating costs associated with the current unit and to provide for better air quality and working conditions for employees.

The Kenmount Road building was built in 1968. The original building consisted of the basement and first floor. In 1979, two additional floors were added.

The HVAC system servicing the bottom two floors was installed during the original construction in 1968 and is 38 years old. The expected life of the system was 25 years. Operational problems have been ongoing for some years. Substandard air conditioning has resulted in employees being exposed to higher temperatures in the summer months and cooler temperatures in the winter months.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011. The replacement of the 1979 vintage HVAC system is scheduled for 2009.

Table 1 **Project Expenditures** **(000s)**				
Cost Category	**2007**	**2008**	**2009 - 2011**	**Total**
Material	$528	-	-	-
Labour – Internal	20	-	-	-
Labour – Contract	-	-	-	-
Engineering	62	-	-	-
Other	-	-	-	-
Total	**$610**	**$0**	**$535**	**$1,145**

Costing Methodology

The budget estimate for this project is comprised of engineering estimates.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

TRANSPORTATION

Project Title: **Purchase Vehicles and Aerial Devices (Pooled)**

Project Cost: **$2,206,000**

Project Description

This Transportation project involves the necessary replacement of heavy fleet, passenger and off-road vehicles. Detailed evaluation of the units to be replaced indicates they have reached the end of their useful lives.

Table 1 lists the units to be acquired in 2007.

Table 1
2007 Proposed Vehicle Replacements

Category	No. of Units
Heavy fleet vehicles[1]	8
Passenger vehicles[2]	35
Off-road vehicles[3]	6
Total	**49**

The expenditures for individual vehicle replacements are not inter-dependent. However, they are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

This project is justified on the basis of the need to replace existing capital items that have reached the end of their useful service lives.

Project Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

[1] The Heavy Fleet vehicles category includes the purchase of replacement line trucks.
[2] The Passenger Fleet vehicles category includes the purchase of cars and light duty trucks.
[3] The Off-road vehicles category includes snowmobiles, ATVs and trailers.

Table 2 Projected Expenditures (000s)				
Cost Category	**2007**	**2008**	**2009 - 2011**	**Total**
Material	$2,149	-	-	-
Labour – Internal	48	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	9	-	-	-
Total	**$2,206**	**$2,714**	**$7,568**	**$12,488**

Table 3 shows the expenditures for this project for the most recent five-year period.

Table 3 Expenditure History (000s)					
Year	**2002**	**2003**	**2004**	**2005**	**2006F**
Total	**$1,609**	**$3,429**	**$2,660**	**$2,838**	**$2,755**

Costing Methodology

Newfoundland Power individually evaluates all vehicles considered for replacement according to a number of criteria to ensure replacement is the least cost option.

Evaluation for replacement is initiated when individual vehicles reach a threshold age or level of usage. Heavy fleet vehicles are considered for replacement at 10 years of age or usage of 250,000 kilometres. For passenger vehicles the guideline is five years of age or 150,000 kilometres.

Vehicles reaching the threshold are evaluated on a number of criteria, such as overall condition, maintenance history and immediate repair requirements, to determine whether they have reached the end of their useful service lives. Based on such evaluations, it has been determined that each unit proposed for replacement has reached the end of its useful life.

New vehicles are acquired through competitive tendering to ensure the lowest possible cost consistent with safe, reliable service.

Future Commitments

This is not a multi-year project.

TELECOMMUNICATIONS

Project Title: **Replace/Upgrade Communications Equipment (Pooled)**

Project Cost: **$101,000**

Project Description

This Telecommunications project involves the replacement and/or upgrade of communications equipment, including radio communication equipment and communications equipment associated with electrical system control.

The Company has approximately 340 pieces of mobile radio equipment in service. Each year approximately 20 units break down and where practical, equipment is repaired and deficiencies rectified. However, where it is not feasible to repair equipment or correct deficiencies, replacement is required.

Newfoundland Power uses the analog cellular telephone system to provide backup SCADA communications to substations and hydro plants. This service is scheduled to be decommissioned by Aliant Mobility in 2007. As a result Newfoundland Power will need to replace the analog cellular modems with digital cellular modems.

Newfoundland Power engages an engineering consultant to inspect radio towers. Deficiencies identified through these inspections are addressed through this project.

Justification

Reliable communications equipment is essential to the provision of safe, reliable electrical service. Communications towers must comply with safety codes and standards to ensure employee and public safety.

The replacement of the analog cellular modems is justified on technical obsolescence and the requirement to provide reliable communications for the remote monitoring and control of key distribution, substation, transmission and generation assets.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1
Project Expenditures
(000s)

Cost Category	2007	2008	2009 - 2011	Total
Material	$ 64	-	-	-
Labour – Internal	6	-	-	-
Labour – Contract	-	-	-	-
Engineering	20	-	-	-
Other	11	-	-	-
Total	**$ 101**	**$ 73**	**$ 225**	**$ 399**

Costing Methodology

Table 2 shows the annual expenditures and costs in current dollars for the most recent five-year period, as well as the projected expenditure for 2006.

Table 2
Expenditure History
(000s)

Year	2002	2003	2004	2005	2006F
Total	**$105**	**$41**	**$150**	**$102**	**$133**
Adjusted Cost[1]	$118	$45	$150	$105	$133

[1] 2006 dollars.

The process of estimating the budget requirement for communications equipment is based on a historical average. Historical annual expenditures related to upgrading and replacing communications equipment over the most recent five-year period, including the current year, expressed in current-year dollars ("Adjusted Cost") are modified by the GDP Deflator for Canada for the budget year to determine the budget estimate. To ensure consistency from year to year, expenditures related to planned projects are excluded from the calculation of the historical average.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

INFORMATION SYSTEMS

Project Title: **Application Enhancements (Pooled)**

Project Cost: **$1,281,000**

Project Description

This Information Systems project is necessary to enhance the functionality of software applications. The Company's software applications are used to support all aspects of business operations including provision of service to customers, ensuring the reliability of the electrical system and compliance with regulatory and financial reporting requirements.

Of the software applications proposed to be enhanced in 2007, some, such as the Customer Service System, are custom-developed while others, such as the Safety Management System, are vendor-provided.

The application enhancements proposed for 2007 are not inter-dependent. But, they are similar in nature and justification and are therefore pooled for consideration as a single capital project.

Details on proposed expenditures are included in ***5.1*** *2007 Application Enhancements*.

Justification

Some of the proposed enhancements included in this project are justified on the basis of improving customer service. Some will result in increased operational efficiencies. Some projects will have a positive impact on both customer service and operational efficiency.

Cost benefit analyses, where appropriate, are provided in ***5.1*** *2007 Application Enhancements*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1 **Project Expenditures** **(000s)**				
Cost Category	**2007**	**2008**	**2009 - 2011**	**Total**
Material	-	-	-	-
Labour – Internal	$850	-	-	-
Labour – Contract	-	-	-	-
Engineering	191	-	-	-
Other	240	-	-	-
Total	**$1,281**	**$1,170**	**$2,795**	**$5,246**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2 **Expenditure History** **(000s)**					
Year	**2002**	**2003**	**2004**	**2005**	**2006F**
Total	**$726**	**$920**	**$1,313**	**$1,185**	**$1,532**

The budget for this project is based on cost estimates for the individual budget items.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist, all materials and services will be negotiated with a sole-source supplier to ensure least cost.

Future Commitments

This is not a multi-year project.

Project Title: **System Upgrades (Pooled)**

Project Cost: **$689,000**

Project Description

This Information Systems project involves necessary upgrades to the computer software underlying the Company's business applications. Most upgrades are required by software vendors to address known software issues or to maintain support provided by the vendors.

For 2007, the project includes upgrades to the Avantis Asset Management System, Reporting Software, Load Research Software and Customer Service System software. The project also includes Application Monitoring and Availability Improvements and Application Change Control Improvements.

The system upgrades proposed for 2007 are not inter-dependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Details on 2007 proposed expenditures are included in ***5.2** 2007 System Upgrades*.

Justification

This project is justified on the basis of maintaining current levels of customer service and operational efficiency supported by the software.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1 Project Expenditures (000s)				
Cost Category	**2007**	**2008**	**2009 – 2011**	**Total**
Material	$70	-	-	-
Labour – Internal	424	-	-	-
Labour – Contract	-	-	-	-
Engineering	20	-	-	-
Other	175	-	-	-
Total	**$689**	**$834**	**$2,285**	**$3,808**

Costing Methodology

Table 2 shows the annual expenditures and unit costs for this project for the most recent five-year period.

Table 2 Expenditure History (000s)					
Year	**2002**	**2003**	**2004**	**2005**	**2006F**
Total	**$724**	**$721**	**$861**	**$779**	**$1,075**

The budget for this project is based on cost estimates for the individual budget items.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist, all materials and services will be negotiated with a sole-source supplier to ensure least cost.

Future Commitments

This is not a multi-year project.

Project Title: **Personal Computer Infrastructure (Pooled)**

Project Cost: **$400,000**

Project Description

This Information Systems project is necessary for the replacement or upgrade of personal computers ("PCs"), printers and associated assets that have reached the end of their useful lives.

In 2007, 80 PCs will be purchased consisting of 57 desktop computers and 23 laptop computers. This project also covers the purchase of additional peripheral equipment such as monitors, scanners, and mobile devices, and the purchase of 9 printers to replace existing printers that have reached the end of their useful lives.

The individual PCs and peripheral equipment are not inter-dependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Minimum specifications for replacement PCs and peripheral equipment are reviewed annually to ensure the personal computing infrastructure remains effective. Industry best practices, technology trends, and the Company's experience are considered when establishing minimum specifications.

Newfoundland Power is currently able to achieve a four to six year life cycle for its PCs before they require replacement. This is achieved through the Company's practice of cascading PCs to employees who do not require the computing power of newer PCs, thereby maximizing the asset life of the PC.

Table 1 outlines the PC additions and retirements for 2005 and 2006, as well as the proposed additions and retirements for 2007.

Table 1

PC Additions and Retirements
2005 – 2007

	2005			**2006**			**2007**		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	76	98	490	47	78	459	57	57	459
Laptop	26	20	123	15	4	134	23	23	134
Total	**102**	**118**	**613**	**62**	**82**	**593**	**80**	**80**	**593**

Justification

This project is justified on the basis of the need to replace personal computers and associated equipment that has reached the end of its useful life.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 2
Project Expenditures
(000s)

Cost Category	2007	2008	2009 - 2011	Total
Material	$219	-	-	-
Labour – Internal	81	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	100	-	-	-
Total	**$400**	**$406**	**$1,260**	**$2,066**

Costing Methodology

Table 3 shows the annual expenditures for this project for the most recent five-year period.

Table 3
Expenditure History
(000s)

Year	2002	2003	2004	2005	2006F
Total	$635	$518	$424	$412	$314

The project cost for this project is calculated on the basis of historical expenditures and on cost estimates for the individual budget items. Historical annual expenditures over the most recent three-year period are considered and an approximate unit cost is determined based on historical average prices and a consideration of pricing trends. These unit costs are then multiplied by the quantity of units (i.e. desktop, laptop, printer, etc.) to be purchased. Quantities are forecast by identifying the number of unit replacements resulting from lifecycle retirements and the number of new units required to accommodate new software applications or work methods. Once the unit price estimates and quantities have been determined, the work associated with the procurement and installation of the units is estimated based on experience and historical pricing.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all materials and services for this project will be purchased after examining the competitive bids of prospective suppliers.

Future Commitments

This is not a multi-year project.

Project Title: **Shared Server Infrastructure (Pooled)**

Project Cost: **$877,000**

Project Description

This Information Systems project includes the procurement, implementation, and management of the hardware and software relating to the operation of shared servers. Shared servers are computers that support applications used by multiple employees. Management of these shared servers, and their components, is critical to ensuring that these applications operate effectively at all times.

This project is necessary to maintain current performance of the Company's shared servers and to provide the additional infrastructure needed to accommodate new and existing applications. This involves the replacement and upgrade of servers, disks, processors, and memory as well as security upgrades.

The shared server infrastructure requirements for 2007 are not inter-dependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Further details on shared server infrastructure requirements for 2007 are provided in ***5.3** 2007 Shared Server Infrastructure*.

Justification

This project is justified on the basis of maintaining current levels of customer service and operational efficiencies that are supported by the Company's shared server infrastructure.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2007 and a projection of expenditures through 2011.

Table 1 Project Expenditures (000s)				
Cost Category	**2007**	**2008**	**2009 – 2011**	**Total**
Material	$560	-	-	-
Labour – Internal	207	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	110	-	-	-
Total	**$877**	**$750**	**$2,323**	**$3,950**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2 Expenditure History (000s)					
Year	**2002**	**2003**	**2004**	**2005**	**2006F**
Total	**$705**	**$1,608**	**$699**	**$593**	**$568**

The budget for this project is based on cost estimates for the individual budget items.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist, all materials and services will be negotiated with a sole-source supplier to ensure least cost.

Future Commitments

This is not a multi-year project.

UNFORESEEN ALLOWANCE

Project Title: **Allowance for Unforeseen Items (Other)**

Project Cost: **$750,000**

Project Description

This Unforeseen Allowance project is necessary to cover any unforeseen capital expenditures which have not been budgeted elsewhere. The purpose of the account is to permit the Company to act expeditiously to deal with events affecting the electrical system in advance of seeking specific approval of the Board. Examples of such expenditures are the replacement of facilities and equipment due to major storm damages or equipment failure.

While the contingencies for which this budget allowance is intended may be unrelated, it is appropriate that the entire allowance be considered as a single capital budget item.

Justification

This project provides funds for timely service restoration.

Projects for which these funds are intended are justified on the basis of reliability, or on the need to immediately replace deteriorated or damaged equipment.

Costing Methodology

An allowance of $750,000 for unforeseen capital expenditures has been included in all of Newfoundland Power's capital budgets in recent years.

To ensure the projects to which the proposed expenditures are applied are completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitment

This is not a multi-year project.

GENERAL EXPENSES CAPITALIZED

Project Title: **General Expenses Capitalized (Other)**

Project Cost: **$2,800,000**

Project Description

General Expenses Capitalized (GEC) are general expenses of Newfoundland Power that are capitalized due to the fact that they are related, directly or indirectly, to the Company's capital projects. GEC includes amounts from two sources: direct charges to GEC and amounts allocated from specific operating accounts.

Justification

Certain of Newfoundland Power's general expenses are related, either directly or indirectly, to the Company's capital program. Expenses are charged to GEC in accordance with guidelines approved by the Board in Order No. P.U. 3 (1995-96).

Costing Methodology (least cost)

In Order No. P.U. 3 (1995-96), the Board approved guidelines to determine the expenses of the Company to be included in GEC. The budget estimate of GEC is determined in accordance with pre-determined percentage allocations to GEC based on the guidelines approved by the Board.

Future Commitment

This is not a multi-year project.

Newfoundland Power Inc.
2007 Capital Budget
Future Required Expenditures

Improvement to Property	Estimated Annual Expenditure	Timing
Microsoft Enterprise Agreement[1]	$210,000	3 Years: 2006 through 2008

[1] This is a multi-year project approved in Order No. P.U. 30 (2005).

Newfoundland Power Inc.
2007 Capital Budget
Rate Base
(000s)

	Historical Data	
	2004	**2005**
Plant Investment	$ 1,113,199	$ 1,148,621
Deduct:		
Accumulated Depreciation	462,946	476,937
Contributions in Aid of Construction	20,495	21,192
Future Income Taxes	1,501	1,375
Weather Normalization Reserve	(10,477)	(10,100)
	474,465	489,404
	638,734	659,217
Add - Contributions Country Homes	563	580
Balance - Current Year	639,297	659,797
Balance - Previous Year	610,975	639,297
Average	625,136	649,547
Cash Working Capital Allowance	5,268	5,514
Materials and Supplies	4,661	4,322
Average Deferred Charges	80,046	86,063
Average Rate Base at Year End	$ 715,111	$ 745,446

2007 Capital Budget Plan

March 2006

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

To provide a broad context for the Board's consideration of its 2007 capital budget application, Newfoundland Power's 2007 Capital Budget Plan provides overviews of (i) the Company's capital management practice and how it is reflected in its annual capital budgets, (ii) the 2007 capital budget and (iii) the 5-year capital outlook through 2011.

1.1 Capital Assets

Newfoundland Power's ability to meet its obligations to provide reliable electricity service to its customers at least cost is largely dependant upon the quality and condition of its capital assets. The capital cost of Newfoundland Power's assets is approximately $1.1 billion. Table 1 provides a breakdown by class of the Company's capital assets.

Table 1
Capital Assets by Class
2005

Asset	**(000s)**
Generation	$ 133,256
Substation	126,101
Transmission	88,769
Distribution	675,787
General Property	52,402
Transportation	20,768
Telecommunications	13,130
Information Systems	38,408
Total	**$ 1,148,621**

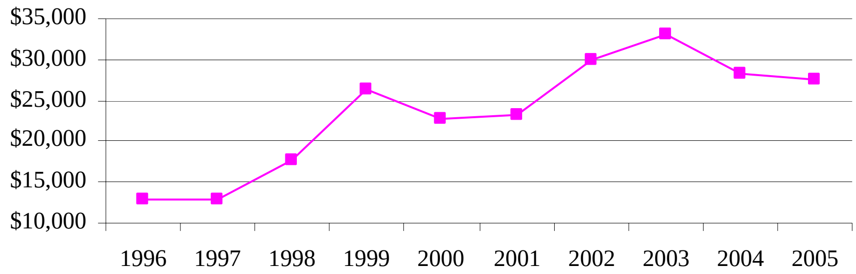
These assets are geographically dispersed throughout the Company's service territory and include: 23 hydroelectric plants; 6 thermal plants; 130 substations with almost 4,000 pieces of critical electrical equipment; approximately 270,000 distribution poles; 27,000 transmission poles; and approximately 10,000 km of distribution and transmission circuitry.

Newfoundland Power's annual capital budgets reflect the management of this relatively large number of components spread over a broad geographical area that make up the electrical system.

1.2 Reliability

A primary driver of Newfoundland Power's capital budgets is reliability. Reliability is, to a large extent, a function of system condition.[1] Graph 1 shows the Company's capital budget expenditure for asset replacement since 1996.

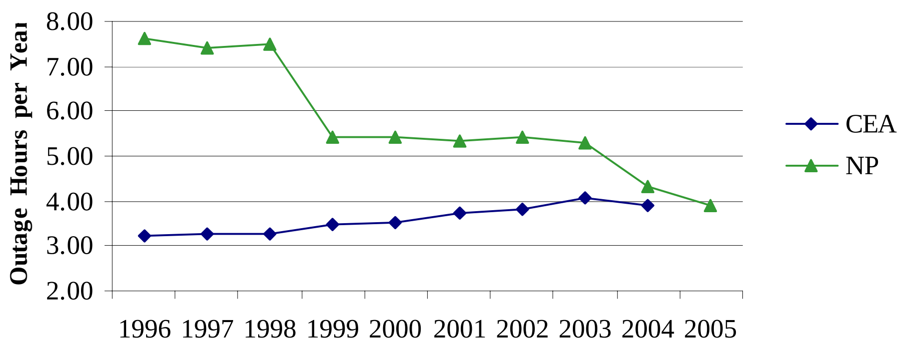
Graph 1
Asset Replacement 1996-2005
(000s)



Average capital expenditure for asset replacement for the most recent 5 year period was $28.4 million.[2] This represents approximately 2.5% of the capital cost of installed plant at 2005.[3]

Graph 2 shows the 5 year average annual duration of outages experienced by Newfoundland Power's customers since 1996.

Graph 2
5 Year Average SAIDI[4]



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[1] George Baker, P.Eng in his 1991 *Report* on *the Technical Performance of Newfoundland Light & Power Co. Limited*, prepared for the Board of Commissioners of Public Utilities, recognized that reliability was largely dependent on the quality of the system and weather.

[2] D. G. Brown, P.Eng in his 1998 report *Newfoundland Light & Power Co. Limited Quality of Service and Reliability of Supply*, prepared for the Board of Commissioners of Public Utilities, identified the need for Newfoundland Power to improve reliability.

[3] Capital cost of installed plant is $1.1 billion at December 31, 2005.

[4] SAIDI refers to System Average Interruption Duration Index. 2005 CEA data was not released at the time of filing.

Over the past number of years, the duration of outages experienced by Newfoundland Power's customers has trended towards the CEA national average.[5]

1.3 The 2007 Capital Budget Plan

The 2007 Capital Budget Plan (the "Plan") provides a broad overview of how Newfoundland Power assesses its annual capital requirements.

In addition, the Plan specifically includes an overview of the 2007 capital budget by the definitions and categories set out in the Board's provisional guidelines of June 2005. Finally, the Plan is intended to provide an overview of Newfoundland Power's 2007 capital budget within the context of a 2007 to 2011 five-year outlook.

2.0 Capital Budgeting

Newfoundland Power's annual capital budgets reflect the Company's capital management practices. The annual budgets are principally aimed at the prudent refurbishment of existing capital assets and the extension of the electricity network to meet increasing customer service requirements.

2.1 Overview

In creating its annual capital budgets, Newfoundland Power's principal purposes are to (i) prudently maintain existing assets in a safe, reliable manner and (ii) extend the electricity network to meet customers' service requirements.

This section, *2.0 Capital Budgeting*, outlines how the Company practically achieves these broad purposes in its annual capital budgeting process.

In the 2006 Capital Budget Plan submitted as part of the 2006 Capital Budget Application, the Company described its capital management practices pertaining to Distribution assets. The 2007 capital budget is unique in that one project, the *Rattling Brook Hydro Plant Refurbishment* project, accounts for 30% of total expenditure. To provide context for consideration of that project, this report places specific emphasis on the Company's capital management practices pertaining to Generation assets.

2.2 Capital Management Practice

2.2.1 General Principles

Newfoundland Power must manage its capital assets in a way that results in the lowest possible cost to customers consistent with reliable service.

[5] SAIFI (System Average Interruption Frequency Index) remains higher than the national average. This is largely attributable to the isolated nature of the Island electrical system.

Conceptually, the Company's approach to capital management of existing assets attempts to balance the maximization of asset lives with the proactive replacement of deteriorated plant and equipment. Maximizing asset lives tends to lower overall costs. However, the longer facilities are in the field and exposed to climatic stresses, the greater the likelihood of failure which often results in increased operating cost and reduced reliability of service.

Due to the long life of utility assets, the replacement cost of plant will generally exceed the historical capital cost of plant particularly due to inflation. Therefore, the Company will continue to balance the maximization of asset lives with the proactive replacement of defective or deteriorated plant. Capital expenditures to replace deteriorated plant typically accounts for 50% to 60% of Newfoundland Power's annual capital budgets.[6]

In addition to maintaining or replacing existing capital assets, Newfoundland Power must invest capital to meet the new service requirements of its customers. Meeting these requirements principally involves investment in the distribution system to connect customers to the system in a cost effective way. Capital expenditures to serve new customers or increased customer requirements typically account for 20 to 25% of Newfoundland Power's annual capital budgets.

Whether the capital expenditure involves asset replacement, maintenance, or investment, the Company incorporates energy efficiency considerations in its capital management practice. For example, the 2007 Capital Budget Application contains projects that (i) maximize the efficient use of existing resources such as the Rattling Brook penstock replacement, (ii) minimize system losses through the purchase of energy efficient transformers, and (iii) reduce peak load such as the replacement of Kenmount Road's HVAC system with an energy efficient HVAC system.

2.2.2 Generation Plant Capital Maintenance

Generation plant assets are engineered assets that require professional oversight to ensure programs, projects and measures are in place to manage the assets effectively. Capital maintenance expenditures generally fall into two broad categories (i) breakdown capital maintenance and (ii) preventive capital maintenance programs.

Breakdown capital maintenance expenditure is responsive in nature and is required to restore electricity production after plant or equipment failure. As well, expenditure is required to perform corrective capital maintenance on plant or equipment that is discovered through inspections, trouble reports or routine operations to be in imminent danger of failing, and thereby at risk of disrupting electricity production or creating a safety hazard. Expenditures in this area are a high priority and cannot be deferred to the next budget year.

Preventive capital maintenance programs are proactive in nature and are necessary to operate generation plants safely and reliably over the long term at least cost. The Company has a structured preventive maintenance program in place for its generation plants that requires both capital and operating expenditures. The Company's preventive maintenance programs are based on industry best practices and typically involve cycles of routine inspections, functional and

[6] Due to the *Rattling Brook Hydro Plant Refurbishment* project, capital expenditure to replace deteriorated plant and equipment in 2007 will approach 70% of overall capital expenditure.

operational testing and major equipment overhauls at specific intervals. For example, a significant component of the Company's preventive maintenance program for generation is derived from the safety guidelines of the Canadian Dam Association. Preventive maintenance capital expenditures are generally directed at the replacement of deteriorated, defective or obsolete plant and equipment.

2.2.3 Generation Plant Capital Project Initiatives

In addition to capital maintenance, there are instances where more comprehensive rebuilding, refurbishment or modernization is required in generating plants. When capital work is required that is, in engineering judgement, beyond the scope of routine capital maintenance, it is considered a capital project initiative. These initiatives normally address specific problems in specific locations.

When the Company proposes to undertake a capital project initiative in a generating plant, a high degree of justification and engineering analysis is required. The Company produces engineering reports for all such initiatives that outline, in considerable detail, the need, justification and cost estimate for the project. Before any capital initiative is undertaken on a generation plant, the Company performs an assessment of the long term economic viability of the generation plant.

2.3 Capital Budgeting Practice

2.3.1 Generation Plant Capital Maintenance

For generation plant capital maintenance as described in *2.2.2 Generation Plant Capital Maintenance* above, proposed annual capital expenditures are found in the *Facility Rehabilitation* project. This project, budgeted at $946,000 for 2007, is described in *1.1 2007 Facility Rehabilitation*. The Company estimates the expenditure required to address breakdown maintenance based on historical levels of expenditure. The level of expenditure required under the preventive maintenance program is based on inspections, engineering judgment and historical levels of expenditure.

2.3.2 Generation Plant Capital Project Initiatives

For generation plant capital project initiatives as described in *2.2.3 Generation Plant Capital Project Initiatives* above, the proposed annual capital expenditures for 2007 are found in the *Rattling Brook Hydro Plant Refurbishment* project. This project is described in *Volume II, Rattling Brook Hydro Plant Refurbishment*.

In managing its generation plant assets, the Company plans to bring forward at least one major capital project initiative annually. In 2007, the Company proposes to refurbish the largest of its hydroelectric plants, Rattling Brook. *Section 4.0 Five-Year Outlook* of this report lists the capital project initiatives the Company is currently proposing for generating plants over the next five years.

2.4 Concluding

Newfoundland Power's capital budgeting practices for Generation assets ensure the prudent maintenance of existing assets, which provides least cost electricity service to customers. The

2007 capital budget contains expenditures to respond to inevitable failures of plant and equipment, expenditures to carry out a preventive capital maintenance program and a substantial capital project initiative to refurbish the Rattling Brook hydroelectric plant.

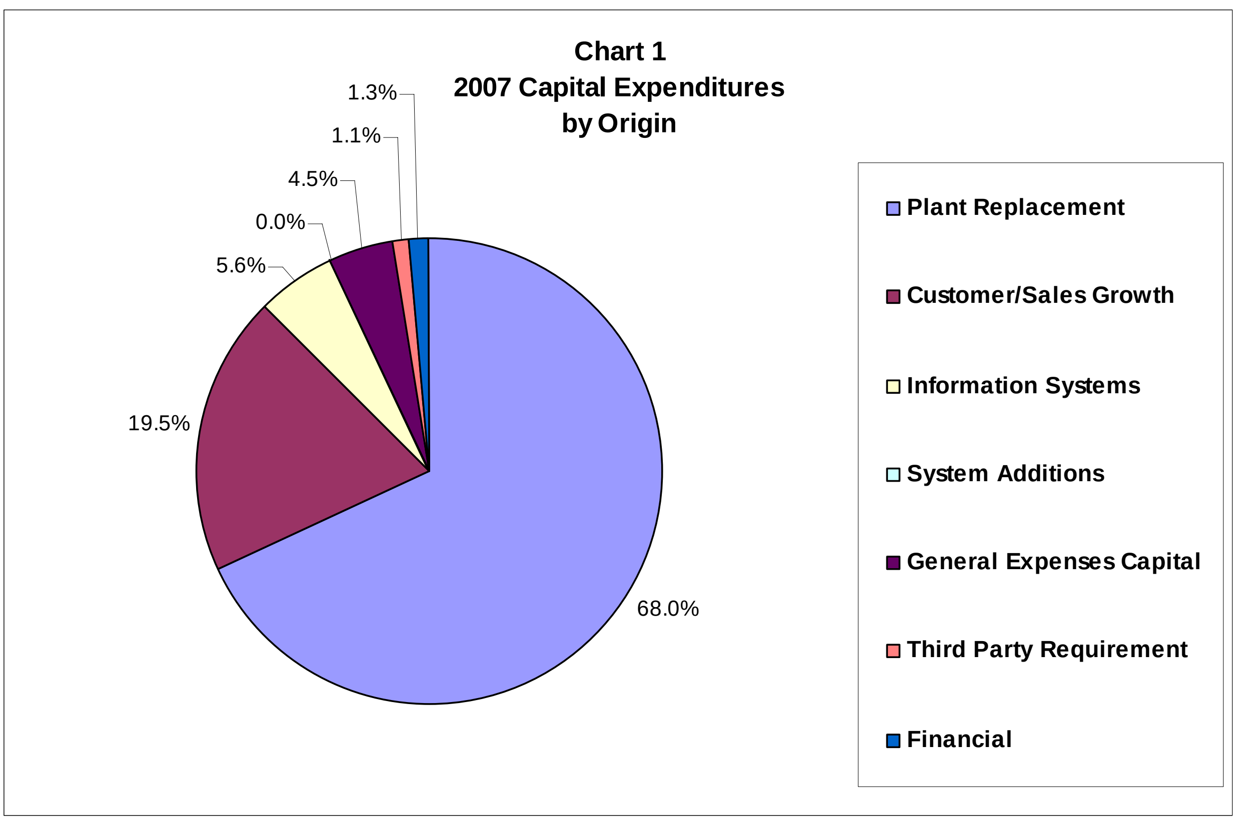
3.0 2007 Capital Budget

Newfoundland Power's 2007 capital budget is $62,166,000. The budget contains a major project to refurbish the Rattling Brook Hydro Plant which constitutes 30% of the proposed budget. This section of the 2007 Capital Budget Plan provides an overview of the 2007 capital budget by origin (root cause) and asset class. In addition, this section summarizes 2007 capital projects by the various categories set out in the Board's June 2005 provisional capital filing guidelines.

3.1 2007 Capital Budget Overview

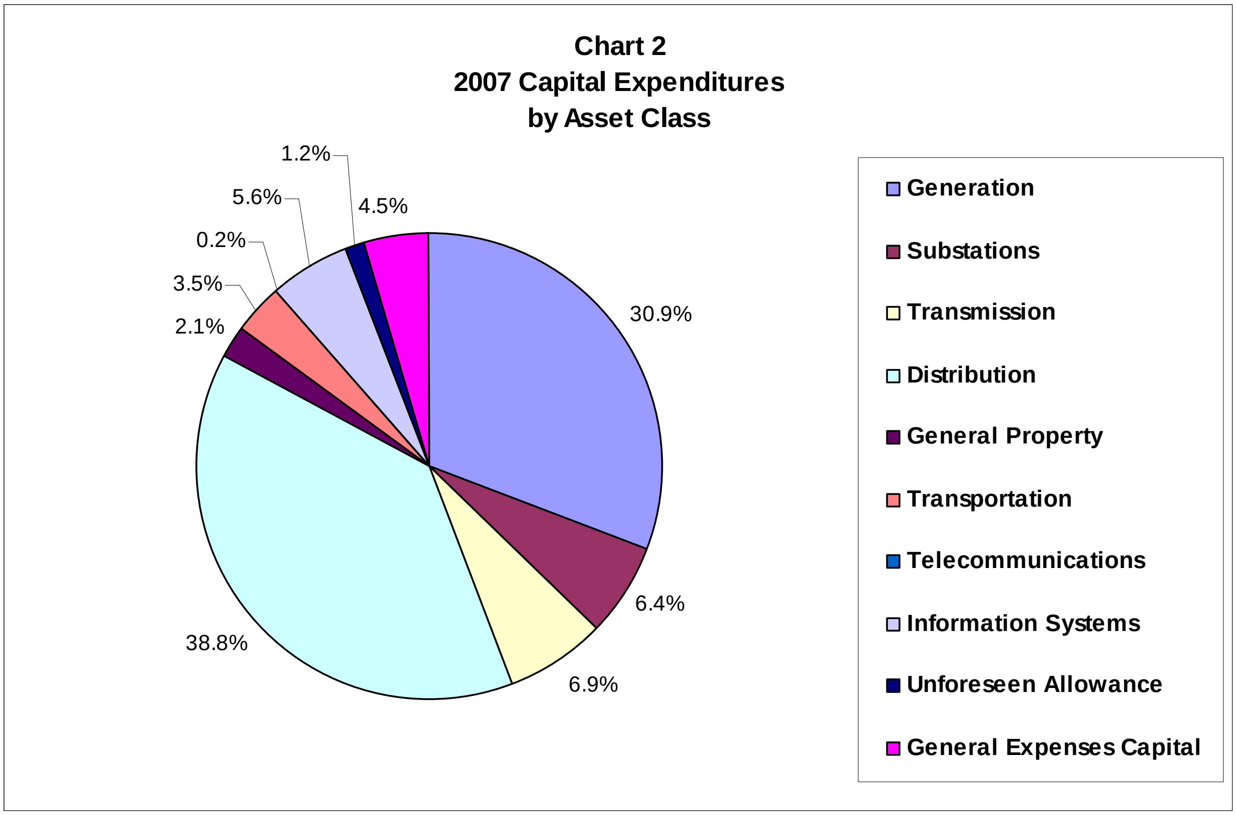
Newfoundland Power's 2007 capital budget contains 26 projects totalling $62,166,000. The budget is different from budgets proposed in recent years in that a single project, the *Rattling Brook Hydro Plant Refurbishment* project, which is budgeted at $18,820,000, constitutes 30% of the overall capital budget.

Chart 1 shows the 2007 capital budget by origin, or root cause.



Approximately 68% of proposed 2007 capital expenditure is related to the replacement of plant. A further 20% of proposed 2007 capital expenditure is required to meet the Company's obligation to provide service to new customers. The percentage of expenditure related to plant replacements is higher than the historical average due to the Rattling Brook project.

Chart 2 shows the 2007 capital budget by asset class.



As in past years, Distribution capital expenditure accounts for the greatest percentage of overall expenditure at $24.1 million, or 39% of the 2007 capital budget. Substations and Transmission capital expenditures account for a further $8.3 million, or 13% of the 2007 capital budget. The refurbishment of the Rattling Brook Hydro Plant has caused an increase in Generation capital expenditure to $19.2 million or 31% of the 2007 capital budget, which is higher than the historical average for Generation.

3.2 The Provisional Guidelines

In June 2005, the Board provided guidelines on the definition and categorization of capital expenditures for which a public utility requires prior approval of the Board (the "Provisional Guidelines").

Newfoundland Power's 2007 capital budget application complies with the Provisional Guidelines.

3.2.1 2007 Capital Projects by Definition

Table 3 summarizes Newfoundland Power's proposed 2007 capital projects by definition as set out in the Provisional Guidelines.

Table 3
2007 Capital Projects
by Definition

Definition	**No.**	**($000s)**
Pooled	21	39,186
Clustered	2	18,820
Other	3	4,160
Total	**26**	62,166

3.2.2 2007 Capital Projects by Classification

Table 4 summarizes Newfoundland Power's proposed 2007 capital projects by classification as set out in the Provisional Guidelines.

Table 4
2007 Capital Projects
by Classification

Classification	**No.**	**($000s)**
Mandatory	0	0
Normal	25	60,885
Justifiable	1	1,281
Total	**26**	62,166

3.2.3 2007 Capital Projects Costing

Table 5 summarizes Newfoundland Power's proposed 2007 capital projects by costing method (i.e., identified need vs. historical pattern) as set out in the Provisional Guidelines.

Table 5
2007 Capital Projects
Costing Method

Method	No.	($000s)
Identified Need	13	36,237
Historical Pattern	13	25,929
Total	**26**	62,166

3.2.4 2007 Capital Projects Materiality

Table 6 segments Newfoundland Power's proposed 2007 capital projects by materiality as set out in the Provisional Guidelines.

Table 6
2007 Capital Projects
Segmentation by Materiality

Segment	No.	($000s)
Under $200,000	3	282
$200,000 - $500,000	1	400
Over $500,000	22	61,484
Total	**26**	62,166

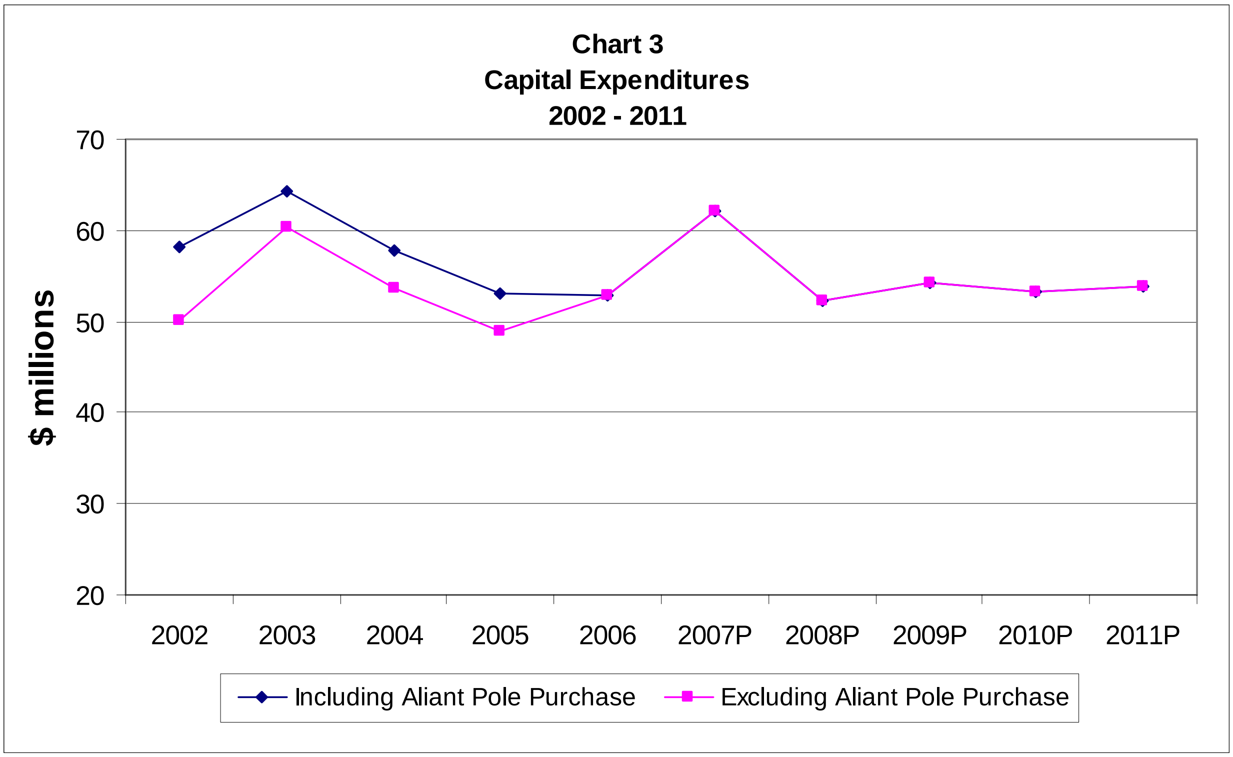
4.0 5-Year Outlook

Newfoundland Power's 5-year capital outlook for 2007 through 2011 is broadly consistent with capital expenditures over the period 2002 through 2006. With the exception of the 2007 Rattling Brook Hydro Plant Refurbishment project, planned capital expenditures are forecast to be stable on a year-to-year basis through 2011.

4.1 Capital Expenditures: 2002 - 2011

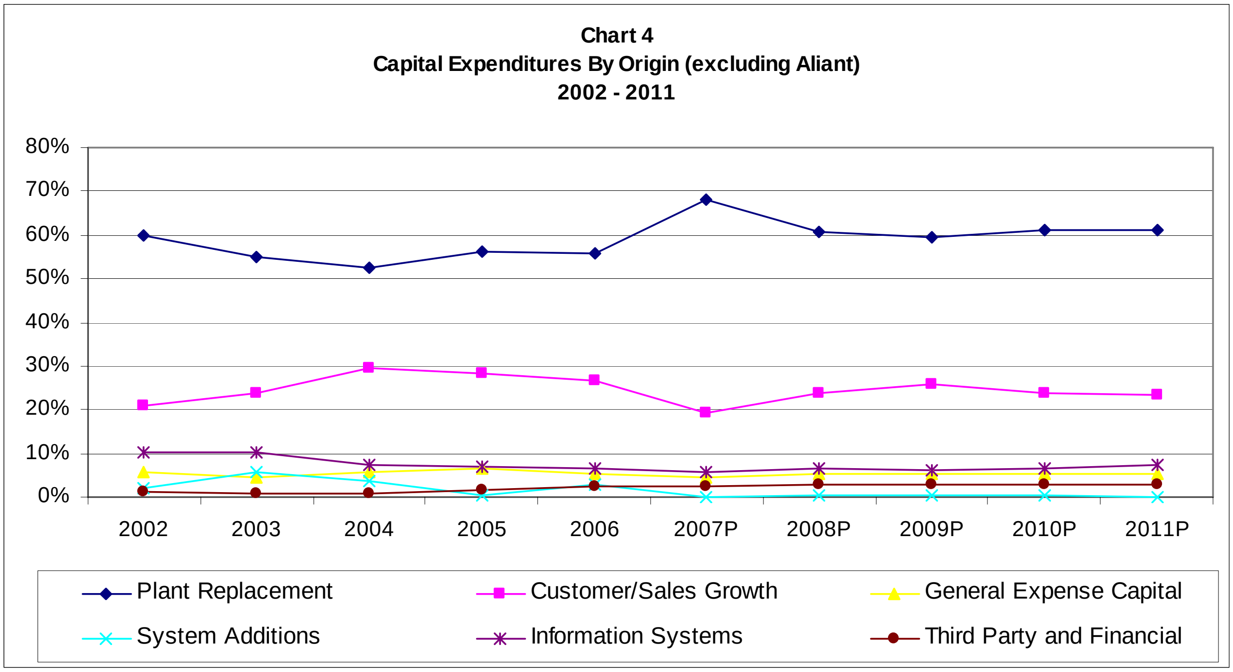
The Company plans to invest approximately $276 million in plant and equipment during the 2007 through 2011 period. On an annual basis, capital expenditures are expected to average approximately $55.2 million and range from a low of $52.2 million in 2008 to a high of $62.2 million in 2007.

Chart 3 shows actual and planned capital expenditures for the period 2002 through 2011 including and excluding the purchase of joint use support structures from Aliant Telecom Inc. over the period 2002 through 2005.



Overall planned capital expenditures over the 5-year period from 2007 through 2011 are expected to be broadly consistent with those in the 5-year period from 2002 through 2006 with the exception of the Rattling Brook project.

Chart 4 shows actual and planned capital expenditures for the period 2002 through 2011 by origin, or root cause. The Aliant Telecom Inc. joint use support structure purchase has been excluded from the analysis.



For the entire 2002 through 2011 period, the replacement of plant has been, and will continue to be, the dominant driver of Newfoundland Power's capital budget, accounting for approximately 59% of total expenditures.

Capital expenditures to meet increases in customer connections and sales will continue to account for approximately 24% of total expenditures.

4.2 2007 – 2011 Capital Expenditures

4.2.1 Overview

The origin of expenditures through the 2007 to 2011 period is consistent with the 2002 through 2006 period. The pattern of expenditures by origin for the 2007 to 2011 period is shown in Chart 5.

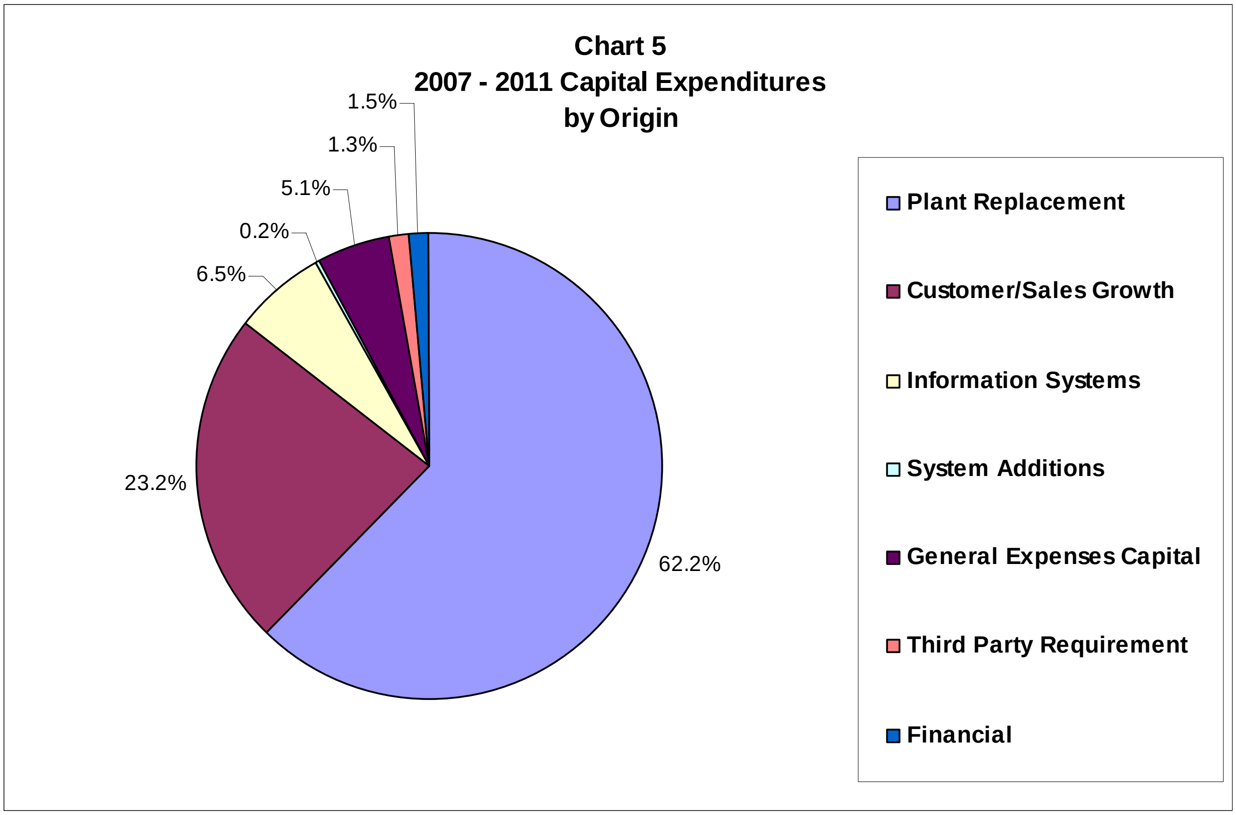
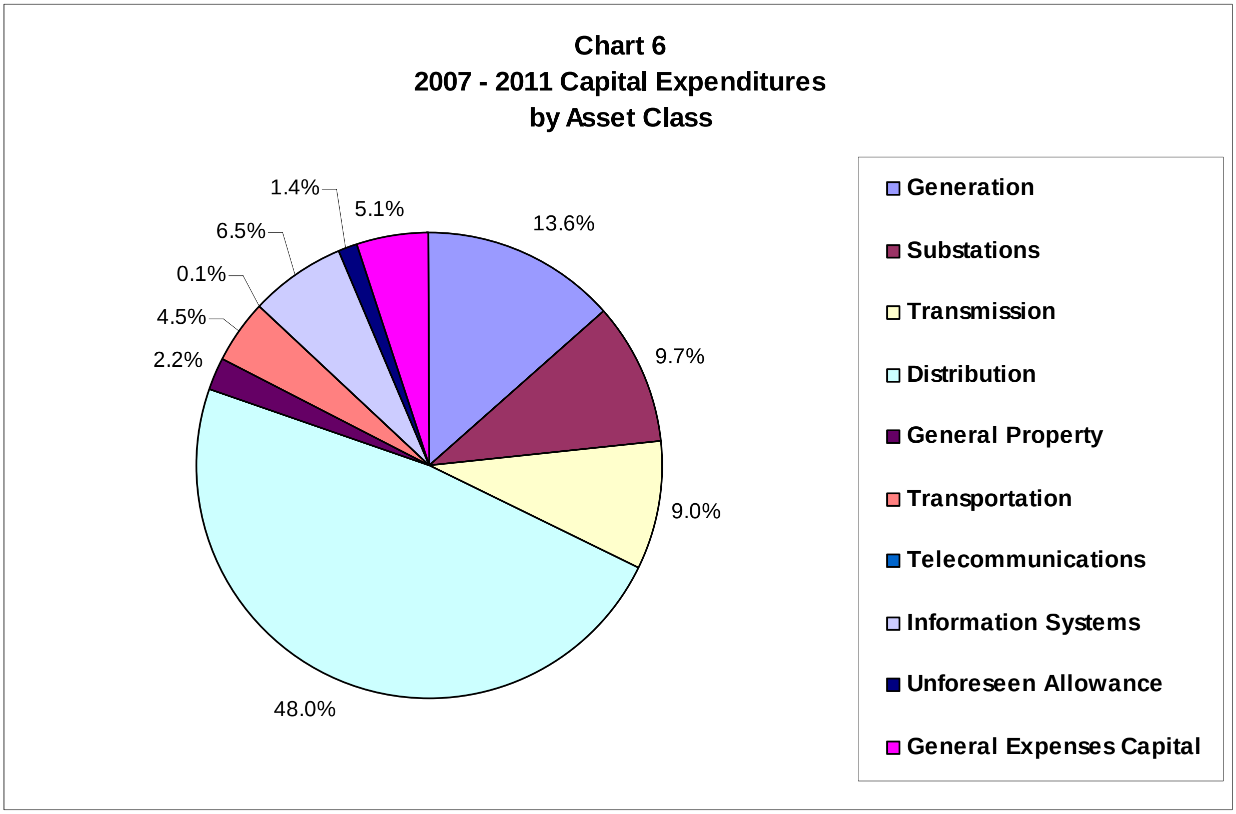


Chart 6 shows planned capital expenditures for the period 2007 through 2011 by asset class. Distribution accounts for 48.0% of all planned expenditures over the next five years, followed by Generation (13.6%), Substations (9.7%) and Transmission (9.0%) The remaining six asset classes account for 19.7% of total capital expenditures for the 2007 through 2011 period.

A summary of planned capital expenditures for the period 2007 through 2011 by asset class along with a breakdown by project is contained in Appendix A. Overall, planned expenditures are expected to remain stable in all asset classes with the exception of generation and transmission. Chart 6 summarizes each asset class.



4.2.2 Generation

Generation capital expenditures will increase in 2007 with the *Rattling Brook Hydro Plant Refurbishment* project but will average approximately $4.5 million per year from 2008 to 2011, which is lower than the average of $6.7 million spent between 2002 through 2006.

Generation capital expenditures on the Company's 23 hydroelectric plants, 3 gas turbines and 3 diesel plants are primarily driven by:

- Breakdown capital maintenance;
- Generation preventive capital maintenance program; and
- Capital project initiatives.

The Company has an industry best practice preventive maintenance program in place for Generation assets. The level of expenditure for capital maintenance, both breakdown and preventive, is expected to be relatively stable over the forecast period and generally consistent with the historical average.

Due to the age of the Company's fleet of generating plants, significant refurbishment will be required over the planning period. The Company plans to continue in the next five years the practice adopted in recent years of undertaking a major initiative, generally exceeding $1 million, in approximately one generation plant per year. Specifically, the following major capital project initiatives are planned:

- In 2007, the refurbishment of the Rattling Brook hydroelectric plant is planned at a cost of $18.2 million as described in *Volume II, Rattling Brook Hydro Plant Refurbishment.*

- In 2008, the Rattling Brook refurbishment is planned to continue with an estimated expenditure of $2.1 million. The Company will request Board approval of this component of the Rattling Brook refurbishment in the 2008 Capital Budget Application.

- In 2009, the Company plans to replace the Rocky Pond hydroelectric plant penstock and main valve at an estimated cost of $3.6 million.

- In 2010, a refurbishment of the Victoria hydroelectric plant is planned at an estimated cost of $2.0 million.

- In 2011, the governors, controls and valves are planned for replacement on the two units at the Lockston hydroelectric plant at a cost of $1.6 million.

- In 2011, the runners and wicket gates are planned for replacement on two units at the Tors Cove hydroelectric plant at an estimated cost of $1.0 million.

In all cases the Company will bring forward, as part of its Capital Budget Application to the Board, engineering reports regarding each of these initiatives as well as analysis of the long term economic viability of each generating plant.

4.2.3 Substations

Substations capital expenditures are expected to average $5.4 million annually over the 2007 through 2011 period which equals the average of $5.4 million spent annually between 2002 and 2006.

The Company operates 130 substations which contain approximately 4,000 pieces of critical electrical equipment. Substation capital expenditures are primarily driven by:

- Breakdown capital maintenance;
- Substation preventive capital maintenance program; and
- System load growth.

The level of breakdown capital maintenance as described in *2.2 2007 Replacements Due to In-Service Failures*, is expected to remain consistent over the forecast period. The Company expects its efforts in preventive maintenance will counter the continuous aging of the substation assets such that the level of failures and overall reliability of substation assets remains stable.

In this Application, the Company has filed a report, *2.1 Substation Strategic Plan*, which details a 10-year plan for substation preventive capital maintenance. The report includes an assessment of the overall condition of the Company's substation assets and proposes a systematic approach to preventive capital maintenance that involves the refurbishment and modernization of substation plant and equipment over the next ten years.

The Company forecasts only one significant project will be required due to system load growth over the planning period. In 2009, a new substation is forecast for construction near the community of Little Rapids in the Humber Valley area.

4.2.4 Transmission

Transmission capital expenditures are expected to average $5.0 million annually over the 2007 through 2011 period. This is higher than the average $3.2 annual expenditure over the 2002 to 2006 period.

The Company operates approximately 2,000 km of transmission lines. Transmission capital expenditures are primarily driven by:

- Breakdown capital maintenance;
- Transmission preventive capital maintenance program; and
- Third party requests.

The Company has an industry best practice maintenance program in place for its transmission assets. However, in-service failures of transmission assets are unavoidable and therefore a level of capital expenditure will be required for breakdown maintenance. The Company expects its efforts in preventive maintenance will counter the continuous aging of the transmission assets such that the capital expenditure due to transmission plant and equipment failures will approximate the historical average cost and remain stable over the next five years.

In the 2006 Capital Budget Application, the Company submitted its 10-year transmission strategy in a report titled *Transmission Line Rebuild Strategy*. The report outlined the need to completely rebuild certain sections of aging transmission lines throughout the Company's service territory that are either deteriorated or of non-standard construction. This proactive approach to managing transmission assets is expected to reduce failures over the long term and is the principal reason for the increase in capital expenditures in transmission over the next five years as compared to the past five years.

Transmission capital expenditures for third party requests by governments, telecommunications companies and individual customers to relocate or replace transmission lines are forecast to approximate the historical average cost and remain stable over the next five years.

4.2.5 Distribution

Distribution capital expenditures are expected to remain relatively stable at an average of approximately $26.5 million for the period 2007 to 2011 compared to an average of $26.4 million for the period 2002 to 2006.

The Company operates approximately 8,000 km of distribution lines serving over 220,000 customers. Distribution capital expenditures are primarily driven by:

- New customers;
- Third party requests;
- Breakdown capital maintenance;
- Distribution preventive capital maintenance program;
- System load growth; and
- Capital project initiatives.

Capital expenditures associated with new customer connections are forecast to remain relatively constant over the planning period. This is primarily due to an anticipated decline in the number of new customer connections offset by normal inflationary increases.

The costs to connect new customers to the electricity system are included in several Distribution projects including *Extensions*, *Transformers*, *Services*, *Meters* and *Street Lighting*. Table 7 shows the total capital expenditures associated with the connection of new customers to the system over the next five years.

Table 7
New Customer Connection Cost

	2007	**2008**	**2009**	**2010**	**2011**
Capital Expenditure	$12,791	$12,788	$12,896	$13,063	$12,982
New Customer Connections	3,307	3,210	3,128	3,081	2,951
Average Cost/Connection	$3,868	$3,984	$4,123	$4,240	$4,399

Distribution capital expenditures for third party requests by governments, telecommunications companies and individual customers to relocate or replace distribution lines are forecast to approximate the historical average cost and remain stable over the next five years.

The Company has an industry best practice maintenance program in place for its distribution assets. However, in-service failures of distribution plant and equipment are unavoidable. The Company expects its efforts in preventive maintenance will counter the continuous aging of the distribution assets such that the capital expenditure due to distribution plant and equipment failures will approximate the historical average cost and remain stable over the next five years.

In the 2004 Capital Budget Application the Company filed several reports pertaining to its preventive capital maintenance program for Distribution assets. These expenditures are budgeted in the project, *Rebuild Distribution Lines*. The Company plans to perform preventive capital maintenance on approximately 45 distribution feeders per year over the planning period.

The amount of Distribution capital expenditure for system load growth is expected to be less than the historical average due to a forecast reduction in load growth over the next five years compared to the previous five years.

In previous years the Company ranked its distribution feeders based on reliability performance and completed in-field assessments of those with the poorest performance statistics. Capital upgrades were performed on the worst performing feeders under a project titled, *Distribution Reliability Initiative*. This capital project initiative is suspended for 2007 to balance overall capital expenditures due to the upward pressure of the Rattling Brook project. In 2008, the Company plans to resume the *Distribution Reliability Initiative* project for the remainder of the planning period as a key strategy in addressing overall system reliability.

4.2.6 General Property

The General Property asset class includes capital expenditures for the addition or replacement of tools and equipment utilized by line and engineering staff in the day-to-day operation of the Company, as well as the replacement or addition of office furniture and equipment. This asset class includes additions to real property necessary to maintain buildings and facilities and to operate them in an efficient manner. Also included in this asset class are investments to increase backup diesel generation and implement demand/load control at Company buildings.

General Property capital expenditures are expected to average $1.2 million annually over the 2007 through 2011 period which is slightly higher than the $1.1 million spent over the 2002 through 2006 period.

4.2.7 Transportation

The Transportation asset class includes the replacement of existing heavy fleet, passenger and off-road vehicles. The replacement of these vehicles can be influenced by a number of factors including kilometres traveled, vehicle condition, operating experience and maintenance expenditures.

Transportation capital expenditures are expected to average $2.5 million annually over the 2007 through 2011 period which is slightly lower than the $2.7 million spent over the 2002 through 2006 period.

4.2.8 Telecommunications

The Telecommunications asset class includes the replacement or upgrading of various communications systems. These systems contribute to customer service, safety, and maintenance of power system reliability by supporting communications between the Company's fleet of mobile vehicles and the various plants and offices.

Telecommunications capital expenditures are expected to average $0.1 million annually over the 2007 through 2011 period.

4.2.9 Information Systems

The Information Systems asset class includes: the replacement of personal computers, printers and associated assets; upgrades to current software tools, processes, and applications as well as the acquisition of new software licenses; and, the development of new applications or enhancements to existing applications to support changing business requirements and take advantage of new developments and product improvements.

Information Systems capital expenditures are expected to average $3.6 million annually over the 2007 through 2010 period which is lower than the $4.4 million spent over the 2002 through 2006 period. Capital expenditure in Information Systems is expected to increase in 2011 to $4.0 million due to the initial expenditure for the anticipated replacement of the Company's Customer Service System.

4.2.10 Unforeseen Allowance & General Expenses Capital

The Unforeseen Allowance covers any unforeseen capital expenditures that have not been budgeted elsewhere. The purpose of the account is to permit the Company to act expeditiously to deal with events affecting the electrical system in advance of seeking the approval of the Board.

The Unforeseen Allowance constitutes $750,000 in each year's capital budget from 2007 through 2011.

General Expenses Capital is the allocation of a portion of administrative costs to capital. In accordance with Order No. P.U. 3 (1995-96), the Company uses the incremental cost method of accounting for the purpose of capitalization of general expenses.

General Expenses Capital of $2.8 million is reflected in each year's capital budget from 2007 through 2011.

4.3 5-Year Plan: Risks

While the Company accepts the Board's view of the desirable effects of year to year capital expenditure stability, the nature of the utility's obligation to serve will not, in some circumstances, necessarily facilitate such stability. The Plan has identified some risks to such stability in the period 2007 through 2011.

Newfoundland Power has an obligation to serve customers in its service territory. Should customer and energy growth vary from forecast, so will the capital expenditures that are sensitive to growth. For example, there are a number of potential mine sites within the Company's service area. Should one of these sites be developed, it may require additional capital expenditures in the order of $5 million. Due to the speculative nature of these developments, the projects have not been included in the Plan.

An example of a potential large project is the impending replacement of the Company's Customer Service System ("CSS"), which is 14 years old. As the replacement cost of a CSS system could be as high as $15 million, the Company is taking steps to extend the life of CSS through 2011. The current plan is to replace CSS over a number of years beginning with a $2 million expenditure in 2011. However, changing technology and vendor support could conceivably dictate otherwise.

Further, the Company intends to continually review its telecommunications requirements and evolving telecommunications technology. Much of the telecommunications circuitry the Company currently leases is an integral part of its SCADA system. As opportunities become available, due to the expiration of lease agreements, the Company will assess whether it is more beneficial from a cost perspective either to continue leasing or to make capital investment in certain telecommunications assets.

Another area that may impact capital expenditures is metering technology. In this plan, the Company intends to continue with its metering strategy as outlined in *Metering Strategy*, filed with the 2006 Capital Budget Application. However, the Company will continually assess technological and business developments in metering and explore opportunities to reduce costs to customers with the implementation of metering technology. This may manifest itself in revisions to the *Metering Strategy* and increased capital expenditures in the future.

Capital expenditures can be impacted by natural disasters. In 1984 and 1994, the Company was impacted by sleet storms that resulted in widespread damage and service interruption to customers. In 2003, Hurricane Juan hit Nova Scotia, resulting in severe damage to that province's transmission and distribution systems and the loss of power to over 260,000 customers. The occurrence and costs of natural disasters are not predictable.

Overall, with the exception of the *Rattling Brook Hydro Plant Refurbishment* project forecast for 2007, planned capital expenditures are forecast to be relatively stable during the 2007 through 2011 period. However, circumstances can change and, as a result, so can priorities and the level of capital expenditures.

Assessment of maximum budget growth in this period necessarily involves a significant degree of conjecture. Given that the addition of a single large general service customer could conceivably add capital expenditures of $5 million, a maximum annual capital budget could approximate $60 - 65 million. In such a case, certain otherwise justifiable projects might be deferred in a way that minimizes the negative impact of deferral on the quality of service.

4.4 5-Year Plan: Summary

Over the next five years, the Company plans to invest approximately $276 million in plant and equipment. Overall, with the exception of the *Rattling Brook Hydro Plant Refurbishment* project in 2007, the planned expenditures are expected to remain relatively stable for all asset classes, and consistent with expenditures incurred during the 2002 through 2006 period.

Approximately 59% of planned expenditures focus on the replacement of deteriorated, defective or obsolete distribution, transmission, generation and substation electrical equipment. Capital expenditures related to customer and sales growth is forecast to remain relatively stable. The Company does not anticipate any significant changes in the pattern of planned expenditures by origin.

While planned capital expenditures are forecast to be relatively stable during the 2007 through 2011 period, circumstances can change and, as a result the maximum capital budget could approximate $60 - 65 million.

Newfoundland Power Inc.
2007-2011 Capital Budget Plan
(000s)

Asset Class	**2007**	**2008**	**2009**	**2010**	**2011**
Generation	$19,188	$4,799	$4,943	$4,006	$4,432
Substations	3,968	5,096	6,050	5,654	6,040
Transmission	4,283	5,056	5,113	5,158	5,226
Distribution	24,103	26,350	26,817	27,347	27,653
General Property	1,310	1,108	1,609	1,019	884
Transportation	2,206	2,714	2,641	2,901	2,026
Telecommunications	101	73	74	75	76
Information Systems	3,457	3,470	3,443	3,514	4,021
Unforeseen Allowance	750	750	750	750	750
General Expenses Capitalized	2,800	2,800	2,800	2,800	2,800
Total	**$62,166**	**$52,216**	**$54,240**	**$53,224**	**$53,908**

Newfoundland Power Inc.
2007-2011 Capital Budget Plan
(000s)

GENERATION

Project	2007	2008	2009	2010	2011
Facility Rehabilitation	$946	$1,858	$1,220	$1,859	$1,644
Rattling Brook Hydro Plant Refurbishment	18,242	-	-	-	-
Rattling Brook Plant – Dam Refurbishment	-	2,080	-	-	-
Facility Rehabilitation - Thermal	-	-	106	134	164
Wesleyville Exhaust Stack Replacement	-	861	-	-	-
Tors Cove Hydro Plant Refurbishment	-	-	-	10	1,032
Rocky Pond Hydro Plant Refurbishment	-	-	3,617	-	-
Lockston Hydro Plant Refurbishment	-	-	-	-	1,592
Victoria Hydro Plant Refurbishment	-	-	-	2,003	-
Total - Generation	**$19,188**	**$4,799**	**$4,943**	**$4,006**	**$4,432**

Newfoundland Power Inc.
2007-2011 Capital Budget Plan
(000s)

SUBSTATIONS

Project	**2007**	**2008**	**2009**	**2010**	**2011**
Substations Refurbishment & Modernization	$2,190	$3,865	$3,277	$4,353	$4,686
Replacements Due to In-Service Failure	1,200	1,231	1,265	1,301	1,354
Additions Due to Load Growth	-	-	1,508	-	-
Rattling Brook Substation Refurbishment	578	-	-	-	-
Total – Substations	**$3,968**	**$5,096**	**$6,050**	**$5,654**	**$6,040**

Newfoundland Power Inc.
2007-2011 Capital Budget Plan
(000s)

TRANSMISSION

Project	2007	2008	2009	2010	2011
Rebuild Transmission Lines	$4,283	$5,056	$5,113	$5,158	$5,226
Total – Transmission	**$4,283**	**$5,056**	**$5,113**	**$5,158**	**$5,226**

Newfoundland Power Inc.
2007-2011 Capital Budget Plan
(000s)

DISTRIBUTION

Project	**2007**	**2008**	**2009**	**2010**	**2011**
Extensions	$6,815	$6,772	$6,802	$6,869	$6,746
Meters	1,100	1,132	1,183	1,256	1,358
Services	1,848	1,850	1,871	1,896	1,883
Street Lighting	1,288	1,288	1,298	1,316	1,308
Transformers	5,728	5,802	5,889	5,990	6,092
Reconstruction	3,077	3,155	3,259	3,345	3,434
Rebuild Distribution Lines	3,625	3,702	3,801	3,890	3,981
Relocate/Replace Distribution Lines For Third Parties	541	555	573	589	604
Distribution Reliability Initiative	-	1,633	1,667	1,710	1,750
Feeder Additions and Upgrades to Accommodate Growth	-	379	391	401	411
Interest During Construction	81	82	83	85	86
Total – Distribution	**$24,103**	**$26,350**	**$26,817**	**$27,347**	**$27,653**

Newfoundland Power Inc.
2007-2011 Capital Budget Plan
(000s)

GENERAL PROPERTY

Project	2007	2008	2009	2010	2011
Tools and Equipment	$600	$681	$693	$634	$645
Additions to Real Property	100	227	231	235	239
Energy Efficient HVAC System	610	-	535	-	-
Stand-By Diesel Generators – Company Buildings	-	200	150	150	-
Total – General Property	**$1,310**	**$1,108**	**$1,609**	**$1,019**	**$884**

Newfoundland Power Inc.
2007-2011 Capital Budget Plan
(000s)

TRANSPORTATION

Project	2007	2008	2009	2010	2011
Purchase Vehicles and Aerial Devices	$2,206	$2,714	$2,641	$2,901	$2,026
Total – Transportation	**$2,206**	**$2,714**	**$2,641**	**$2,901**	**$2,026**

Newfoundland Power Inc.
2007-2011 Capital Budget Plan
(000s)

TELECOMMUNICATIONS

Project	**2007**	**2008**	**2009**	**2010**	**2011**
Replace/Upgrade Communications Equipment	$101	$73	$74	$75	$76
Total – Telecommunications	**$101**	**$73**	**$74**	**$75**	**$76**

Newfoundland Power Inc.
2007-2011 Capital Budget Plan
(000s)

INFORMATION SYSTEMS

Project	**2007**	**2008**	**2009**	**2010**	**2011**
Application Enhancements	1,281	$1,170	$1,240	$1,255	$300
System Upgrades	899[1]	1,044[1]	925	960	400
Personal Computer Infrastructure	400	406	413	420	427
Shared Server Infrastructure	877	750	762	774	787
Network Infrastructure	-	100	103	105	107
Customer Service System Replacement	-	-	-	-	2,000
Total – Information Systems	**$3,457**	**$3,470**	**$3,443**	**$3,514**	**$4,021**

[1] Includes Microsoft Enterprise Agreement ($210,000) approved with the 2006 Capital Budget Application for 2006 to 2008.

Newfoundland Power Inc.
2007-2011 Capital Budget Plan
(000s)

UNFORESEEN ALLOWANCE

Project	2007	2008	2009	2010	2011
Allowance for Unforeseen	$750	$750	$750	$750	$750
Total – Unforeseen Allowance	**$750**	**$750**	**$750**	**$750**	**$750**

Newfoundland Power Inc.
2007-2011 Capital Budget Plan
(000s)

GENERAL EXPENSES CAPITALIZED

Project	**2007**	**2008**	**2009**	**2010**	**2011**
General Expenses Capitalized	$2,800	$2,800	$2,800	$2,800	$2,800
Total – General Expenses Capitalized	**$2,800**	**$2,800**	**$2,800**	**$2,800**	**$2,800**

2006 Capital Expenditure Status Report

March 2006

NEWFOUNDLAND POWER INC.

2007 CAPITAL BUDGET APPLICATION

2006 Capital Expenditure Status Report

Explanatory Note

This report is presented in compliance with the directive of the Board of Commissioners of Public Utilities (the "Board") contained in paragraph 4 of Order No. P.U. 35 (2003).

Page 1 of the 2006 Capital Expenditure Status Report outlines the forecast variances from budget of the capital expenditures approved by the Board in Order No. P.U. 30 (2005) and Order No. P.U. 34 (2005). The detailed tables on pages 2 to 9 provide additional detail on capital expenditures in 2006, and also include information on those capital projects approved for 2005 that were not completed prior to 2005.

Variances of more than 10% of approved expenditure and $100,000 or greater are explained in the Notes contained in Appendix A, which immediately follows the blue page at the conclusion of the 2006 Capital Expenditure Status Report.

Newfoundland Power Inc.
2007 Capital Budget

2006 Capital Budget Variances
(000s)

	Approved by Order No. P.U. 30 (2005)	Forecast	Variance
Energy Supply[1]	$3,908	$3,908	$0
Substations	4,040	4,038	(2)
Transmission	4,054	4,060	6
Distribution	26,809	29,212	2,403
General Property	1,527	1,662	135
Transportation	2,755	2,755	0
Telecommunications	78	133	55
Information Systems	3,500	3,489	(11)
Unforeseen Items	750	750	0
General Expenses Capital	2,800	2,800	0
Total	$50,221	$52,807	$2,586
Projects carried forward from 2005		$94	

[1] Budget includes $963,200 for Rocky Pond Switchgear approved in Order No. P.U. 34 (2005).

2006 Capital Expenditure Status Report
(000s)

	Capital Budget			Actual Expenditures			Forecast			
	2005	2006	Total	2005	2006	Total To Date	Remainder 2006	Total 2006	Overall Total	Variance
	A	B	C	D	E	F	G	H	I	J
2006 Projects	$ -	$ 49,258	$ 49,258	$ -	$ 11,061	$ 11,061	$ 40,783	$ 51,844	$ 51,844	$ 2,586
2005 Projects	850	963	1,813	768	570	1,338	487	1,057	1,825	12
Grand Total	**$ 850**	**$ 50,221**	**$ 51,071**	**$ 768**	**$ 11,631**	**$ 12,399**	**$ 41,270**	**$ 52,901**	**$ 53,669**	**$ 2,598**

Column A	Approved Capital Budget for 2005
Column B	Approved Capital Budget for 2006
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2005
Column E	Actual Capital Expenditures for 2006
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2006
Column H	Total of Column E and G
Column I	Total of Column D and H
Column J	Column I less Column C

2006 Capital Expenditure Status Report
(000s)

Category: Energy Supply

Project	Capital budget 2005	Capital budget 2006	Capital budget Total	Actual Expenditures 2005	Actual Expenditures 2006	Actual Expenditures Total To Date	Forecast Remainder 2006	Forecast Total 2006	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2006 Projects											
Hydro Plants - Facility Rehabilitation	$ -	$ 996	$ 996	$ -	$ 145	$ 145	$ 851	$ 996	$ 996	$ -	
Plant Refurbishment - Petty Harbour	-	1,829	1,829	-	115	115	1,714	1,829	1,829	-	
Port Aux Basques Fuel Tank Replacement	-	120	120	-	5	5	115	120	120	-	
Total - 2006 Projects	**$ -**	**$ 2,945**	**$ 2,945**	**$ -**	**$ 265**	**$ 265**	**$ 2,680**	**$ 2,945**	**$ 2,945**	**$ -**	
2005 Projects											
Plant Refurbishment - Rattling Brook	350	-	350	256	22	278	72	94	350	-	
Rocky Pond - Switchgear Replacement	500	963	1,463	512	548	1,060	415	963	1,475	12	
Total - 2005 Projects	**$ 850**	**$ 963**	**$ 1,813**	**$ 768**	**$ 570**	**$ 1,338**	**$ 487**	**$ 1,057**	**$ 1,825**	**$ 12**	
Total - Energy Supply	**$ 850**	**$ 3,908**	**$ 4,758**	**$ 768**	**$ 835**	**$ 1,603**	**$ 3,167**	**$ 4,002**	**$ 4,770**	**$ 12**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2005
Column B	Approved Capital Budget for 2006
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2005
Column E	Actual Capital Expenditures for 2006
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2006
Column H	Total of Column E and G
Column I	Total of Column F and G
Column J	Column I less Column C

2006 Capital Expenditure Status Report
(000s)

Category: Substations

Project	Capital budget 2006	Capital budget Total	Actual Expenditures 2006	Actual Expenditures Total To Date	Forecast Remainder 2006	Forecast Total 2006	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2006 Projects									
Rebuild Substations	$ 710	$ 710	$ 96	$ 96	$ 612	$ 708	$ 708	$ (2)	
Replacement and Standby Substation Equipment	1,918	1,918	654	654	1,264	1,918	1,918	-	
Protection and Monitoring Improvements	423	423	21	21	402	423	423	-	
Distribution System Feeder Remote Control	779	779	65	65	714	779	779	-	
Feeder Additions Due to Load Growth	210	210	1	1	209	210	210	-	
Total - Substations	**$ 4,040**	**$ 4,040**	**$ 837**	**$ 837**	**$ 3,201**	**$ 4,038**	**$ 4,038**	**$ (2)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2006
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2006
Column D	Total of Column C
Column E	Forecast for Remainder of 2006
Column F	Total of Column C and E
Column G	Total of Column D and E
Column H	Column G less Column B

2006 Capital Expenditure Status Report
(000s)

Category: Transmission

Project	Capital Budget 2006	Capital Budget Total	Actual Expenditures 2006	Actual Expenditures Total To Date	Forecast Remainder 2006	Forecast Total 2006	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2006 Projects									
Rebuild Transmission Lines	$ 4,054	$ 4,054	$ 384	$ 384	$ 3,676	$ 4,060	$ 4,060	$ 6	
Total - Transmission	**$ 4,054**	**$ 4,054**	**$ 384**	**$ 384**	**$ 3,676**	**$ 4,060**	**$ 4,060**	**$ 6**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2006
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2006
Column D	Total of Column C
Column E	Forecast for Remainder of 2006
Column F	Total of Column C and E
Column G	Total of Column D and E
Column H	Column G less Column B

2006 Capital Expenditure Status Report
(000s)

Category: Distribution

Project	Capital Budget 2006 A	Capital Budget Total B	Actual Expenditures 2006 C	Actual Expenditures Total To Date D	Forecast Remainder 2006 E	Forecast Total 2006 F	Forecast Overall Total G	Variance H	Notes*
2006 Projects									
Extensions	$ 6,766	$ 6,766	$ 1,687	$ 1,687	$ 6,143	$ 7,830	$ 7,830	$ 1,064	1
Meters	1,192	1,192	144	144	1,412	1,556	1,556	364	2
Services	1,851	1,851	444	444	1,405	1,849	1,849	(2)	
Street Lighting	1,272	1,272	388	388	877	1,265	1,265	(7)	
Transformers	5,540	5,540	2,040	2,040	3,500	5,540	5,540	-	
Reconstruction	2,849	2,849	720	720	2,158	2,878	2,878	29	
Trunk Feeders									
Rebuild Distribution Lines	3,190	3,190	1,257	1,257	1,933	3,190	3,190	-	
Relocate/Replace Distribution Lines For Third Parties	685	685	78	78	1,562	1,640	1,640	955	3
Distribution Reliability Initiative	3,114	3,114	831	831	2,283	3,114	3,114	-	
Feeder Additions and Upgrades to Accommodate Growth	266	266	7	7	259	266	266	-	
Interest During Construction	84	84	3	3	81	84	84	-	
Total - Distribution	**$ 26,809**	**$ 26,809**	**$ 7,599**	**$ 7,599**	**$ 21,613**	**$ 29,212**	**$ 29,212**	**$ 2,403**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2006
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2006
Column D	Total of Column C
Column E	Forecast for Remainder of 2006
Column F	Total of Column C and E
Column G	Total of Column D and E
Column H	Column G less Column B

2006 Capital Expenditure Status Report
(000s)

Category: General Property

Project	Capital Budget 2006	Capital Budget Total	Actual Expenditures 2006	Actual Expenditures Total To Date	Forecast Remainder 2006	Forecast Total 2006	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2006 Projects									
Tools and Equipment	$ 587	$ 587	$ 248	$ 248	$ 431	$ 679	$ 679	$ 92	
Additions to Real Property	132	132	27	27	148	175	175	43	
Standby Diesel Generators - Duffy Place and Clarenville	665	665	7	7	658	665	665	-	
Demand/Load Control - Company Buildings	143	143	3	3	140	143	143		
Total - General Property	**$ 1,527**	**$ 1,527**	**$ 285**	**$ 285**	**$ 1,377**	**$ 1,662**	**$ 1,662**	**$ 135**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2006
Column B	Total of Column A
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Column G	Total of Column D and E
Column H	Column G less Column B

2006 Capital Expenditure Status Report
(000s)

Category: Transportation

Project	Capital Budget 2006	Capital Budget Total	Actual Expenditures 2006	Actual Expenditures Total To Date	Forecast Remainder 2006	Forecast Total 2006	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2006 Projects									
Purchase Vehicles and Aerial Devices	$ 2,755	$ 2,755	$ 148	$ 148	$ 2,607	$ 2,755	$ 2,755	$ -	
Total - Transportation	**$ 2,755**	**$ 2,755**	**$ 148**	**$ 148**	**$ 2,607**	**$ 2,755**	**$ 2,755**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2006
Column B	Total of Column A
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Column F	Total of Column C and E
Column G	Total of Column D and E
Column H	Column G less Column B

2006 Capital Expenditure Status Report
(000s)

Category: Telecommunications

Project	Capital Budget 2006	Capital Budget Total	Actual Expenditures 2006	Actual Expenditures Total To Date	Forecast Remainder 2006	Forecast Total 2006	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2006 Projects									
Replace/Upgrade Communications Equipment	$ 78	$ 78	$ 6	$ 6	$ 127	$ 133	$ 133	$ 55	
Total - Telecommunications	**$ 78**	**$ 78**	**$ 6**	**$ 6**	**$ 127**	**$ 133**	**$ 133**	**$ 55**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2006
Column B	Total of Column A
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Column F	Total of Column C and E
Column G	Total of Column D and E
Column H	Column G less Column B

2006 Capital Expenditure Status Report
(000s)

Category: Information Systems

Project	**Capital budget** 2006	**Capital budget** Total	**Actual Expenditures** 2006	**Actual Expenditures** Total To Date	**Forecast** Remainder 2006	**Forecast** Total 2006	**Forecast** Overall Total	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2006 Projects									
Application Enhancements	$ 1,589	$ 1,589	$ 352	$ 352	$ 1,180	$ 1,532	$ 1,532	$ (57)	
System Upgrades	1,076	1,076	219	219	856	1,075	1,075	(1)	
Personal Computer Infrastructure	327	327	59	59	255	314	314	(13)	
Shared Server Infrastructure	508	508	134	134	434	568	568	60	
Total - Information Systems	**$ 3,500**	**$ 3,500**	**$ 764**	**$ 764**	**$ 2,725**	**$ 3,489**	**$ 3,489**	**$ (11)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2006
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Column F	Total of Column C and E
Column G	Total of Column D and E
Column H	Column G less Column B

2006Capital Expenditure Status Report
(000s)

Category: Unforeseen Items

Project	Capital Budget 2006	Capital Budget Total	Actual Expenditures 2006	Actual Expenditures Total To Date	Forecast Remainder 2006	Forecast Total 2006	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2006 Projects									
Allowance for Unforeseen Items	$ 750	$ 750	$ -	$ -	$ 750	$ 750	$ 750	$ -	
Total - Unforeseen Items	**$ 750**	**$ 750**	**$ -**	**$ -**	**$ 750**	**$ 750**	**$ 750**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2006
Column B	Total of Column A
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Column F	Total of Column C and E
Column G	Total of Column D and E
Column H	Column G less Column B

2006 Capital Expenditure Status Report
(000s)

Category: General Expenses Capital

Project	Capital Budget 2006 (A)	Capital Budget Total (B)	Actual Expenditures 2006 (C)	Actual Expenditures Total To Date (D)	Forecast Remainder 2006 (E)	Forecast Total 2006 (F)	Forecast Overall Total (G)	Variance (H)	Notes*
2006 Projects									
Allowance for General Expenses Capital	$ 2,800	$ 2,800	$ 773	$ 773	$ 2,027	$ 2,800	$ 2,800	$ -	
Total - General Expenses Capital	**$ 2,800**	**$ 2,800**	**$ 773**	**$ 773**	**$ 2,027**	**$ 2,800**	**$ 2,800**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2006
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2006 Capital Expenditure Status Report
Notes

Distribution

1. *Extensions:*
Budget: $6,766,000 Forecast: $7,830,000 Variance: $1,064,000

The capital expenditure variance for Extensions is due to recent approvals for service for four cabin areas. The expenditure for Cape Pond cabin area ($200,000) was approved in Order No. P.U. 36 (2005), the expenditure for Witless Bay Line cabin area ($100,000) was approved in Order No. P.U. 28 (2005), the expenditure for Thorburn Lake cabin area ($586,000) was approved in Order No. P.U. 32 (2005) and the expenditure for Belbins Pond cabin area ($135,000) was approved in Order No. P.U. 5 (2006).

2. *Meters:*
Budget: $1,192,000 Forecast: $1,556,000 Variance: $364,000

The capital expenditure variance for Meters is due to a greater number of meters requiring replacement as a result of meter testing conducted as required under the *Electricity and Gas Inspection Act (Canada)*. In 2006, Newfoundland Power is required to replace an additional 7,486 meters due to the failure of three groups of meters that were purchased and installed in 1971, 1988 and 1993. The increase in meter replacements is largely related to a particular manufacturer and model of meter and is also being experienced at other utilities in Canada.

3. *Relocate/Replace Distribution Lines for Third Parties:*
Budget: $685,000 Forecast: $1,640,000 Variance: $955,000

The capital expenditure variance for Relocate/Replace Distribution Lines for Third Parties is required to upgrade distribution lines to accommodate a third party request to place a fibre optic cable ($855,000) and a request by the City of St. John’s to relocate distribution lines between Savannah Park Drive and Portugal Cove Road ($100,000).

2007 Facility Rehabilitation

March 2006

Prepared by:

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April 2006
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1.0 Introduction

The 2007 Facility Rehabilitation project is necessary for the replacement or rehabilitation of deteriorated plant components that have been identified through routine inspections, operating experience and engineering studies. The project includes expenditures necessary to improve the efficiency and reliability of various hydro plants or to replace plant due to in-service failures.

The Company has 23 hydroelectric and six thermal plants that range in age from two to 106 years old. These facilities provide energy to the Island Interconnected electrical system. Maintaining these generating facilities reduces the need for additional, more expensive, generation.

Projects involving replacement and rehabilitation work, which are identified during inspections and maintenance activities, are necessary to the continued operation of these generation facilities in a safe, reliable and environmentally compliant manner. The Company's hydro generation facilities produce a combined normal annual production of 419.6 GWh. The alternative to maintaining these facilities would be to retire them.

The 2007 Facility Rehabilitation project totalling $946,000 is comprised of Hydro Dam Rehabilitation and Generation Equipment Replacements Due to In-Service Failures.

2.0 Hydro Dam Rehabilitation

Cost: $521,000

This item involves the refurbishment of deteriorated components at various dam structures. The projects primarily include upstream slope improvements at embankment dams and outlet structure concrete repairs.

Specific projects to be completed in 2007 include:

1. Horsechops West Dam Riprap Upgrades ($76,000)
   This item involves refurbishment of the upstream slope at Horsechops West Dam. Specific observations arising from inspection reports include holes in riprap, lack of bedding transition material and evidence of breaching.

2. Bay Bulls Big Pond Dam Riprap Upgrades ($76,000)
   This item involves improvements to the upstream riprap zone. The riprap does not extend to the reservoir low supply level, creating a potential for undermining erosion. In addition, the riprap is small and requires re-grading.

3. Pittman's Pond Riprap Upgrades ($75,000)
   The upstream slope of Pittman's Pond West Dyke requires rehabilitation of the protective riprap zone. Recent inspections have shown that the upstream riprap is sparse and does not provide adequate protection for the adjacent internal embankment zones of the dam.

4. West Lake Outlet Rehabilitation ($69,000)
   This item involves rehabilitation of the concrete wing walls adjacent to the outlet structure. The outlet structure is showing signs of concrete deterioration. In particular, excessive cracking, spalling, weathered concrete, and exposed rebar is evident throughout.

5. Paddy's Pond Outlet Structure Refurbishment ($101,000)
   This item involves refurbishment of the timber crib control structure at the outlet of Paddy's Pond reservoir, as recommended in recent inspection reports. Specific observations include misalignment of gate and gate guides, deterioration of timber stoplogs within the gate, displacement of material from cribs, and deterioration of adjacent timber facing.

6. Petty Harbour Forebay Dam – Overtopping Protection ($50,000)
   This item involves the placement of anti-scour and erosion protection adjacent to the dam abutments, as well as along the downstream toe. These modifications will enhance dam safety performance of the structure under flood conditions.

7. Topsail Pond Dam – Overtopping Protection ($46,000)
   This item involves dam improvements and other flood damage reduction measures including abutment protection, spillway riprap refurbishment, and pressure relief holes in concrete spillway bays.

8. Lookout Brook Concrete Spillway Upgrades ($28,000)
   This item involves concrete upgrades to protect against further undercutting and erosion at the bedrock and concrete interface along the downstream toe of the spillway.

The physical condition and observed deterioration of these structures has been assessed within the scope of regularly scheduled dam safety inspections. These inspections are the primary means of identifying deficiencies and establishing capital improvement plans on a priority basis.

Newfoundland Power has over 150 dam structures throughout its 23 hydroelectric facilities. Based on the average age of structures in the Newfoundland Power system, deterioration of embankment and concrete dams is to be expected. Refurbishment is required to ensure integrity of the structures is maintained to an appropriate level of dam safety as per the guidelines established by the Canadian Dam Association. The cost of the projects is justified based on the need to restore the structures to an appropriate safety level based on the site design conditions and to allow for future operation of the hydro system in a safe and reliable manner.

3.0 Generation Equipment Replacements Due to In-Service Failures

Cost: $425,000

Equipment and infrastructure at generating facilities such as turbines and generators routinely requires upgrading or replacement to extend the life of the asset.

This item involves the refurbishment or replacement of structures and equipment due to damage, deterioration, corrosion, technical obsolescence and in-service failure. This equipment is critical to the safe and reliable operation of generating facilities and must be replaced in a timely manner. Equipment replaced under this item includes civil infrastructure, instrumentation, mechanical, electrical, and protection and controls equipment.

Replacements under this item are typically due to one of two reasons:

1. Emergency replacements – where components fail and require immediate replacement to return a unit to service; or

2. Observed deficiencies – where components are identified for replacement due to imminent failure or for safety or environmental reasons.

Table 1 shows the expenditures for replacements due to in-service failures since 2002.

Table 1
Expenditures Due to In-Service Failures
(000s)

Year	**2002**	**2003**	**2004**	**2005**	**2006F**
Total	$566[1]	$365	$385	$570[2]	$230[2]

[1] Excludes Rattling Brook generator rewind.
[2] Excludes Rocky Pond rebuild.

Based upon this recent historical information and engineering judgement, $425,000 is estimated to be required in 2007 for replacement equipment due to in-service failures or equipment at risk of imminent failure.

Generation equipment, buildings, intakes, dams and control structures are critical components in the safe and reliable operation of generating facilities. This item is required to enable the timely refurbishment or replacement of equipment to facilitate the continued operation of generating facilities in a safe and reliable manner.

4.0 Recommendation

This project, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable plant operations. A 2007 budget of $946,000 for Facility Rehabilitation is recommended as follows:

- $521,000 for Hydro Dam Rehabilitation; and
- $425,000 for Generation Equipment Replacements Due to In-Service Failures.

Wesleyville Gas Turbine Refurbishment Update

February 2006

Prepared by:

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1.0 Background

In Order No. P.U. 43 (2004), the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board"), approved the Newfoundland Power 2005 Capital Budget which included the Wesleyville Gas Turbine Overhaul project estimated at a cost of $1,124,000.

As per Order No. P.U. 43 (2004), the Company filed the report *Wesleyville Gas Turbine Refurbishment Alternatives* with the 2006 Capital Budget Application. This report outlined the request for proposal process for the two alternatives for the Wesleyville gas turbine refurbishment and provided an update on the status of the evaluation process.

In Order No. P.U. 30 (2005), the Board ordered:

> *In relation to the Wesleyville Gas Turbine Refurbishment project the Board will order NP to file, no later than the filing of its 2007 Capital Budget Application, a report including the final cost estimate, on the chosen alternative.*

In compliance with this order, Newfoundland Power provides the following update to the Board regarding the successful completion of this project.

2.0 Chosen Alternative

During 2005, Newfoundland Power completed the upgrades to the Rolls Royce AVON gas generator at the Wesleyville Gas Turbine facility. Newfoundland Power received proposals from four companies to either overhaul Newfoundland Power's existing gas generator or to exchange the unit for a zero hour rated refurbished gas generator.

Newfoundland Power contracted with Siemens Canada to complete the project. Siemens Canada provided the lowest bid on both options thereby allowing Newfoundland Power to further evaluate the least cost option with that company.

Newfoundland Power's gas generator was sent to Siemens Canada's overhaul facility for a detailed inspection and cost estimate. Based upon the findings of the inspection, the final estimate for the overhaul option was in excess of the project budget. As a result, Newfoundland Power selected the alternative of exchanging the gas generator for a refurbished zero hour unit. The price of this option had been pre-negotiated and was within the project budget.

The gas generator has since been installed and commissioned in Wesleyville at a final cost of $1,139,000 compared to the Board approved budget of $1,124,000.

Substation Strategic Plan

March 2006

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1.0 Introduction

This report outlines a change in the way Newfoundland Power's ("the Company") substation capital projects are planned and executed. This change will help the Company realize productivity and reliability gains by organizing refurbishment and modernization projects on an individual substation basis. In addition, capital work will be coordinated as much as possible with major operating maintenance work, thereby minimizing service interruptions to customers.

In recent years, the Company's substation capital program has consisted of five projects: Rebuild Substations, Replacement and Standby Equipment, Protection and Monitoring Improvements, Additions Due to Load Growth and Feeder Remote Control. In 2007 and beyond, Newfoundland Power's substation capital budget will be organized into three projects as follows:

1. Substation Refurbishment and Modernization;
2. Replacements Due to In-Service Failures; and
3. Additions Due to Load Growth.

The revised approach is supported by a detailed review of the Company's substation assets that was recently undertaken. The review has identified Substation Refurbishment and Modernization capital projects in 80% of the Company's substations. These capital projects will be planned in conjunction with operating maintenance involving major equipment over a ten-year cycle. The Substation Refurbishment and Modernization capital projects are expected to require an average annual capital expenditure of approximately $4 million.

2.0 Background

2.1 Newfoundland Power's Substations

Newfoundland Power has 130 substations located throughout its operating territory. A small number of those substations connect generating plants to the electrical system. The remainder, which constitute the vast majority of the Company's substations, interconnect transmission lines and distribute electricity to customers via distribution feeders. The equipment in the substation controls the flow of that electrical energy to other parts of the electrical system, safely and at appropriate voltage levels. Appendix A is a description of a typical substation.

Figure 1 on the following page shows the location of the Company's transmission lines, substations and generating plants, as well as those of Newfoundland and Labrador Hydro on the island of Newfoundland. Substations are listed in the map legend as "Terminal Stations", and each substation is depicted on the map as a small black square labelled with the substation's three-letter designation.

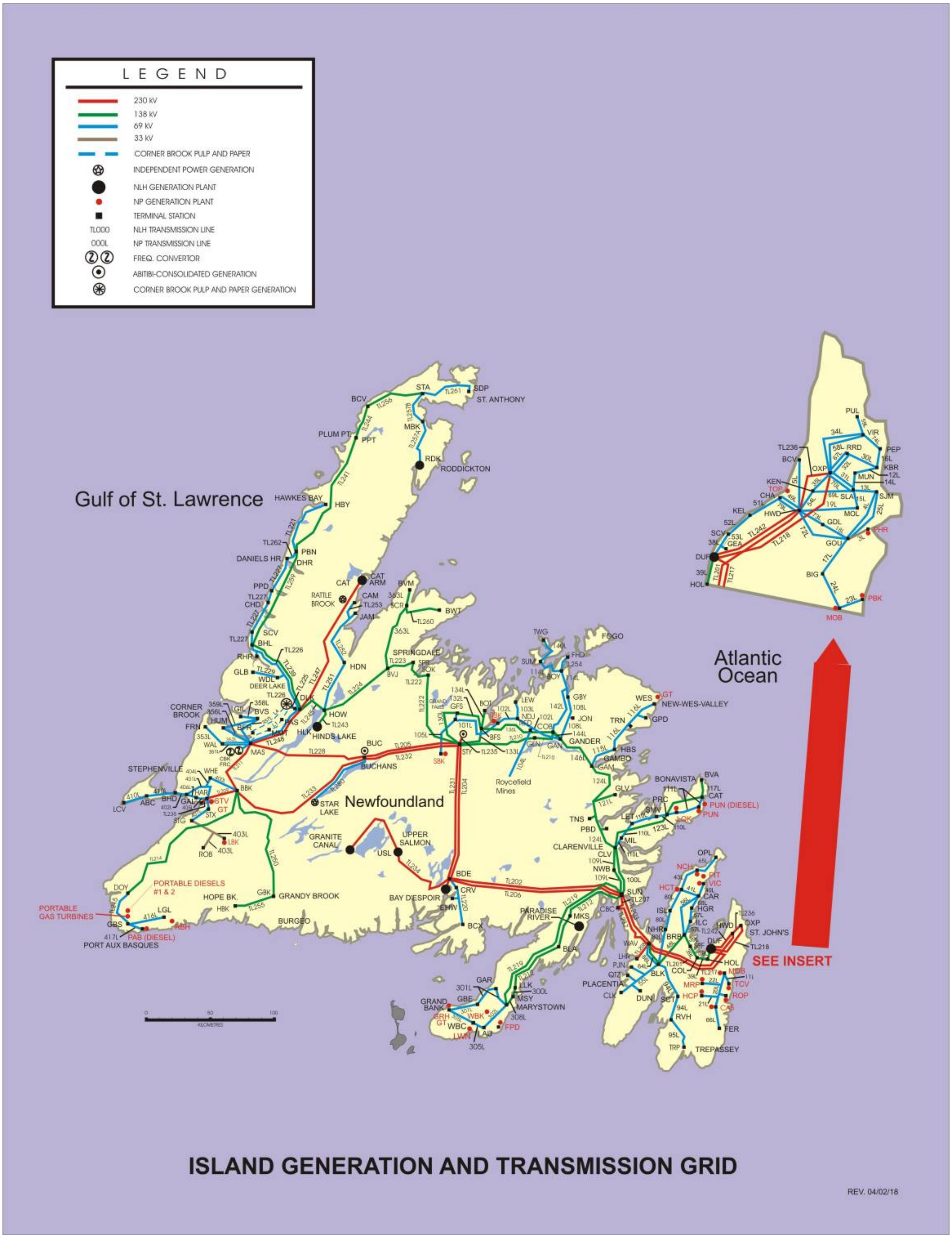
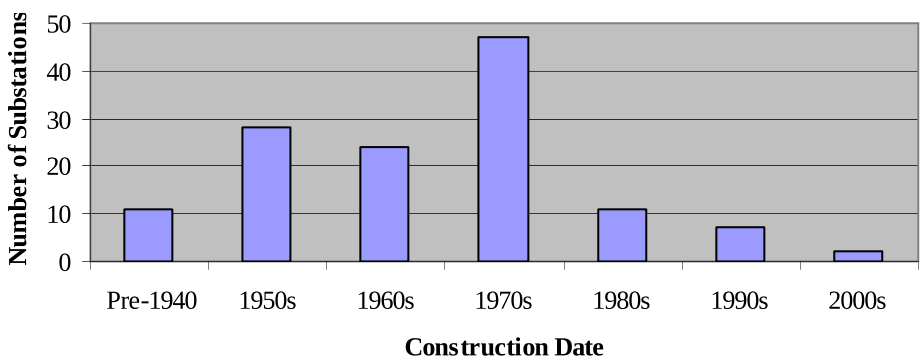

LEGEND
230 kV
138 kV
69 kV
33 kV
CORNER BROOK PULP AND PAPER
INDEPENDENT POWER GENERATION
NLH GENERATION PLANT
NP GENERATION PLANT
TERMINAL STATION
TL000 NLH TRANSMISSION LINE
000L NP TRANSMISSION LINE
FREQ. CONVERTOR
ABITIBI-CONSOLIDATED GENERATION
CORNER BROOK PULP AND PAPER GENERATION
Gulf of St. Lawrence
Atlantic Ocean
Newfoundland
ST. ANTHONY
RODDICKTON
HAWKES BAY
DANIELS HR.
CORNER BROOK
STEPHENVILLE
HINDS LAKE
BUCHANS
STAR LAKE
GRANITE CANAL
UPPER SALMON
BAY D'ESPOIR
GRANDY BROOK
HOPE BK.
PORTABLE DIESELS #1 & 2
PORTABLE GAS TURBINES
PAB (DIESEL)
PORT AUX BASQUES
SPRINGDALE
GANDER
GAMBO
FOGO
NEW-WES-VALLEY
BONAVISTA
PUN (DIESEL)
CLARENVILLE
PARADISE RIVER
MARYSTOWN
GRAND BANK
PLACENTIA
ST. JOHN'S
TREPASSEY
Roycefield Mines
SEE INSERT
ISLAND GENERATION AND TRANSMISSION GRID
REV. 04/02/18

Figure 1

2.2 Aging Substation Infrastructure

Nearly half of Newfoundland Power's substations are over 40 years old, with approximately one-third exceeding 50 years of age. The core infrastructure and major equipment in the Company's substations includes foundations, structures, grounding systems, fencing, power transformers, oil filled breakers, cables, potential transformers, control buildings, switchgear and protective relaying. With few exceptions, the core infrastructure and major equipment in the Company's substations has been in service since the substations were built. Chart 1 shows the age grouping of the Company's 130 substations.

Chart 1
Age of Substations



Typically, the requirement for refurbishment or replacement of substation equipment is minimal during the first 40 years in service. During this period, components will be replaced or refurbished if their condition warrants it. Consequently, the Company's substation capital refurbishment and replacement programs have tended to focus on specific equipment with a recent history of failure. Examples of this program-based approach include the insulator replacement programs of the 1990s and the lightning arrestor program which is currently being implemented. These programs have been successful in reducing the risk associated with specific substation equipment.

Beyond 40 years of age, the number of substation components requiring refurbishment or replacement tends to increase significantly. Civil infrastructure, including foundations and bus structures, reach the end of their useful lives and must be replaced. On the other hand, other major substation equipment, such as power transformers, can remain in service if the external components of the equipment such as gas relays are refurbished or replaced in a timely way.

2.3 Substation Maintenance Program

Because of the critical role they play in the power system, substations must be designed and maintained to provide a high degree of reliability. Unplanned outages to Newfoundland Power customers caused by substation problems have accounted for only 6% of total unplanned customer minutes of outage over the past 5 years. The three leading causes of substation outages have been failures of breakers and reclosers, failures of lightning arrestors and failures caused by birds and animals. These account for about 25%, 20% and 15%, respectively, of unplanned substation related customer minutes of outage.

While substation-based outages are infrequent, they affect a large number of customers (typically several thousands) when they do occur. It is therefore essential that substation outages be avoided where possible.

Newfoundland Power has an effective substation asset management and equipment maintenance program that follows industry best practices. The scheduling of maintenance on major substation equipment such as transformers and breakers is condition-based, relying on results from oil testing and other predictive techniques. Maintenance of substation yards, structures and auxiliary equipment usually follows inspection results. All remaining substation equipment is generally maintained on a time-based schedule.

The Company's predictive and preventive equipment maintenance programs are designed to minimize unexpected mechanical and electrical equipment failures. One of the major challenges presented by Newfoundland's harsh, salt-contaminated environment, however, is the prevention of premature failure of equipment due to corrosion. In the Company's experience, time-based maintenance is most effective when it comes to dealing with corrosion. The Company has found that a 10-year substation maintenance cycle is appropriate.

Many types of substation maintenance work can only be carried out when the substation is de-energized. When the nature or extent of the work could result in a lengthy outage, one of the Company's portable substations is deployed to carry the substation load. In some cases, particularly in urban areas where switching options are greater, the load can alternatively be transferred to other substations.

Whenever possible, the Company will coordinate all future maintenance work on individual substations so that it is carried out on a single occasion. This approach will be further coordinated with substation capital work as described in this report. The coordinated approach will minimize service interruptions to customers and will also take maximum advantage of the deployment of portable substations or the switching of loads to other substations, as the case may be.

2.4 A Modified Approach to Capital Work

In light of the large number of substations that are now in excess of 40 years of age, Newfoundland Power is modifying its approach to substation capital improvement. Following a detailed individual assessment of all of its substations, the Company has determined that an approach that focuses on the overall condition of individual substations will be more effective and efficient than the existing program-based approach.

Each substation has been assessed, with particular consideration given to the physical condition of core infrastructure and equipment. Based on these individual substation assessments, the Company has established priorities and developed a plan for the overall refurbishment and modernization of its substations that will coordinate with ongoing major equipment maintenance and replacement activities.

The substation plan will follow a 10-year cycle, coinciding with the maintenance cycle for major substation equipment. The objective is to complete the capital work at each substation at the same time as major operating maintenance work. This will improve the overall condition of individual substations, and will be more productive and less disruptive to the operation of the substation than having multiple jobs scheduled for individual substations over a period of time.

In between the planned capital and major operating maintenance work, regular substation inspections and equipment preventive maintenance will continue as usual. Additions and modifications due to load growth, as well as replacements due to in-service failures, will also continue on an as-required basis.

2.5 Benefits of the New Approach

For the most part, the Company's existing capital program has focused on programs that addressed issues identified with specific equipment and infrastructure. This has allowed the Company to address high priority reliability and safety issues affecting most of the Company's substations. Programs such as wholesale insulator replacements (because of high failure rates due to cement growth) and, more recently, the replacement of silicon carbide lightning arrestors (due to high failure rates from aging) are examples of focused programs that had immediate positive impacts on substation reliability.

The new approach will focus on coordinating substation major operating maintenance and substation capital work on a substation by substation basis to improve reliability and productivity. With this approach, 80% of the Company's substations will be refurbished and modernized on a priority basis over the 10-year planning period.

Capital projects will be planned in conjunction with major operating maintenance to realize improved productivity, with project planning and execution encompassing both capital and operating work. This is similar to the "blitz" approach to line work adopted by the Company in recent years where all deficiencies on a distribution line are addressed at the same time. This approach will be particularly beneficial when installation of a portable substation or offloading of the substation is required, as it will reduce the number of outages required to perform work on the substation.

Advanced planning and coordination of both capital and operating maintenance work will achieve the following benefits:

- Greater utilization of (and thus fewer overall) portable transformer set ups and substation offloading will reduce costs.
- Greater use of the "blitz" approach to execute work will increase worker productivity and efficiency, and will create savings by reducing overall travel time and accommodation expenses.
- A reduction in the number of smaller projects will reduce the total number of projects and associated project overheads such as job plans, safety and environmental management plans, protection plans, switching orders and work orders.
- There will be more effective use of project supervisors, who will manage more work in a shorter period of time.
- Fewer overall projects, portable installs and switching orders will result in fewer outages to customers.

3.0 Substation Refurbishment and Modernization Plan

The new 10-year substation refurbishment and modernization plan was developed following a detailed review of the assets in each of the Company's substations. Each substation was assessed based on a number of factors including physical condition, history of equipment maintenance and performance, equipment life expectancy, impact of failures on service to customers and requirements for modernizing substation protection and control.

The following is a high level overview, with reference to specific substation components, of the refurbishment and modernization work identified from the substation assessments.

3.1 Power Transformers

It has been the industry experience that power transformers often remain in service well beyond the manufacturer's estimate of life expectancy. It is not unusual to find units in service for well in excess of fifty years. Incidents of heavy loading and damage caused by external forces, such as lightning, resulting in premature failure are rare in Newfoundland Power's system. Good maintenance practices should therefore ensure that Newfoundland Power's units remain in service for a very long time.

The Company will continue with oil sampling and analysis to gauge the internal health of transformers and plan transformer replacements based upon this predictive style of maintenance. However, if a transformer fails unexpectedly, the Company will bypass it with the use of a portable transformer until a replacement unit can be installed.

Although power transformers are expected to remain in service for a long time, the associated monitoring and protection equipment, which is exposed to the climate, often requires earlier replacement. For example, to function effectively, transformer radiators are made of thinner metals. Although newer radiators are made of galvanized steel to prevent premature rust perforations and oil leaks, some older units will require replacement due to corrosion.

To ensure reliable operation, the auxiliary equipment used to monitor and protect power transformers must be replaced after 25 to 30 years in service. The condition of such auxiliary devices as gas relays, temperature and oil level gauges, pressure relief switches and associated piping, conduits, cabinets and wiring is determined from inspection and testing. All auxiliary equipment will be replaced at the same time during a scheduled maintenance overhaul of power transformers.

Sixty-eight of the Company’s 190 transformers have tap changer mechanisms that adjust the transformer’s output voltage. The older tap changer controllers contain discrete electronic components that age and deteriorate with time, causing the tap changer to fail to operate. Based on the Company’s experience with failures of tap changer controllers they will be replaced when they approach 25 years of age. The newer technology tap changer mechanisms can be integrated with the Company’s SCADA system, enabling remote control of those units replaced in substations that have remote control infrastructure in place.

3.2 Lightning Arrestors

The primary function of lightning arrestors is to protect power transformers. Until the early 1980s, silicon carbide lightning arrestors were standard. They are known to fail as they age due to water leaking into the arrestor through failed seals. The Company has experienced increasing failures of this type of lightning arrestor. There is no reliable way to test or monitor an arrestor to predict its failure. All remaining silicon carbide lightning arrestors will be replaced on a prioritized basis over the next 5 years. The majority of these replacements will require the use of a portable transformer, and will be coordinated with other capital work and transformer maintenance.

3.3 Bus Structures and Foundations

Bus structures are galvanized steel or wood pole structures that support the switches, insulators and conductors in a substation. Newfoundland Power has 118 wooden and 138 steel bus structures in service. Galvanized steel structures last longer than wood structures, and are essentially maintenance-free. They are also more physically stable than wood structures, making them more suited to ensuring isolating switches stay properly aligned, reducing maintenance. Steel structures do not require guying. This decreases the overall dimensions of the substation compared to designs employing guyed wooden structures. In future, Newfoundland Power will install only galvanized steel structures.

Existing steel structures are in generally good condition. The existing wooden bus structures range in age from five to over 60 years of age. Wooden structures over 50 years of age are showing signs of deterioration such as rotting, cracking and splitting. Some have deteriorated to the point where replacement of some or all of the structure is necessary.

Concrete foundations weather over time and begin to deteriorate. If left unchecked, the deterioration of foundations and footings can jeopardize the structural stability of substation equipment. The Company will repair or replace these as required in conjunction with planned substation work.

3.4 Buses and Insulators

The main problem with buses is the failure of supporting insulators. One of the most common modes of failure of porcelain insulators is cement growth. In the 1990s, the Company undertook a major program to replace substation insulators vulnerable to this mode of failure. Newer insulators are not failing due to cement growth. Overall, the insulators and buses in Newfoundland Power substations are in very good condition, and no major upgrading work is required.

3.5 Power Cables

Power cables in substations are used to transfer the output of the power transformer to the low-voltage bus. The majority of these cables are the original equipment installed when the substation was built. Experience has shown that power cable failures begin to occur when cables are about 35 years old. There is currently no accurate test to predict cable failure. Failure normally occurs in the termination at the end of the cable. Replacing cable terminations is difficult due to the cable's fabrication, location and made-to-measure installation. To ensure reliable operation of substation power cables, the Company will replace those that are more than 35 years old.

3.6 Protective Relaying

Protective relaying protects transmission lines, substation equipment and distribution feeder circuits. Most of the Company's substations were constructed with electro-mechanical relays. Electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. In recent years, there has been ongoing replacement of distribution feeder protective relaying as part of the Company's Feeder Remote Control program. In addition, relaying associated with the St. John's transmission system has been replaced to improve fault-clearing times. However, much of the protective relaying equipment in Newfoundland Power's substations is the original electro-mechanical equipment.

The Company has also experienced failure in electronic components in older transmission line relays. The failures are due to the aging of components causing the relays to drift out of calibration. As recently as March 2006, the relay at Carbonear Substation for transmission line 56L failed to operate to clear a fault, resulting in customer outages. The Company's experience has been that as these older type relays approach 40 years of age they may fail to clear faults.

Failure of protective relaying can result in widespread outages and significant equipment damage and can jeopardize the safe operation of the electrical system. Older relays will be scheduled for replacement with modern protective relaying as part of substation refurbishment and modernization upgrading plans.

3.7 Switches

Substation switches provide isolation for equipment such as power transformers, breakers and reclosers. Switches that are operated infrequently have a tendency to seize due to deterioration of bushings, corrosion in operating mechanisms or misalignment of blades. Substation switches such as transformer isolating and bus tie switches are operated infrequently. Consequently, they are susceptible to failure.

The work required to address seized bushings and switch alignment problems cannot practically be undertaken while a switch is energized. As well, refurbishment of the switch is best undertaken in a maintenance shop environment. The Company's strategy for switches is to operate and maintain switches whenever opportunities and substation work permit, and to replace switches when they are more than 30 years old. Switches removed from the field will be refurbished at the electrical maintenance shop, or scrapped if deemed uneconomical to repair.

3.8 Buildings and Batteries

Many of the Company's substation buildings are of steel pre-engineered fabrication and are generally in good condition. However, the roofs of some buildings are more than 25 years old and are badly corroded. If left unchecked, corrosion can result in water entering a substation building and damaging protective equipment and controls. The Company will carry out substation building upgrading work such as roof replacement when other major work is planned for the substation.

Battery banks provide continuous power to substation protection and control equipment and have a normal life expectancy of 15 to 20 years. Testing will determine when the entire battery bank needs to be replaced.

3.9 Protection from Animals and Birds

Small animals and birds have caused significant substation outages. Most commonly, they cause short circuits in equipment such as reclosers, metering tanks and station service transformers, often severely damaging the equipment. The problem has been more prevalent in rural substations.

Insulated coverings, guards and leads can be effective in preventing damage and outages caused by small animals and birds. In future, Newfoundland Power will install the necessary protective covers and insulated leads in rural substations.

4.0 Substation Capital Budget Presentation

4.1 Modified Presentation

The revised approach to substation capital budget planning has prompted the Company to modify its presentation of the capital budget for substation work. In recent years, the Company's substation capital program has consisted of the following five major projects:

Rebuild Substations
The Rebuild Substations project provided for replacement of deteriorated substation infrastructure such as buses, structures, foundations, fencing, switches, lightning arrestors and other equipment, including replacement of PCB contaminated equipment.

Replacement and Standby Equipment
The Replacement and Standby Equipment project provided for the replacement of deteriorated or unreliable equipment on a planned basis and the replacement of equipment that actually failed in service also provided for the appropriate inventory levels of spare equipment for use during emergencies.

Protection and Monitoring Improvements
The Protection and Monitoring Improvements project provided for the upgrading of protective relaying equipment and control devices required to improve or maintain the protection and control of the electrical system to ensure a reliable supply of electricity.

Feeder Remote Control
Feeder Remote Control was a specific program to replace old protective relays and oil filled reclosers on distribution lines and to expand the remote control of the electrical system to realize productivity and reliability gains.

Additions Due to Load Growth
Additions Due to Load Growth provided for the upgrading of system and equipment capacity, as well as the installation of additional system capacity or new equipment to accommodate load growth and the connection of new customers on the system.

Commencing with the 2007 Capital Budget Application, the Rebuild Substations, Protection and Monitoring Improvements and Feeder Remote Control projects have been consolidated into a single project known as Substation Refurbishment and Modernization. All planned replacements of substation equipment under the new 10-year plan described in this report will be included in this project.

The Replacement and Standby Substation Equipment project is renamed the Replacements Due to In-Service Failures project. This project is ultimately driven by the need to replace failed equipment and equipment identified as being in imminent danger of failing.

The Additions Due to Load Growth project is unchanged.

4.2 2007 Substation Capital Program

Newfoundland Power's 2007 substation capital program is presented as three projects:

1. Substation Refurbishment and Modernization;
2. Replacements Due to In-Service Failures; and
3. Additions Due to Load Growth.

The Substation Refurbishment and Modernization project will address all planned work that has been identified based upon inspections and testing. The capital work will be coordinated with the ten-year cycle of major operating substation maintenance work and scheduled to maximize productivity.

In the first ten-year period, Substation Refurbishment and Modernization work will take place in 80% of the Company's substations and will require an average annual expenditure of approximately $4 million.

The Replacements Due to In-Service Failures and Additions Due to Load Growth projects permit the Company to respond to equipment failures and customer load growth, respectively. Replacements Due to In-Service Failures will be budgeted based primarily on historical budget data. Additions Due to Load Growth will be based on load forecasts and equipment ratings.

Appendix B shows the proposed ten-year substation plan and expenditures for Substation Refurbishment and Modernization. The plan will be revisited yearly as part of the preparation of the annual capital budget, and may change due to changing priorities as indicated by the most recent inspections, assessments and operating experience.

Appendix C contains a detailed review of the Substation Refurbishment and Modernization work required in 2007.

Appendix A

A Typical Substation

A Typical Substation

A typical distribution substation “steps down” electricity from the transmission network to the distribution network. Stepping down involves converting high voltage power, necessary to transport electricity over great distances at lower losses, to lower voltage power, capable of being used by residential and commercial customers.

Electricity enters a distribution substation via transmission lines. The electricity passes through a high voltage bus, disconnect switches and circuit breakers on the way to the step down power transformer. Circuit breakers monitor the electrical current and will break the circuit if they detect a problem thus protecting the electrical equipment from damage caused by an overload or a short circuit.

Switches allow the entire substation or separate distribution lines to be disconnected from the network when necessary. Switching can be planned, for example to perform maintenance, or unplanned, for example to isolate problems on the grid.

By far, the largest, most critical, and most expensive piece of equipment in a substation is the power transformer. The transformer converts high voltage power to low voltage power. Once the voltage has been lowered it passes through the voltage regulator and on to the distribution low voltage bus.

The voltage regulator ensures the power is maintained at a constant voltage level making the necessary adjustments as the customer loads vary throughout the day. The distribution low voltage bus, which is comprised of conductors and insulators, splits the power off into multiple directions for delivery to particular service areas by using distribution breakers or reclosers.

All the major components and high voltage buses are located outdoors. Equipment such as buses and switches are mounted on wooden or steel structures. Equipment such as transformers and voltage regulators are mounted on concrete foundations. Where outdoor space is restricted, some equipment, such as low voltage buses and some circuit breakers, is located inside substation buildings.

Substations also include many systems and devices such as grounding systems and telecommunications devices, to provide protection for equipment as well as remote control and monitoring of substations from a central location.

A key aspect of substation design is employee and public safety. Substations are surrounded by security fences with secured access for employees only. All equipment is grounded to ensure safe operation and can be isolated from the network for safety and maintenance reasons.

Figure 1 is a photograph of a typical substation. The red arrows depict the direction and flow of electricity through the substation. The major substation components have been numbered according to the legend.

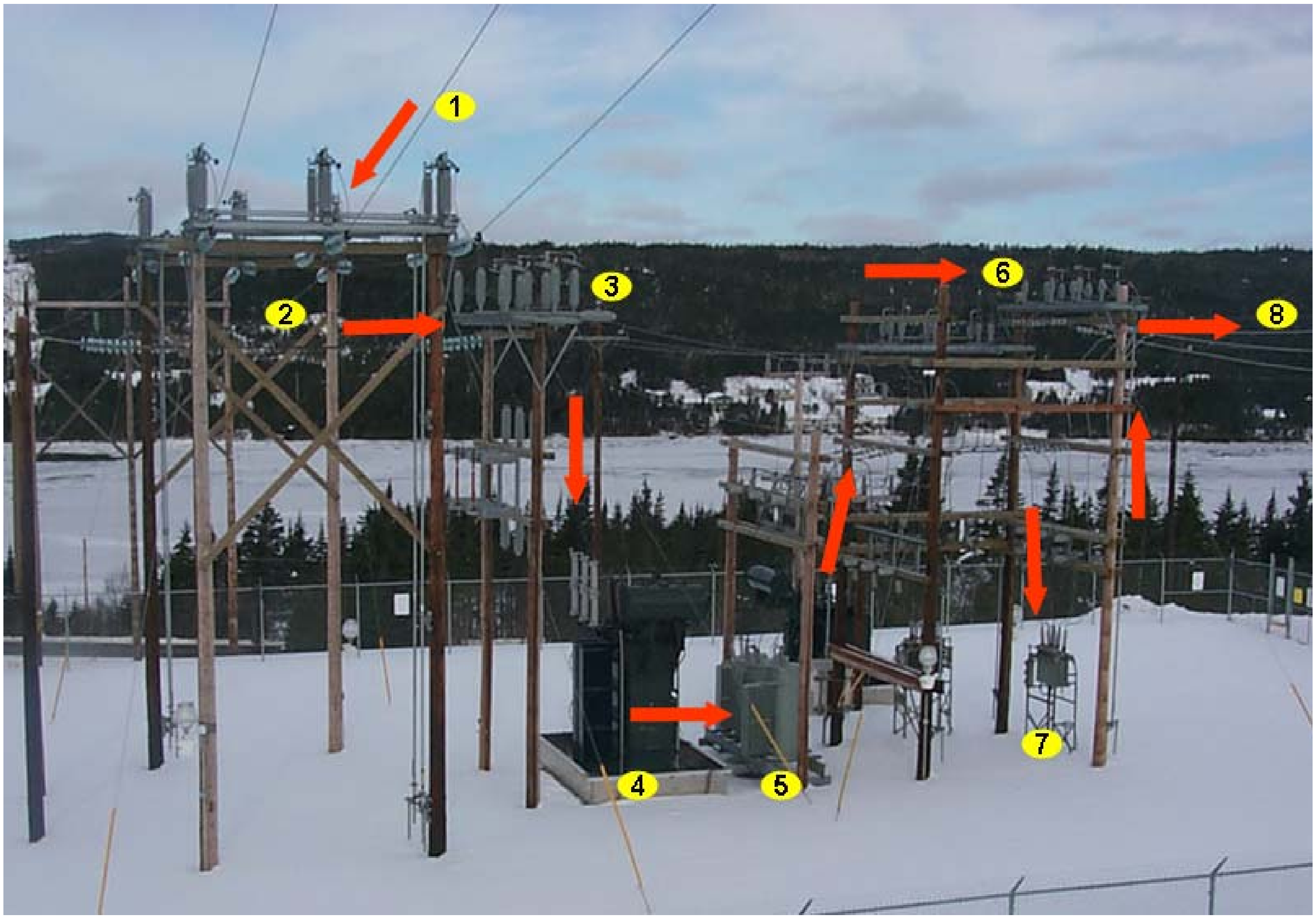


Figure 1

Legend

1	Transmission Line	5	Voltage Regulator
2	High Voltage Bus	6	Low Voltage Bus
3	Switch	7	Recloser
4	Power Transformer	8	Distribution Feeder

Appendix B

Ten-Year Substation Refurbishment and Modernization Plan

Ten-Year Substation Refurbishment and Modernization Capital Plan
($000s)

2007		**2008**		**2009**		**2010**		**2011**		**2012**		**2013**		**2014**		**2015**		**2016**	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
BLK	231	CLV	476	ABC	99	CAR	464	BRB	770	GBE	71	LLK	596	CAT	574	SLA	306	BCV	411
CAR	26	BOT	538	BHD	228	GAL	396	BON	620	BLA	161	GBY	162	HUM	803	CAB	834	COL	277
CLV	26	FER	57	BOY	26	FRN	436	GIL	145	BVS	567	GPD	195	LEW	498	CHA	238	HOL	822
CLK	215	GAN	738	GFS	749	GLN	183	MAS	367	BIG	295	HWD	290	MIL	451	COB	1,058	ICV	507
GAL	46	BVJ	68	HCT	187	HGR	1,276	MKS	428	GAM	697	MOL	322	PBD	335	FPD	108	LAU	399
GAR	374	KEL	218	LET	105	HAR	159	NHR	423	HBS	165	NWB	633	PUL	304	HCP	77	PJN	15
GLV	209	KBR	654	NCH	428	JON	13	QTZ	24	ISL	114	PEP	389	SCV	546	MMT	389	RVH	472
GOU	174	LOK	178	P335	237	SPR	222	SCR	516	P135	377	SPF	553	SMV	937	PAS	536	SUM	1,135
GRB	11	LBK	12	P435	237	STX	123	TWG	165	ROB	170	SJM	185			PBK	77	WES	129
LLK	26	MOB	277	STV	239	VIR	223	WAL	345	SCT	81	TCV	247						
PUN	16	OXP	117	SUN	318	WAV	154	ROB	16	TBS	712								
RRD	312	ROP	388	FPD	7	BLA	17	SPF	57	TRP	880								
SBK	15	LEW	48	PJN	7	ISL	53	DLK	57	TRN	154								
SLA	509	MIL	48	PAB	182	P135	10	PAS	17	WBC	235								
		BRC	48	SLP	221	TRN	53	PBK	8	BFS	603								
				WES	7	PEP	49	ICV	55										
						SCV	7	LAU	17										
						SUM	16	WES	8										
						MMT	53	MRP	11										
						VIC	446	MGT	8										
								GBS	629										
Total	**2,190**		**3,865**		**3,277**		**4,353**		**4,686**		**5,282**		**3,572**		**4,448**		**3,623**		**4,167**

Notes: SUB: Substation - Refer to the Electrical System handbook for three letter substation designations.
P135, P335 and P435 are the designations for the portable substations.

Appendix C

2007 Substation Refurbishment and Modernization Projects

2007 Projects

Table 1 is a summary of the Substation Refurbishment and Modernization projects planned for 2007. A further $578,000 is budgeted for the Rattling Brook Substation Rebuild, which is clustered with the Rattling Brook Plant Refurbishment project in accordance with the Provisional Capital Budget Application Guidelines.

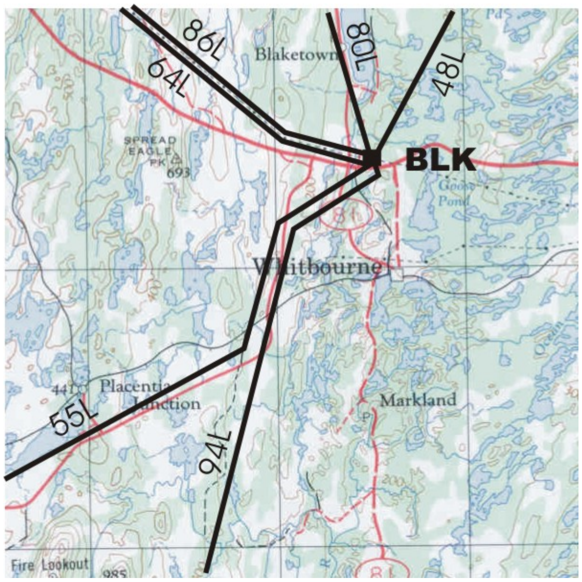
Table 1
2007 Substation Projects
(000s)

Substation	Budget
Blaketown (BLK)	$ 231
Carbonear (CAR)	26
Clarenville (CLV)	26
Clarkes Pond (CLK)	215
Gallant Street (GAL)	46
Garnish (GAR)	374
Glovertown (GLV)	209
Goulds (GOU)	174
Grand Beach (GRB)	11
Linton Lake (LLK)	26
Port Union (PUN)	16
Ridge Road (RRD)	312
Sandy Brook (SBK)	15
Stamps Lane (SLA)	509
Total	**$ 2,190**

The following pages outline the above projects as well as the ongoing lightning arrestor and tap changer projects.

1. Blaketown Substation ($231,000)

Blaketown substation was built in 1977 as a combined transmission and distribution substation. It contains a 138 kV to 66 kV, 42 MVA transformer (T3) and a 138 kV to 25 kV, 20 MVA transformer (T2). The 138 kV bus is energized via two 138 kV transmission lines, 64L from Western Avalon substation and 48L transmission line from Bay Roberts substation. The 66 kV bus has four transmission lines terminated on it. Line 55L is a radial transmission line to Clarkes Pond substation. Line 94L is a radial line to St. Catherines substation. Line 80L services New Harbour substation and line 86L is an in-feed from Western Avalon substation. The distribution part of the substation services approximately 2,600 customers in the Whitbourne and Blaketown areas through two 25 kV feeders.



Blaketown Substation Location

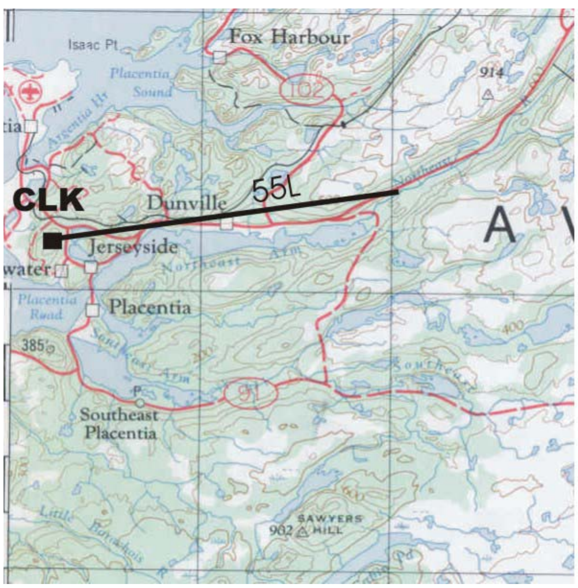
After reviewing maintenance records and conducting on-site engineering assessments it was determined that the 138 kV, 66 kV and 25 kV steel structures and concrete foundations are in good condition with no sign of deterioration. The 138 kV, 66 kV and 25 kV bus and insulators are also in good condition with no signs of deterioration.

T3 transformer is in good condition. T2 transformer has cooling radiator fin edges that are perforated due to rusting. The perforated fin edges have been patched as a temporary measure to prevent leaking but require replacement. The lightning arrestors on T2 and T3 transformers are silicon carbide and require replacement with metal oxide arrestors. The air break switch on T2 transformer is 30 years old and requires replacement. Protection against small animals should be installed on the 25 kV equipment and bus. A maintenance overhaul is required for the T2 and T3 power transformers in 2007 which will be completed at the same time as the required capital work.

Deteriorated radiator fin edges – Blaketown Substation

2. Clarkes Pond Substation ($215,000)

Clarkes Pond substation was built in 1976 as a distribution substation. It contains two 66 kV to 12.5 kV power transformers (T1 & T2). Each power transformer is rated for 7.5 MVA for a total station capacity of 15 MVA. The 66 kV bus is energized via a radial 66 kV transmission line 55L from Blaketown substation. The substation services approximately 2,500 customers in the Placentia/Argentia areas through three 12.5 kV feeders.



Clarkes Pond Substation Location

After reviewing maintenance records and conducting on-site engineering assessments, it was determined the 66 kV and 12.5 kV steel structures are in good condition with no sign of deterioration. Inspections of the concrete foundations show that there are two recloser and three bus structure concrete foundations that are crumbling and require replacement.

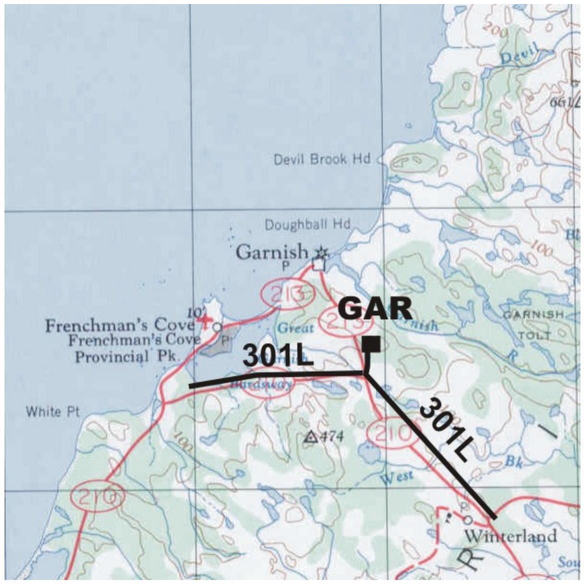
The two power transformers are in good condition with no obvious signs of deterioration. The tap changer controllers on T1 and T2 are twenty-nine and thirty years old respectively and require replacement. Small animal protection should be installed on the 12.5 kV equipment and bus. The Nulec reclosers were installed in 2002 and are capable of being remote controlled. The three feeders will be automated to allow remote control from the System Control Centre. A maintenance overhaul is required to be completed for both power transformers T1 and T2 in 2007 which will be completed at the same time as the required capital work.

Foundation damage at Clarkes Pond Substation

3. Garnish Substation ($374,000)

The 38 year old Garnish substation services approximately 430 customers. The substation is deteriorated and will be replaced with a new substation. All the insulators are old and prone to cement growth failure. The fence is deteriorated. Cross-arms are split and wood rot is present. Some cross-arms have been temporarily reinforced to prevent failure. Most of the concrete foundations are crumbling. The metering tank and other equipment are severely rusted. The transformer fans have to be replaced as their motor bearings are seized.

The new substation will be built adjacent to Highway 210, reducing overall cost and improving access for operational staff. The current substation required a high voltage bus structure. However, when transmission line 301L was rebuilt in 2003, it was constructed so that a high voltage bus structure would not be required for the new substation thereby reducing the capital and operating costs associated with this substation. Establishing this new site will also avoid rebuilding the transmission tap to the existing substation.



Garnish Substation Location

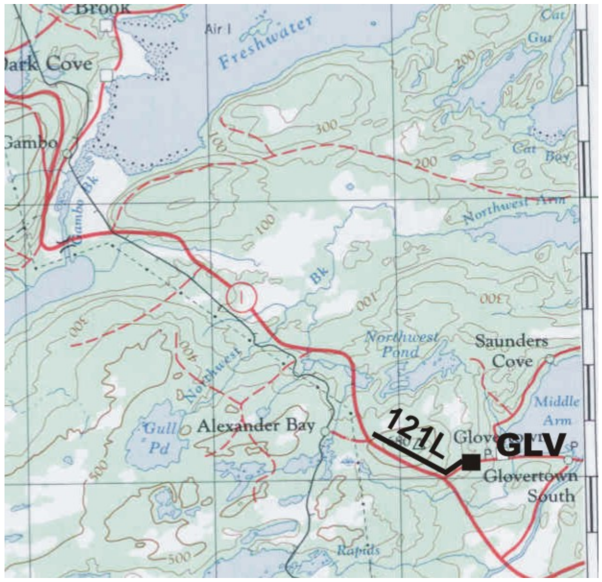
Cracked crossarm Garnish Substation

Corrosion damage Garnish Substation

Foundation damage Garnish Substation

4. Glovertown Substation ($209,000)

Glovertown substation was built in 1976 as a distribution substation. The power transformer (T1) is a 138 kV to 25 kV, 20 MVA unit. The 138 kV bus is energized via a tap from 124L transmission line which runs between Clarenville and Gambo substations. The substation services approximately 2,300 customers in the Glovertown area through two 25 kV feeders.



Glovertown Substation Location

After reviewing maintenance records and conducting on-site engineering assessments it was determined that the 138 kV and 25 kV wood pole structures and concrete foundations are in good condition with no sign of deterioration. The power transformer is in good condition with no signs of deterioration.

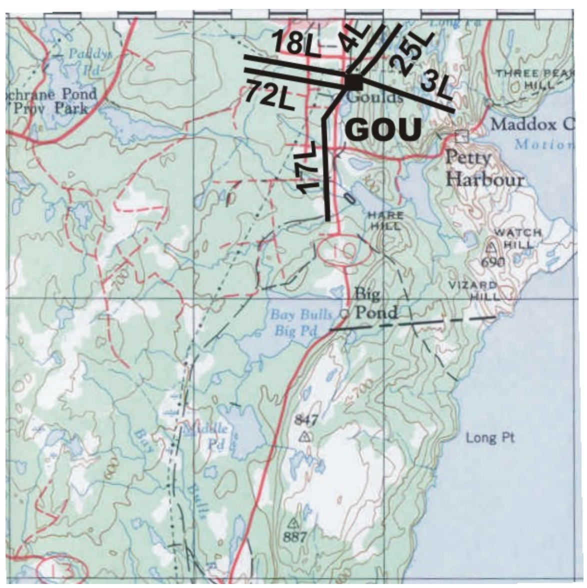
The lightning arrestors on T1 are silicon carbide and require replacement with metal oxide arrestors. The tap changer controller is thirty years old and should be replaced. Small animal protection will be installed on the 25 kV equipment and bus.

The Nulec reclosers in this substation were installed in 2002 and are capable of being remote controlled. The two feeders and the transformer tapchanger require automation to allow remote control from the System Control Centre. A maintenance overhaul is required to be completed on power transformer T1 in 2007 which will be completed at the same time as the required capital work.

5. Goulds Substation ($174,000)

Goulds substation was built in 1954 as a major 66 kV transmission switching substation and also as a 12.5 kV distribution substation. The substation contains two distribution power transformers (T2 & T3) with a combined capacity of 33 MVA. The substation directly services approximately 3,400 customers in the Goulds and Kilbride areas through three 12.5 kV feeders.

As a transmission substation there are five 66 kV transmission lines terminated in the substation. These are transmission lines 4L to St. John's Main substation, 17L to Big Pond substation, 18L to Glendale substation, 25L to St. John's Main substation and 72L to Hardwoods substation. As well there is a 66kV to 33 kV power transformer (T1) servicing 3L transmission line to Petty Harbour substation.



Goulds Substation Location

After reviewing maintenance records and conducting on-site engineering assessments it was determined that the 66 kV and 12.5 kV wood pole structures are in good condition and no issues are expected over the next ten years. The concrete foundations are in good condition with no signs of deterioration with the exception of T1 concrete foundation which must be replaced.

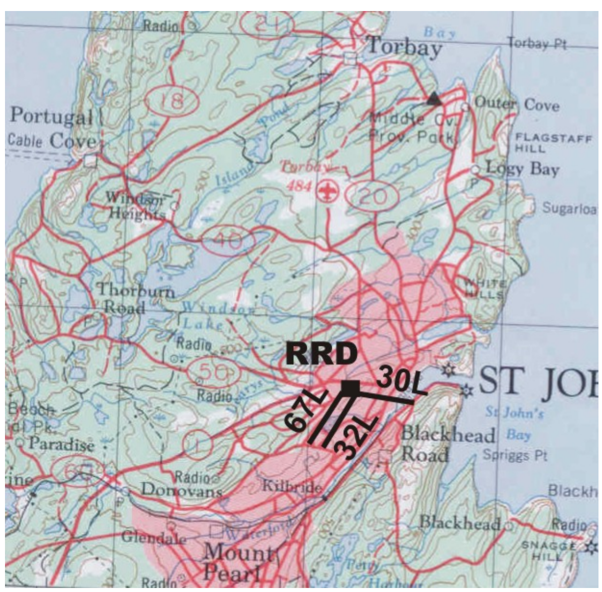
The power transformers are in good condition with no obvious signs of deterioration. The switches in the substation are in good condition with the exception of one 66 kV bus tie switch which is inoperable and currently bypassed. This switch must be replaced.

The radial line 17L to Big Pond substation requires a bypass switch to facilitate maintenance on the breaker. The 66 kV potential transformers are over 40 years old and showing signs of deterioration. These potential transformers are essential for providing protection for the transmission lines and equipment at Goulds substation and must be replaced to maintain reliability. A maintenance overhaul is required to be completed on the three power transformers in 2007 which will be completed at the same time as the required capital work.

Bus Tie Switch Bypassed Goulds Substation

6. Ridge Road Substation ($312,000)

Ridge Road substation was built in 1963 as a 66 kV transmission switching substation and as a 12.5 kV distribution substation. The substation contains three power transformers (T1, T2 & T3) with a combined capacity of 40 MVA at 12.5 kV and 2.2 MVA at 4.16 kV. The existing 4.16 kV section of the substation is being converted to 12.5 kV and the 4.16 kV power transformer (T1) will be retired in 2006. The substation directly services approximately 4,200 customers in the Higgins Line area of St. John's through eight 12.5 kV metal clad switchgear feeders. In the substation there are three 66 kV transmission lines terminated in the high voltage bus. These are transmission lines 30L to King's Bridge substation and 32L and 67L to Oxen Pond substation.



Ridge Road Substation Location

After reviewing maintenance records and conducting on-site engineering assessments it was determined the 66 kV steel structures and 12.5 kV metal clad switchgear are in good condition with no signs of deterioration.

The concrete foundations are in good condition with no signs of deterioration, with the exception of one 66 kV structure concrete foundation which must be refurbished.

The power transformers are in good condition with no obvious signs of deterioration. As a continuation of the feeder remote control program the eight 12.5 kV feeders will have relaying replaced and be automated to allow remote control from the System Control Centre. A maintenance overhaul is required to be completed on the two power transformers in 2007 which will be completed at the same time as the required capital work.

7. Stamps Lane Substation ($509,000)

Stamp's Lane substation was built in 1963 as a 66 kV transmission switching substation and as a 4.16 kV and a 12.5 kV distribution substation. The distribution substation contains four power transformers (T1, T2, T3 & T4) with a combined capacity of 50 MVA at 12.5 kV and 21 MVA at 4.16 kV. The substation directly services approximately 9,300 customers in the central area of St. John's through five 4.16 kV metal clad switchgear feeders and six 12.5 kV outdoor feeders. There are six 66 kV transmission lines terminated in the substation. These are transmission lines 13L to St. John's Main substation, 14L to Memorial substation, 15L to Molloy's Lane substation, 69L to Kenmount substation and 31L and 70L to Oxen Pond substation.

Ridge Road Substation Location

After reviewing maintenance records and conducting on-site engineering assessments it was determined that the 66 kV and 12.5 kV steel structures and 4.16 kV metal clad switchgear are in good condition with no signs of deterioration. Four 66 kV concrete structure foundations are in poor condition and require refurbishment. The remaining concrete foundations are in good condition with no signs of deterioration.

The power transformers are in good condition with no signs of deterioration. The 1971 power cables connecting transformer T2 show signs of compound leaking and require replacement. Eleven feeders will have relaying replaced and be automated to allow remote control from the System Control Centre. A maintenance overhaul is required to be completed on the power transformers in 2007 which will be completed at the same time as the required capital work.

8. Tap Changer Controllers ($124,000)

As discussed in the strategic plan, tap changer controllers have a service life of approximately 25 years. The older tap changer controllers contain discrete electronic components that age and deteriorate with time causing the tap changer to fail to operate. Regulation of the transformer tap is critical in maintaining the distribution feeder voltage within acceptable values.

Tap changer controllers will be replaced with SCADA operated tap changer controllers at the following substations:

- Carbonear Substation
- Clarenville Substation
- Gallants Substation
- Linton Lake Substation

9. Lightning Arrestors ($42,000)

As discussed in the strategic plan, lightning arrestors protect power transformers and other substation equipment. Silicon carbide lightning arrestors were installed on power transformers until the early 1980s. It has been Newfoundland Power's experience that these arrestors fail as they age due to water leaking into the arrestor through failed seals. All remaining silicon carbide arrestors will be replaced on a prioritized basis within the next 5 years.

Silicon carbide lightning arrestors will be replaced in the following substations:

- Sandy Brook Substation
- Grand Beach Substation
- Port Union Substation

2007 Replacements Due to In-Service Failures

February 2006

Prepared by:

Glenn Samms, P.Eng., MBA

REGISTERED PROFESSIONAL ENGINEER
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1.0 Background

Each year Newfoundland Power retires substation equipment because of vandalism, storm damage, lightning strikes, electrical or mechanical failure, corrosion damage, technical obsolescence and failure during maintenance testing. This equipment is essential to the integrity and reliability of the electrical supply to our customers and must be replaced in a timely manner.

2.0 Corporate Standby Equipment

The most significant items related to replacement equipment include replacement circuit breakers, reclosers, potential transformers, voltage regulators, protective relays, DC power systems and switches. The following provides details on these major components.

2.1 Circuit Breakers

Newfoundland Power has approximately 400 circuit breakers in service. Breakers are used to interconnect and switch transmission lines, power transformers, feeders, generators and other equipment. In conjunction with protective relaying, circuit breakers isolate electrical faults.

The majority of breakers are either transmission breakers (138 or 66 kV) or distribution breakers (15 or 25 kV). The remainder are required in generation stations. The older breakers are often oil-filled and represent an environmental risk due to deterioration and unexpected failure. Approximately 26 circuit breakers have been retired since 2000 because of deterioration, electrical failure, or technological obsolescence.

Based on past experience, the Company maintains a pool of breakers to respond to failures. This pool normally contains one 138 kV, two 66 kV and two 25 kV breakers. The 25 kV units can be installed in either 15 or 25 kV installations, thereby reducing the number of spares required. New units have either galvanized or stainless steel exteriors to minimize corrosion related problems and are oil free, low maintenance units.

2.2 Electronic Reclosers

The Company has approximately 200 reclosers in service. Reclosers allow switching of rural feeders, which carry lighter loads and have smaller electrical fault levels than urban feeders. They have built-in control units that sense electrical faults and operate to de-energize the feeder in the event of a fault.

The newer reclosers have greater functionality and electrical isolating capabilities than the older hydraulic, relay and resistor types.

Reclosers are replaced due to failure, deterioration, and obsolescence. Since 2000, approximately 59 units have been retired. In order to respond to replacement requirements, the Company maintains a pool of spare reclosers. Each new unit will be oil free, low maintenance and digitally controlled and can replace any other recloser. They will also have either stainless steel or galvanized exteriors to minimize corrosion related problems.

2.3 Potential Transformers (PTs)

The Company has approximately 220 PTs in service. They measure voltage levels for input to protective relays, the SCADA system and metering circuitry. Failure of this equipment compromises the reliable operation of the electrical system. Each year, PT replacements are required due to in-service failures. Since 2000, 21 PTs were retired due to rusting and oil leakage. New units will be of oil-free design, eliminating the environmental risk associated with the older oil-filled units.

2.4 Voltage Regulators

The Company has approximately 360 voltage regulators in service. These regulators are used to control voltages on long feeders.

Regulators are replaced due to failure, deterioration and obsolescence. Since 2000, approximately 83 units have been retired. In order to respond to replacement requirements, the Company maintains a pool of spare voltage regulators. The new units can operate at 15 or 25 kV, minimizing the size of the pool. They also have stainless steel cases to minimize corrosion related failures.

2.5 Protective Relays

Newfoundland Power has approximately 2,500 protective relays in service. These relays are critical for isolating equipment to minimize the impact of electrical faults. Each year, some relays require replacement because of deterioration or failure. The Company maintains a pool of relays to allow for the prompt replacement of failed units.

2.6 Direct Current Electrical Supply Systems (Batteries and Battery Chargers)

The Company has approximately 115 battery banks. They provide continuous power for protective relays, circuit breakers, reclosers and emergency substation lighting.

Battery chargers are low maintenance, long life devices. The Company maintains a pool of units to allow prompt replacement of failed units to ensure the security of its DC electrical supplies. Since 2000, approximately 20 battery systems have been replaced due to failure.

2.7 Switches

Newfoundland Power has approximately 2,500 high voltage switches in service. Each year switches require replacement because of deterioration or failure. The Company maintains a pool of switches to allow for the prompt replacement of failed units.

2.8 2007 Expenditures

Each year, equipment is required to either replace equipment that fails in the field or to keep the pool of standby equipment at appropriate levels. The equipment to be purchased will depend on actual failures. However, based on past experience and engineering judgment, the following equipment will be required in 2007:

- 1 – 66 kV Circuit Breaker
- 1 – 25 kV Circuit Breaker
- 2 – 25 kV Electronic Reclosers
- 3 – 66 kV Potential Transformers
- 3 – 25 kV Potential Transformers
- 2 – High Voltage 3 phase bank of switches
- 6 – 25 kV 100 amp Voltage Regulators
- 6 – 25 kV 200 amp Voltage Regulators
- 3 – 15 kV 500 amp Voltage Regulators
- 10 – Universal Regulator Controls and Enclosures for Voltage Regulators
- 3 – 48 Volt Battery Banks
- 7 – 120 Volt Battery Banks
- 10 – Battery Chargers

3.0 Recommendation

When substation equipment, material and civil infrastructure fails or deficiencies are identified, it is necessary to proceed with immediate correction or replacement to maintain electrical system reliability and safety. Based on engineering cost estimates and historical expenditures, a 2007 budget of $1,200,000 for Replacements Due to In-Service Failures is recommended.

Transmission Line Rebuild

February 2006

Prepared by:

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1.0 Transmission Line Rebuild Strategy

Transmission lines play a critical role in providing reliable service to a large number of customers. The Company must be proactive in ensuring that transmission lines are maintained so as to avoid significant failure. From both a cost and reliability perspective, transmission lines must not be allowed to reach the point of imminent failure.

As part of its 2006 Capital Budget Application, the Company submitted its *Transmission Line Rebuild Strategy* outlining a 10-year plan to rebuild aging transmission lines. The strategy outlined a structured approach to maintaining the Company's transmission line system and prioritized the rebuild of transmission lines based on physical condition, risk of failure, and potential customer impact in the event of a failure.

The *Transmission Line Rebuild Strategy* is reviewed and revised on an ongoing basis to ensure that it accurately reflects the latest reliability and inspection data, as well as the capital requirements within other asset classes. The strategy will change with time to ensure targeted spending on the highest priority transmission lines and alignment with corporate goals and objectives.

2.0 Transmission Line Rebuild Projects Planned for 2007

In 2007, the Company plans to continue the rebuild of transmission lines 43L and 110L and to rebuild a section of transmission line 20L. Major sections of these lines are within several kilometres of the coastline and subject to extreme salt contamination, high winds and icing.

The poles, crossarms, hardware, and conductor on these lines are generally in a poor and weakened condition increasing the risk of power outages and making the lines vulnerable to large scale damage when they are exposed to heavy wind, ice and snow loading.

These lines are all approximately 50 years old and many of the original poles are deteriorated. Inspections have identified substantial evidence of external and/or internal rotting, insect and woodpecker damage, and cracks and splits in poles, crossarms, cross braces, and other hardware. Many of the insulators on this line are also original equipment and are nearing the end of their service lives.

The existing conductors are small by current standards and the steel core of each conductor shows evidence of corrosion which reduces the physical strength and electrical capacity of the conductor.

Appendix A contains topographic views of each of the lines to be rebuilt and Appendix B contains photographs of the existing lines.

2.1 Transmission Line 43L

43L is a 66 kV transmission line built in 1956. The line runs between Heart's Content Substation and New Chelsea Substation on the Bay de Verde Peninsula. It is a radial line, 25.1 kilometres in length and is of H-frame wood pole construction. The line serves over 2,500 customers in the New Chelsea to Old Perlican area. The Company's New Chelsea hydro plant is connected to the main electrical grid through this line.

Because of the age, design, and location of this line, it is prone to cascading failure. If one structure fails, there is risk that the additional loading placed on adjacent structures will cause a chain reaction of multiple structure failures.

As part of the 2005 Capital Program, the Company rebuilt an 8.0 kilometre section of 43L. In 2006, an additional 12.0 kilometres will be rebuilt. Based on the overall deteriorated condition of the remaining section of line, it is recommended that the remaining 5.1 kilometres of line be rebuilt in 2007. The estimated cost to complete the required work is $570,000. The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

2.2 Transmission Line 110L

110L is a 66 kV transmission line originally built in 1958. The line runs between Clarenville Substation and Lockston Substation on the Bonavista Peninsula. The line is 79 kilometres in length and is of single wood pole construction. The line serves approximately 6,000 customers on the Bonavista Peninsula between Milton and Lockston. This line also connects the Company's Lockston hydro plant to the main electrical grid.

The conductor on this line is damaged and deteriorated in many places. The steel core shows evidence of rust and the aluminium strands are corroded which reduces the physical strength and the electrical capacity of the conductor. The conductor has deteriorated to the point that the line has been de-rated to about one-half of its original load carrying capacity due to concern that the conductor will burn off and fall to the ground.

Since 2001, there have been several outages on this line due to wind and ice conditions causing conductors to slap together. This results in conductor damage and often conductor failure. The most recent occurrences happened in December 2003 and April 2004 when ice build-up on overhead conductors caused the line to fail resulting in outages to customers.

The majority (43.4 kilometres) of the existing line is original 1958 construction. In 1966, 17.4 kilometres of the line was upgraded and between 1972 and 1974, an additional 18.2 kilometres was upgraded. Currently, the most deteriorated sections of the line are along the 21 kilometres that extends between the Company's Lockston substation and Summerville substation. As part of the 2006 Capital Program, the Company will be rebuilding 6.7 kilometres of this section. Based on the condition of this line, it is recommended that the remaining 14.1 kilometres of 110L between Lockston and Summerville substations be rebuilt in 2007 at an estimated cost of $1,311,000.

The report *Bonavista Loop Transmission Planning*, filed with Newfoundland Power's 2006 Capital Budget Application, compared alternatives for addressing transmission line requirements on the Bonavista Peninsula. The analysis determined that the rebuilding of 110L, as recommended in this report, is the most cost-effective alternative to ensure the continued provision of safe, reliable electrical service.

2.3 Transmission Line 20L

20L is a 66kV transmission line built in 1951. The line runs between Mobile Substation and Cape Broyle Substation on the Southern Shore of the Avalon Peninsula. It is a radial line 20.1 kilometres in length and is of H-frame wood pole construction. It serves over 1,700 customers in the Cape Broyle area. The local load includes customers serviced through Cape Broyle Substation and extends south to those serviced through Fermeuse Substation. The line also serves as the connection to the main electrical grid for the Company's Morris, Rocky Pond, Horsechops, and Cape Broyle hydro plants.

Because of the age, design, and location of this line, it is prone to cascading failure. If one structure fails, there is risk that the additional loading placed on adjacent structures will cause a chain reaction of multiple structure failures. Some repairs have been made over the years to extend the life of the line. Due to the temporary nature of these repairs, there has not been any substantial improvement to the overall integrity of the line.

Based on the overall deteriorated condition of the line, it is recommended that the entire line be rebuilt with a 7.5 kilometre section to be rebuilt in 2007. The estimated cost of this work is $687,000. The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

Appendix A

Topographic Maps of Transmission Lines 43L, 110L and 20L

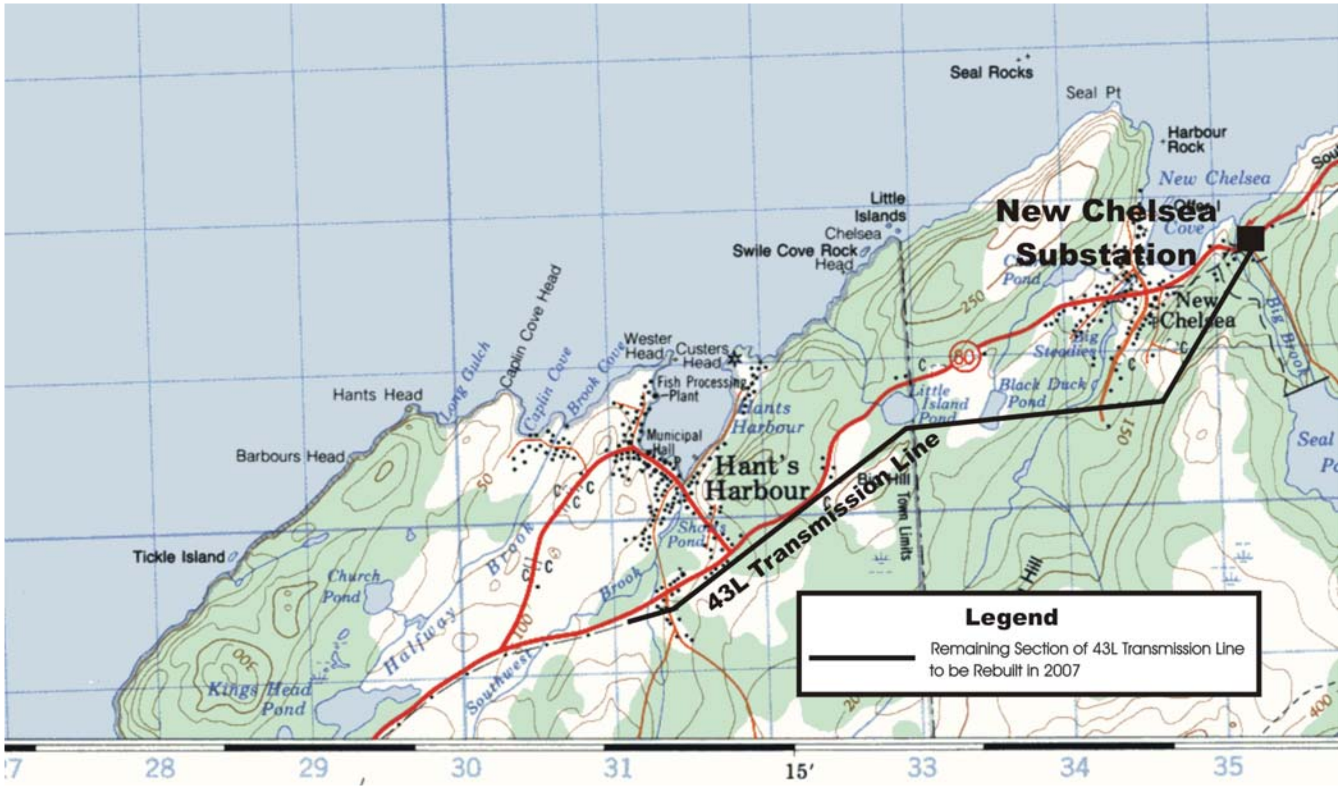

Figure 1 - Topographic Map 43L

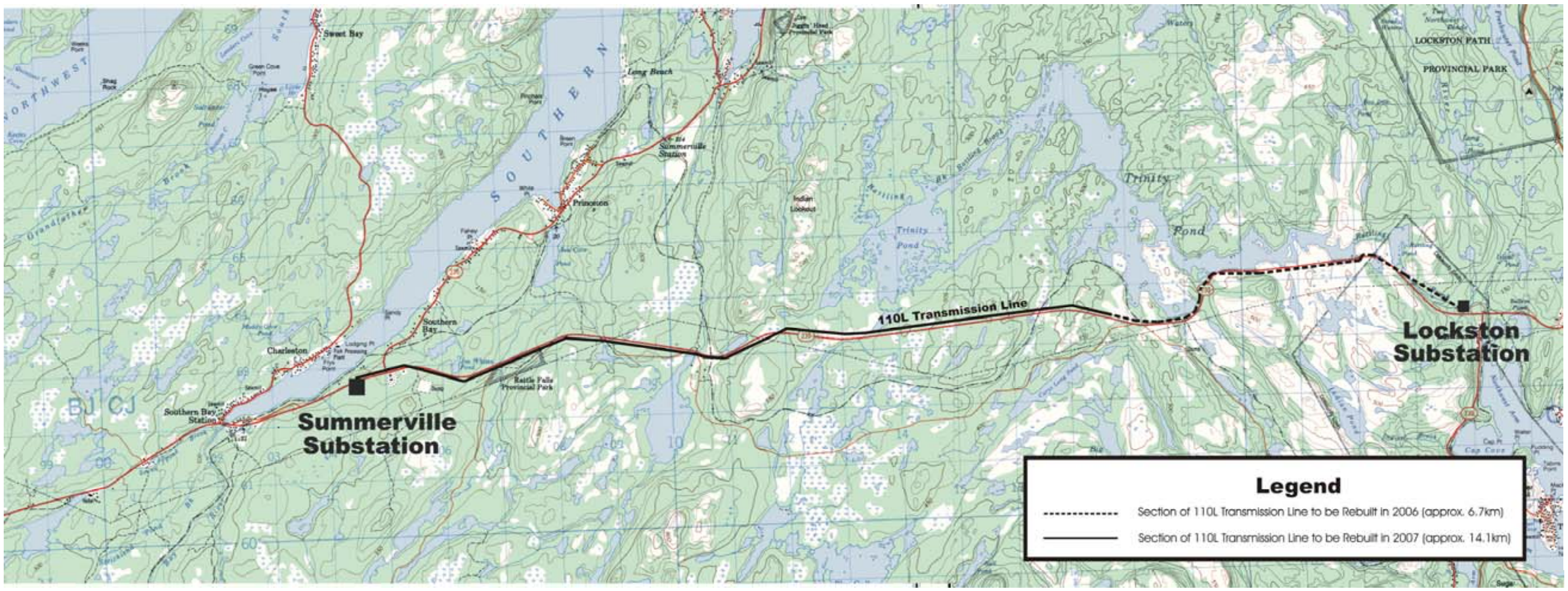

Figure 2 – Topographic Map 110L

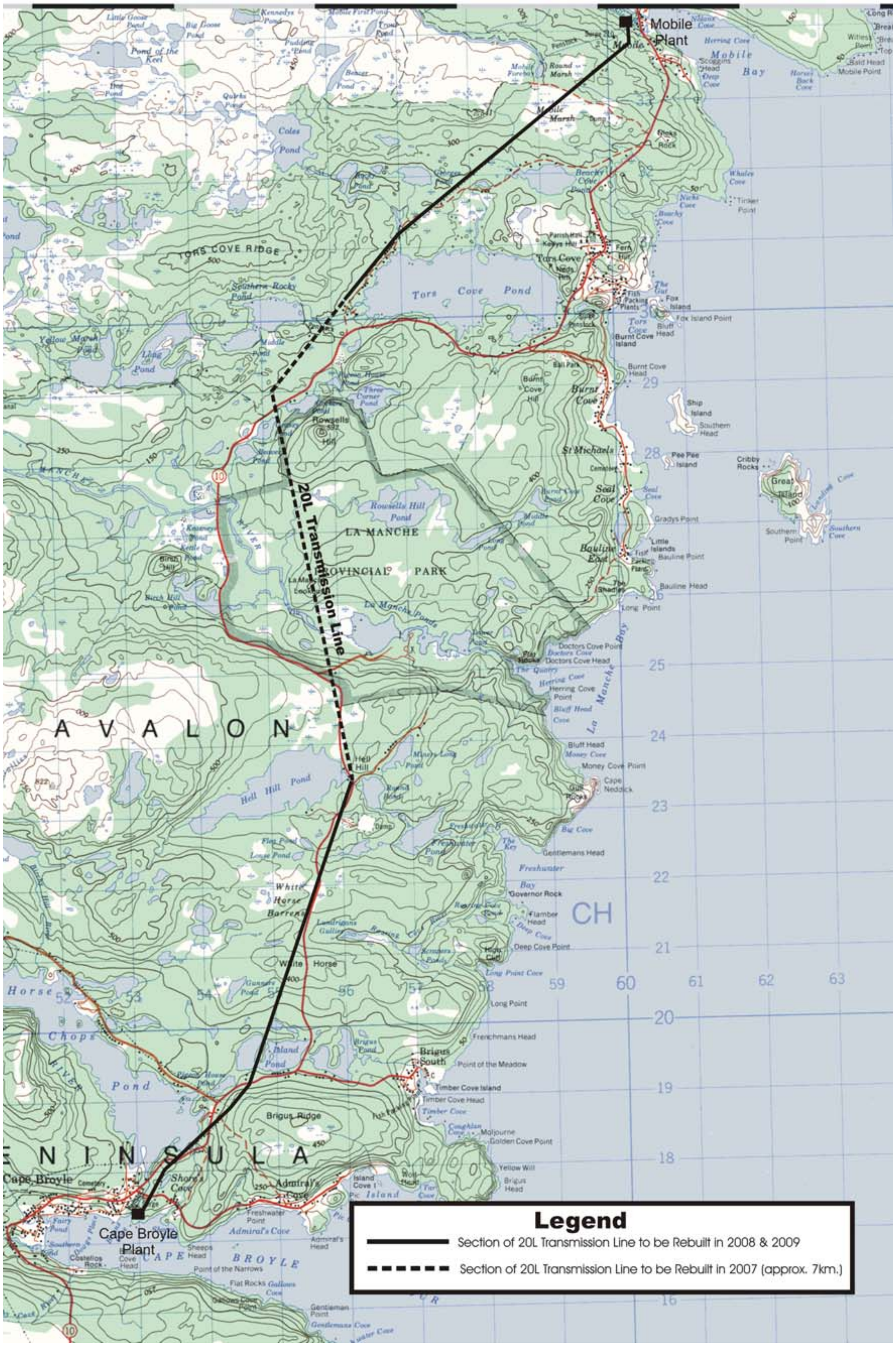

Figure 3 – Topographic Map 20L

Appendix B

Photographs of Transmission Lines 43L, 110L and 20L

Figure 1 - Rusty guy wire 43L

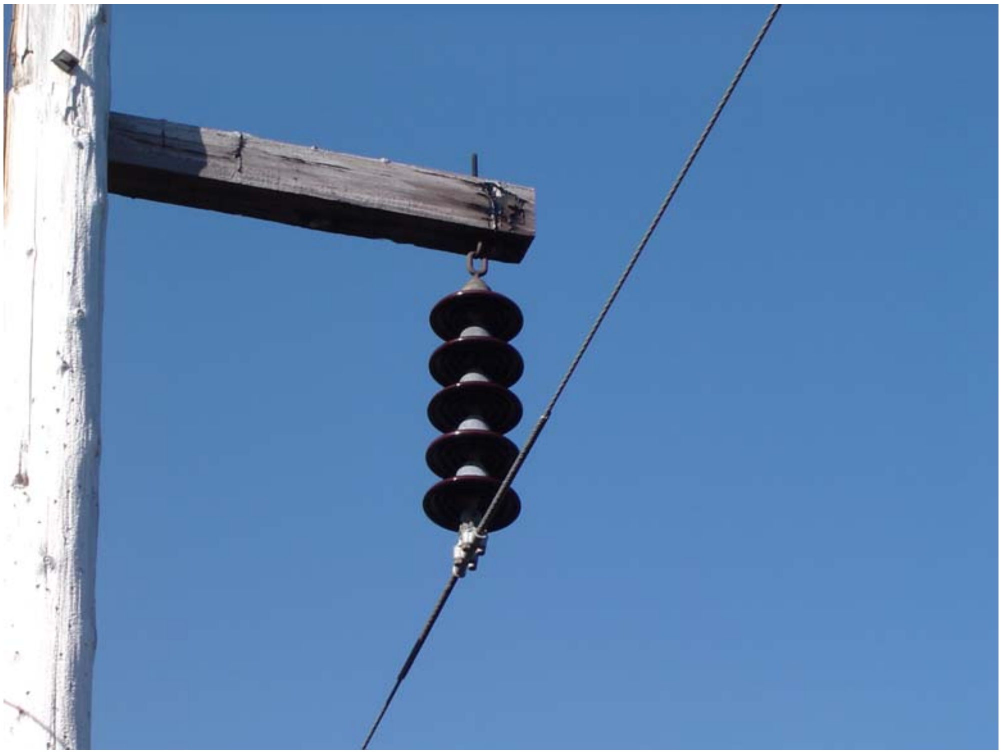

Figure 2 - Old insulators 43L

Figure 3 - Deteriorated cribs 43L

Figure 4 - Woodpecker damage 43L

Figure 5 - Deteriorated pole (ant damage) 43L

Figure 6 - Ice Storm Damage December 2003 110L

Figure 7 - Broken conductor - ice build up December 2003 110L

Figure 8 - Deteriorated pole 110L

Figure 9 - Deteriorated pole 110L

Figure 10 - Temporary Repair 20L

Figure 11 - Erosion 20L

Figure 12 - Old Insulators 20L

Figure 13 - Deteriorated Poles (top split) 20L

Kenmount Road Office Building
HVAC System Replacement

March 2006

Prepared by:
Trina Cormier, B.Eng

Approved By:
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1.0 Introduction

The Kenmount Road office building is the corporate head office for Newfoundland Power and is the workplace for 172 employees. The building serves as the primary office for the following departments: Information Services, Human Resources, Safety, Environment, Finance, Engineering, Regulatory Affairs and Company Executive.

The Kenmount Road office building was built in 1968 as a two storey structure with one air handling unit that serviced both floors. In 1979, two additional floors were added to the building with each floor having its own air-handling system. These systems are now 38 and 26 years old respectively.

Due to the age, condition and operational issues with the HVAC (heating, ventilation and air-conditioning) systems at Kenmount Road, Newfoundland Power retained the consulting services of Newton Engineering (2005) Limited ("NEL"). NEL evaluated the HVAC systems and provided recommendations for their upgrade or replacement to address issues and improve energy efficiency. The report prepared by NEL is contained in Appendix A.

Newfoundland Power completed a feasibility analysis based on the alternatives provided by NEL. It is recommended that the ground floor/first floor HVAC be replaced in 2007 with a Ground Source Closed Loop Heat Pump System. This system has the lowest net present value and is the most energy efficient replacement alternative for the HVAC system. This system will reduce the total building energy consumption by 441,000 kWh and demand by 100 kVA.

2.0 Existing HVAC System

The Kenmount Road building consists of three air-handling systems which provide general ventilation and air-conditioning for the entire complex[1]. The ground and first floor system was installed in 1968 and is serviced by one air-handling unit. The second and third floors have their own air-handling systems which were installed in 1979.

2.1 Ground Floor/First Floor System

The ground floor/first floor system was designed for the original building in 1968 as a multi-zone system. This multi-zone system was modified in 1985, changing it to a Variable Air Volume ("VAV") system. The current control system partially utilizes the pneumatic system originally installed and a Direct Digital Control ("DDC") system that was installed in 1985.

This HVAC system is approximately 38 years old and requires replacement for the following reasons:

- The current air handling system is inefficient and results in high operational costs and wasted energy.

[1] The computer room has a dedicated air-conditioning system which is not a subject of this report.

- The system is at the end of its useful life and it is expected that maintenance costs will increase in the near future.
- The system design which utilizes “dumping boxes” results in comfort problems. Certain areas of the building are too cold during the winter and other areas are too warm in the summer which has been intolerable for staff at times.
- The washroom exhaust system does not have a heat recovery system, which results in wasted energy to constantly heat the fresh air coming into the system.
- The cooling system uses Freon R-22 refrigerant which is not environmentally friendly and is scheduled to be phased out of commercial equipment by 2010.

2.2 Second Floor/Third Floor System

With the addition of the second and third floors in 1979, a VAV air handling system was installed on each floor. Each floor has its own air handling unit, humidifier and control systems and share a common condenser and liquid cooler. The controls for this system are also pneumatic with modifications made to it to introduce a DDC interface.

This HVAC system is approximately 26 years old and is considered to be in fair condition. With upgrades, this system should be able to provide several years of reliable service.

The operational concerns with this system are as follows:

- Some components of this system such as the humidifier have exceeded expected service life and will require replacement.
- The air handling unit static pressure controller is a motorized damper which does not provide the accurate control needed in a VAV system.
- The system does not have a return air fan which results in poor air circulation and the inability to provide free cooling when outdoor conditions permit.
- The system is not balanced due to building modifications that have taken place since 1979.
- Washroom exhaust system does not have a heat recovery system, which results in wasted energy to constantly heat the fresh air coming into the system.
- The cooling system uses Freon R-22 refrigerant which is not environmentally friendly and is scheduled to be phased out of commercial equipment by 2010.

3.0 Alternatives

The ground floor/first floor system is in poor condition and is not energy efficient. It has reached the end of its useful life and will be replaced in 2007. Replacement with an energy efficient system is preferable.

NEL provided three replacement alternatives for Newfoundland Power to consider for the existing system on the ground floor/first floor. These alternatives include:

- Upgrade the existing system utilizing the VAV system approach;

- Install a new Closed Loop Heat Pump System ("CLHP"); or
- Install a new Ground Source Closed Loop Heat Pump ("Ground Source CLHP") System.

A detailed description of each alternative is located in Appendix A.

The second floor/third floor system is in fair condition. Upgrades or replacement of the second floor/third floor system should be reviewed again in 2008. At that time, deficiencies noted in the NEL report should be addressed and a review completed to determine if replacement of the system with a more energy efficient option is feasible at that time.

4.0 Economic Analysis

An economic analysis was completed by Newfoundland Power to determine the most feasible alternative for the replacement of the ground floor/first floor system. The capital and annual costs used in the analysis for each alternative were provided by NEL and are based on their research and experience in designing and installing these types of systems. The annual cost for each alternative was determined based on energy, demand and maintenance costs associated with each alternative.

An economic analysis of the alternatives was performed using the net present value ("NPV") of the revenue requirement method (customer cash flow) for a 25 year period. The results are provided in Table 1.

Table 1
Ground Floor/First Floor Replacement Alternatives

	VAV	**CLHP**	**Ground Source CLHP**
Construction Cost	$ 350,000	$ 460,000	$ 528,000
Engineering Cost	42,000	55,000	62,000
Internal Labour Cost	20,000	20,000	20,000
Total Capital Cost	412,000	535,000	610,000
Total Annual HVAC Energy Cost[2]	29,172	20,321	7,875
Total Annual Maintenance Cost	7,175	8,700	8,175
NPV @ 25 Years	**$ 948,815**	**$ 987,871**	**$ 897,437**

Table 1 shows that the economic analysis results favour the Ground Source CLHP system. The detailed NPV calculations are located in Appendix B of this report.

2 Annual HVAC Energy is based on $6.64/kW/month for demand as approved by the Public Utilities Board in Order No. P.U. 44 (2004) and $0.067/kWh for energy published as the maximum energy rate Newfoundland and Labrador Hydro will accept for displacing Holyrood generation in the *Wind Generation RFP* .

In addition to having the lowest NPV, the Ground Source CLHP System has the following additional benefits:

- It has the lowest energy cost, reducing the annual energy cost of the existing ground floor/first floor system from approximately $37,415 to $7,875, with a reduction of approximately 441,000 kWh per year.
- It will reduce the building connected electrical load since it only requires one unit of electrical energy to produce three units of heat output. This translates into an overall estimated demand reduction for the ground floor/first floor system by approximately 100kVA.

5.0 Recommendation

Based on the economic analysis, and the energy cost and demand benefits associated with the system, it is recommended to replace the ground floor/first floor system with a Ground Source CLHP system. This system is also the most energy efficient option.

The second floor/third floor systems should be evaluated again in 2008 to determine the best methods to address system concerns. As part of the detailed analysis it should be determined if a more energy efficient replacement option is feasible at that time. It is recommended that replacement or upgrading of the second floor/third floor systems occur in 2009.

Appendix A

Newton Engineering Ltd. (2005)
HVAC Systems Analysis
NF Power Corporate Building
Kenmount Road, St. John's

HVAC Systems Analysis

NF Power Corporate Building
Kenmount Road, St. John's

Completed by:

Newton Engineering Limited 2005

Client:

NEWFOUNDLAND POWER
A FORTIS COMPANY

Date:
March 2006

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1.0 INTRODUCTION

Newton Engineering(2005) Limited(NEL) was retained by Newfoundland Power to re-evaluate the heating, ventilation and air-conditioning (HVAC) systems for the Kenmount Road office building. The first review of the system was completed in 1999 and the scope of this report includes updating capital cost estimates and energy consumption estimates for various replacement options. This evaluation will also outline the existing equipment and systems, their condition, and provide recommendations detailing upgrades based on cost, energy, and comfort.

Andrew Small, P. Eng., from NEL has visited the site on several occasions and has reviewed drawings that were available. This report will provide the Owner with an update as to the operation of the various systems and their conditions. Replacing the existing system components will be discussed and options for replacing the entire HVAC system with a much more energy efficient model will also be evaluated.

The Kenmount Road office building was built in 1968 as a two storey structure, consisting of a ground and first floor. One air-handling unit serviced these two floors with electric heat as the primary heat source. In 1979 two more floors were added and each floor was provided with its own air-handling system and again heated electrically. The total building contains approximately 4800 square meters of space.

2.0 DESCRIPTION

2.1 Existing H.V.A.C. System

The existing building consists of three existing air-handling systems, which provides both ventilation and air-conditioning for the entire complex, except for a special dedicated system, which serves the lower level computer room. These three systems are as follows:

1. Ground Floor/First Floor System - installed in 1968.
2. Second Floor System - installed in 1979.
3. Third Floor System - installed in 1979.

2.2 Ground Floor/First Floor System

The system designed for the original building in 1968 is commonly known as a multi-zone system, which consists of an air-handling unit, complete with a supply air fan, heating deck, cooling deck, return air fan, filters, mixing box and pneumatic control system. The system heating is generated using an electric heating coil and the cooling is obtained from what is generally referred to as a DX (Direct Expansion) system using refrigerant gas, compressors, condensers and cooling coils.

A multi-zone system is designed to control several unique zones in a building which have their own supply air duct and distribution. A temperature controller (thermostat) in a particular zone will call for either cooling or heating. This will operate a damper system in the air handling unit to supply either cold air or hot air to this particular zone from the cold deck or hot deck. Multi-zone systems were used frequently during this period of time until variable air volume (V.A.V) systems became more popular.

This multi-zone system was modified in 1985 to become a V.A.V. system. Changes were made to the unit and to the duct system in order to have this system installed. The V.A.V. system supplies conditioned air to V.A.V. boxes located in separate zones throughout the building. A thermostat in a zone will then control the air flow from a V.A.V. box. On a call for cooling, the maximum air will flow from a box and on a call for heating the box will supply a minimum air flow. V.A.V. systems are generally used in most environmentally controlled office spaces today. However, the type of V.A.V. boxes used here are dumping boxes, which means that any excess air not required for cooling is dumped into the ceiling space. This dumped excess air generally pressurizes the space above the ceiling tiles with cold air. A return fan located in the basement mechanical room pulls air from the ceiling space, exhausts a small portion and recycles the rest through the air handling unit.

The controls for this system have two components, the original pneumatic system, and a Direct Digital Control (D.D.C) computerized control system which has been added to control some aspects of the HVAC systems. The control system for this unit utilizes what is referred to as a free cooling option. This option allows outside air to be used to provide free cooling when needed provided outside conditions will allow it. The space control temperature has thermostats controlling V.A.V. boxes which will vary the air flow from a maximum position on a call for cooling to a minimum position on a call for heating. However, on a call for heating, a second stage of control will energize an electric baseboard heater in a particular zone.

As part of the ventilation system, the first two floors also have a number of washrooms which are provided with dedicated exhaust systems. These systems exhaust air directly to the exterior using roof mounted fans and were extended to the new roof after the extension occurred in 1979.

2.3 Second Floor/Third Floor System

The building's addition in 1979 added two floors to the building with separate air-handling V.A.V. systems. These systems consist of indoor air handling units with supply fans, electric heating coils, chilled water cooling coils, filters, mixing boxes and control systems. Cooling was achieved using a chilled water system which supplies chilled water to a cooling coil in each unit. The chilled water system consists of a roof mounted air-cooled condensing unit and a liquid cooler located in the third floor mechanical room.

The conditioned air from these units supplies air to V.A.V. boxes located throughout the space for various zones. The V.A.V. boxes in this case are ***NOT*** bypass boxes, but are referred to as true V.A.V. boxes. They are positioned to vary the air flow, however, as these boxes are controlled in a minimum position, the static pressure in the duct system rises. As the static pressure increases, a static pressure controller will decrease the air flow from the air-handling unit.

The controls for this system are also a pneumatic system modified to introduce a D.D.C interface. The system however does not have a free cooling cycle like the older units on the ground/first floor. This system does not have a return air fan to allow the removal of the total air to take advantage of free cooling when available.

These floors also have dedicated exhaust fans for washrooms, but in this case these fans provide the relief for the excess fresh air being introduced into the system from the air handling systems. The amount of fresh air being introduced into this system is equal to the capacity of the washroom exhaust system.

3.0 OPERATIONAL OBSERVATIONS

3.1 Ground Floor/First Floor System

As described earlier, the 38-year-old air-handling system for these two floors is a multi-zone air-handling system converted to V.A.V. operation using V.A.V. dumping boxes. Below are the main issues surrounding this system:

- The air-handling unit basically supplies a constant volume of air regardless of cooling need. This leads to wasted energy due to the fan running at full capacity even when the cooling loads are low.

- The V.A.V. boxes are dumping boxes, which are not recommended for large areas because they tend to cause cool pressurized ceiling spaces. This system is often responsible for comfort problems due to cold air dropping through return grilles and openings in the ceiling.

- The distribution of supply and return grilles, the zone airflows, and the number of V.A.V. boxes are not ideally balanced within the spaces because of changes to the building layouts that have occurred since the initial installation.

- The washroom exhaust system exhausts air directly to the exterior and does not have a heat recovery feature which would recover at least 60% of the energy contained in the warm exhaust air.

- The cooling system is operated using Freon R-22 refrigerant which is not considered an environmentally friendly refrigerant agent. This refrigerant is due to be phased out of commercial air conditioning equipment by the year 2010.

- This system is at the end of it’s useful life and is generally in poor condition. It is expected that maintenance costs and reliability will cause problems in the near future.

- The fresh air dampers in the main air handling unit recently had to be changed due to excessive corrosion which implies that corrosion problems may be more extensive in other unit components.

- There are numerous comfort issues within the spaces due to the poor system layouts and operation.

3.2 Second/Third Floor System

These systems, as described earlier, are approximately twenty six years old and considered to be acceptable. However, we have identified several problems with the system:

- The air-handling unit static pressure controller is a motorized damper, which does not provide the accurate control needed in a V.A.V. system.

- The system does not have a return air fan which results in poor air circulation and the inability to provide free cooling when outdoor conditions permit.

- The distribution of supply and return grilles, the zone airflows, and the number of V.A.V. boxes are not ideally balanced within the spaces because of changes to the building layouts that have occurred since the initial installation.

- The washroom exhaust system exhausts air directly to the exterior and does not have a heat recovery feature which would recover at least 60% of the energy contained in the warm exhaust air.

- The refrigerant used is Freon R-22, which is not considered an environmental friendly refrigerant agent. This refrigerant is due to be phased out of commercial air conditioning equipment by the year 2010.

- There are comfort issues experienced with these systems, however not to the degree of the lower two floors.

4.0 EQUIPMENT DESCRIPTION

Following is a list and description of the major equipment being used for the three air-handling systems. We reviewed the condition of the equipment and discussed its operation with maintenance personnel.

4.1 Ground Floor/First Floor System (H.V.A.C Equipment)

- **Air Handling Unit** - Carrier 39E, Size 21. This unit is approximately 38 years old and has been changed from a multi-zone to a single zone unit. The unit itself, the housing, fans and filters, are in reasonably good condition. However, other components such as motors, v-belt drives, dampers, heating and cooling coils are subject to breakdowns and failures after a 25 year life cycle. This unit should be replaced with a properly designed V.A.V. unit. This system, although its physical appearance looks reasonably good, it is approaching the end of it's life.

- **Return Fan** - Woods Fans, Model EMM68 is an inline tubular fan. The fan and its housing is in good condition, but 38 years old has outlived its service life and should be replaced with a V.A.V. controlled fan.

- **Humidifier** - Nortec NHB-100. The humidifier is also 38 years old and in our opinion has exceeded its useful life and should be replaced.

- **Controls** - The control system is a combination of pneumatics and D.D.C which have been reasonably upgraded and are sufficient for today's use. The only real concern with the controls is their inability to directly control/monitor some of the equipment due to the pneumatic control interface.

4.2 Second Floor System (H.V.A.C Equipment)

- **Air Handling Unit** - Carrier Model 39ED21. The unit is approximately 26 years old and is commonly referred to as a built-up unit consisting of a fan section, cooling and heating coil section, a filter section and a mixing box. Similar to the ground floor unit, the housing (casing) looks to be in reasonably good condition, but working parts such as motors, v-belts, bearing, dampers, heating and cooling coils are all subject to breakdowns and failures after 25 years. This system, although its physical appearance looks reasonably good, it is approaching the end of it's life.

- **Humidifier** - Nortec Model #ES400. This electric humidifier is 26 years old and in our opinion has lived its useful life.

- **Controls** - The controls system is a combination of pneumatic and D.D.C. The system appears to be adequate, however we would recommend replacing the pneumatic controls with D.D.C. devices.

4.3 Third Floor System (H.V.A.C Equipment)

- **Air Handling Unit** - Carrier Model 39ED21. The unit is approximately 26 years old and it is commonly referred to as a built-up unit consisting of a fan section, cooling and heating coil section, a filter section and a mixing box. Similar to the ground floor unit, the housing (casing) looks to be in reasonably good condition, but working parts such as motors, v-belts, heating and cooling coils are all subject to breakdowns and failures after 25 years. In our opinion this system is in reasonably good condition and if maintained can operate efficiently for another 10 to 15 years.

- **Humidifier** - Nortec Model #ES400. This electric humidifier is 26 years old and in our opinion has lived its useful life.

- **Controls** - The controls system is a combination of pneumatic and D.D.C. The system appears to be adequate for today's needs and can be reused, however we would recommend replacing the pneumatic controls with D.D.C. devices.

4.4 Cooling System

There are two condensing units on the roof; one serves the air-conditioning for the ground floor while the other serves the chiller for the units on the second/third floors. A chiller is also located on the third floor.

4.4.1 Ground Floor Condensing Unit

The condensing unit serving the ground floor air handling unit is a Carrier Model 38AB-064400, located on the roof. The unit is 38 years old and is showing signs of aging with rusting occurring around the housing. This unit supplies Freon R-22 to a direct expansion cooling coil in the unit. The system is nearing the end of its useful life and should be replaced. As well Freon R-22 refrigerant, is ***not*** considered an environmentally friendly agent.

4.4.2 Second/Third Floor Units

This Carrier Model 38AE-004 condensing unit is also located on the roof and provides cooling to a liquid cooler located in the third floor Mechanical Room. This unit is not rusting as badly as the ground floor unit but is nearing the end of useful life.

4.4.3 Liquid Cooler

This Carrier chiller is located in the third floor Mechanical Room. This unit looks to be in good condition and has operated effectively for the past 26 years. However, it is nearing the end of its useful life.

5.0 RECOMMENDATIONS

The existing systems as described are at or very close to the end of their useful lives and several system options are available for replacement and upgrading. Energy costs for various systems will also be estimated using Carrier hourly analysis software. These operating costs can then be used to determine paybacks periods for the higher capital cost options.

Three system options are considered in the following analysis. Each of these options have some unique features from the other, especially with capital cost considerations. The three options we offer for consideration are as follows:

- Upgrade the existing systems utilizing the V.A.V. system approach
- Install a new Closed Loop Heat Pump System - conventional
- Install a new Ground Source Closed Loop Heat Pump System

5.1 Upgrade the Existing System (Option 1)

The recommended upgrades to the existing system will address problems and concerns that were raised in our observations. It will also bring the system up to today's indoor air quality standards.

- Replacing the air-handling unit for the ground/first floors.
- Replace all V.A.V. dumping boxes that exist on the ground/first floors.
- Add a new chilled water cooling system for all units.
- Revamp the duct system with an upgrading of the air distribution system and additional V.A.V. boxes.
- Add return air fans to the second and third floor units to enable proper air control and free cooling.

- Adjust air flow from V.A.V. boxes to meet today's fresh air requirements.
- Add variable frequency drive fan speed controllers to the air distribution system to control static pressure.
- Add a heat recovery unit for all washroom exhaust systems.
- Revamp the control system to add CO_2 sensors for fresh air control.

5.2 Closed Loop Heat Pump System (Option 2)

A more energy efficient system suited to this application is a closed loop heat pump system (CLHP). This system operates on the principle of moving heat around a building. If a space needs cooling because of equipment loads or solar loads, the heat from these areas is transferred to other areas needing heating. The transfer is achieved using water piping connecting water-to-air heat pumps strategically located throughout the ceiling space. Each heat pump would be considered a zone for a particular office or group of offices, and it supplies a constant volume of air flow to the space. If additional heat is needed in the system (winter), than an electric boiler will provide heat as required and conversely if heat is must be rejected (summer), then a cooling tower will remove excess heat from the system.

This system will provide both the heating and cooling while the introduction of fresh air will be achieved using a heat recovery system. The heat recovery unit will introduce 100% outside air into the ceiling space at or near the heat pumps. The return air will be extracted from the washrooms or from general areas to be exhausted through the heat recovery unit. The heat recovery unit will extract approximately 60% of the heat from the exhaust air.

5.3 Ground Source Heat Pump System (Option 3)

This system is very similar to the CLHP system described in 5.2, but the key difference lies in the heat source and heat sink. Piping installed in drilled wells provides the needed heat in winter and also provide the means to reject heat in the summer. Even though the temperature of the ground wells is 7.2°C there is sufficient heat available to heat this building. The low ground temperature also provides almost free cooling throughout the summer regardless of the outdoor temperatures. To prevent freezing an environmentally friendly food grade anti-freeze solution is used in the circulation loop between the building and the multiple wells. A heat exchanger will transfer the heat gained from the wells to the building loop where the heat pumps will then operate to cool or heat the spaces.

This system has the lowest energy costs of all conventional building heating and cooling systems and is a proven system. There are numerous buildings throughout the city, which are served by a ground source heat pump system. Another advantage is the reduction in the building connected electrical load as the ground source heat pump requires only one unit of electrical energy to produce 3 units of heat output. This translates into an overall estimated demand reduction for the building of approximately 200kVa.

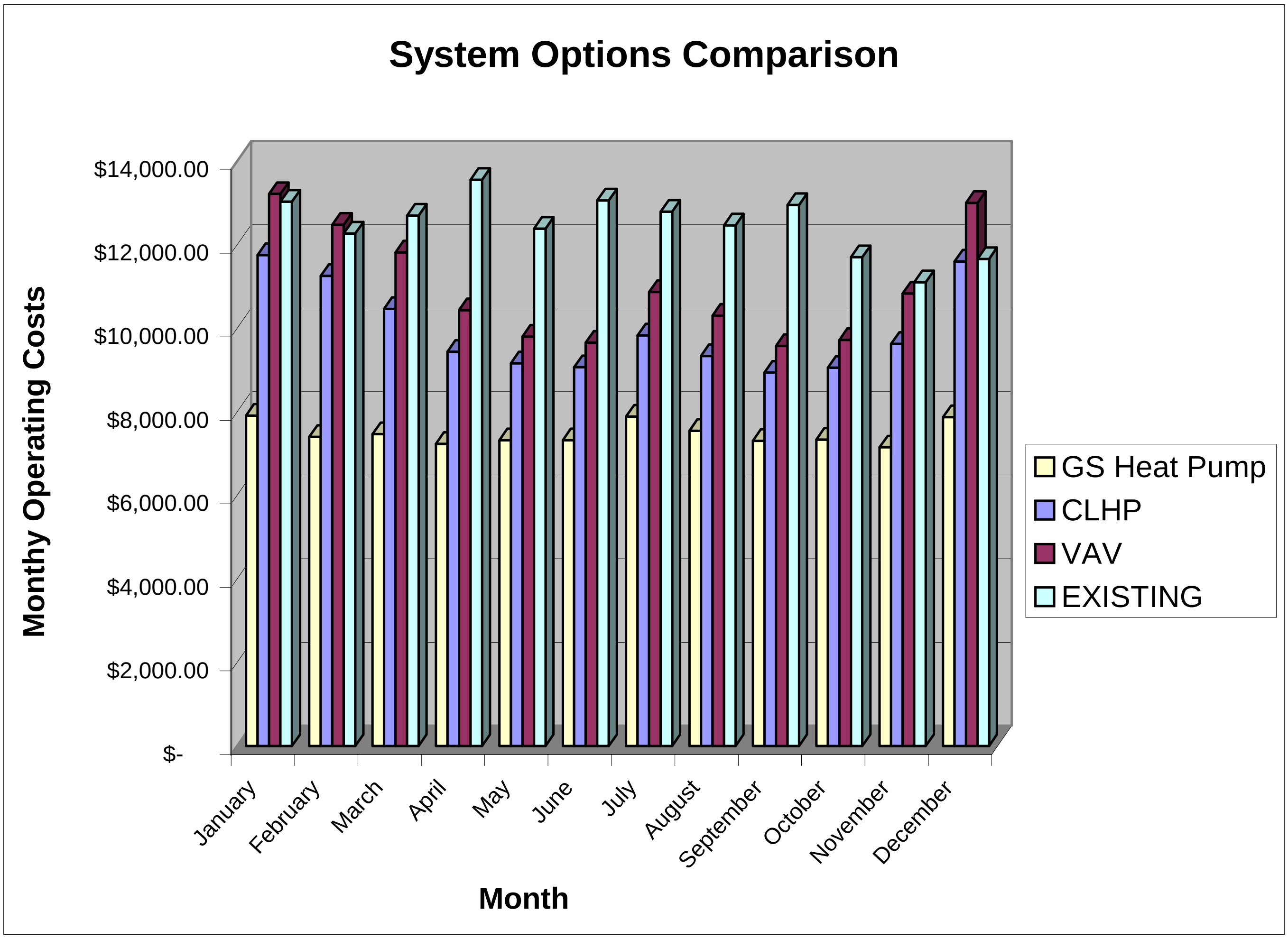
6.0 OPERATING AND CAPITAL COSTS

The estimated operating and budget capital costs for a V.A.V., CLHP and ground source systems are provided in the table below with the energy model summary provided in Attachment A. The electric energy costs calculated are based on an energy rate of 6.7 ¢/kWh while the demand rates are calculated using $6.64/kVa. The operating costs given below are estimates of the energy consumption of the systems options as described in section 5.0 including the savings associated with upgrades to the existing lighting systems. The maintenance costs associated with each system is also considered and provided in the analysis table.

Component	New V.A.V. System	C.L.H.P.	Ground Source Heat Pumps
LEVEL 1 AND 2 SYSTEMS			
Est. Demolition Costs (Level 1&2)	$35,000	$35,000	$35,000
Est. Construction Costs (Level 1&2)	$350,000	$460,000	$528,000
Est. Engineering Costs (Level 1&2)	$42,000	$55,000	$62,000
Total Est. Capital Costs (Level 1&2)	**$427,000**	**$550,000**	**$625,000**
LEVEL 3 AND 4 SYSTEMS			
Est. Demolition Costs (Level 3&4)	$20,000	$35,000	$35,000
Est. Construction Costs (Level 3&4)	$210,000	$460,000	$528,000
Est. Engineering Costs (Level 3&4)	$20,000	$55,000	$62,000
Total Est. Capital Costs (Level 3&4)	**$250,000**	**$550,000**	**$625,000**
TOTAL Est. Annual Building Energy Costs	**$131,701.00**	**$119,534.00**	**$89,730.00**
TOTAL Est. Annual HVAC Energy Costs	**$58,344.00**	**$40,642.00**	**$15,750.00**
Estimated Annual Maintenance Costs	**$14,350.00**	**$17,400.00**	**$16,350.00**

The current energy consumption and demand levels are provided in Attachment B for the previous 12 months. These costs were determined using 6.7 ¢/kWh and $6.64/kVa Maintenance costs estimates are based on ASHRAE 2003 Applications Handbook.

Attachment A
Energy Analysis Summary


System Options Comparison
Monthy Operating Costs
$14,000.00
$12,000.00
$10,000.00
$8,000.00
$6,000.00
$4,000.00
$2,000.00
$-
January
February
March
April
May
June
July
August
September
October
November
December
Month
GS Heat Pump
CLHP
VAV
EXISTING

Estimated Energy Consumption
Variable Air Volume System

NF Power Corporate Building
Kenmount Road

Date	Demand	Energy	Demand Cost*	Energy Cost	Total Monthly
January	468	150477	$ 3,134.08	$ 10,081.96	$ 13,216.04
February	472	139484	$ 3,134.08	$ 9,345.43	$ 12,479.51
March	423	129576	$ 3,134.08	$ 8,681.59	$ 11,815.67
April	395	108959	$ 3,134.08	$ 7,300.25	$ 10,434.33
May	361	99544	$ 3,134.08	$ 6,669.45	$ 9,803.53
June	358	97313	$ 3,134.08	$ 6,519.97	$ 9,654.05
July	408	115432	$ 3,134.08	$ 7,733.94	$ 10,868.02
August	389	106965	$ 3,134.08	$ 7,166.66	$ 10,300.74
September	361	96148	$ 3,134.08	$ 6,441.92	$ 9,576.00
October	359	98280	$ 3,134.08	$ 6,584.76	$ 9,718.84
November	400	114903	$ 3,134.08	$ 7,698.50	$ 10,832.58
December	453	147290	$ 3,134.08	$ 9,868.43	$ 13,002.51
		Totals	**$ 37,608.96**	**$ 94,092.86**	**$ 131,701.82**

Total Annual Estimated Energy/Demand Cost: $ 131,701.82

Notes:

1. Using: $6.64/kVa for demand and $0.067/kWh for energy costs
2. * Demand based on highest monthly demand(ie. 472kVa)
3. Estimates include all loads including lighting, computers, equipment, etc.

Estimated Energy Consumption Closed Loop Heat Pump NF Power Corporate Building Kenmount Road					
Date	**Demand**	**Energy**	**Demand Cost***	**Energy Cost**	**Total Monthly**
January	479	125077	$ 3,373.12	$ 8,380.16	$ 11,753.28
February	508	117638	$ 3,373.12	$ 7,881.75	$ 11,254.87
March	405	105764	$ 3,373.12	$ 7,086.19	$ 10,459.31
April	369	90536	$ 3,373.12	$ 6,065.91	$ 9,439.03
May	318	86415	$ 3,373.12	$ 5,789.81	$ 9,162.93
June	281	85048	$ 3,373.12	$ 5,698.22	$ 9,071.34
July	304	96416	$ 3,373.12	$ 6,459.87	$ 9,832.99
August	293	88995	$ 3,373.12	$ 5,962.67	$ 9,335.79
September	282	83015	$ 3,373.12	$ 5,562.01	$ 8,935.13
October	301	84771	$ 3,373.12	$ 5,679.66	$ 9,052.78
November	363	93358	$ 3,373.12	$ 6,254.99	$ 9,628.11
December	450	122773	$ 3,373.12	$ 8,225.79	$ 11,598.91
		Totals	**$ 40,477.44**	**$ 79,047.03**	**$ 119,524.47**

Total Annual Estimated Energy/Demand Cost: **$ 119,524.47**

Notes:

1. Using: $6.64/kVa for demand and $0.067/kWh for energy costs
2. * Demand based on highest monthly demand(ie. 508kVa)
3. Estimates include all loads including lighting, computers, equipment, etc.

Estimated Energy Consumption
Ground Source Heat Pump
NF Power Corporate Building
Kenmount Road

Date	Demand	Energy	Demand Cost*	Energy Cost	Total Monthly
January	304	85256	$ 2,197.84	$ 5,712.15	$ 7,909.99
February	331	77618	$ 2,197.84	$ 5,200.41	$ 7,398.25
March	240	78649	$ 2,197.84	$ 5,269.48	$ 7,467.32
April	217	75146	$ 2,197.84	$ 5,034.78	$ 7,232.62
May	227	76445	$ 2,197.84	$ 5,121.82	$ 7,319.66
June	240	76494	$ 2,197.84	$ 5,125.10	$ 7,322.94
July	252	84862	$ 2,197.84	$ 5,685.75	$ 7,883.59
August	247	79764	$ 2,197.84	$ 5,344.19	$ 7,542.03
September	240	76193	$ 2,197.84	$ 5,104.93	$ 7,302.77
October	223	76627	$ 2,197.84	$ 5,134.01	$ 7,331.85
November	213	73899	$ 2,197.84	$ 4,951.23	$ 7,149.07
December	275	84665	$ 2,197.84	$ 5,672.56	$ 7,870.40
		Totals	**$ 26,374.08**	**$ 63,356.41**	**$ 89,730.49**

Total Annual Estimated Energy/Demand Cost: $ 89,730.49

Notes:
1. Using: $6.64/kVa for demand and $0.067/kWh for energy costs
2. * Demand based on highest monthly demand(ie. 331kVa)
3. Estimates include all loads including lighting, computers, equipment, etc.

Attachment B
Existing Energy Use Summary

Existing Energy Consumption NF Power Corporate Building Kenmount Road					
Date	**Demand**	**Energy**	**Demand Cost***	**Energy Cost**	**Total Monthly**
March 17, 2005	500	130000	$ 3,984.00	$ 8,710.00	$ 12,694.00
April 18, 2005	480	142800	$ 3,984.00	$ 9,567.60	$ 13,551.60
May 17, 2005	440	125400	$ 3,984.00	$ 8,401.80	$ 12,385.80
June 17, 2005	480	135500	$ 3,984.00	$ 9,078.50	$ 13,062.50
July 19, 2005	480	131500	$ 3,984.00	$ 8,810.50	$ 12,794.50
August 18, 2005	500	126600	$ 3,984.00	$ 8,482.20	$ 12,466.20
September 19, 2005	500	133800	$ 3,984.00	$ 8,964.60	$ 12,948.60
October 18, 2005	400	115200	$ 3,984.00	$ 7,718.40	$ 11,702.40
November 16, 2005	440	106200	$ 3,984.00	$ 7,115.40	$ 11,099.40
December 15, 2005	420	114600	$ 3,984.00	$ 7,678.20	$ 11,662.20
January 16, 2006	500	135000	$ 3,984.00	$ 9,045.00	$ 13,029.00
February 15, 2006	600	123600	$ 3,984.00	$ 8,281.20	$ 12,265.20
		Totals	**$ 47,808.00**	**$ 101,853.40**	**$ 149,661.40**

Total Annual Cost **$ 149,661.40**

Notes:

1. Using: $6.64/kVa for demand and $0.067/kWh for energy costs
2. * Demand based on highest monthly demand(ie. 600kVa)

Appendix B

Net Present Value Calculations

Alternative No. 1
VAV System (Ground Floor/First Floor Only)
Present Worth Analysis

Weighted Average Incremental Cost of Capital: 7.15%
Present Worth Year 2007

	Buildings	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
2007	412,000	49,739	36,347	**0**	-86,086	-80,341	-80,341
2008	0	44,311	36,892	0	-81,203	-70,728	-151,069
2009	0	43,722	37,519	0	-81,241	-66,039	-217,108
2010	0	43,118	38,157	0	-81,275	-61,658	-278,765
2011	0	42,499	38,806	0	-81,305	-57,565	-336,330
2012	0	41,868	39,388	0	-81,256	-53,691	-390,021
2013	0	41,223	39,979	0	-81,202	-50,075	-440,096
2014	0	40,566	40,578	0	-81,145	-46,701	-486,797
2015	0	39,898	41,187	0	-81,085	-43,552	-530,349
2016	0	39,217	41,805	0	-81,022	-40,615	-570,964
2017	0	38,526	42,432	0	-80,958	-37,874	-608,838
2018	0	37,824	43,069	0	-80,893	-35,319	-644,157
2019	0	37,112	43,715	0	-80,827	-32,935	-677,092
2020	0	36,391	44,370	0	-80,761	-30,712	-707,804
2021	0	35,660	45,036	0	-80,696	-28,640	-736,444
2022	0	34,920	45,711	0	-80,631	-26,707	-763,151
2023	0	34,172	46,397	0	-80,569	-24,906	-788,057
2024	0	33,415	47,093	0	-80,508	-23,226	-811,283
2025	0	32,650	47,799	0	-80,450	-21,661	-832,944
2026	0	31,878	48,516	0	-80,394	-20,201	-853,145
2027	0	31,098	49,244	0	-80,342	-18,841	-871,986
2028	0	30,312	49,983	0	-80,295	-17,574	-889,560
2029	0	29,519	50,732	0	-80,251	-16,392	-905,952
2030	0	28,719	51,493	0	-80,212	-15,291	-921,243
2031	0	27,913	52,266	0	-80,179	-14,264	-935,507
2032	0	27,101	53,050	0	-80,151	-13,308	-948,815
2033	0	26,283	53,846	0	-80,129	-12,417	-961,232
2034	0	25,460	54,653	0	-80,114	-11,586	-972,817
2035	0	24,632	55,473	0	-80,105	-10,812	-983,629
2036	0	23,798	56,305	0	-80,104	-10,090	-993,719

Alternative No. 2
CLHP System (Ground Floor/First Floor Only)
Present Worth Analysis

Weighted Average Incremental Cost of Capital: 7.15%
Present Worth Year 2007

	Buildings	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
2007	535,000	64,588	29,021	0	-93,609	-87,362	-87,362
2008	0	57,540	29,456	0	-86,996	-75,773	-163,136
2009	0	56,774	29,957	0	-86,731	-70,502	-233,637
2010	0	55,990	30,466	0	-86,456	-65,589	-299,226
2011	0	55,187	30,984	0	-86,172	-61,010	-360,236
2012	0	54,367	31,449	0	-85,816	-56,704	-416,941
2013	0	53,530	31,921	0	-85,451	-52,695	-469,636
2014	0	52,677	32,400	0	-85,077	-48,964	-518,600
2015	0	51,809	32,886	0	-84,694	-45,491	-564,091
2016	0	50,925	33,379	0	-84,304	-42,260	-606,350
2017	0	50,028	33,880	0	-83,907	-39,254	-645,605
2018	0	49,117	34,388	0	-83,504	-36,459	-682,064
2019	0	48,192	34,904	0	-83,096	-33,859	-715,923
2020	0	47,255	35,427	0	-82,682	-31,443	-747,366
2021	0	46,306	35,959	0	-82,264	-29,196	-776,562
2022	0	45,345	36,498	0	-81,843	-27,109	-803,671
2023	0	44,373	37,045	0	-81,419	-25,168	-828,839
2024	0	43,391	37,601	0	-80,992	-23,366	-852,205
2025	0	42,398	38,165	0	-80,563	-21,691	-873,896
2026	0	41,395	38,738	0	-80,132	-20,136	-894,032
2027	0	40,383	39,319	0	-79,701	-18,691	-912,723
2028	0	39,361	39,908	0	-79,270	-17,349	-930,072
2029	0	38,331	40,507	0	-78,838	-16,103	-946,175
2030	0	37,293	41,115	0	-78,407	-14,947	-961,122
2031	0	36,246	41,731	0	-77,977	-13,873	-974,995
2032	0	35,192	42,357	0	-77,549	-12,876	-987,871
2033	0	34,130	42,993	0	-77,123	-11,951	-999,821
2034	0	33,061	43,638	0	-76,699	-11,092	-1,010,913
2035	0	31,986	44,292	0	-76,278	-10,295	-1,021,208
2036	0	30,903	44,956	0	-75,860	-9,555	-1,030,764

Alternative No. 3
Ground Source CLHP (Ground Floor/First Floor Only)
Present Worth Analysis

Weighted Average Incremental Cost of Capital: 7.15%
Present Worth Year 2007

	Buildings	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
2007	610,000	73,642	16,050	0	-89,692	-83,707	-83,707
2008	0	65,606	16,291	0	-81,897	-71,332	-155,039
2009	0	64,733	16,568	0	-81,301	-66,088	-221,126
2010	0	63,839	16,849	0	-80,688	-61,213	-282,339
2011	0	62,924	17,136	0	-80,060	-56,683	-339,022
2012	0	61,989	17,393	0	-79,382	-52,453	-391,475
2013	0	61,035	17,654	0	-78,688	-48,525	-440,000
2014	0	60,062	17,919	0	-77,980	-44,880	-484,879
2015	0	59,072	18,187	0	-77,259	-41,497	-526,377
2016	0	58,065	18,460	0	-76,525	-38,360	-564,737
2017	0	57,041	18,737	0	-75,778	-35,451	-600,188
2018	0	56,002	19,018	0	-75,020	-32,755	-632,942
2019	0	54,948	19,303	0	-74,251	-30,256	-663,198
2020	0	53,880	19,593	0	-73,473	-27,941	-691,139
2021	0	52,797	19,887	0	-72,684	-25,796	-716,935
2022	0	51,702	20,185	0	-71,887	-23,811	-740,746
2023	0	50,594	20,488	0	-71,082	-21,973	-762,719
2024	0	49,473	20,795	0	-70,269	-20,272	-782,991
2025	0	48,341	21,107	0	-69,448	-18,699	-801,690
2026	0	47,198	21,424	0	-68,622	-17,243	-818,933
2027	0	46,044	21,745	0	-67,789	-15,897	-834,830
2028	0	44,879	22,071	0	-66,950	-14,653	-849,483
2029	0	43,705	22,402	0	-66,107	-13,503	-862,986
2030	0	42,521	22,738	0	-65,259	-12,440	-875,426
2031	0	41,327	23,079	0	-64,407	-11,458	-886,885
2032	0	40,125	23,426	0	-63,551	-10,552	-897,437
2033	0	38,915	23,777	0	-62,692	-9,715	-907,151
2034	0	37,696	24,134	0	-61,830	-8,942	-916,093
2035	0	36,470	24,496	0	-60,965	-8,228	-924,321
2036	0	35,236	24,863	0	-60,099	-7,570	-931,891

2007 Application Enhancements

February 2006

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Page

1.0 Introduction

The Company operates and supports over 50 computer applications including package software such as the Great Plains financial system and the Avantis Asset Management System as well as internally developed software such as the Customer Service System ("CSS") and the Outage Management System. These applications help employees work more effectively and efficiently in their daily duties including providing effective customer service.

The Company's computer applications are divided into categories including: Customer Systems, Operations and Engineering Systems, Internet/Intranet Systems and Business Support Systems. In addition, the Company budgets for minor enhancements to respond to unforeseen requirements.

Identifying opportunities to improve these applications either through vendor supplied functionality or internal software development ensures the Company is able to respond to changing business requirements.

The following sections describe the projects budgeted for 2007.

2.0 Customer Service Systems Enhancements

2.1 Contact Centre Improvements ($94,000)

Description

This project involves the automation of current manual work processes. Improvements include the automatic transfer of customer selected service options such as eBills, Authorized Payment Plan ("APP"), and Power of Life donations to customers' new bill accounts when customers move, and automating the finance plan credit approval process.

Operating Experience

The Customer Contact Centre is staffed with approximately 40 employees who provide a variety of services to customers. Activities involved with maintaining customer accounts and providing service often cannot be completed while a customer is on the phone with a Customer Account Representative ("CAR"). This is mainly a result of certain processes requiring other inputs or approvals before completion. Delayed recording of the required information electronically increases the manual effort and the risk of errors when the information is entered.

In 2005, the Company received over 24,000 requests for a final meter reading primarily due to customers moving out of a premise. Over 2,500 of these requests were for accounts that included one or more of the following programs: APP, eBills and Power of Life Donations. When customers open a new account and want to have the programs transferred from prior accounts, the CAR has to set up the programs again on the new account.

In 2005, the Company processed over 1,800 finance plans for such things as “Wrap up for Savings” promotions, hot water tank purchases, and contributions in aid of construction. The credit approval process for finance plans is currently manual. Information contained in the CSS and received from the customer is often captured on paper and manually tracked through the approval process, increasing the overall effort and chance of errors, ultimately affecting the level of service provided to customers.

Justification

In this project, the CSS will be enhanced so that customer program transfers to new accounts and the credit approval process will be automated, reducing the manual effort once necessary for these tasks.

The improvements identified will enhance service to customers by allowing service requests to be completed more timely and accurately.

A financial analysis of the costs and benefits associated with this project indicate in a positive net present value over the next 5 years.

2.2 IVR Enhancements ($77,000)

Description

This project involves integrating Interactive Voice Recognition technology (“IVR”) with the CSS in order to provide an option for automated payment arrangements.

Operating Experience

In 2005, customer calls to make credit payment arrangements represented approximately 40% of all incoming calls. The majority of these calls have been prompted by written correspondence from the Company. When a call is made, the customer indicates to the CAR the type of payment arrangement that is satisfactory to the customer and the Company. The CAR accepts the arrangement and enters a record of the call and the payment commitment into the CSS for the customer.

Justification

This project is justified on customer service and productivity improvements.

Automating payment arrangements from customers via the IVR will reduce the need for a CAR to process the request over the phone, thus, improving productivity. It is expected that 10% of customers would avail of this payment arrangement option.

As well, payment arrangements can be made via the IVR 24 hours a day, increasing the level of service provided to customers.

A financial analysis of the costs and benefits associated with this project results in a positive net present value over the next 5 years.

2.3 Customer Relationship Management Enhancements ($125,000)

Description

The Customer Contact Centre receives over 300,000 customer calls annually. This project will improve service to customers by providing CARs with a comprehensive view of the number and nature of previous interactions a customer has had with the Company.

Operating Experience

Currently, when a customer calls to discuss a previous contact with the Company the CAR does not have automatic access to the prior customer contacts. Unless specifically stated by the customer, the CAR is often not aware of past requests by the customer, thereby affecting the CARs response to the customer's inquiry. The CAR must search through multiple screens within CSS and possibly access other systems such as the Outage Management or Avantis system and manually record the information required to respond to the inquiry. During this search time the customer is often kept waiting or in some cases the CAR has to inform the customer that the Company will have to phone them back once the search for the required information is complete.

Justification

This project is justified on improvements to customer service. The changes to the customer contact process will reduce the time customers have to wait for resolution to their request by consolidating and presenting a complete record of the customer's contacts with the Company. Access to call history allows the CAR to more efficiently gather the necessary information. As well, the CAR is able to provide improved customer service by being able to follow-up with the customer on their satisfaction with past requests, and suggest improved service options to the customer based on their previous and current requests.

3.0 Operations and Engineering Enhancements

3.1 Outage Management Enhancements ($79,000)

Description

The Outage Management System ("OMS") captures and monitors customer trouble calls. Crews are dispatched to the field based on the information entered into the OMS. The system will be improved to ensure that maintenance and upgrades of the electrical distribution system identified during customer trouble calls are scheduled and executed as part of the Company's work plan.

Operating Experience

On average, approximately 1,200 trouble calls require follow-up work yearly such as upgrades to customer service connections where temporary repairs were made during storms or the replacement of distribution transformers or in-line fuses that are no longer able to satisfy distribution system load requirements.

Currently, follow-up work required as the result of a customer trouble call is tracked and completed using the OMS application. However, this application does not have the functionality for the planning, scheduling and tracking of work related to distribution system maintenance and upgrades. Using the OMS to track follow-up work often results in inefficiencies and delays in getting the work to the appropriate employees. The current notification process uses email to inform staff of the requirement for follow-up work. This one-way communication makes it difficult to determine if and when the work has been completed.

Justification

The Outage Management System and Avantis Asset Management System are an integral part of Company operations. Being able to record and assign work effectively ensures that the Company is able to provide a sustainable level of customer service.

By automating the creation of a work order in the Avantis system from a customer trouble call in the OMS that requires follow-up work, the Company will improve its ability to schedule, monitor and complete work related to distribution system repairs and upgrades.

A financial analysis of the costs and benefits associated with this project results in a positive net present value over the next 5 years.

3.2 Asset Management System Enhancements ($356,000)

Description

This project involves enhancements to the Avantis Asset Management System. This includes (i) enabling employees to complete distribution work orders in the field that will electronically update the Avantis Asset Management System without the need for additional data entry, and (ii) improving the integration between the Company's Great Plains financial system and Avantis related to inventory and procurement management.

Operating Experience

The Company manages over 300 distribution feeders throughout the Company's service territory. Approximately 45 feeders are inspected annually. Completion of these inspections can result in the identification of 500 or more deficiencies per feeder that have to be addressed. Deficiencies include deteriorated poles, broken insulators, rusted transformers and vegetation growth in the right-of-way. Annually, the follow-up work can generate 1,000 to 2,000 work orders each containing 10 or more tasks in the Avantis system are generated to address these deficiencies. Examples of tasks include replace a transformer, replace a cross-arm, and install a guy wire.

The recording of the inspection data and associated deficiencies, and the creation of work orders and tasks in Avantis required to correct the deficiencies, is currently a manual operation. The effort to enter this information impedes the effective scheduling and execution of the follow-up work.

The Company manages over 1,000 work orders annually that require materials to be issued from inventory or through procurement. Currently there is no capability to automatically reduce the inventory level stored in the Great Plains system whenever materials are issued for a work order in Avantis. The effort to transfer inventory requirements from Avantis to Great Plains is a manual process and often results in inaccurate tracking of material levels in Avantis.

Justification

Enhancing Avantis will increase efficiency by utilizing mobile devices to capture feeder inspection data in the field thereby reducing the amount of time spent manually recording information in the field and entering it into Avantis. This will also improve data quality by reducing the amount of manual transcription from paper forms. Improving the consistency of the inspection process and the data capture process will in turn improve the Company's ability to more effectively address deficiencies.

Improving the integration between Avantis and Great Plains will reduce the effort to keep the inventory data in the systems synchronized and ensure the materials required to perform the required work is available when necessary.

A financial analysis of the costs and benefits associated with this project results in a positive net present value over the next 5 years.

3.3 SCADA Enhancements ($70,000)

Description

The Supervisory Control and Data Acquisition ("SCADA") system communicates with electronic field equipment and provides the System Control Centre ("SCC") Operators with the ability to remotely monitor and control field devices related to the operation of the electrical system. Information being monitored has been configured such that when pre-defined thresholds are exceeded, alarms are presented to the SCC Operator requiring their acknowledgement. The addition of alarm notification functionality will allow for the routing of non-critical alarms via e-mail and/or text messaging to appropriate Company personnel, ensuring that only alarms critical to the ongoing operation of the electrical system are presented to the SCC Operator.

Operating Experience

In 2005, approximately 170,000 alarms were presented to SCC Operators that required acknowledgement. Approximately 38,000 of these alarms were related to non-critical SCADA system issues such as communications alarms and computer hardware alarms. Currently, SCC Operators must acknowledge these non-critical alarms, thereby taking their attention away from more critical electrical system monitoring and control activities.

Justification

Information being gathered by the SCADA system provides the SCC with a wealth of information about the current state of the electrical system, as well as information about the SCADA system infrastructure and field equipment. This information is often in the form of critical and non-critical alarms to alert the SCC Operator of issues that require attention.

By routing non-critical alarms via e-mail and text messaging to appropriate Company personnel, the SCC Operators can focus on more immediate electrical system activities rather than acknowledging alarms that should not require their immediate attention. As well, re-routing the non-critical alarms eliminates the possibility of SCC Operators inadvertently acknowledging a critical alarm if it is presented at a time when a number of non-critical system alarms are presented.

This enhancement will also improve the follow-up work required for maintenance or operational issues such as feeder imbalance by reducing the need to conduct periodic reviews of historical data, allowing staff to focus on the follow-up work that could affect customer service and electrical system reliability.

A financial analysis of the costs and benefits associated with this project results in a positive net present value over the next 5 years.

4.0 Intranet/Internet Enhancements

4.1 Intranet Enhancements ($98,000)

This project involves enhancements to the Company's Intranet to improve Customer Contact Centre productivity and to improve the management of regulatory documentation.

Operating Experience

The Company's Intranet is the central repository for corporate policies and procedures as well as several applications used to support customer service such as high bill inquires, equal payment plan estimation, and outage notification. Over 350 employees execute more than 3,500 Intranet transactions and queries daily.

The Intranet along with the CSS is integral to Customer Contact Centre employee productivity and the provision of customer service. The Customer Contact Centre handles over 300,000 calls annually. The Intranet is used to ensure that these customer calls are handled in a consistent and effective manner. By retrieving the necessary information as quickly as possible, the CARs are able to quickly respond to customer queries.

As part of the regulatory process the Company creates and files thousands of pages of documentation annually. For example, the 2003 General Rate Application resulted in a record of over 13,000 pages. This does not include the documents required to be completed in preparation of the hearing. Employees involved with this process must manually search through electronic files as well as through hard-copy reports to retrieve previously filed information required to prepare for various regulatory proceedings.

Justification

This project is justified on customer service improvements and on productivity improvements. Accessing accurate documentation regarding Customer Service policies, procedures and supporting information through improved searching capabilities ensures that customers that contact the Customer Contact Centre are served promptly and consistently.

Providing a means for employees to create, file, search and retrieve Company documents related to regulatory matters on the Intranet will reduce the time spent searching for the required documents and ensure that employees are referencing the most up-to-date versions of documents.

A financial analysis of the costs and benefits associated with this project results in a positive net present value over the next 5 years.

4.2 Customer Service Internet ($190,000)

Description

This project involves enhancements to customer self-service options on the Company’s Internet website. For 2007, these initiatives include providing contractors and landlords with the ability to communicate with the Company via a secured area on the Internet website and enhancements to the website’s navigation and search capabilities.

Operating Experience

The Company tracks over 8,000 active landlord agreements. Landlord agreements are arrangements made with property owners that have one or more rental premises with electricity service. When tenants leave, depending on the agreement, the landlord can have service continued (with an account set up automatically in their name) or have electricity service disconnected. For landlords with many premises there is no means for them to view the status of the premises under their agreement without contacting the Customer Contact Centre.

The Company works with numerous contractors on an annual basis with regards to line construction and maintenance and service connections. Contractors include companies that are involved with home construction as well as contractors the Company hires to perform pole and line installation and vegetation management.

The Company receives over 9,000 calls annually regarding technical requests from general contractors. These requests usually involve temporarily disconnecting and reconnecting service in order to perform construction and electrical maintenance work or to set up service for new house construction. These requests often require planning, coordination and completion of work among a number of parties to secure approvals and ensure activities are completed in the proper sequence. As a result, contractors frequently communicate with the Company to obtain status on a particular work order or to provide new information about a work order.

The Company processes over 2,000 pieces of correspondence to and from various contractors annually. This includes invoices, work status reports and regularly produced reports such as tool testing results, safety and environment compliance reports and vehicle inspections related to work performed by contractors on behalf of the Company. This correspondence is often hand written or typed, and mailed or faxed to the Company. This manual process causes delays in receiving, processing and responding to contractors. As well, it requires a high level of administration by Company employees to file, search and copy/fax related documentation, ultimately affecting the level of customer service provided.

In 2005, the Company's Internet website received an average of over 20,000 visits per month. Visitors to the Internet website depend on the website's navigation and search capabilities to find the desired information in a reasonable amount of time.

Justification

This project is justified on productivity improvements and customer service improvements.

By providing landlords with a self-service feature on the Company's Internet website, requests for changes to landlord agreements could be handled without a phone call and the landlord would be able to view an up-to-date status of the premises on their agreement at their convenience.

The provision of a contractor self-service feature will allow invoices, and other required reports to be posted to the website, allowing Company employees the ability to process the information more readily. As well, housing contractors will be able to obtain an up-to-date status of their jobs without having to call the Customer Contact Centre.

For the portion of the project related to landlord and contractor self-service features, a financial analysis of the costs and benefits associated with this project results in a positive net present value over the next 5 years.

A portion of this project is justified on improved customer service. Enhancing the website's navigation and search capabilities ensures that customers will receive timely and efficient responses to information requests on the Company's Internet website.

5.0 Business Support Systems

5.1 Safety Management System Enhancements ($42,000)

Description

The purpose of this item is to complete enhancements to the Company's Safety Management System ("SWMS"). This includes improvements to the accident investigation reporting process, and improved integration with the Company's Human Resource System ("HRS") which is required to ensure that changes in employee positions that affect safety training and certification requirements are properly reflected in the SWMS.

Operating Experience

Currently, accident investigation reports are completed manually by supervisory staff in the various areas and departments. Once completed, these forms are sent by mail to the Safety department where the information is keyed into the SWMS. Safety department staff often have to contact area personnel to track down the reports in order to ensure that monthly safety reporting is correct and complete.

Today changes in employee organizational reporting have to be manually updated in the SWMS to ensure that the Company and its employees are aware of the safety training and compliance requirements based on the position an employee holds.

Justification

Providing an automated workflow process for the accident investigation reporting process will reduce the amount of re-keying of information as well as the amount of tracking and compiling of reports on a monthly basis. Providing an automated integration between the SWMS and the HRS will eliminate the inconsistencies in employee data between the two systems and ensure employees have the appropriate safety training and certification when required.

A financial analysis of the costs and benefits associated with this project results in a positive net present value over the next 5 years.

6.0 Various Minor Enhancements ($150,000)

Description

The purpose of this item is to complete enhancements to the Company's computer applications in response to unforeseen requirements such as legislative and compliance changes, vendor driven changes and employee identified enhancements designed to improve customer service or employee productivity.

Operating Experience

Examples of previous projects under this budget item include enhancing collections processes in the Customer Service System to reduce bad debt expense and enhancements to the Company's Outage Management System to improve communications to customers and employees.

Justification

Work completed as part of various minor enhancements is justified on the basis of improved customer service, operating efficiencies and regulatory and legislative requirements.

Appendix A

Net Present Value Analyses

Contact Centre Improvements

		Capital Impacts			Ongoing Operating Expenditures						
					Cost Increases		Cost Benefits				
	YEAR	New Software	Capitalized for CCA	CCA Tax Software	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B	C	D		E		F	G	H
0	2007	($94,000)	($94,000)	$47,000	$0	$0	$0	$0	$0	$16,976	($77,024)
1	2008			$47,000	$0	$0	$30,160	$0	$30,160	$6,083	$36,243
2	2009				$0	$0	$31,065	$0	$31,065	($11,221)	$19,844
3	2010				$0	$0	$31,997	$0	$31,997	($11,557)	$20,440
4	2011				$0	$0	$32,957	$0	$32,957	($11,904)	$21,053
	Present Value (See Note I)	**@**		**6.07%**							**$8,543**

NOTES: A is the sum of the software additions by year.

B is the amount eligible for capital cost allowance deductions.

C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.

D is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated to current year using the GDP Deflator Index.

E is the reduced operating costs. The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.

F is the sum of columns D and E.

G is the impact on taxes from the CCA and operating cost expenditures. It is equal to column C less column F times the tax rate.

H is the after tax cash flow which is the sum of the capital expenditure (column A) plus operating expenditures (column F) plus income tax (column G).

I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

IVR Enhancements

		Capital Impacts			Ongoing Operating Expenditures						
					Cost Increases		Cost Benefits				
	YEAR	New Software	Capitalized for CCA	CCA Tax Software	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B	C	D		E		F	G	H
0	2007	($77,000)	($77,000)	$38,500	$0	$0	$0	$0	$0	$13,906	($63,094)
1	2008			$38,500	$0	$0	$26,000	$0	$26,000	$4,515	$30,515
2	2009				$0	$0	$26,780	$0	$26,780	($9,673)	$17,107
3	2010				$0	$0	$27,583	$0	$27,583	($9,963)	$17,620
4	2011				$0	$0	$28,411	$0	$28,411	($10,262)	$18,149
	Present Value (See Note I)		**@**	**6.07%**							**$9,984**

NOTES: A is the sum of the software additions by year.

B is the amount eligible for capital cost allowance deductions.

C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.

D is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated to current year using the GDP Deflator Index.

E is the reduced operating costs. The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.

F is the sum of columns D and E.

G is the impact on taxes from the CCA and operating cost expenditures. It is equal to column C less column F times the tax rate.

H is the after tax cash flow which is the sum of the capital expenditure (column A) plus operating expenditures (column F) plus income tax (column G).

I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

Outage Management Enhancements

		Capital Impacts			Ongoing Operating Expenditures						
					Cost Increases		Cost Benefits				
	YEAR	New Software	Capitalized for CCA	CCA Tax Software	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B	C	D		E		F	G	H
0	2007	($79,000)	($79,000)	$39,500	$0	$0	$0	$0	$0	$14,267	($64,733)
1	2008			$39,500	$0	$0	$31,065	$0	$31,065	$3,047	$34,112
2	2009				$0	$0	$31,997	$0	$31,997	($11,557)	$20,440
3	2010				$0	$0	$32,957	$0	$32,957	($11,904)	$21,053
4	2011				$0	$0	$33,945	$0	$33,945	($12,261)	$21,684
	Present Value (See Note I)	**@**		**6.07%**							**$20,367**

NOTES: A is the sum of the software additions by year.

B is the amount eligible for capital cost allowance deductions.

C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.

D is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated to current year using the GDP Deflator Index.

E is the reduced operating costs. The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.

F is the sum of columns D and E.

G is the impact on taxes from the CCA and operating cost expenditures. It is equal to column C less column F times the tax rate.

H is the after tax cash flow which is the sum of the capital expenditure (column A) plus operating expenditures (column F) plus income tax (column G).

I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

Asset Management System Enhancements

		Capital Impacts		CCA Tax Deductions				Ongoing Operating Expenditures: Cost Increases		Cost Benefits				
	YEAR	New Software	New Hardware	Software	Hardware	Residual CCA	Total	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B	C				D		E		F	G	H
0	2007	($356,000)	($25,000)	$178,000	$5,625		$183,625	$0	$0	$0	$0	$0	$66,325	($314,675)
1	2008			$178,000	$8,719		$186,719	$0	$0	$122,571	$0	$122,571	$23,170	$145,741
2	2009				$4,795		$4,795	$0	$0	$126,248	$0	$126,248	($43,869)	$82,380
3	2010				$2,637		$2,637	$0	$0	$130,036	$0	$130,036	($46,016)	$84,020
4	2011				$1,451	$1,562	$3,013	$0	$0	$133,937	$0	$133,937	($47,290)	$86,647
	Present Value (See Note I)	**@**		**6.07%**										**$34,809**

NOTES: A is the sum of the software additions by year.
B is the sum of the computer network hardware additions by year.
C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
D is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated to current year using the GDP Deflator Index.
E is the reduced operating costs. The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
F is the sum of columns D and E.
G is the impact on taxes from the CCA and operating cost expenditures. It is equal to column C less column F times the tax rate.
H is the after tax cash flow which is the sum of the capital expenditure (columns A and B) plus operating expenditures (column F) plus income tax (column G).
I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

SCADA Enhancements

		Capital Impacts			Ongoing Operating Expenditures						
					Cost Increases		Cost Benefits				
	YEAR	New Software	Capitalized for CCA	CCA Tax Software	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B	C	D		E		F	G	H
0	2007	($70,000)	($70,000)	$35,000	$0	$0	$0	$0	$0	$12,642	($57,358)
1	2008			$35,000	$0	$0	$26,333	$0	$26,333	$3,131	$29,463
2	2009				$0	$0	$27,123	$0	$27,123	($9,797)	$17,326
3	2010				$0	$0	$27,936	$0	$27,936	($10,091)	$17,846
4	2011				$0	$0	$28,775	$0	$28,775	($10,393)	$18,381
	Present Value (See Note I)	**@**		**6.07%**							**$15,295**

NOTES: A is the sum of the software additions by year.

B is the amount eligible for capital cost allowance deductions.

C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.

D is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated to current year using the GDP Deflator Index.

E is the reduced operating costs. The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.

F is the sum of columns D and E.

G is the impact on taxes from the CCA and operating cost expenditures. It is equal to column C less column F times the tax rate.

H is the after tax cash flow which is the sum of the capital expenditure (column A) plus operating expenditures (column F) plus income tax (column G).

I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

Intranet Enhancements

		Capital Impacts			Ongoing Operating Expenditures						
					Cost Increases		Cost Benefits				
	YEAR	New Software	Capitalized for CCA	CCA Tax Software	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B	C	D		E		F	G	H
0	2007	($98,000)	($98,000)	$49,000	$0	$0	$0	$0	$0	$17,699	($80,301)
1	2008			$49,000	$0	$0	$33,280	$0	$33,280	$5,678	$38,958
2	2009				$0	$0	$34,278	$0	$34,278	($12,381)	$21,897
3	2010				$0	$0	$35,307	$0	$35,307	($12,753)	$22,554
4	2011				$0	$0	$36,366	$0	$36,366	($13,135)	$23,231
	Present Value (See Note I)	**@**		**6.07%**							**$13,143**

NOTES: A is the sum of the software additions by year.

B is the amount eligible for capital cost allowance deductions.

C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.

D is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated to current year using the GDP Deflator Index.

E is the reduced operating costs. The cost estimate is escalated to current year using Newfoundland Power’s Labour Escalation Rates.

F is the sum of columns D and E.

G is the impact on taxes from the CCA and operating cost expenditures. It is equal to column C less column F times the tax rate.

H is the after tax cash flow which is the sum of the capital expenditure (column A) plus operating expenditures (column F) plus income tax (column G).

I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

Customer Service Internet

		Capital Impacts			Ongoing Operating Expenditures						
					Cost Increases		Cost Benefits				
	YEAR	New Software	Capitalized for CCA	CCA Tax Software	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B	C	D		E		F	G	H
0	2007	($160,000)	($160,000)	$80,000	$0	$0	$0	$0	$0	$28,896	($131,104)
1	2008			$80,000	$0	$0	$50,960	$0	$50,960	$10,489	$61,449
2	2009				$0	$0	$52,489	$0	$52,489	($18,959)	$33,530
3	2010				$0	$0	$54,063	$0	$54,063	($19,528)	$34,536
4	2011				$0	$0	$55,685	$0	$55,685	($20,114)	$35,572
	Present Value (See Note I)		**@**	**6.07%**							**$13,674**

NOTES: A is the sum of the software additions by year.

B is the amount eligible for capital cost allowance deductions.

C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.

D is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated to current year using the GDP Deflator Index.

E is the reduced operating costs. The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.

F is the sum of columns D and E.

G is the impact on taxes from the CCA and operating cost expenditures. It is equal to column C less column F times the tax rate.

H is the after tax cash flow which is the sum of the capital expenditure (column A) plus operating expenditures (column F) plus income tax (column G).

I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

Safety Management System Enhancements

		Capital Impacts			Ongoing Operating Expenditures						
					Cost Increases		Cost Benefits				
	YEAR	New Software	Capitalized for CCA	CCA Tax Software	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B	C	D		E		F	G	H
0	2007	($42,000)	($42,000)	$21,000	$0	$0	$0	$0	$0	$7,585	($34,415)
1	2008			$21,000	$0	$0	$15,106	$0	$15,106	$2,129	$17,235
2	2009				$0	$0	$15,559	$0	$15,559	($5,620)	$9,939
3	2010				$0	$0	$16,026	$0	$16,026	($5,789)	$10,237
4	2011				$0	$0	$16,507	$0	$16,507	($5,962)	$10,545
	Present Value (See Note I)		**@**	**6.07%**							**$7,577**

NOTES: A is the sum of the software additions by year.

B is the amount eligible for capital cost allowance deductions.

C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.

D is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated to current year using the GDP Deflator Index.

E is the reduced operating costs. The cost estimate is escalated to current year using Newfoundland Power’s Labour Escalation Rates.

F is the sum of columns D and E.

G is the impact on taxes from the CCA and operating cost expenditures. It is equal to column C less column F times the tax rate.

H is the after tax cash flow which is the sum of the capital expenditure (column A) plus operating expenditures (column F) plus income tax (column G).

I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

2007 System Upgrades

February 2006

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1.0 Introduction

The Company depends on the effective implementation and on-going operation of its business applications. These applications need to be upgraded to address vendor obsolescence, ensure continued vendor support and software compatibility and to take advantage of newly developed capabilities.

This project consists of upgrades to several of the Company's business applications and the information technology used to operate and support the Company's business applications.

2.0 Business Application Upgrades

2.1 Description

The upgrades to the Company's business applications ensure that these applications continue to function in a stable and reliable manner with the appropriate level of vendor support. Each year, applications are reviewed to determine which ones require upgrades. For 2007, upgrades include:

1) Avantis Asset Management System Upgrade - $142,000

   This item involves upgrades to the Company's asset management system, Avantis, to the most current vendor supported version of the software. Avantis is used by employees to manage work associated with electrical system components. The version currently used by the Company will no longer be supported by the vendor after July 2006. The risk of operational problems is minimal during the time between when support ends and the upgrade occurs as the system is currently stable and no significant enhancements are planned for the last half of 2006.

2) Customer Service System (CSS) Components Upgrade - $154,000

   This item involves an upgrade to the Company's CSS software components. The upgrade is required to ensure the components used to operate the CSS application (including Oracle, Powerhouse, and Axiant) are compatible with the CSS servers being replaced as part of the Shared Server Infrastructure project.

3) Reporting Software Upgrade - $53,000

   This item involves upgrading the Company's data reporting software, Cognos Impromptu, to the most current version of the software. The Cognos Impromptu software is used to produce and distribute reports used in daily operations such as SCADA reports, employee reports such as electronic pay stubs, and Customer Service reports such as credit analysis. The version currently used by the Company is no longer being supported by the vendor.

4) Load Research Software Upgrade – $153,000

   This item involves upgrading the Company's Itron MV-90 software which is used to collect and analyze system load data from meters installed at customer premises. The version currently used by the Company will no longer be supported by the vendor as of May 2007.

2.2 Operating Experience

System upgrades help ensure the reliability and effectiveness of the Company's business applications and mitigate risks associated with technology related problems. The timing of the upgrades is based on a review of the risks and operational experience of the applications being considered for an upgrade.

As well, upgrades are often completed in order to take advantage of functional or technical enhancements.

2.3 Justification

Investment in Business Application Upgrades is necessary to replace outdated technology that is no longer supported by vendors and to take advantage of newly developed capabilities. Unstable and unsupported software applications can negatively impact operating efficiencies and customer service.

3.0 Information Technology Management

3.1 Description

Managing the information technology used to operate and support the Company's business applications consists of a variety of interrelated technologies and processes. These technologies are used to develop, configure, test, implement, monitor and maintain applications throughout the Company. For 2007 this includes:

1) Application Monitoring and Availability Improvements - $126,000

   This project involves the implementation of software to provide 24 hours per day application monitoring of the Company's critical business applications. This software will notify technical staff of issues or pending problems with applications via remote messaging. This will enable staff to respond to issues faster which in turn will reduce the amount of time an application is not functioning properly, thereby reducing or preventing negative impact to customer service and employee productivity.

2) Application Change Control Improvements - $61,000

   This project involves enhancing the software the Company uses to monitor changes to business applications to prevent unauthorized changes to these applications. The improved system will be used to log and report changes made to applications such as the CSS and Great Plains financial application as part of normal system operations, upgrades and enhancements. This will improve audit reporting capabilities, ensuring that only authorized changes that have been fully tested and documented are made to applications by personnel with the appropriate security and approval levels.

3.2 Operating Experience

The Company depends on the stable operation of its over fifty business applications such as the CSS, Hand Held Meter Reading and Great Plains in order to sustain an effective level of customer service and employee productivity. These applications have many different information technology components that must work together to achieve stable operations. Should one of these components fail the Company's ability to operate efficiently and maintain an effective level of customer service would be diminished.

The Company must protect its applications and data from unexpected events such as software bugs, hardware failures, or intrusion from external entities. Being alerted immediately as issues occur (or detecting potential problems before they occur) minimizes the negative impact on customer service and employee productivity.

Through normal business activities, applications such as CSS and Great Plains are modified to sustain normal operations or to make functional improvements. In 2005, the Company made over 600 changes to its applications and technology infrastructure. With this level of ongoing change to the Company's information technology, the ability to consistently demonstrate that only appropriate, approved, and tested changes have been completed is critical to ensuring that application reliability and data integrity is maintained.

3.3 Justification

Managing the information technology used to operate and support the Company's business applications is justified on the basis of maintaining customer service levels and existing operating efficiencies.

Technical problems can occur at any time during the day or night. Without the appropriate mechanisms in place, problems can go undetected, potentially disrupting the Company's ability to complete customer requests or perform work effectively. Implementing technology that can monitor the condition of the Company's applications and notify employees when applications are not operating properly will minimize these disruptions.

Allowing only authorized changes to the Company's business applications ensures effective Company operations. Failure to resolve any unauthorized application changes could result in reduced customer service or data integrity issues.

2007 Shared Server Infrastructure

February 2006

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1.0 Introduction

The shared server infrastructure consists of over 100 shared servers that are used for production, testing, and disaster recovery for the Company's business applications. The Company relies on these shared servers to ensure the efficient operation and support of its customer service, engineering and business support systems. Each year an assessment is completed to determine the Company's shared server infrastructure requirements. This assessment involves identifying servers and peripherals to be replaced based on age and risk of failure, as well as determining any new computing requirements for corporate applications.

2.0 Description

This project involves the addition, upgrade and replacement of computer hardware components and related technology associated with the Company's shared server infrastructure. For 2007, this project includes:

1. The purchase and implementation of additional disk, memory and CPU upgrades for servers which are currently used to run corporate applications. The budget for this item is $99,000.

2. The purchase and installation of a server and a tape library to meet the Company's business application availability and data storage requirements. The server and tape library will provide disaster recovery capabilities for the Company's business applications. The budget for this item is $254,000.

3. The replacement of two Customer Service System (CSS) production and test servers. These servers have been installed since 1997 and will be in service for 10 years in 2007. The Company's *Customer Service System Replacement Analysis* report filed with the 2004 Capital Budget Application refers to sustaining an adequate level of vendor support related to the CSS application until the application is replaced. The timely replacement of aging servers will help to maximize the useful life of the CSS. The budget for this item is $311,000.

4. The replacement of two SCADA production servers used to monitor and control the electrical system. These current SCADA servers have been in production since 1999. In September of 2005 the failure of a Central Processing Unit (CPU) in one of these servers resulted in the server being unavailable for approximately eight hours. Operations continued on the backup server; however automatic SCADA system failover was not available during this time. This is an unacceptable risk for the Company's SCADA system as monitoring and control of the electrical system using the SCADA system would not be possible if a server issue occurred with only one server in operation. The budget for this item is $149,000.

5. Enhancements to the physical security and monitoring capabilities used to provide protection to the Company's information technology facilities. This project involves the addition, upgrade and replacement of hardware components and related technology associated with the Company's physical security including cameras, door readers, intruder detection and security monitoring. The budget for this item is $64,000.

3.0 Operating Experience

The Shared Server Infrastructure project includes the purchase, implementation and management of the hardware and software related to the operation of shared servers. Shared servers are computers that support applications used by multiple employees. Management of these shared servers and their components is critical to ensuring that these applications are available in order for the Company to provide service to customers and operate efficiently.

Technology components such as servers and disk storage require on-going investment to ensure that they continue to operate effectively. To maintain this effectiveness, upgrades, monitoring and security investments are necessary.

Factors considered in determining when to upgrade, replace or add server components include: the current performance of the components; the level of support provided by the vendor; the criticality of the applications running on the shared server components; the ability of the components to meet future growth; the cost of maintaining and operating the components using internal staff ; the cost of replacing or upgrading the components versus operating the current components; and the business or customer impact if the component fails.

Gartner states that computer servers have a useful life of approximately 5 years[1]. By making appropriate investments in its shared server infrastructure, Newfoundland Power's experience is that the useful life of its corporate servers has exceeded Gartner's findings.

In order to ensure high availability of applications and minimize the vulnerability of its computer systems to external interference, the Company invests in system availability and proactive security monitoring tools. These tools allow the Company to monitor and respond to problems that could impede the normal operation of applications or damage or destroy information.

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[1] Gartner Inc. is the leading provider of research and analysis on the global Information Technology industry. They help more than 10,000 companies make informed technology and business decisions by providing in-depth analysis and advice on virtually all aspects of technology. Founded in 1979, Gartner is headquartered in Stamford, Connecticut and consists of 4,600 associates, including 1,400 research analysts and consultants, in more than 75 locations worldwide.

4.0 Justification

The shared server infrastructure is vital to maintaining the provision of low cost, efficient and reliable service to customers. The need to replace, upgrade and modernize information technology infrastructure is fundamentally the same as the need to replace, upgrade and modernize the components of the Company's electrical system infrastructure as it deteriorates or becomes obsolete. Instability within the shared server infrastructure has the potential to impact high numbers of employees and customers and therefore is critical to the Company's overall operations and to the provision of overall customer service.

Investments in the Shared Server Infrastructure are made by evaluating the alternatives of modernizing or replacing technology components. The Company selects the least cost alternative whenever possible.

Deferred Charges and Rate Base

March 2006

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

In Order No. P.U. 19 (2003), the Board ordered Newfoundland Power Inc. (the "Company") to incorporate deferred charges in rate base commencing in 2003. In addition, the Board ordered that evidence relating to changes in deferred charges, including deferred pension costs, be filed annually with the Company's capital budget application.

This report provides evidence with respect to changes in deferred charges.

2.0 Deferred Charges

2.1 Summary

Table 1 outlines the forecast deferred charges at December 31, 2005 reported in the Company's 2005 Capital Budget Application, the actual deferred charges reported at December 31, 2005 and forecast deferred charges at December 31, 2006 and 2007.

Table 1
Deferred Charges: 2005-2007F
($000s)

	2005F	Actual 2005	2006F	2007F
Deferred Pension Cost	84,993	84,999	90,333	96,882
Weather Normalization Account	9,971	10,100	8,998	7,872
Unamortized Debt Discount & Issue Expense	3,464	3,228	3,035	2,842
Unamortized Capital Stock Issue Expense	261	261	199	137
Deferred Retiring Allowances	0	671	134	0
Deferred Credit Facility Issue Costs	0	117	116	58
Deferred Depreciation Expense	0	0	5,793	5,793
Total Deferred Charges	98,689	99,376	108,608	113,584

The total deferred charges at December 31, 2005 were approximately $0.7 million higher than that forecast in the Company's 2005 Capital Budget Application. This was due primarily to the amortization methodology for retiring allowances related to the 2005 Early Retirement Program as approved by the Board in Order No. P.U. 49 (2004). The omission of the resultant deferred retiring allowances in the report on Deferred Charges and Rate Base was an oversight.

2.2 Deferred Pension Costs

The difference between pension plan *funding* and pension plan *expense* with regard to the Company's defined benefit pension plan is captured as a deferred pension cost on the Company's balance sheet in accordance with Order No. P.U. 17 (1987).

Table 2 sets out (i) forecast December 31, 2005 deferred pension cost per the Company's 2005 Capital Budget Application, (ii) actual deferred pension costs at December 31, 2005, and (iii) forecast deferred pension cost at December 31, 2006 and 2007.

Table 2
Forecast Deferred Pension Costs: 2005-2007F
($000s)

	2005F	**2005A**	**2006F**	**2007F**
Deferred Pension Costs, January 1st	79,008	79,008	84,999	90,333
Pension Plan Funding				
- Current Service Funding	3,162	3,162	3,200	3,417
- Special Funding	7,414	7,414	7,391	6,747
Total Pension Plan Funding	10,576	10,576	10,591	10,164
Pension Plan Expense	(4,591)	(4,585)	(5,257)	(3,615)
Increase in Deferred Pension Costs	5,985	5,991	5,334	6,549
Deferred Pension Costs, December 31st	84,993	84,999	90,333	96,882

Pension plan funding is comprised of two components: current service funding which is determined by an independent actuary and is related to service rendered by active employees in the current year; and, special funding which reflects additional pension funding requirements to address increases in the unfunded liability in the pension plan since its inception. The status of the unfunded liability is determined each time an actuarial study is completed which, under pension legislation, has to occur at least every three years. The next valuation is required to be completed as of December 31, 2006.

The Company calculates annual pension expense in accordance with recommendations of the Canadian Institute of Chartered Accountants ("CICA") and relevant Board orders, the most recent of which is Order No. P.U. 49 (2004). In this order, the PUB approved a variation from generally accepted accounting principles with respect to the amortization of costs associated with the 2005 Early Retirement Program. These costs have been deferred and are being amortized on a straight line basis over 10 years commencing April 1, 2005.

The forecast pension expense for 2007 is subject to change based upon the following factors:

1. The final pension expense for 2007 cannot be determined until early in 2007 once actual pension plan asset balances for 2006 are known. This determination is made based on the December 31, 2006 market value of pension plan assets in accordance with CICA Handbook recommendations and Order No. P.U. 19 (2003).

2. In accordance with CICA Handbook recommendations the discount rate required to calculate 2007 pension expense is the actual market rate of interest at December 31, 2006. Pension expense for 2007 in Table 2 above is calculated assuming a 5.25% discount rate at December 31, 2006. If a change in discount rate is required based on December 31, 2006 market interest rates, 2007 pension expense will vary from the amount forecast 2007 in Table 2.

While pension plan expense for 2007 is subject to change from the forecast provided above, it will be determined based on standards that have been consistently applied year over year, and these standards are in compliance with CICA recommendations, actuarial principles, and Board orders.

2.3 Weather Normalization Account

The Weather Normalization Account has historically been included in rate base. Its treatment is unchanged by the inclusion of additional deferred charges in rate base as ordered by the Board in Order No. P.U. 19 (2003).

The balance in the Weather Normalization Account is comprised of two reserve accounts as shown in Table 3. The forecast change in each reserve account is shown in Table 4 and Table 5.

Table 3
Weather Normalization Account: 2005-2007F
($000s)

	2005F	Actual 2005	2006F	2007F
Hydro Production Equalization Reserve	6,164	6,001	4,539	3,413
Degree Day Normalization Reserve	3,807	4,099	4,459	4,459
Total	9,971	10,100	8,998	7,872

The functioning of these reserves is governed by orders of the Board; Order No. P.U. 32 (1968) in the case of the Hydro Production Equalization Reserve, and Order No. P.U. 1 (1974) in the case of the Degree Day Normalization Reserve.

Table 4
Hydro Production Equalization Reserve: 2005-2007F
($000s)

	2005F	Actual 2005	2006F	2007F
Balance, January 1st	7,828	7,828	6,001	4,539
Reduction per P.U. 19(2003)	(1,126)	(1,126)	(1,126)	(1,126)
Normal operation of the reserve	(538)	(701)	(336)	0
Balance, December 31st	6,164	6,001	4,539	3,413

In Order No. P.U. 19 (2003), the Board accepted the Company's proposal to amortize the recovery of the $5.6 million non-reversing balance in the Hydro Production Equalization Reserve at a rate of $1.126 million per year over a period of five years commencing in 2003. The annual reduction in the Hydro Production Equalization Reserve of $1.126 million is included in the forecast for 2006 and 2007. The remaining forecast change in the Hydro Production Equalization Reserve in 2006 relates to the normal operation of the reserve.

Table 5
Degree Day Normalization Reserve: 2005-2007F
($000s)

	2005F	Actual 2005	2006F	2007F
Balance, January 1st	2,649	2,649	4,099	4,459
Normal operation of the reserve	1,158	1,450	360	0
Balance, December 31st	3,807	4,099	4,459	4,459

Both the Hydro Production Equalization Reserve and the Degree Day Normalization Reserve are affected by actual weather patterns as compared to normal weather patterns. The difference between normal weather patterns and the patterns actually experienced to the end of January 2006 has been reflected in the 2006 forecast. The 2006 and 2007 forecasts assume normal weather conditions from February 2006 through December 2007.

On February 23, 2006, the Company filed an application with the Board requesting approval of the balance in the Weather Normalization Accounts as at December 31, 2005.

2.4 Unamortized Debt Discount & Issue Expense

Change in Unamortized Debt Discount & Issue Expense is set out in Table 6.

Table 6
Unamortized Debt Discount & Issue Expense: 2005-2007F
($000s)

	2005F	Actual 2005	2006F	2007F
Balance, January 1st	3,169	3,169	3,228	3,035
Costs incurred during the year	493	260	0	0
Amortization during the year	(198)	(201)	(193)	(193)
Balance, December 31st	3,464	3,228	3,035	2,842

The balance of the Unamortized Debt Discount & Issue Expense at December 31, 2005 is less than that forecast in the Company's 2005 Capital Budget Application. This reflects the fact that the 2005 issue expenses for Series AK First Mortgage Sinking Fund Bonds were less than expected.

2.5 Unamortized Capital Stock Issue Expense

Change in Unamortized Capital Stock Issue Expense is set out in Table 7

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Table 7
Unamortized Capital Stock Issue Expense: 2005-2007F
($000s)

	2005F	Actual 2005	2006F	2007F
Balance, January 1st	325	325	261	199
Amortization during the year	(64)	(64)	(62)	(62)
Balance, December 31st	261	261	199	137

The decline in the Unamortized Capital Stock Issue Expense each year reflects the normal amortization of these costs over a 20-year period.

2.6 Deferred Retiring Allowances

The details of the changes are set out in Table 8.

Table 8
Deferred Retiring Allowances: 2005-2007F
($000s)

	2005F	Actual 2005	2006F	2007F
Balance, January 1st	0	0	672	134
Cost incurred during the year	0	1,683	0	0
Amortization during the year	0	(1,012)	(538)	(134)
Balance, December 31st	0	671	134	0

In Order No. P.U. 49 (2004), the Board ordered that retiring allowances related to the 2005 Early Retirement Program be amortized over twenty-four months. The year-over-year change in deferred retirement allowances reflects the amortization methodology approved by the Board.

2.7 Deferred Credit Facility Issue Costs

The details of the changes are set out in Table 9.

Table 9
Deferred Credit Facility Issue Costs: 2005-2007F
($000s)

	2005F	Actual 2005	2006F	2007F
Balance, January 1st	0	0	117	116
Cost incurred during the year	0	205	57	0
Amortization during the year	0	(88)	(58)	(58)
Balance, December 31st	0	117	116	58

In Order No. P.U. 4 (2006), the Board approved the extension of the maturity date of the Company's revolving term credit facility (the "Credit Facility") to January 20, 2009. The fees related to this amendment, along with the unamortized balance at the end of 2005 of the fees related to the initial establishment of the facility, are being amortized on a straight line basis over the term of the amended facility (thirty-six months).

2.8 Deferred Depreciation True-up

The details of the changes are set out in Table 10.

Table 10
Deferred Depreciation Expense: 2005-2007F
($000s)

	2005F	Actual 2005	2006F	2007F
Balance, January 1st	0	0	0	5,793
Cost deferred during the year	0	0	5,793	0
Balance, December 31st	0	0	5,793	5,793

In Order No. P.U. 40 (2005), the Board ordered the Company to defer depreciation expense of $5,793,000 related to the amortization of depreciation true-up. The recovery of these costs in future rates will be determined as part of the next GRA and has not been reflected in the table above.

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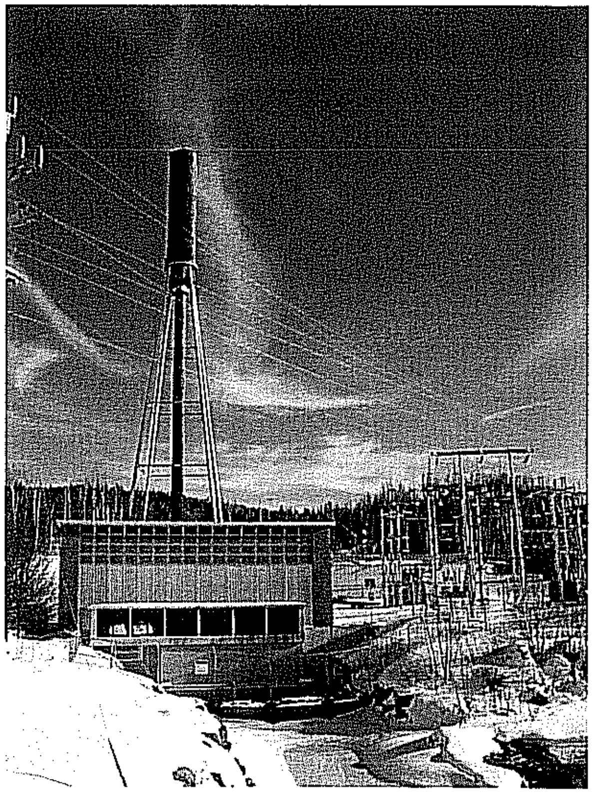

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March 2006

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NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
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1.0 Introduction

The Rattling Brook hydroelectric development is the largest generating station operated by Newfoundland Power. It is located approximately 50 kilometres west of Gander in the Notre Dame Bay community of Norris Arm South. The development went into service in December 1958 and has provided 48 years of reliable energy production. The normal annual plant production is approximately 69.8 GWh of energy, or about 16.6% of Newfoundland Power's total hydroelectric generation.

In 2007, Newfoundland Power has confirmed that the woodstave penstock and surge tank require replacement and refurbishment respectively. In addition, Newfoundland Power has identified necessary electrical and mechanical upgrades for 2007.

In 2008, Newfoundland Power has identified replacement and refurbishment work required on the dams and spillways that comprise the water storage system for the Rattling Brook development.

This project is necessary at this time due to the age and physical condition of the plant assets, the details of which are included in the appendices of this report. The woodstave penstock is 48 years old and at the end of its service life. It is in poor condition and must be replaced in 2007. The surge tank has a corroded lower riser pipe and deteriorated surfaces and coating in the main tank. In addition, the exterior cladding system is deteriorated and requires replacement. Undertaking the refurbishment of the surge tank in 2007 will avoid the complete replacement of this 300 foot high structure in the near future. See Appendix A for pictures of the penstock and surge tank.

Due to the condition of the penstock, the only alternative to this project is to decommission the plant, resulting in the loss of 69.8 GWh of energy and 11.2 MW of capacity. However, results of the feasibility analysis conclude that the continued operation of the Rattling Brook hydroelectric development, including the planned replacement and refurbishment project, is economically viable over the long term.

The replacement of the penstock and main valves provides an opportunity to increase the energy production from the plant. By delivering the water to the generator turbines more efficiently, 6.2 GWh in additional energy can be recovered. This quantity of incremental energy is similar to the quantity of energy provided annually from the Morris plant on the Southern Shore and will displace approximately 10,500 barrels of oil per year burned at Newfoundland and Labrador Hydro's Holyrood thermal generating plant.

After refurbishment, the Rattling Brook plant will provide an additional 2.9 MW of energy on peak to the Island Interconnected electrical system. This project will allow Newfoundland Power to continue to operate this facility over the long term, maximizing the benefits of this renewable resource for its customers.

2.0 Background

The Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") approved the expenditure of $350,000 in Newfoundland Power's 2005 Capital Budget Application for the preparation of detailed engineering relating to the Rattling Brook plant rehabilitation. As part of this engineering, Newfoundland Power commenced an assessment of the Rattling Brook system early in 2005 to determine the project scope and verify the budget for the work to be completed. Assessment reports are included as Appendices B through F of this summary report. Appendix G includes the project schedule. Appendix H includes a feasibility analysis of the costs and benefits associated with the project. Figure 1 is a map of the lower section of the Rattling Brook hydroelectric development.

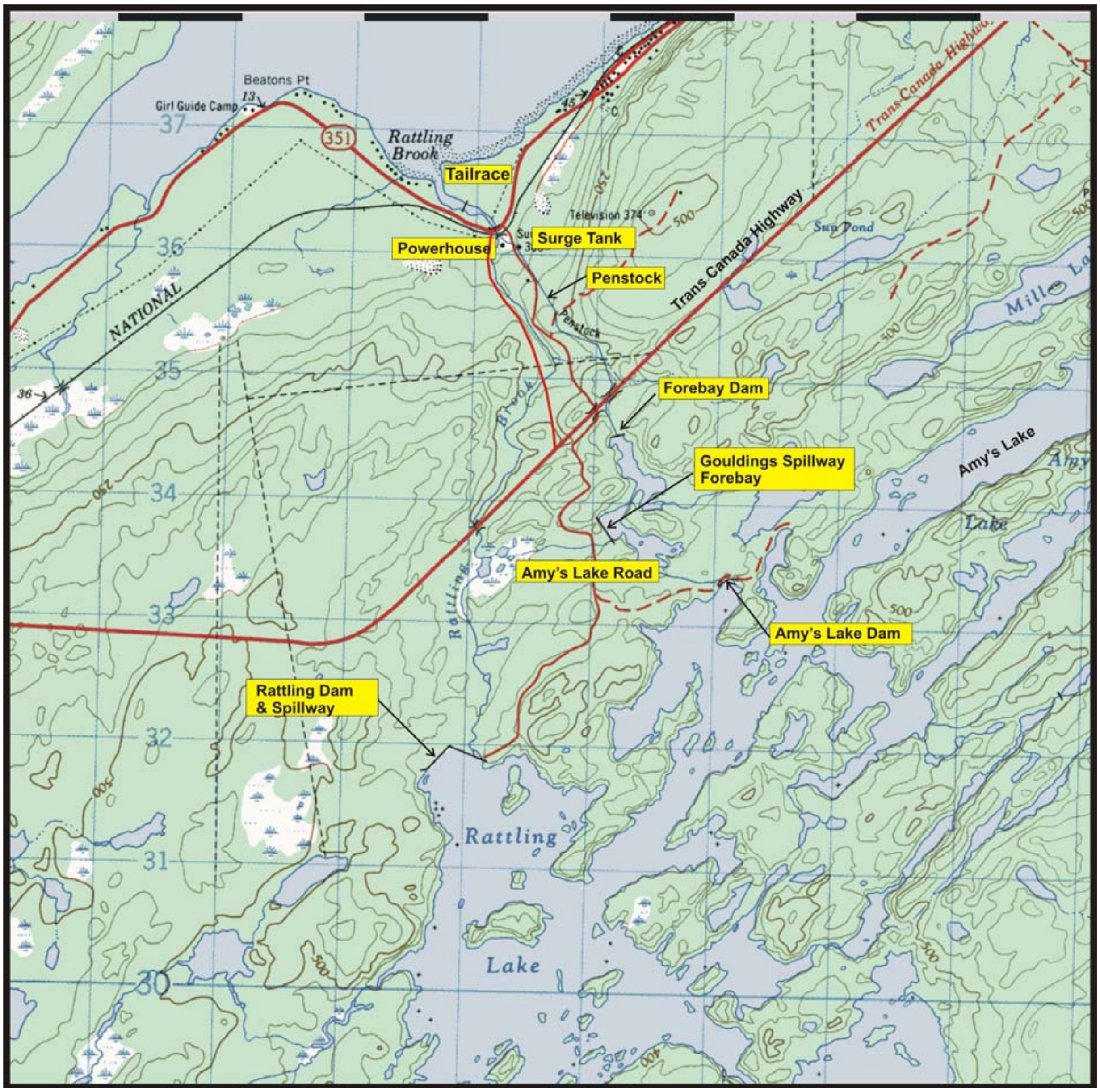

Figure 1

Since 1958, there have been various upgrades to the original plant and equipment. The major upgrades that have occurred in the past 20 years are:

- In 1986 and 1987, the turbine runners were replaced on both units;
- In 1988, Frozen Ocean Lake dam was rebuilt;
- In 2002, a new power transformer was installed in the substation replacing the two original transformers;
- In 2002, the stator on unit #2 generator was rewound due to an in-service failure; and
- In 2004, the stator on unit #1 generator was rewound.

Due to these past upgrades, no work is required on the above plant and equipment at this time.

Engineering assessments were completed on the penstock and surge tank in 2003. Engineering assessments for the remaining systems were completed in 2005 and early 2006. All major components of the Rattling Brook system have been reviewed. Based on these engineering assessments, the project scope and budget have been finalized and are presented in this report.

3.0 Civil Works

The engineering assessment has identified the following civil work to be completed during the plant refurbishment:

- Replace woodstave penstock;
- Coat interior of existing steel penstock;
- Refurbish surge tank; and
- Powerhouse extension and other plant modifications.

Justification for replacement of the woodstave penstock and upgrades to the surge tank were submitted to the Board as part of the 2005 Capital Budget Application. The report completed by SGE Acres titled *Surge Tank and Penstock Replacement – Rattling Brook Hydroelectric Development* is located in Appendix B.

3.1 Penstock

The woodstave penstock is 48 years old and is in poor condition with excessive deterioration and significant leakage along the spring line. The penstock bedding is saturated resulting in localized settlement of the pipe, with the penstock resting on the ground in a number of locations. In recent years, a number of major leaks have resulted in undermining of the support structure in several locations. Leakage is expected to worsen causing operational difficulties, increasing maintenance costs and lost energy. It is proposed to replace the woodstave penstock in 2007.

The lower steel section of the penstock is in fair condition but is showing signs of internal corrosion. It is proposed to coat the interior of the existing steel penstock with a coating system to extend the life of this section of the penstock.

3.1.1 Optimum Penstock Diameter

The existing penstock diameter limits the maximum output of the plant when both units are in operation. When the plant was originally designed, it operated on an isolated system in the Grand Fall's area. Only one unit was operated at a time, with the second unit available as a backup for maintenance purposes. When the plant was connected to the provincial grid the operational requirements changed and both units were in-service simultaneously. However, the plant output and capacity were limited when operating the two units due to high head losses in the penstock. Newfoundland Power intends to increase the plant output and capacity by installing a larger diameter penstock when replacing the deteriorated woodstave penstock. The larger diameter penstock will reduce the head losses in the penstock and result in higher plant production and capacity.

Newfoundland Power intends to replace the existing 2.1 and 2.3 metre diameter woodstave penstock with a 2.9 metre diameter penstock to obtain an additional estimated 5.2 GWh of energy and 2.9 MW of capacity. The incremental cost of increasing the penstock diameter to the optimal diameter of 2.9 metres is justified by the increased energy supplied.

A review selecting the optimum replacement diameter for the woodstave penstock was completed by SGE Acres. A copy of this report is contained in Appendix C *Rattling Brook Development Selection of Optimum Penstock Diameter*. It should be noted that no additional water is required to obtain this energy gain from the system. The additional energy is a result of reduced head losses in the larger diameter penstock, resulting in a higher head at the turbines and thus higher energy output. The larger penstock will increase the megawatt output at the plant from 11.2 to 14.1 MW.

3.1.2 Penstock Replacement Options

Two options are being considered for the replacement of the penstock. These include:

- Building a new penstock adjacent to the existing; or
- Building a new penstock in the same location as the existing.

A review of both options was completed to determine the most feasible and lowest cost alternative. The completed assessment identified several reasons construction of a new penstock adjacent to the existing penstock was not feasible. The reasons include:

1. The surge tank requires a six month outage to complete the refurbishment during which the penstock and surge tank must be drained. Therefore, lost production will not be avoided by twinning the penstock route during this period;

2. The section where the existing penstock crosses under the TCH could not accommodate the second parallel penstock;

3. The civil cost associated with building an adjacent penstock and access road is greater than the cost of replacing the penstock in the existing location;

4. Project costs increase with twinning of the penstock as the project would have to be executed over two construction seasons; and

5. Demolition costs increase significantly as the old penstock must be removed with the new penstock in place making demolition and removal costly as access to the old penstock would be obstructed by the new penstock.

For these reasons the most feasible option is to construct the new penstock in the same location as the existing penstock with some slight alignment improvements over one construction season. The existing penstock does not have an access road adjacent to it. Either replacement option will require the construction of an access road along the existing penstock.

In addition to the two options presented above, the following construction material options are being considered for the replacement of the penstock:

- Building a steel penstock; or
- Building a fibreglass reinforced penstock.

The penstock can potentially be constructed from steel or fibreglass. Engineering estimates have shown that currently the steel and fibreglass options are similar in cost. However, both materials have seen volatility in pricing in recent years. While steel is widely used for penstock applications, fibreglass is not commonly used in the larger diameter penstock proposed for Rattling Brook. It is planned to tender both the steel and fibreglass options to ensure competitive bidding and proceed with the least cost option that meets all technical and engineering requirements.

3.2 Surge Tank

The surge tank is in fair to poor condition and requires an extensive refurbishment to extend the life of the structure. Significant rehabilitation of the structural steel, main tank and internal riser are required. The external riser has deteriorated to the point where complete replacement is necessary. An inspection of the surge tank was completed by SGE Acres in 2003 and their report is included in Appendix B. Issues that will be addressed as part of the 2007 refurbishment plan includes:

- Replacement of the external riser due to heavy corrosion;
- Sandblasting and coating of the tank section;
- General structural and coating upgrades;
- Demolition of the deteriorated wood cladding and installation of a new metal cladding system;
- Installation of a new tank winter heating system; and
- Installation of a new fall arrest system to comply with safety code requirements.

Upgrades to the surge tank will extend the life of the structure and avoid costly replacement of the entire structure in the near future.

3.3 Civil Infrastructure (2008)

Assessments were completed of the civil infrastructure at Rattling Brook including dams, dykes, tunnels, control gates and roads. The assessment is included in Appendix D, *Civil Infrastructure Assessment*. In summary, the civil infrastructure is in good condition. However several items require attention in 2008 to ensure the continued safe and reliable operation of this facility.

Based on the findings in the report the following work is planned for the Rattling Brook hydro system in 2008:

- Replacement of Rattling Lake spillway;
- Upgrades to Amy's dam and Amy's three freeboard dams;
- Replacement of Amy's outlet gate;
- Upgrades to Rattling Lake dam; and
- Upgrades to site access roads.

Due to the need to maximize water storage in the reservoir during the 2007 construction period, water levels in the reservoir will be too high to complete the dam and spillway upgrades. The upgrades will be scheduled in 2008 so they can be completed at lower water levels and without any additional spill from the system. The proposed upgrades will be submitted for approval with the 2008 Capital Budget Application.

3.4 Powerhouse Upgrades

The powerhouse will be upgraded to house the communications equipment, office space and washroom facilities, which are currently in the former control centre building. A small extension will be required in the powerhouse to accommodate these additions. The former control centre building will be used during construction for office space by the project team but will be demolished after completion of the project. This will result in operational savings by eliminating any future maintenance and upgrades to the control centre building.

Other upgrades to the powerhouse include replacement of the 25 year old roof, replacement of the overhead door, provision for a battery room, provision of a switchgear room and installation of access ladders and platforms which are required for safe access to equipment. The garage building adjacent to the powerhouse has become dilapidated and will be renovated.

In summary, the powerhouse upgrades will include:

- Powerhouse building extension;
- Replacement of the powerhouse roof;
- Provision of access ladders and platforms;
- Construction of battery and switchgear rooms within existing building;
- Upgrades to the garage building; and
- Demolition of the old control centre building.

4.0 Electrical Works

Except for the new power transformer, the substation is in its original 1958 condition. Consequently, the materials, hardware and clearances do not comply with current standards. Advances in materials and electrical equipment standards provide a safer and more reliable electrical system. In particular, modern day protective relays are able to respond within fractions of a second to disturbances in the power system, thereby isolating expensive power system equipment such as transformers and generators from the energy of the fault. This results in a longer life for power system equipment and lower operating costs overall.

Deficiencies have been identified with the electrical protection of the generator windings, lack of instrumentation for unit protection, and limitations with the operation of the existing Woodward hydraulic governors. The switchgear, current/potential transformer windings and power cables are original to the 1958 installation and due to age and deterioration must be replaced.

In 2002, the windings were replaced on unit no. 2 generator after there was an in-service failure. The windings on unit no. 1 generator were replaced in 2004. The set of electromechanical protective relays on the generators do not meet the current IEEE recommendations, falling short in the area of ground fault protection, over-frequency protection and stator unbalance. The additional protection provided by implementing the complete set of IEEE recommended protection elements will reduce the risk of the windings failing in service.

The synchronizer is vacuum tube technology dating back to the 1958 installation. Replacement vacuum tubes are no longer manufactured. Similarly, the alarm annunciator is constructed using antiquated technology and fails regularly. Both the synchronizer and annunciator must be replaced in 2007.

The plant AC and DC systems are no longer supported by the manufacturer and do not meet current CSA standards. The 25 kV distribution line to the forebay and Amy's dam is deteriorated and the communications cable to the upstream gate structures is unreliable and must be replaced.

Appendix E, *Electrical Equipment Site Assessment* has identified electrical work to be completed during the plant refurbishment including extension and upgrades to the substation, replacing the existing switchgear and replacing the transmission line and bus protection.

5.0 Mechanical Works

An internal inspection of the turbine runners was completed in 1998 and a further inspection was completed in February of 2005. Some minor work was identified to be completed in 2007. The turbines are in fair condition and a major overhaul will not be required until 2012 and 2013. At that time, one turbine overhaul can be completed in each year, thus resulting in no lost energy.

As was evident during the inspection in February 2005, the main valves do not seal completely. During the assessment, a number of pressure tests were performed. The results show that the main inlet butterfly valves have pressure losses that are approximately three times more than that of modern butterfly valves. Losses across the valves will be reduced significantly by replacing them with new butterfly valves. The new valves will result in an additional 0.5 GWh of energy per unit. It is recommended that the main valves and associated equipment be replaced.

While the governors are in good shape, they do require a minor mechanical overhaul to prevent issues in the future. In order to avail of better unit control and operation with a PLC based control system, the governors will be upgraded with a new electronic control head.

A redesign of the cooling water system is required to address existing operational issues. Separate cooling water systems and backwash strainers for each turbine will result in a more reliable system.

The generator cooling intake dampers are dilapidated and require replacement. An associated walkway for the damper system will be refurbished to provide safe access for employees.

Appendix F, *Mechanical Site Assessment*, has identified mechanical work to be completed during the plant refurbishment including a minor turbine overhaul, replacement of the main valves and associated systems, and overhauling the governors.

6.0 Project Execution

The refurbishment of the Rattling Brook hydroelectric development is necessary for 2007. The completion of the dam and other civil upgrades will be planned for 2008 due to the high storage levels that will exist during construction in 2007.

Consideration was given to completing the entire refurbishment planned for 2007 over one or two years. An engineering review has determined that completing the majority of the work over one year is the least cost alternative. The plant outage required to complete the surge tank upgrade is estimated to take 24 weeks. It is estimated that it will take 32 weeks to complete the woodstave penstock replacement. As a result these two items will be completed in parallel with only eight weeks additional work related to the penstock project. If the project were to be completed over two years additional costs would be incurred due to staging the project twice, maintaining the upper half of the watered woodstave penstock and increasing the duration of the construction period.

Staging the project over two years introduces risk that is not present in the one year option. The risk is due to the need to maintain the upper half of the penstock while the lower half is being replaced. The upper half of the penstock would have to remain watered to keep the wood staves from drying out to the point that they will no longer seal. The penstock would remain under pressure and a bulkhead would have to be installed to seal the end. The bulkhead structure would take three weeks to construct. During this time the woodstave penstock would remain dewatered and the wood staves would shrink as the penstock dries. This shrinkage would result in new leaks when the penstock is watered and considerable effort would be required to reseal the wood staves after the bulkhead is complete. The addition of the bulkhead would involve considerable construction, engineering and maintenance effort, all of which would increase the cost of the project.

Another factor in the decision to complete the penstock replacement and surge tank refurbishment in one year was the necessity to replace the Rattling Lake spillway in 2008. Penstock replacement and dam upgrades cannot be completed during the same construction season because of their different water storage requirements. During penstock replacement the dams must maximize their storage. During dam upgrades, production must be maximized to lower water elevations to allow work to be completed on the dam.

In consideration of all options, the most feasible engineering and financial solution is to complete the penstock and surge tank work in one construction season. All other scheduled work in 2007 will be completed within the 32 week plant outage required for the penstock replacement. The mechanical and electrical upgrades will be scheduled such that installation and pre-commissioning will be completed while the plant is out of service. When the new penstock is re-watered, commissioning can commence and the plant will be back in service within three weeks of rewatering. It is estimated that the plant will be out of service for 35 weeks from early April until the end of November.

In order for the project to be completed on schedule several major items will have to be procured in 2006. The penstock will have to be tendered in the 3rd Quarter of 2006 and awarded in early October 2006 in order to meet the project schedule for fabrication of the penstock. An access road will have to be constructed along the existing penstock in 2006 to advance construction in 2007. Similarly the surge tank rehabilitation will have to be tendered in 2006 and awarded in late 2006 to allow for fabrication of the riser. Other major equipment to be ordered in late 2006 includes the switchgear, main valves and governor controls.

During the 35 week plant downtime it is estimated that 38.2 GWh of water will be spilled at the plant. This lost production has a value of $1.8 million in increased purchase power costs. This lost production is factored into the feasibility analysis.

A detailed project schedule is found in Appendix G. Table 1 shows the proposed high-level schedule for the project.

Table 1
High-Level Project Schedule

2006	2007	2008
Complete engineering design of penstock and surge tank	Replace Penstock	Replace Rattling spillway
Complete electrical engineering design	Refurbish surge tank	Replace Amy's outlet gate
Complete mechanical engineering design	Replace main valves on units #1 and #2	Upgrade Amy's dam
Prepare tenders necessary for 2006 construction	Complete powerhouse extension and upgrades	Upgrade Rattling Brook dam
Tender and award penstock contract	Complete mechanical system upgrades	Upgrade site access roads
Tender and award surge tank contract	Complete substation upgrades	
Tender and award major equipment supply	Complete electrical upgrades	
Construct access road along existing penstock	Complete protection and control upgrades	
	Upgrade forebay/Amy's communication line	
	Upgrade forebay/Amy's distribution line	
	Prepare and execute tenders necessary for 2008	

7.0 Project Cost

The total project cost is estimated at $20.9 million which includes $18.82 million in 2007 and an additional $2.08 million in 2008. Table 2 below provides the project cost breakdown by electrical, mechanical and civil works and by year and system component.

Table 2
Cost Estimate for Rattling Brook Refurbishment
(000s)

Description	2005	2006	2007	2008
Engineering[1]				
Engineering Assessments 2005	$256			
Engineering Assessments 2006		$94		
Civil				
Penstock			$11,705	
Upgrade Existing Steel Penstock			$193	
Surge Tank Upgrade			$1,470	
Plant Upgrades			$352	
Civil Infrastructure				
Amy's Gate				$208
Rattling Spillway				$1,467
Access Road				$35
Amy's Lake Dam Rehabilitation				$218
Rattling Lake Dam Rehabilitation				$152
Sub-Total			**$13,720**	**$2,080**
Mechanical				
Main Valves			$729	
Governor Upgrades			$26	
Cooling Water System			$144	
Plant HVAC and Balance of Plant			$96	
Bearings and Instrumentation			$97	
Commissioning			$25	
Sub-Total			**$1,117**	
Electrical				
Substation Upgrades[2]			$578	
AC and DC Distribution			$154	
Protection and Remote Control			$483	
Switchgear HV			$670	
Exciter Upgrades/Grounding			$68	
Control, Automation and Governor			$760	
Instrumentation			$126	
Communications Relocations			$53	
Communications/Distribution Line			$129	
Supervision and Commissioning			$297	
Sub-Total			**$3,318**	
Project Management				
IDC			$350	
Project Management and Insurance			$315	
Sub-Total			**$665**	
ANNUAL TOTALS	**$256**	**$94**	**$18,820**	**$2,080**
Lost Production			**$1,833**	

1 Expenditure approved in Order No. P.U. 43 (2004).
2 This project is budgeted under the Substations category.

8.0 Feasibility Analysis

Appendix H provides a feasibility analysis for the continued operation of the Rattling Brook hydroelectric development assuming that the planned capital refurbishment is undertaken. The results of the feasibility analysis show that the continued operation of the facility is economical over the long term. Investing in the life extension of the Rattling Brook hydroelectric development ensures the continued availability of 69.8 GWh of energy plus the addition of 6.2 GWh of new low cost energy to the Island Interconnected electrical system.

The estimated levelized cost of energy from Rattling Brook over the next 50 years, including the proposed capital expenditures, is 2.9 cents per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation. Incremental energy from the Holyrood thermal generating station is estimated to cost 7.1 cents per kWh in the short term (assuming $45.00[3] per barrel), with an associated levelized cost of 8.8[4] cents per kWh.

9.0 Conclusion

Engineering assessments have been completed on the civil, electrical and mechanical systems of the Rattling Brook hydroelectric development as approved in the 2005 Capital Budget Application. The engineering assessments have identified necessary work associated with the refurbishment and life extension of the Rattling Brook hydroelectric development. In particular, the woodstave penstock must be replaced as it is at the end of its service life and continues to deteriorate.

Increasing the diameter of the penstock and replacing the main valves will provide 6.2 GWh of new energy and 2.9 MW of capacity. This amount of energy and capacity would be similar to what would be expected from a new small hydroelectric development. This new energy will be provided from a more efficient use of the existing water resource. No additional water will be required to provide the new energy.

The feasibility analysis included in Appendix H verifies the financial viability of completing this project. The 76 GWh of energy that will be available from Rattling Brook each year will play a significant role in providing affordable energy to the customers of Newfoundland Power for years to come. The planned schedule for project execution ensures the minimum amount of lost production due to spill. Based upon these considerations, and others outlined in this report and attached assessments, the project is recommended to proceed in the 4th Quarter of 2006 with execution of construction in 2007.

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3 Newfoundland and Labrador Hydro’s forecast fuel price submitted in response to request for information PUB 13 NLH for their application for 1 percent sulphur fuel recovery costs through the RSP.

4 50-year levelized using escalation factors based on the Conference Board of Canada GDP deflator, December 13, 2005.

Appendix A

Pictures of Rattling Brook Penstock and Surge Tank

Figure 1: Water Leakage from Penstock

Figure 2: Water Leakage from Penstock

Figure 3: Water Leakage from Penstock

Figure 4: Water Leakage from Penstock

Figure 5: Water Leakage from Penstock

Figure 6: View of Surge Tank

Figure 7: Lower Section of Woodstave Penstock

Figure 8: Ice Build-up on Penstock due to Water Leakage

Figure 9: Ice Build-up on Penstock due to Water Leakage


Figure 10: Ice Forming on Penstock during Winter


Figure 11: Settlement of Penstock Supports

Figure 12: Crushing of Woodstaves

Figure 13: Undermining of Penstock Bedding

Figure 14: Settlement of Penstock into Bedding

Figure 15: Repairing Leakage

Figure 16: Leakage at Lower Section of Penstock

Figure 17: Leaking Woodstaves

Figure 18: Leakage at Expansion Joint

Figure 19: Leakage at Expansion Joint

Appendix B

SGE Acres: Surge Tank and Penstock Replacement – Rattling Brook Hydroelectric Development

Prepared for

Newfoundland Power

55 Kenmount Road, St. John's, NL   A1B 3P6

Consulting Services for

Surge Tank and Penstock Inspection – Rattling Brook Hydroelectric Development

Final Report

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 APEGN T0060
which is valid for the year 2003

REGISTERED PROFESSIONAL ENGINEER
G. D. SAUNDERS
SIGNATURE
DEC 8/03
DATE
NEWFOUNDLAND & LABRADOR

Prepared by

SGE Acres Limited

November 2003

P15310.00

SGE Acres

Table of Contents

1 Introduction

1.1 General

Following the submission of a proposal on September 18, 2003, SGE Acres was contracted by Newfoundland Power (NP) to carry out an inspection of the penstock and surge tank at the company's Rattling Brook hydroelectric station in central Newfoundland. This report is the result of that inspection.

Prior to the site visit, as a requirement of the contract, SGE Acres submitted a project specific Health and Safety Plan to NP for review. SGE Acres also subcontracted inspection support relating to rigging and structure access to Remote Access Technology (Newfoundland) Limited of St. John's. This company also carried out ultrasonic thickness measurements as required by the contract.

The site inspections, which were carried out from October 14-17, 2003, comprised:

- a visual inspection of the exterior of the woodstave portion of the penstock
- a visual inspection of the interior of the surge tank and surge tank internal and external risers
- a visual inspection of the surge tank support structure
- a visual inspection of the interior and exterior of the steel portion of the penstock
- ultrasonic measurements of the wall thickness of the surge tank and steel penstock.

Mr. G. Saunders, P.Eng., of SGE Acres St. John's office carried out the inspections with the support of the subcontractor. Mr. G. Murray, P.Eng., was NP's representative during the inspections.

1.2 Description of the Facility

The Rattling Brook Hydroelectric Development, which is located near Norris Arm in central Newfoundland, has a capacity of 15 MW from two identical units fed from a bifurcation. The facility was commissioned in 1958. The water conveyance system consists of a combination woodstave and steel penstock and steel surge tank. The tank has four main components:

- Four support legs with a base diameter of 9.6 m (31'- 6") and height of 63.1m (207' ft)
- Steel tank which is 32.9 m (107'-9") high with a 6.1 m (20'- 0") ID steel shell and 6.6 m (21'- 8" ft) OD frost casing
- Internal riser with a diameter of 1.8 m(6'- 0") and height of 32 m (105ft)
- External riser with a diameter of 2.1 m (7'- 0"), 2.5 m (8'-4") diameter frost casing and height of 62 m (203'-9").

The tank and lower riser are protected with an external creosoted timber jacket.

The woodstave/steel penstock is approximately 1980 m (6500 ft) long. The first 1677 m (5550 ft) is woodstave with the first 634 m (2080 ft) having an internal diameter of 2.3 m (7.5 ft) and the remainder having a diameter of 2.1m (7 ft). The steel portion is 290 m (950 ft) long and about 192 m of this is upstream of the surge tank and is supported on steel saddles on concrete bases. The remaining 97.5 m (320 ft) downstream of the surge tank is buried.

2 Results of the Inspection

2.1 Woodstave Portion of Penstock

A visual inspection of the woodstave penstock from the intake thimble to the aboveground steel portion of the penstock was undertaken on October 14, 2003. This inspection was carried out while the penstock was pressurized so that an assessment of the water leakage and condition could be made under normal operating conditions. To visually inspect as much as possible Mr. Saunders and Mr. Murray walked opposite sides of the penstock.

The wood staves were found to be in poor condition. (See photo number 16)
Many areas along the spring line were leaking. Most of the leaks were in end joints; however, there were leaks in longitudinal joints and displaced knots. As would be expected, the leakage intensified as the pressure in the penstock increased. (See photos number 17, 18 and 19)

The steel bands and rod ends were in good condition with little corrosion evident. The stud bolts holding the saddles together showed signs of corrosion.

Along the penstock, there was evidence of previous repairs which included steel plates and wooden wedges.

Two different styles of wooden saddles were used to support the penstock. In general both support types were in satisfactory condition. In some areas, the cradle blocks were cracked around the tie rods. These cracks in the wood were not serious enough to weaken the saddle load carrying capacity. A few of the saddles were in areas of high water flow, caused by leakage, where washout of the supporting gravel base was a concern. (See photo number 20)

Following the inspection, repairs were made to previously identified areas. Approximately 100 steel plates 1.6 mm thick ranging in size from 300 mm x 300 mm to 300 mm x 1200 mm were placed between the exterior of the penstock and the steel bands. Rubber gasket material was placed underneath the plates to make a seal. After the penstock was depressurized, 30 bundles of cedar roofing shingles were used to seal some of the remaining leaking areas. (See photos number 14 and 15)

2.2 Steel Portion of the Penstock

2.2.1 External

An external visual and ultrasonic thickness inspection of the steel penstock was performed. The initial inspection was made when the penstock was pressurized so that any areas of leakage could be identified.

The penstock changes from woodstave to a welded steel section as it nears the surge tank. There are two concrete anchor blocks and two slip type expansion joints in the aboveground section of the penstock. The penstock was shop fabricated in sections of approximately 30 to 40 feet and field welded together. The aboveground sections are supported on steel saddles and concrete base pads. The supports have a fabric bearing pad placed between the curved saddle plate and the penstock; there are no wear plates welded to the penstock at the saddle locations. The notes on the drawing indicate the bearing fabric is a bonded material containing asbestos. This original material was supplied in two pieces which were cemented to the saddle and penstock metal surfaces. During the initial inspection it was noted that in some areas the bearing fabric was pulled out from between the penstock and the saddle. These areas were revisited after the penstock was dewatered. It would appear that the longitudinal motion due to expansion and contraction has caused slippage of the fabric. (See photo number 11)

The above ground portion of the steel penstock runs from the first concrete anchor block, where the woodstave is connected, to the surge tank anchor block. The portion of the penstock downstream of the surge tank is underground and can be accessed through hatches in each leg of the bifurcation located inside the powerhouse, through the hatch at the bottom on the surge tank external riser or through the main penstock access hatch located downstream of the second anchor block.

The penstock is coated with a silver coloured painting system which is in good condition. There is one area near the first expansion joint where the paint is missing causing the steel plate to oxidize. (See photo number 21)

The welded joints are sound; however, there is evidence of out of roundness and peaking at many of the joints. None of these defects are detrimental to the performance of the penstock.

The penstock supports were in good condition with no signs of damage or corrosion. The concrete base pads and the anchor bolts were inspected and found to be in good condition.

The concrete anchor blocks were in good condition considering their age. One area requiring repair was found on the upstream end of the first anchor block. There was concrete damage and a small amount of water leakage at the 6 o'clock position.

The expansion joints were inspected and found to be tightened incorrectly. The packing ring was not pulled in evenly around the circumference indicating the tensioning bolts were not tightened evenly. The expansion joint located between the two anchor blocks was not leaking; however, the second expansion joint, located between the second anchor block and the surge tank, had a large leak at the top which appeared to have been leaking for some time. (See photo number 12)

The inspection hatch, which is located in the top of the penstock just downstream of the second anchor block, was found to be in good condition with no evidence of leakage.

After the penstock was dewatered, a second external inspection was completed. This included a further inspection of the saddles, ultrasonic thickness measurements of the penstock shell plate and the interior of the access hatch. The recorded thickness readings can be found in Appendix C.

2.2.2 Internal

After the penstock was dewatered, the inspection hatches in the powerhouse, surge tank and aboveground steel penstock were opened and the penstock allowed too ventilate naturally. The penstock was then checked for oxygen level before entering.

The inspection was performed in two phases. The first phase of the inspection was carried out by a two person team which included Mr. Saunders and an assistant from RAT. This phase involved the inspection of the interior of the penstock from the access hatch to the surge tank tee where the slope was shallow and rope access unnecessary.

The 23 m (75 ft) section of the penstock upstream of the access hatch has a steep slope and could not be accessed for inspection.

A thick cake-like deposit was found on the bottom of the penstock, at the base of the elbow located at anchor block number 2. This deposit was easily chipped away from the penstock exposing a layer of oxidized metal. (See photo number 10)

Moderate corrosion pitting of the interior surface was evident over the entire length. The surface was generally rough with no signs of erosion damage on any surfaces. There did not appear to be any increased corrosion activity at the welded joints.

The expansion joint appeared to be in good condition with no significant corrosion of the leading edge of the slip joint. There was no build up of sediment in the joint and it appeared free to move. (See photo number 7)

The surge tank tee had the most corrosion. The low pressure area just above the upstream entrance to the tee was covered in large scale deposits and carbuncles. (See photos number 8 and 9) Also areas around the bottom of the tee had thick cake deposits similar to those found at the base of the upstream elbow. Samples of this caked material were taken for future analysis.

Removal of the deposits and carbuncles revealed large deep pitting of the metal surface. The surface was very rough, making it impossible to accurately measure the depth of the corrosion.

The lower section of the penstock from the surge tank tee to the powerhouse required rope access and was completed by RAT during the second phase of the inspection. The interior of the underground portion of the penstock was found to be in a similar condition to the aboveground portion.

2.3 Surge Tank

The surge tank inspection was performed in several phases all of which required rope access and were completed by RAT personnel under the supervision of Mr. Saunders.

2.3.1 Exterior Structure

The surge tank is supported on four pipe legs with a system of diagonal rod braces and horizontal box sections used to transfer the wind loads to the foundations. There are two platform levels, one at the external riser expansion joint and the other at the base of the surge tank. The platform at the base of the tank also serves as the compression ring at the top of the support legs. Both platforms were found to be in good condition. (See photo number 6)

The caged ladder is attached to the leg on the southeast corner. The ladder has an anti-fall device, which has been condemned. Rope access was used to provide a safe means of ascending and descending the ladder.

An inspection of the surge tank tower was completed in 1998 by Varcon Inc. The results of this inspection were made available to the inspection team, and it was found that the issues which were found in 1998 were still evident during this inspection. In addition NP advised that a leak in the surge tank access opening located in the side of the hemispherical dish had caused a large buildup of ice during the 2002 -2003 winter. Mild temperatures caused a large piece of ice to fall and strike one of the tie rods connecting the external riser to the support leg and a horizontal support member. The tie rod was found hanging from its pin connection at the leg because the connection plate to the external riser had sheared at the weld. To remove the potential hazard, the tie rod was cut using a hand grinder and lowered to the ground. (See photo number 5)

The horizontal member located on the north face, second horizontal from the top has been bent and has two cracks in the welds which connect the clevis plates to the end plate of the box section. The two cracks, which are short in length, are located on the top of the joints and are consistent with an impact load acting on the top of the horizontal member. This joint is normally under compression and the welds under shear due to the horizontal compression from the diagonal bracing and vertical dead load. It is not anticipated that the cracks will grow under normal live and dead loads. (See photo number 21)

As stated in the Varcon report the diagonal braces are sagging and have kinks and bends. At the point where they cross, there is noticeable metal loss due to the constant rubbing. (See photos number 3 and 4)

The frost casing is made of wood. There is noticeable deterioration of the wooden surface due to weathering. (See photo number 6)

The 2-inch pipe nipple connection to the external riser, located inside the small building at the base of the surge tank, was removed and replaced with a 2 inch 3000# capacity coupling and steel plug.

The cover of the external riser access hatch was heavily corroded.

2.3.2 Surge Tank Interior

Rope access was used to inspect the interior surface of the surge tank. The tank, roof structure and vent are in good condition for the upper 17 m with the painting system intact. The lower section is in fair condition with surface corrosion and pitting.

Thickness measurements were taken on the shell plate using an ultrasonic thickness meter. The measurements are listed in Appendix C.

2.3.3 Internal Riser

Rope access was used to inspect both surfaces of the riser. The upper tie rods and upper 17 m of the riser and external stiffener rings are all in good condition with the painting system intact. The lower section is in fair to poor condition with surface corrosion and pitting. (See photo number 2)

The connection to the hemispherical dished head is in fair condition with surface corrosion and pitting.

Thickness measurements were taken on the shell plate using an ultrasonic thickness meter. The measurements are listed in Appendix C.

2.3.4 External Riser

Rope access was used to inspect the interior surface of the external riser. The surface is rough and corroded over the entire length. The surface roughness was such that no thickness or reliable pitting measurements could be taken on the interior. Some ultrasonic thickness measurements were taken from the exterior near the access opening at the base of the riser and are listed in Appendix C.

3 Conclusions and Recommendations

3.1 Woodstave Penstock

3.1.1 General

Based on a visual inspection, the penstock is in poor condition. Leakage of the penstock at the springline is substantial. The surface quality of the wood is poor and the saddles, although substantially intact, are showing their age. Woodstave penstocks generally have a life of 50 years and this penstock is currently 45 years old. We recommend the penstock be replaced in the near future as we expect the leakage problem to worsen causing operational difficulties and increasing maintenance costs.

3.2 Steel Portion of the Penstock

3.2.1 General

The penstock is in fair condition, but there is evidence of deep isolated pitting of the internal surface. There are many areas of thick surface deposits such as carbuncles and thick cake.

There is no immediate danger to the structural integrity of the penstock shell but continued surface corrosion will reduce its service life. Failure due to pitting corrosion will not be catastrophic but will come in the form of pinhole leaks. The penstock life could be extended indefinitely provided the corrosion deposits are removed and the metal surface blast cleaned and coated with a high build epoxy coating system.

3.2.2 Aboveground Penstock

1. The saddle bearing fabric should be readjusted where it has moved out of position. Appropriate care in handling should be taken as the material contains asbestos and is considered hazardous.
2. Where paint is missing, it should be repaired.
3. The expansion joints should be checked periodically for leakage. During the inspection, the second expansion joint was disassembled, due to a large leak at the top, and repacked with new flax rope. Care was taken to tighten the packing evenly around the circumference.

4. Concrete repairs are needed on the upstream side of the first anchor block. There is leakage and deteriorated concrete at the 6 o'clock position.

3.2.3 Underground Penstock

See general recommendations Section 3.2.1.

3.3 Surge Tank Structure, Surge Tank and Internal Riser

1. The horizontal support which was damaged during the winter of 2002/03 should be replaced. One of the clevis ends is cracked at the welds. See location marked on Drawing No. P15310.00SK-01.
2. Due to the type of loading to which this member is subjected, we do not anticipate the cracks will grow and cause a failure of the connection. We recommend the structural member be replaced as early as practical.
3. The diagonal bracing is sagging and needs to the tightened. In some of the braced bays the bracing appears to be bent or permanently deformed. A replacement assessment should be made after tightening is attempted.
4. Due to the sagging of the diagonal rod bracing, there is metal loss where the rods cross. The material loss should be stopped by attaching a wear plate between the two rods. We recommend using 10mm thick HDPE plastic pads which can be attached to the rods with galvanized U-bolts.
5. There is a loose piece of expanded metal mesh on the revolving dolly located on the roof. A temporary repair was made during the inspection, but a permanent repair should be made as soon as practical.
6. The removed external riser tie rod should be replaced.
7. The wooden frost casing is dried out and should be replaced within the next 5 years.
8. The surge tank and internal riser are deteriorating and need to be blast cleaned and coated with a high build epoxy paint system. Some of the plate may require patching but an assessment is not possible without blast cleaning the surface. If necessary, the lower can sections could be replaced when the external riser is replaced.
9. General painting touch-up should be carried out where rusted areas appear. The coatings, both internal and external, should be inspected every five years. Maintenance of the coatings will prevent further corrosion of the steel and

avoid costly replacement of the surge tank, surge tank risers and its structural frame.

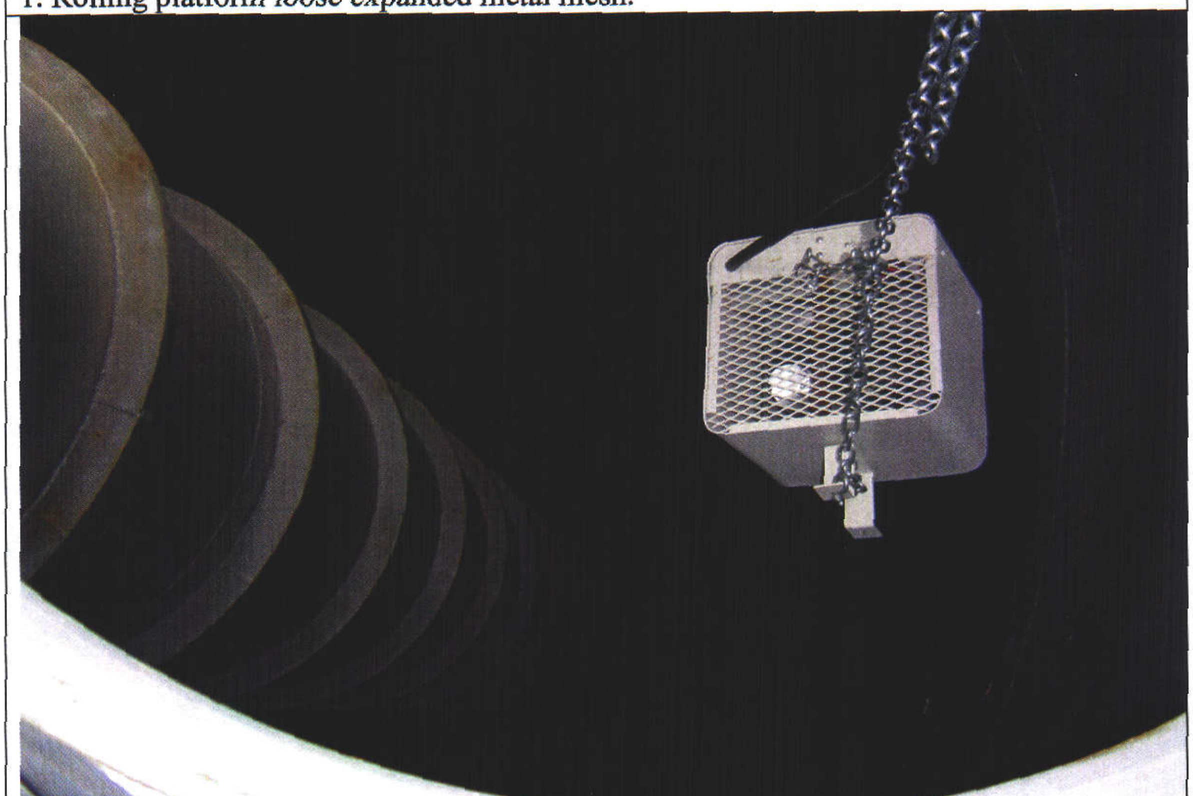
10. Concrete repairs identified in the 1998 Varcon report for the crack at the top of the surge tank anchor block and the tops of the concrete foundations under the surge tank legs should be completed in 2004. The cost to repair these areas is small. Delaying these repairs by many years will allow continued deterioration of the anchor block and its steel reinforcing and deterioration of the support grout under the surge tank legs. (See photos 3 and 4 in the 1998 Varcon report)

3.4 External Riser

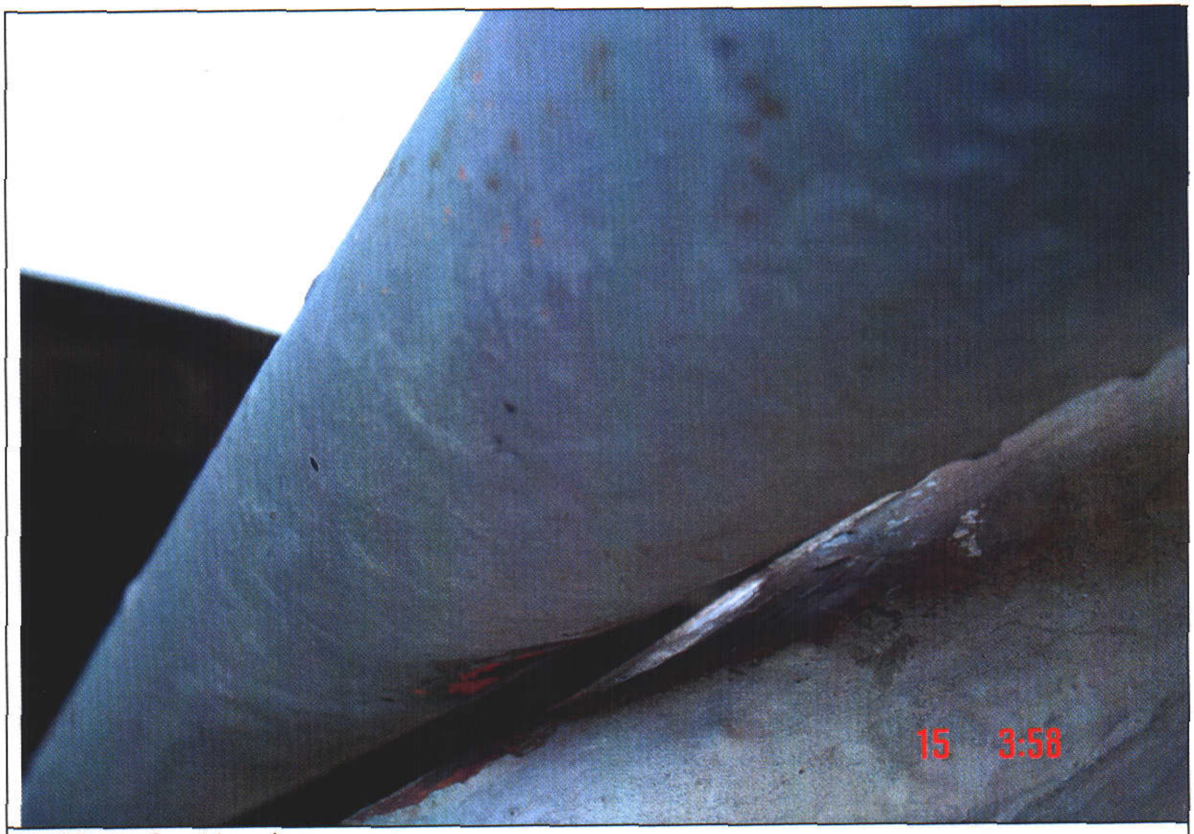
The external riser is heavily corroded and is in the worst condition of all the fabricated steel components. In our opinion, it has deteriorated to the point that it cannot be repaired and should be replaced within the next 5 years.

Appendix A – Photographs

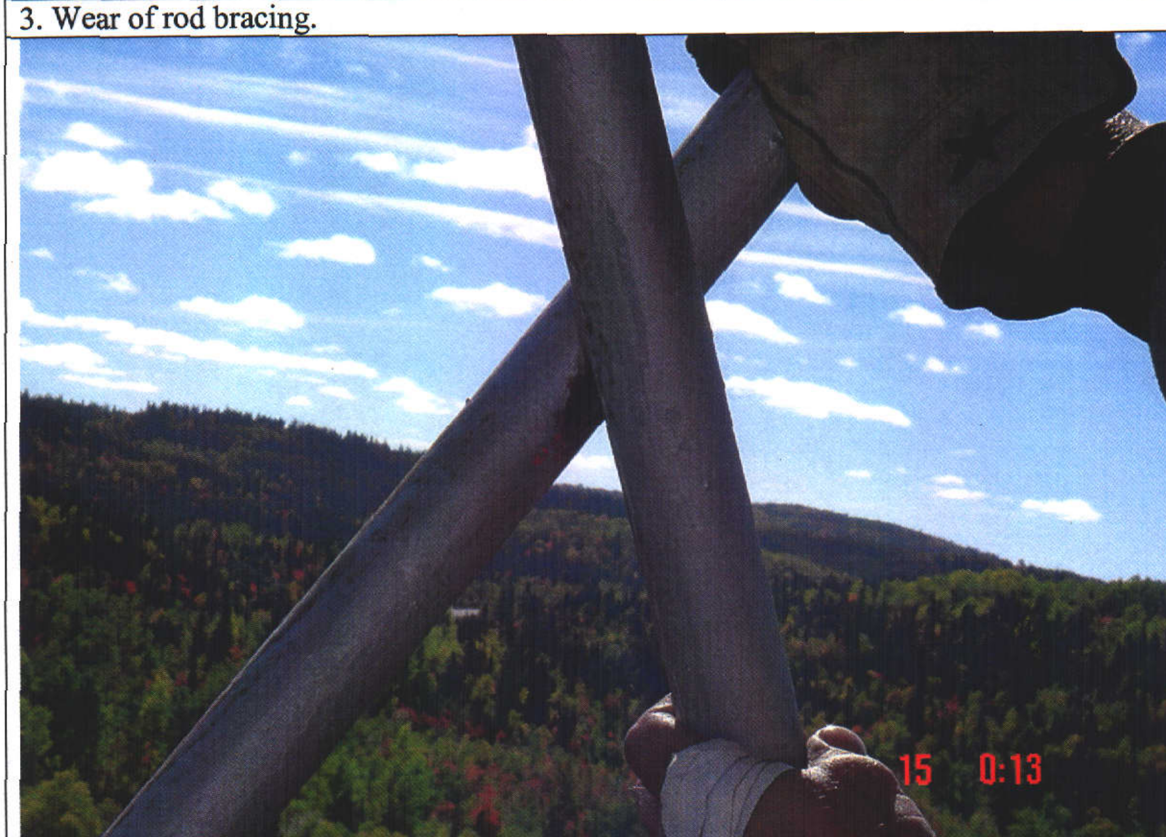
1. Rolling platform loose expanded metal mesh.



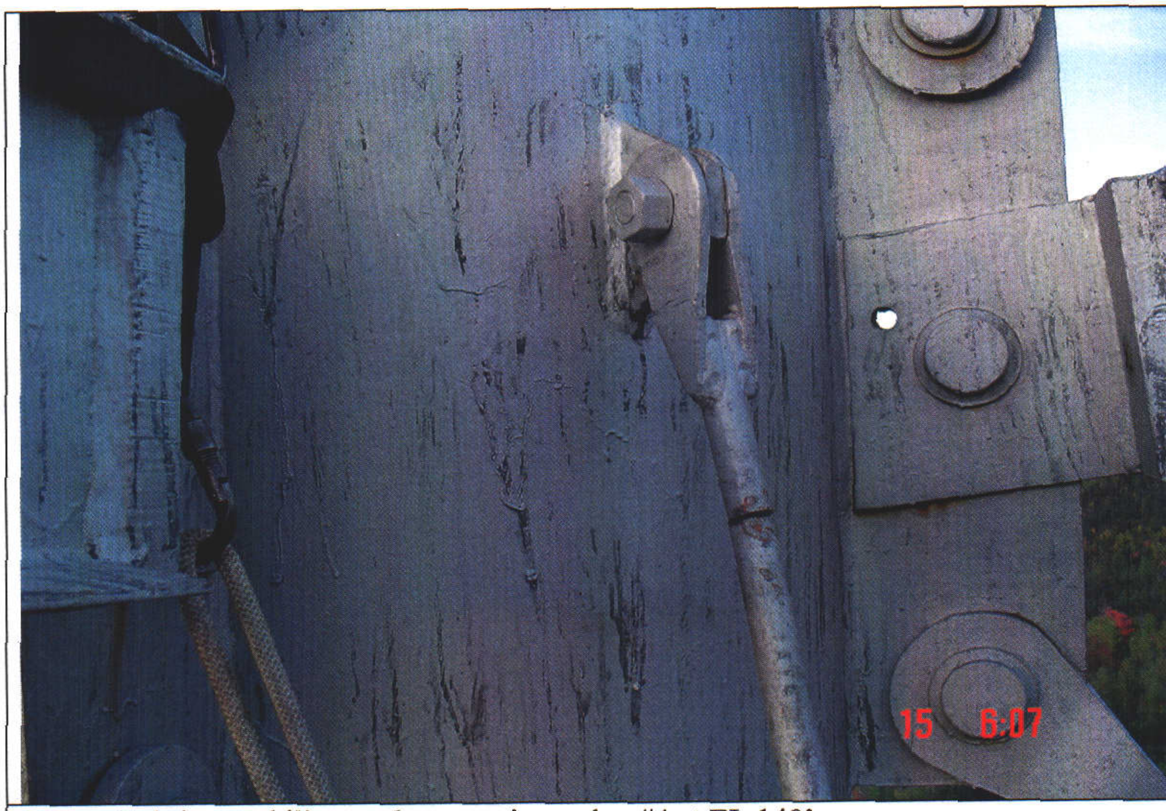
2. View of internal riser and surge tank from roof hatch.



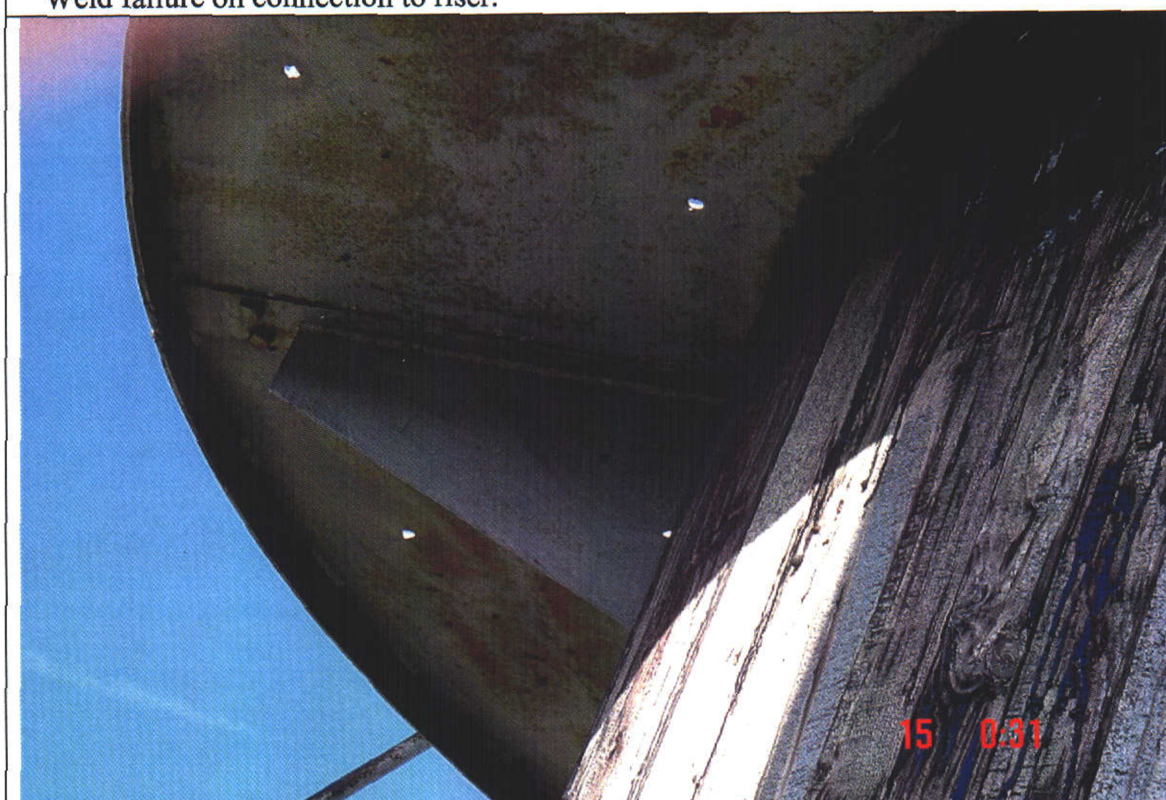
3. Wear of rod bracing.



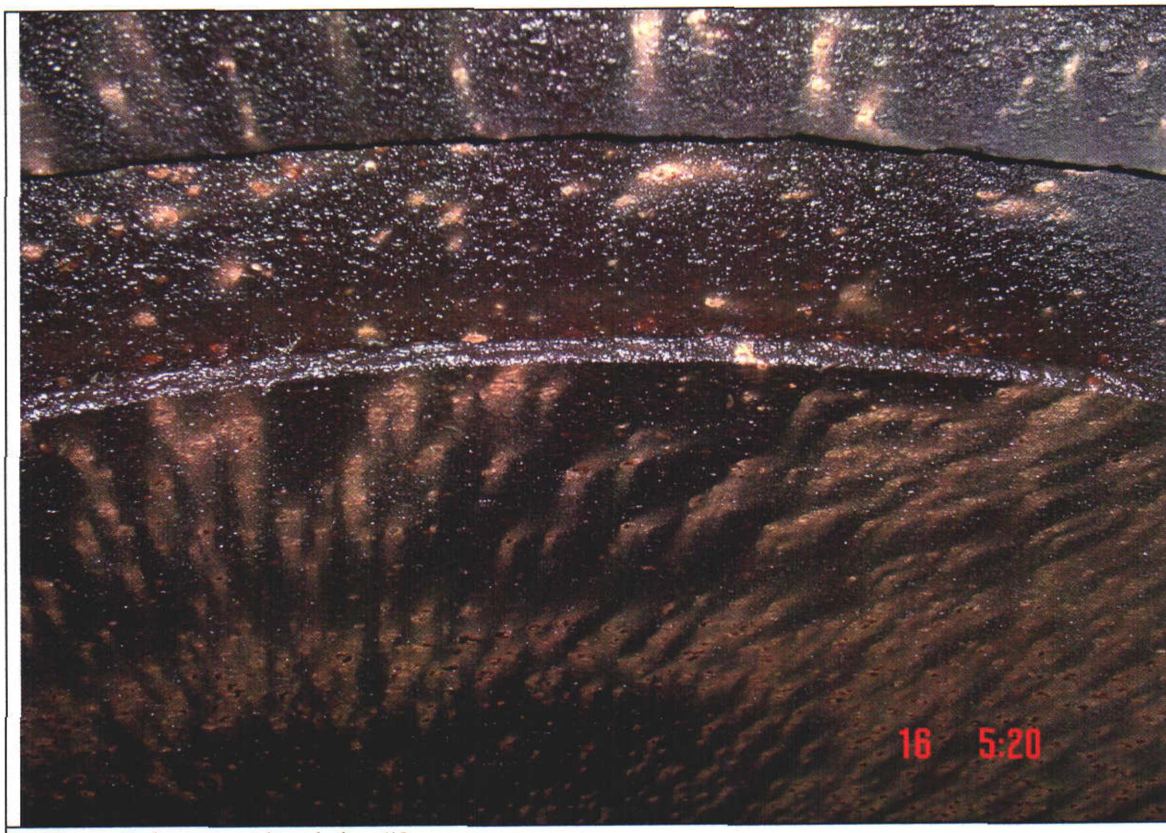
4. Wear of diagonal rod bracing.



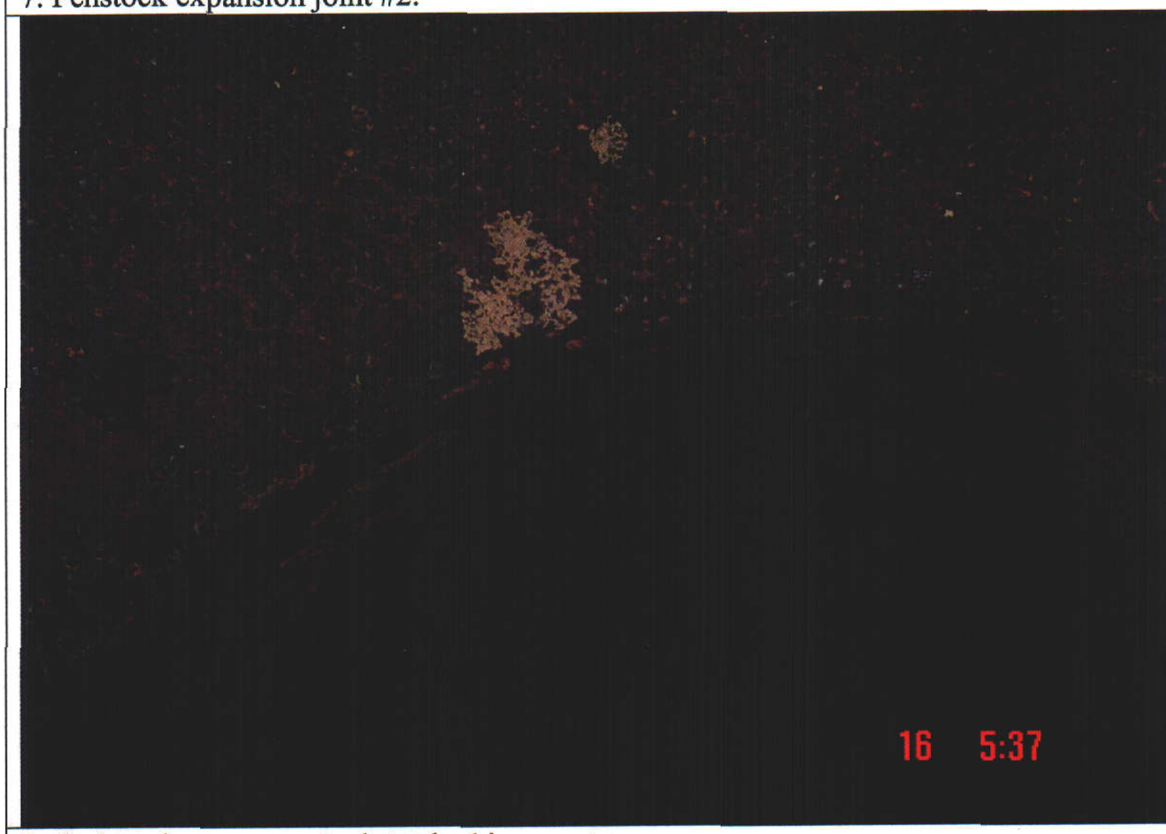
5. External riser stabilizer rod connection to leg #4 at EL.140’.
Weld failure on connection to riser.



6. Compression ring and walkway at EL.207’.

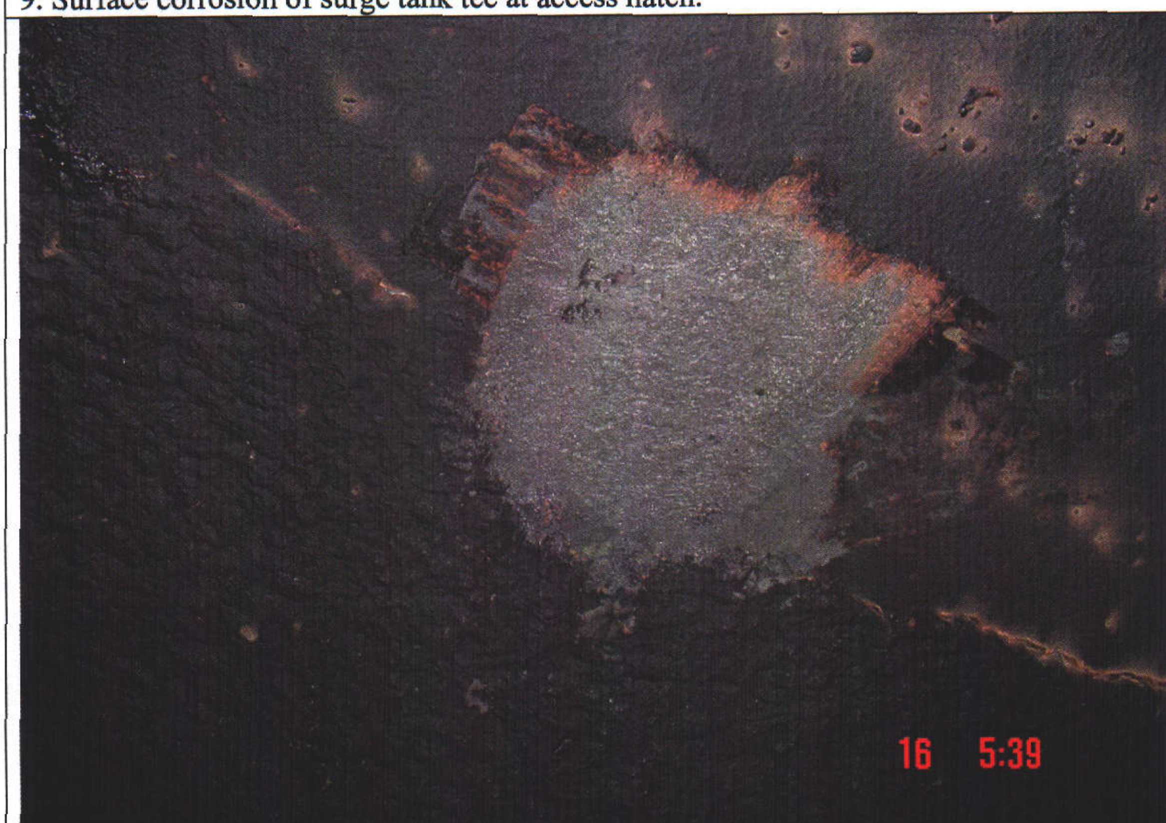


7. Penstock expansion joint #2.



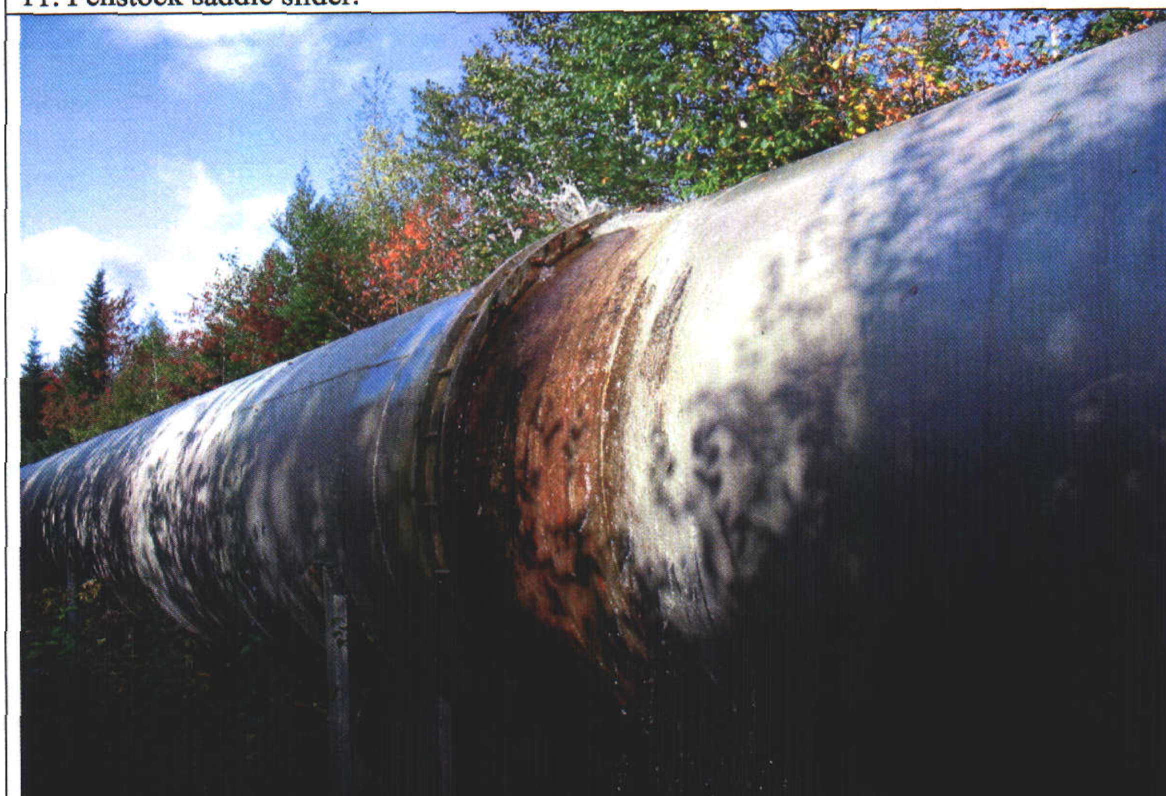
8. Carbuncles on surge tank tee looking up stream.

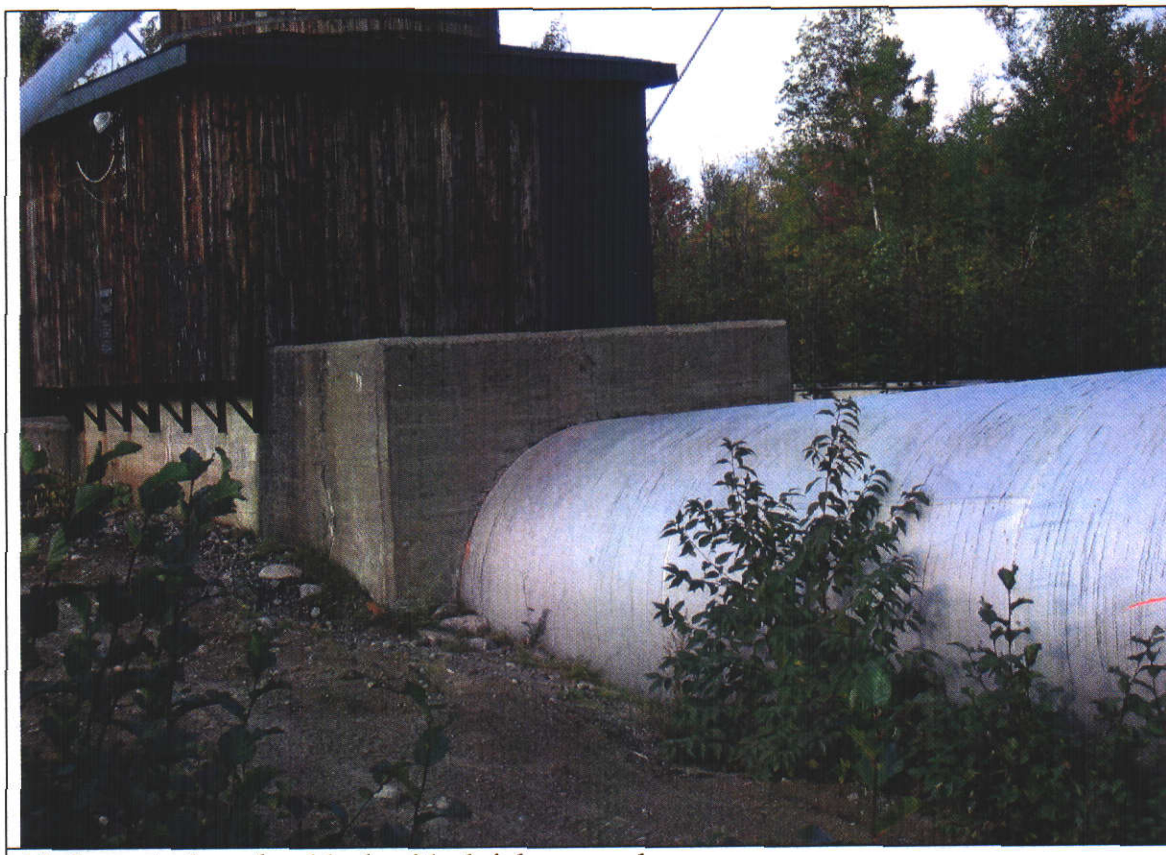
9. Surface corrosion of surge tank tee at access hatch.



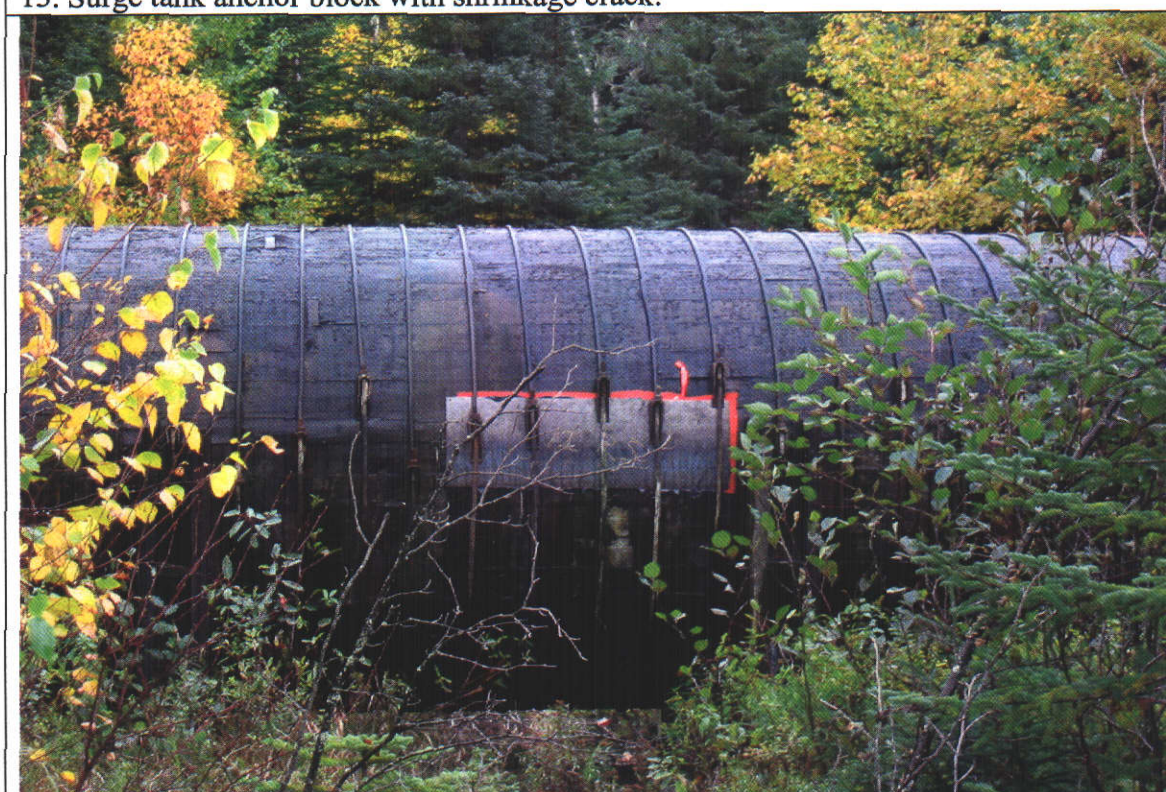
10. Caked build up on floor of surge tank tee.


11. Penstock saddle slider.


12. Expansion joint #2 leaking at top.



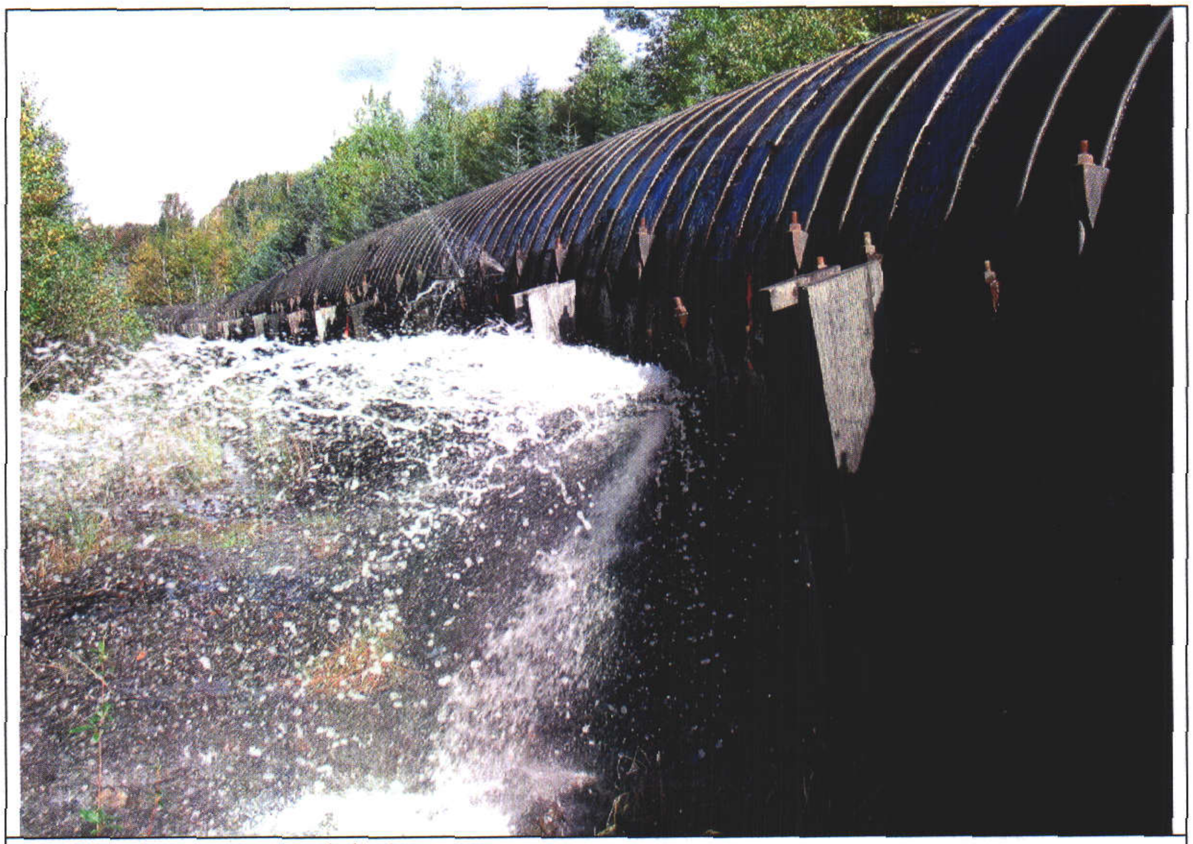
13. Surge tank anchor block with shrinkage crack.



14. Wood stave penstock steel plate patch.

15. Wood stave penstock typical patch plate location marking.

16. Wood stave penstock surface condition.

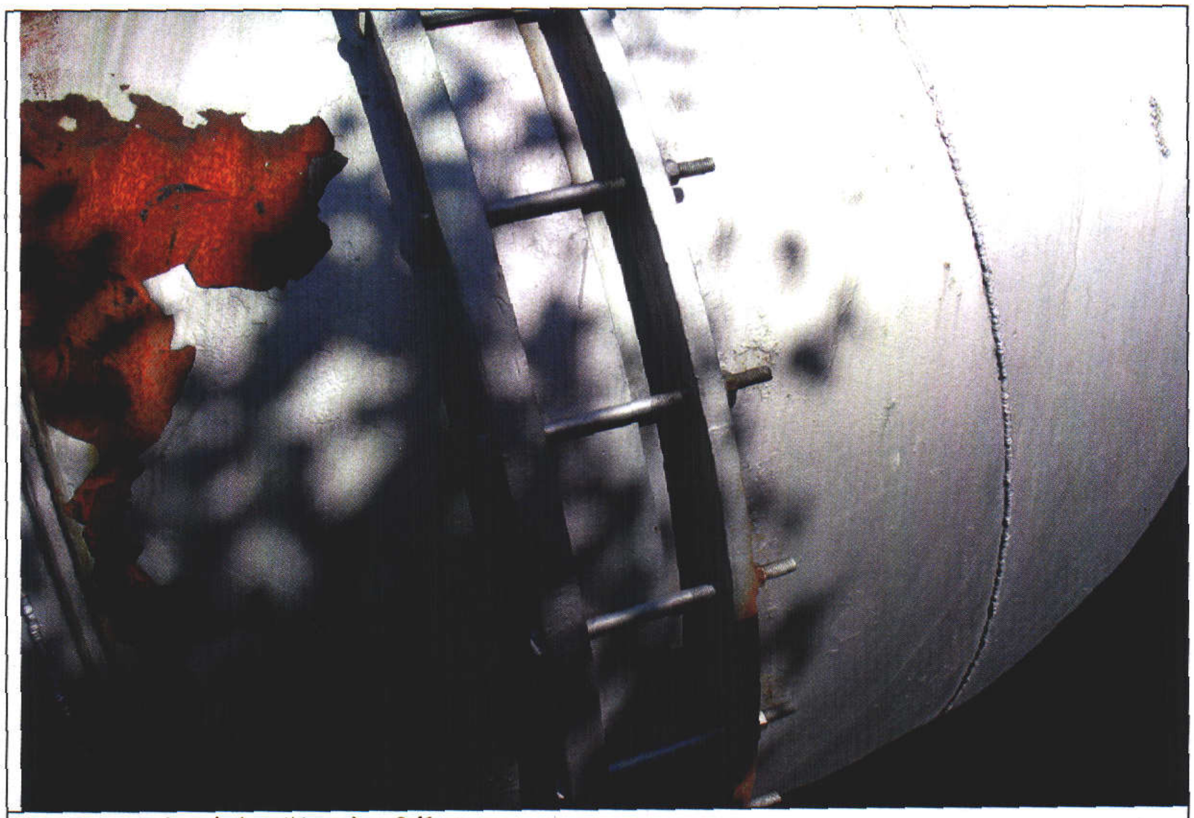


17. Wood stave penstock leakage.

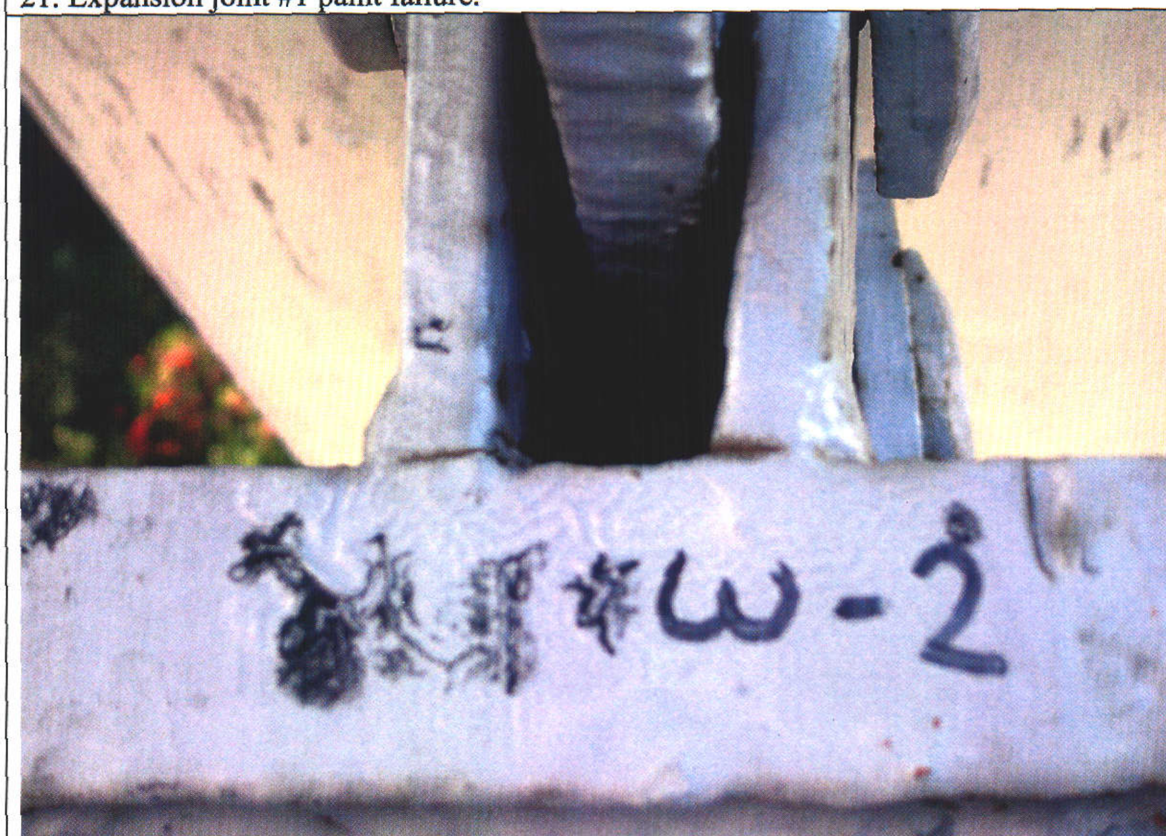
18. Wood stave penstock leakage.

19. Wood stave penstock leakage.

20. Wood stave penstock saddle deterioration.

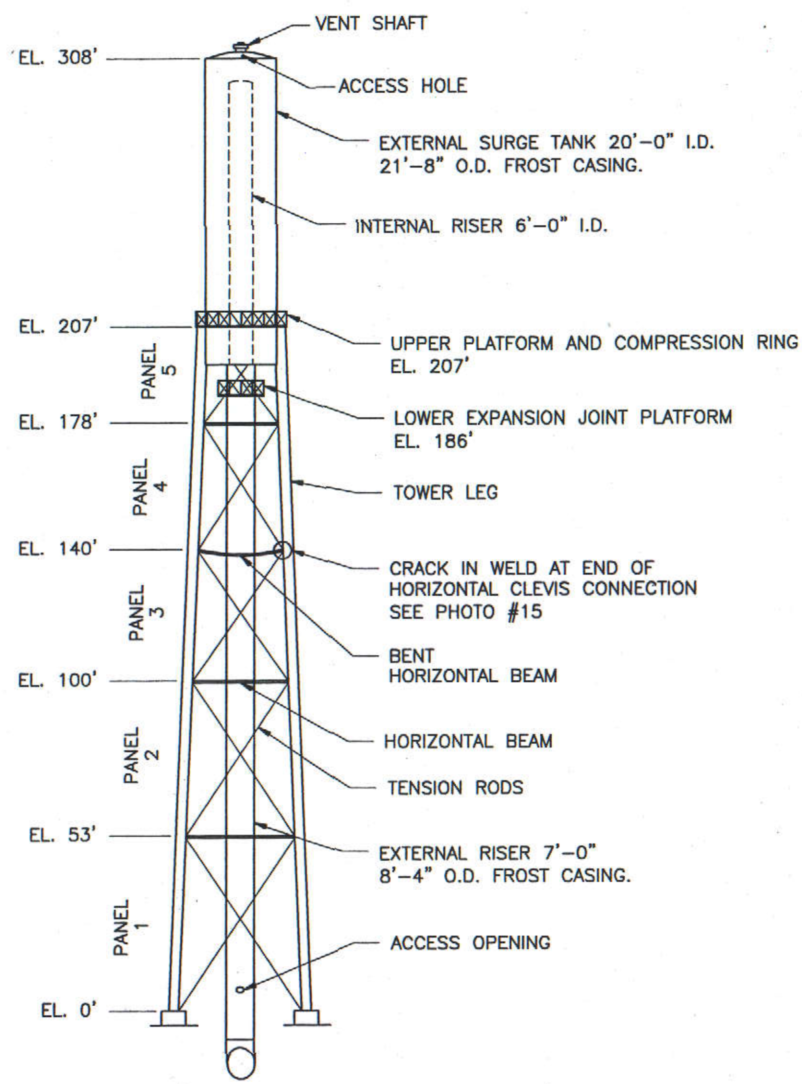


21. Expansion joint #1 paint failure.

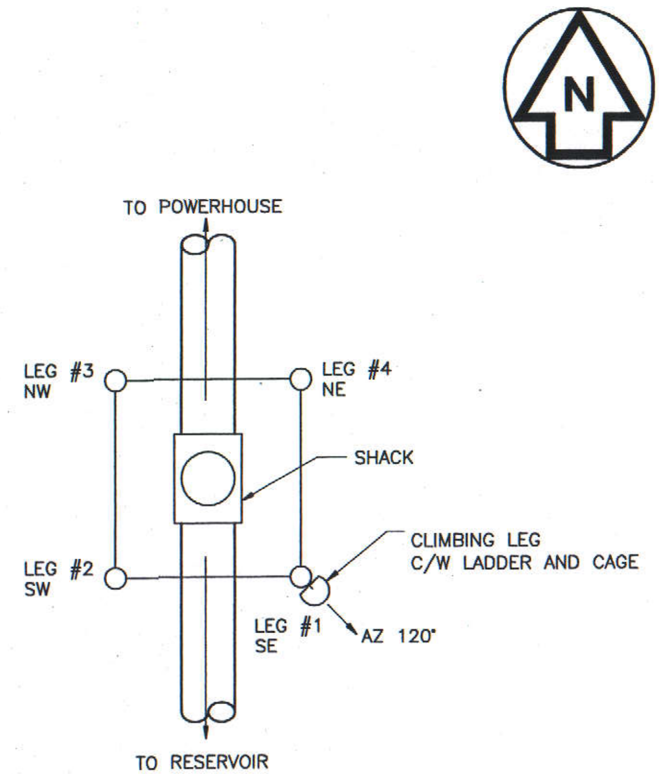


22. Horizontal brace north face at leg #3. Cracks in welds.

Appendix B – Sketches



NORTH ELEVATION
NTS



SITE LAYOUT
NTS

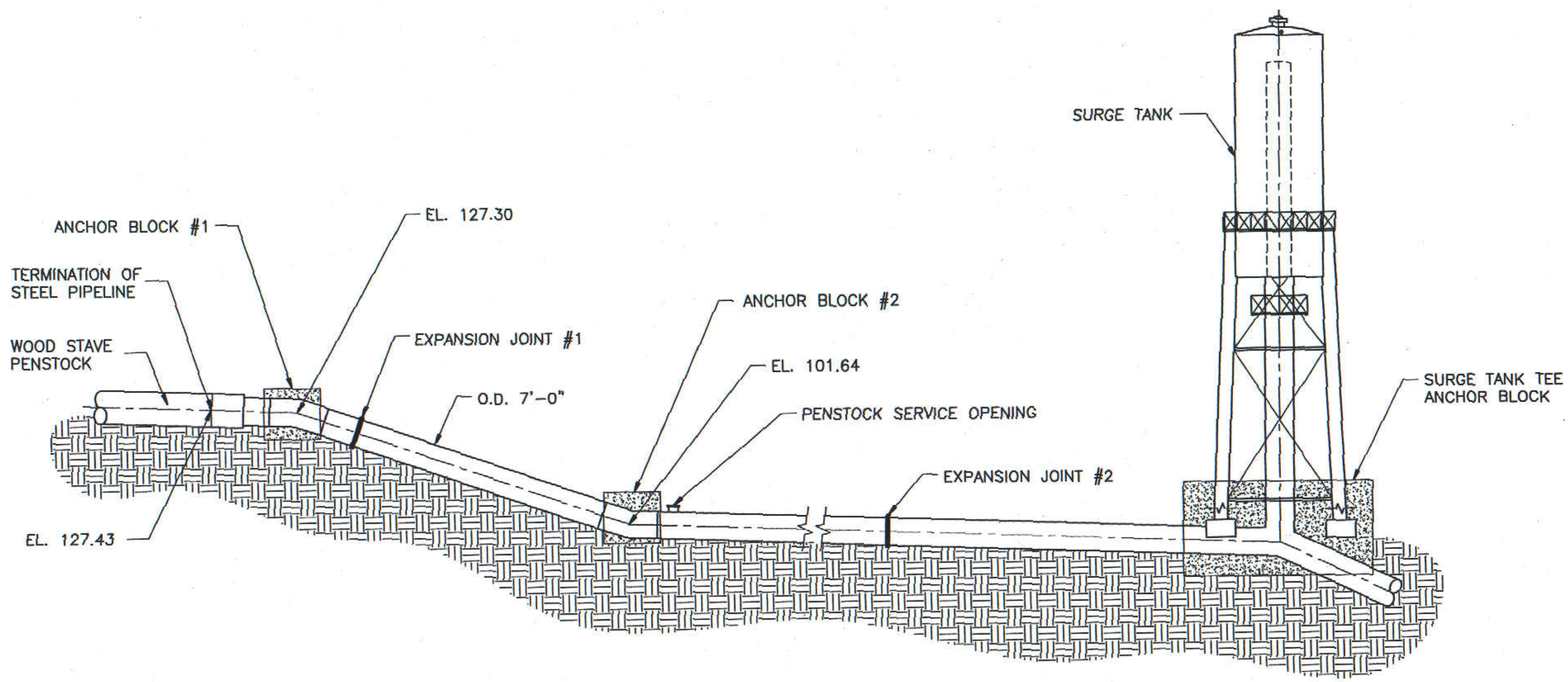
SGE Acres
SGE ACRES LIMITED

NEWFOUNDLAND POWER
RATTLING BROOK

PREPARED: M. Woodford
CHECKED: G. Saunders
PROJECT MANAGER: G. Saunders
DATE: DEC.01.2003

308' DIFFERENTIAL SURGE TANK
ELEVATION AND LAYOUT

ACRES PROJECT No. P15310.00
DRAWING No. P15310.00–SK–01
REVISION 0



PENSTOCK ELEVATION

NTS

SGE Acres SGE ACRES LIMITED	NEWFOUNDLAND POWER RATTLING BROOK	
PREPARED: M. Woodford CHECKED: G. Saunders PROJECT MANAGER: G. Saunders DATE: DEC.01,2003	7'-0" DIAMETER PENSTOCK AND SURGE TANK ELEVATION	
	ACRES PROJECT No.: P15310.00	DRAWING No.: P15310.00-SK-02

Appendix C – Thickness Measurements

Newfoundland Power
Rattling Brook Penstock Inspection

Penstock Ultrasonic Thickness Readings (Starting From Surge Tank Going Upstream)

Can Number	Thickness inches	Pit Indication Lowest Thickness inches	Original Thickness	Percentage Loss	Location
#1	0.446		0.4375	0.00	First Can Upstream of Surge Tank Anchor Block
#2	0.460	0.134	0.4375	0.00	
#3	0.417	0.233	0.4375	4.69	
#4	0.409	0.31	0.4375	6.51	
#5	0.447	0.29	0.4375	0.00	
#6	0.480	0.123	0.4375	0.00	
#7	0.462	0.383	0.4375	0.00	
#8	0.489		0.4375	0.00	
#9	0.466	0.342	0.4375	0.00	
#10	0.466		0.4375	0.00	
#11	0.435	0.163	0.4375	0.57	
#12	0.447		0.4375	0.00	
#13	0.445		0.4375	0.00	
#14	0.461		0.4375	0.00	
#15	0.435		0.4375	0.57	
#16	0.443		0.4375	0.00	
#17	0.450		0.4375	0.00	
#18	0.448		0.4375	0.00	
#19	0.437		0.4375	0.11	
#20	0.464	0.108	0.4375	0.00	
#21	0.443		0.4375	0.00	
#22	0.456		0.4375	0.00	
#23	0.373	0.28	0.375	0.53	
#24	0.360		0.375	4.00	
#25	0.361		0.375	3.73	
#26	0.338	0.173	0.375	9.87	
#27	0.360	0.115	0.375	4.00	
#28	0.354		0.375	5.60	

Newfoundland Power
Rattling Brook Penstock Inspection

Penstock Ultrasonic Thickness Readings (Starting From Surge Tank Going Upstream)

Can Number	Thickness inches	Pit Indication Lowest Thickness inches	Original Thickness	Percentage Loss	Location
#29	0.353		0.375	5.87	
#30	0.371	0.187	0.375	1.07	
#31	0.338		0.375	9.87	
#32	0.361		0.375	3.73	
#33	0.359		0.375	4.27	
#34	0.376		0.375	0.00	
#35	0.364		0.375	2.93	
#36	0.377		0.375	0.00	
#37	0.364		0.375	2.93	
#38	0.355		0.375	5.33	
#39	0.357		0.375	4.80	
#40	0.359	0.21	0.375	4.27	
#41	0.364	0.248	0.375	2.93	
#42	0.356	0.171	0.375	5.07	
#43	0.372		0.375	0.80	
#44	0.354		0.375	5.60	
#45	0.359		0.375	4.27	
#46	0.359		0.375	4.27	
#47	0.362		0.375	3.47	
#48	0.369	0.053	0.375	1.60	
#49	0.361		0.375	3.73	
#50	0.371		0.375	1.07	
#51	0.356		0.375	5.07	
#52	0.355		0.375	5.33	
#53	0.369		0.375	1.60	
#54	0.305		0.375	**18.67**	
#55	0.367		0.375	2.13	
#56	0.371	0.109	0.375	1.07	

Newfoundland Power
Rattling Brook Penstock Inspection

Penstock Ultrasonic Thickness Readings (Starting From Surge Tank Going Upstream)

Can Number	Thickness inches	Pit Indication Lowest Thickness inches	Original Thickness	Percentage Loss	Location
#57	0.388		0.375	0.00	
#58	0.378		0.375	0.00	
#59	0.369		0.375	1.60	
#60	0.361		0.375	3.73	
#61	0.370		0.375	1.33	
#62	0.371		0.375	1.07	
#63	0.367		0.375	2.13	
#64	0.376	0.248	0.375	0.00	
#65	0.370		0.375	1.33	
#66	0.364		0.375	2.93	
#67	0.363		0.375	3.20	
#68	0.362		0.375	3.47	
#69	0.381		0.375	0.00	
#70	0.368	0.152	0.375	1.87	
#71	0.359		0.375	4.27	
#72	0.370		0.375	1.33	
#73	0.360		0.375	4.00	
#74	0.361		0.375	3.73	
#75	0.371		0.375	1.07	
#76	0.370		0.375	1.33	
#77	0.395		0.4375	9.71	Thimble Attached to Woodstave Penstock

Note - negative numbers represent thickness which exceed the thickness stated on the original drawings.

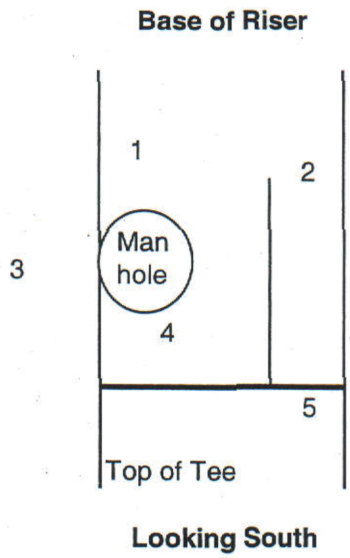
Newfoundland Power
Rattling Brook Penstock Inspection

Surge Tank Shell Ultrasonic Thickness Readings

Can Number	Thickness inches	Pit Indication Lowest Thickness inches	Original Thickness inches	Percentage Loss	Location
1	0.323		0.313	0.00	Top of Surge Tank
2	0.317		0.313	0.00	
3	0.326		0.313	0.00	
4	0.310		0.313	0.96	
5	0.331		0.313	0.00	
6	0.297		0.313	**5.11**	
7	0.303		0.313	3.19	
8	0.332		0.344	3.49	
9	0.391	0.297	0.375	0.00	
10	0.419	0.328	0.406	0.00	
11	0.471		0.438	0.00	
12	0.467		0.468	0.21	
13	0.682		0.688	0.87	Hemispherical Head

Newfoundland Power
Rattling Brook Penstock Inspection

External Riser Ultrasonic Thickness Readings



Location Number	Thickness inches	Pit Indication Lowest Thickness inches	Original Thickness	Percentage Loss
1	0.476		0.531	10.36
2	0.473		0.531	**10.92**
3	0.488	0.34	0.531	8.10
4	0.531	0.343	0.531	0.00
5	0.615	0.264	Unknown	

Newfoundland Power
Rattling Brook Penstock Inspection

Internal Riser Ultrasonic Thickness Readings

Can Number	Thickness inches	Pit Indication Lowest Thickness inches	Original Thickness	Percentage Loss	Location
1	0.347		0.313	0.00	Top of Riser
2	0.323		0.313	0.00	
3	0.332		0.313	0.00	
4	0.319		0.313	0.00	
5	0.321		0.313	0.00	
6	0.302		0.344	12.21	
7	0.316		0.344	8.14	
8	0.311		0.375	17.07	
9	0.291		0.375	**22.40**	
10	0.344	0.313	0.375	8.27	
11	0.373		0.375	0.53	
12	0.397		0.375	0.00	
13	0.405		0.375	0.00	

Appendix D – Safety Reports

REMOTE ACCESS TECHNOLOGY
50 Pippy Place, St. John's, Newfoundland, Canada A1B 4H7
Ph: 709 738 6353 Fax: 709 738 6355 e-mail: info@ropeaccess.ca

October 22, 2003

Greg,

Here is all the information gathered during the inspection. It was a pleasure working with you, not to mention, the chuckle I got when I saw you in your $0.50 rain gear made the trip worthwhile. I look forward to working with you again in the future.

Cheers,

JB DelRizzo
General Manager
Remote Access Technology (Newfoundland) Inc.

Prejob Site Meeting
Contractor Safety Checklist

NEWFOUNDLAND POWER
A FORTIS COMPANY

Contractor's Name: SGE-Acres and Remote Access Technology

Location: Rattling Brook

Date: Oct 14/03

Personal Protective Equipment	✓ Yes ___ No ___ N/A
First Aid Equipment	✓ Yes ___ No ___ N/A
Fire Protection	___ Yes ✓ No ___ N/A
Emergency Communication and Response	✓ Yes ___ No ___ N/A
Fall Protection	✓ Yes ___ No ___ N/A
Minimum Approach Distances Maintained	___ Yes ___ No ✓ N/A
Tail Board / Tool Box Meetings	✓ Yes ___ No ___ N/A
Warning /Danger Signs	✓ Yes ___ No ___ N/A
Public Safety	✓ Yes ___ No ___ N/A

Comments:

Remote access Conducted their own Tool box Meeting. Completed prejob / hazard checklist.

Lockout Provided by NF Power to enter tank and penstock.

Action taken to address any issues:

Signature of Owner's Representative: [signature]

Signature of Contractor's Supervisor: [signature]

White: Originator, Yellow: Contractor

Form No. 399 Revised 03/28/01

Remote Access Technology (Newfoundland) Inc.

Confined Space Entry Checklist ✓

	Yes	No	
	✓		Personnel entering confined space have been trained in the hazards of confined space entry.
	✓		Approved Permit to Work has been obtained.
	✓		Designated trained standby person assigned to standby the confined space entrance at all times.
	✓		Oxygen/Gas detector is present and calibrated.
N/A		✓	Minimum of two explosion-proof portable lights in use.
N/A		✓	Explosion-proof personal radios in use.
N/A		✓	Appropriate warning signs/barricades in use.
	✓		Portable tripod with a combined fall arrestor-retrieving winch or similar system in use.
	✓		One Company approved full body harness in use per person.
	✓		Internal pressure checked and vented before removing fastening devices on confined space.
	✓		Designated standby person will monitor air quality upon entry and each re-entry.
	✓		Oxygen levels is between 19.5% to 22% **DO NOT ENTER IF ABOVE OR BELOW AFOREMENTIONED RANGE!**
	✓		Air Quality is tested for H2S / Explosive gases – None Present.
		✓	Confined space will be sounded for fluid before entered. Flotation device will be worn if a drowning hazard exists.
	✓		Standby person will maintain constant radio contact with persons in confined space and control room.
	✓		Standby person knows how to raise the alarm if person inside or confined space require emergency assistance and knows not to enter confined space until assistance arrives.
	✓		Adequate rescue equipment is readily available and standby person is familiar with its use.
	✓		Standby person will keep a tally of number / names of persons inside confined persons.
	✓		Standby person will notify Person in Charge for a relief watchman to be assigned as relief and wait until being properly relieved before leaving the post.
	✓		Adequate handover and safety briefing will be conducted with any person who relieves the standby person or crew members working in the confined space.
	✓		Explosion proof ventilation will be used for a continuous supply of fresh air unless sufficient airflow is obtained through a free flow process.
N/A		✓	No source of ignition will be introduced into a confined space where flammable vapors or gasses may be present.
	✓		All pipelines discharging into that space will be closed with blind flanges, plugs or valves and energy isolation signs and tags posted.
N/A		✓	If torch cutting or welding is carried out on pipelines passing through confined spaces , they will be isolated, purged if necessary, energy isolations signs and tags posted prior to the hot work starting.
N/A		✓	Oxygen/ Acetylene hoses will be removed from confined space where during the extended breaks and air retested for gas before reentry.
	✓		The time of opening or closing a confined space entry or exit of personnel will be recorded at the manned control point (Control Room, Radio Room, etc.)

Person in charge: J.B. DelRizzo (name) [signature] (sign)

Date: Oct 16/03 Time: 4:48 pm

Standby Person: Steve Deathe (name) ____________ (sign)

747-2515

REMOTE ACCESS TECHNOLOGY	Safety Policy and Procedures Manual **ANNEX A – Code of Practice**		Reviewed by: MDS
	Doc: 13354.1	Date: 2003-04-08	Approved by: ADB

TAILGATE SAFETY MEETING REPORT

Date of Meeting: Oct 15/03

Time of Meeting: 8:30 am/pm

Location of Meeting: Rattling brook P.S. / NFLD

Employees Present:

1	Steve Deathe	9	
2	JB Delrizzo	10	[signature]
3	Pat Heath Pat Heath	11	
4	Hayward Miller	12	Hayward Miller
5	G. Murray	13	[signature]
6	G. Saunders	14	[signature]
7		15	[signature]
8		16	

Items Discussed

1 Review unsafe situations mentioned at previous meeting
2 Review any safety suggestions from the crew
3 Review of hazards expected in upcoming work
4 Proper P.P.E, radio communication, First Aid kit in the truck
5 lanyards on all tools, all rigging assessed by Level 3 climber
6 install fall arrest system for climbing ladders
7 Follow all TIATA GUIDELINES FOR ACCESS METHODS
8

Comments

This safety meeting conducted by: [signature]

COPIES TO: OFFICE (ORIGINAL) Safety Coordinator

FORM 9-4-13

JOB HAZARD ANALYSIS

Date: Oct 15/03 Time: 8:30 Location: Ratling Brook P.S./NFLD

Supervisor:

Job Description: Inspection of surge tank & penstock (visual & U.T.)

Work Crew (List names & have employees initial on same line) Completed By: Steve Deathe

Name: Steve Deathe Name: Pat Heath Name: G. McCoy

Name: JB Delrizzo Name: Hayward Miller Name: G. Sanders

Permits Required	yes	no	n/a	Other Checks	yes	no	n/a
General Work	✓			Safety Operator Required		✓	
Hot Work		✓		Hazardous Material Present		✓	
Entry	✓			Evac./Assembly Are Confirmed	✓		
RPP Scba	✓			Job Objective Discussed with Crew	✓		
Other ( )		✓		Is Crew Aware of MSDS Location			✓

yes	no	n/a		Comments / Notes / Actions
✓			Proper permits obtained/signed?	
✓			RPP equipment required?	Scba's on standby for internal work
✓			Confined space entry permit req'd?	
	✓		Staging required / OK Tag?	
✓			Personal fall protection req'd?	
		✓	Staging(s) inspected & confirmed adequate by	
✓			Evacuation/assembly area known?	
		✓	Eyewash/safety shower location known?	
		✓	Hot work requirements?	
✓			Protective equipment required?	
		✓	Location of fire equipment known?	
✓			Equipment blinded or not?	
✓			Proper lighting for work?	outside natural / internal headlamps & Flashlights
	✓		Conflicting jobs in area?	
			Safety behaviors discussed	**Hazard recognized/corrective action**
✓			Proper PPE Used (eye/hearing/gloves/nomex/etc.)	
✓			Housekeeping (tripping hazards/hoses/leads)	

Rope Hazard Identification & control

Hazard	Rank	Corrective Actions
Pinch points	A	proper rigging / assessed by Level 3
Sharp edges	A	proper rope protection

Considerations / Comments:

Corrective actions carried out? Yes / No If no, state reason below:

Rank: **A = could easily result in a fatality** **B = could result in serious injury** **C = could result in minor injury**

Form 12-6-19

SAFETY MEETING FORM

Document #: R-QA1002

Page 1 **of** 1 **Date:** Oct 16/03 **Job #:**

Project: Inspection of surge tank & penstock

Location: Rattling Brook G.S. NFLD

Supervisor: JB Delrizzo

Topics Discussed:

Constant air monitoring
Scba's for rescue personal
Radio communication (10-15 min checkins)
fall arrest harness for rescue purposes
all equipment locked & taged out
be aware of slippery conditions

20.2 o°	0	0	0

Personnel to print and sign below to say that you have read and understood the specific rescue procedure.

Print Name	Signature	Print Name	Signature
JB Delrizzo	[signature]		
GREG SAUNDERS	[signature]		
HAYWARD Miller	[signature]		
Steve Westhe	[signature]		

Appendix C

SGE Acres: Rattling Brook Development Selection of Optimum Penstock Diameter

March 17, 2006
H-322125

Newfoundland Power
P.O. Box 8910
55 Kenmount Rd
St. John's, NL A1B 3P6

Attention: Mr. Gary Murray, P.Eng.

Dear Sir:

Rattling Brook Development
Selection of Optimum Penstock Diameter

Newfoundland Power (NP) proposes to replace the existing woodstave penstock at the Rattling Brook Development with a new steel penstock. NP requested SGE Acres to carry out a study to determine the optimum diameter for the replacement penstock. NP requested an incremental analysis, with the energy benefits incremental to existing, and costs incremental to replacement.

The findings of this study are that a penstock with a diameter of 9 ½ ft is optimal. The capacity at full output will increase by about 2.9 MW, the incremental expected average energy output is estimated to be at least 5.1 GWh over existing, and, and the incremental cost over replacement is about $2.1 million.

This letter report documents the analysis and results of the study.

1 System Description

The Rattling Brook hydroelectric station is located near Norris Arm, on the northeast coast of the Island of Newfoundland. It was built in 1958, with a nominal installed capacity of 12.75 MW provided by two units. The nameplate capacity is 15.1 MW; the nameplate unit capacities are 7.5 MW and 7.6 MW. The gross head is 99 m.

The woodstave penstock is 1693 m long, 1054 m of 7 ft. diameter and 639 m of 7 ½ ft. diameter. (Penstock diameters are given here in imperial units for consistency with design drawings and previous reports.) A 7 ft. steel section 50 m long provides the connection from the intake to the woodstave section. The penstock winds along a river valley, with numerous changes to the alignment.

The last 309 m of penstock is a steel section, of which the last 115 m from the surge tank to the units is buried. The penstock bifurcates about 16 m upstream of the units into two sections leading to the two units. Each section is 4ft. 9 in. inside diameter. A butterfly valve is located just upstream of each of the units.

2 Methodology

2.1 Capacity and Energy Benefits

Based on previous reports and practical considerations, diameters in the range of 7 ½ ft. to 10 ft were considered. An energy simulation model of the Rattling Brook system previously developed for NP for a Water Management Study was used to estimate the available energy.[1] A 15 year inflow sequence was used in the simulation, as in the Water Management Study.

The head losses in the existing and proposed system, required for the energy calculations, were estimated using data from index testing in the 1980's by NP, from efficiency testing carried out by SGE Acres for NP in 2000 and standard references. Additional tests in 2005 confirmed the assumed values for the woodstave portion. The reduction in head losses with increasing penstock diameter leads to increasing energy. A reduction in head loss due to the larger penstock also increases the available capacity.

The actual energy generated at the station is higher than simulated, 69.8 GWh compared to the 63.5 GWh simulated. This difference is likely due to more runoff, as discussed in the Water Management Study. Given this possibility, the energy was also calculated using a mean annual runoff 10 per cent higher than previously assumed, to determine the effect of higher runoff on incremental energy. Detailed site data to allow calculation of inflows would be required to confirm the runoff.

2.2 Costs

NP prepared detailed cost estimates for replacing the woodstave section with a steel penstock of 7 ½ ft. diameter, as well as with a 9 ½ ft. diameter steel penstock. NP advised that the costs for other sizes in approximately this range could be estimated by linear interpolation.

2.3 Economic Analysis

The annual value of the incremental benefits of each diameter under consideration was calculated assuming values of \$0.071/kWh and \$0.093/kWh. These values were provided by NP. The lower value is the cost of short run energy at Holyrood, and the higher value is a blended rate, including both the cost of short run energy plus capacity benefits. A discount rate of 7.15 per cent and a period of 50 years were assumed, also provided by NP. The sensitivity of the results to a period of 25 years was also checked.

The net present worth value (benefits minus costs) and the incremental (stepwise) net benefit were then calculated. The optimal diameter is the diameter which maximizes the net present worth, and for which the incremental investment is still positive.

[1] Acres International, *Water Management Study*, Report prepared for Newfoundland Power, December 2000.

3 Results

The results of the power and energy analysis are shown in Figure 1, which plots energy and capacity as a function of penstock diameter. This figure shows that the capacity and energy continue to increase as the diameter increases, but the curves flatten out at the larger diameters. The annual incremental energy benefits over the existing simulated energy range from from 2.6 GWh for the 8 ft. penstock to 5.5 GWh for the 10 ft. penstock. For the case of the 10 per cent increase in runoff, the simulated existing average annual energy increments range from 2.9 GWh for the 8 ft penstock to 6.4 GWh for the 10 ft diameter.

The capacity increases from the existing 11.2 MW to 12.5 MW with the 8 ft. penstock and 14.3 MW with the 10 ft. penstock. (Losses in the existing steel section limit the plant to an output below the full nameplate production of 15.1 MW even with a larger diameter penstock as replacement for the woodstave section.)

Figure 2 shows the present value of the benefits for the two different assumptions of value of energy, and Figure 3 shows the linear cost curve. The cost estimate for supply and installation of the 7 ½ ft diameter penstock is $9,541,000, and $11,706,000 for the 9 ½ ft. penstock. The incremental cost is thus approximately $541,000 for each ½ ft. increment.

The information in these plots is combined in Figures 4 and 5 to show the results of the optimization. Figure 4 shows the net present value of the project, assuming each of the penstock diameters, in ½ ft increments. Figure 4a shows the results for the given discount rate and two values of energy case (no increase in runoff, period of 50 years). The net present value is optimized at the 9 ½ ft. diameter. Figure 4b shows the results for the sensitivity to period (25 years) and to higher runoff. The range of optimal diameters is from 9 ft. to 10 ft. in all cases.

Figures 5a and 5b show the results as incremental net benefits. From an economic perspective, it is beneficial to invest each incremental amount (in this case, $541,000) until the incremental net present value is negative. The diameter at which the return is still positive is the optimum, in this case 9 ½ ft. The range for all sensitivities is 9 ft. to 10 ft.

The results are also summarized in Table 1.

4 Conclusions and Recommendations

The conclusions of this study are that a 9 ½ ft. diameter penstock is optimal, for the costs and economic parameters evaluated. It is a robust choice, since the optimum diameter ranges from 9 ft. to 10 ft. for the sensitivities considered.

The estimated cost for supply and installation of the 9 ½ ft. diameter penstock is $11,706,000, an increment of $2,165,000 over the cost of replacement with a 7½ ft. diameter penstock. The average annual energy is expected to increase by at least 5.1 GWh. Given the present production of 69.8 GWh, the expected average annual energy would be about 75 GWh. The capacity benefit is 2.9 MW, from the existing 11.2 MW to an estimated 14.1 MW.

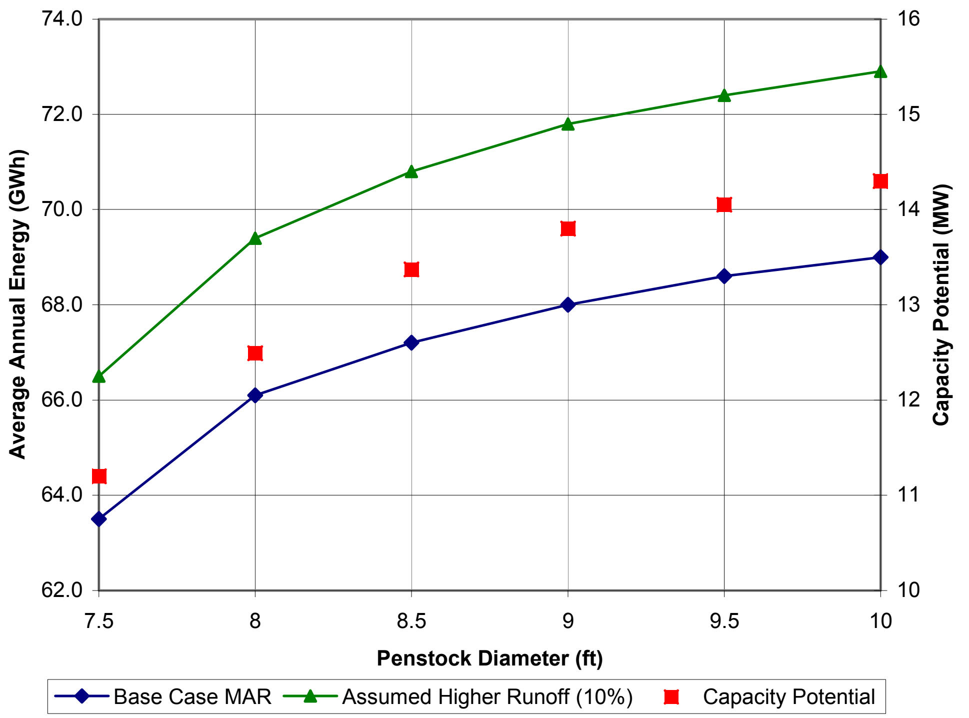
Yours very truly,

SHR:sjc

Susan Richter, P.Eng.
Project Manager

Attachments

Figure 1: Average Annual Energy and Capacity Potential as a function of Penstock Diameter



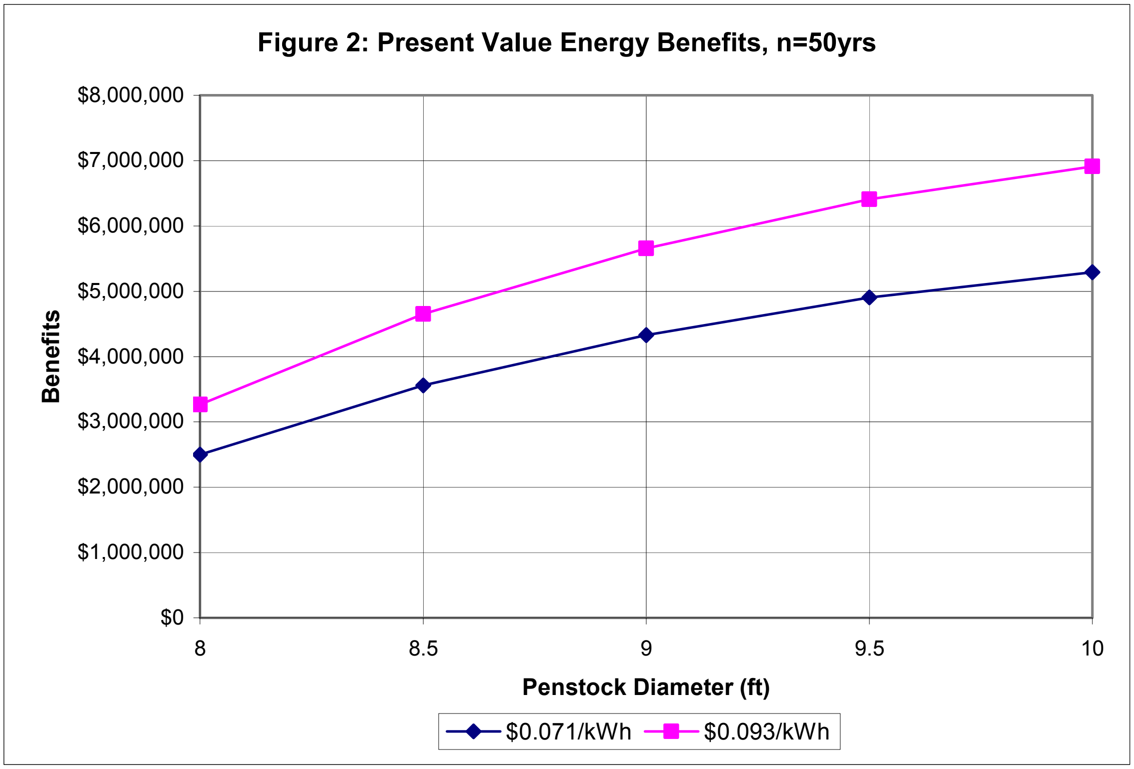


Figure 2: Present Value Energy Benefits, n=50yrs
$8,000,000
$7,000,000
$6,000,000
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000
$0
Benefits
8
8.5
9
9.5
10
Penstock Diameter (ft)
$0.071/kWh
$0.093/kWh

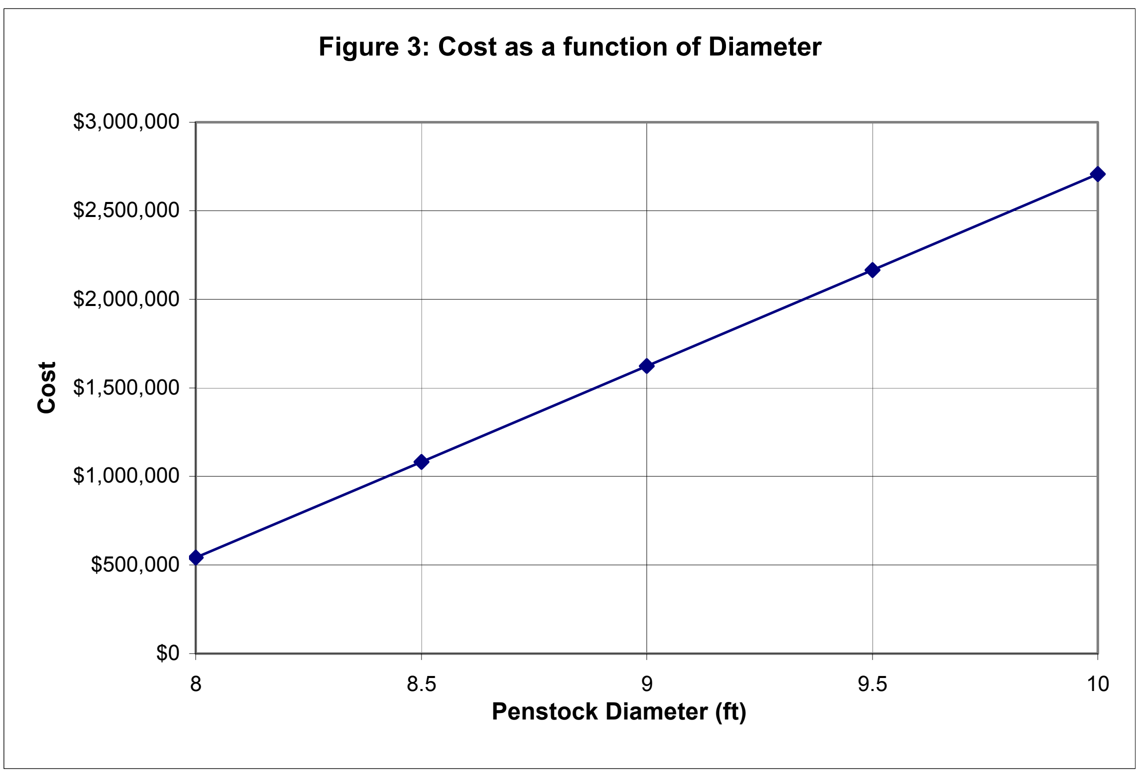


Figure 3: Cost as a function of Diameter
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
Cost
8
8.5
9
9.5
10
Penstock Diameter (ft)

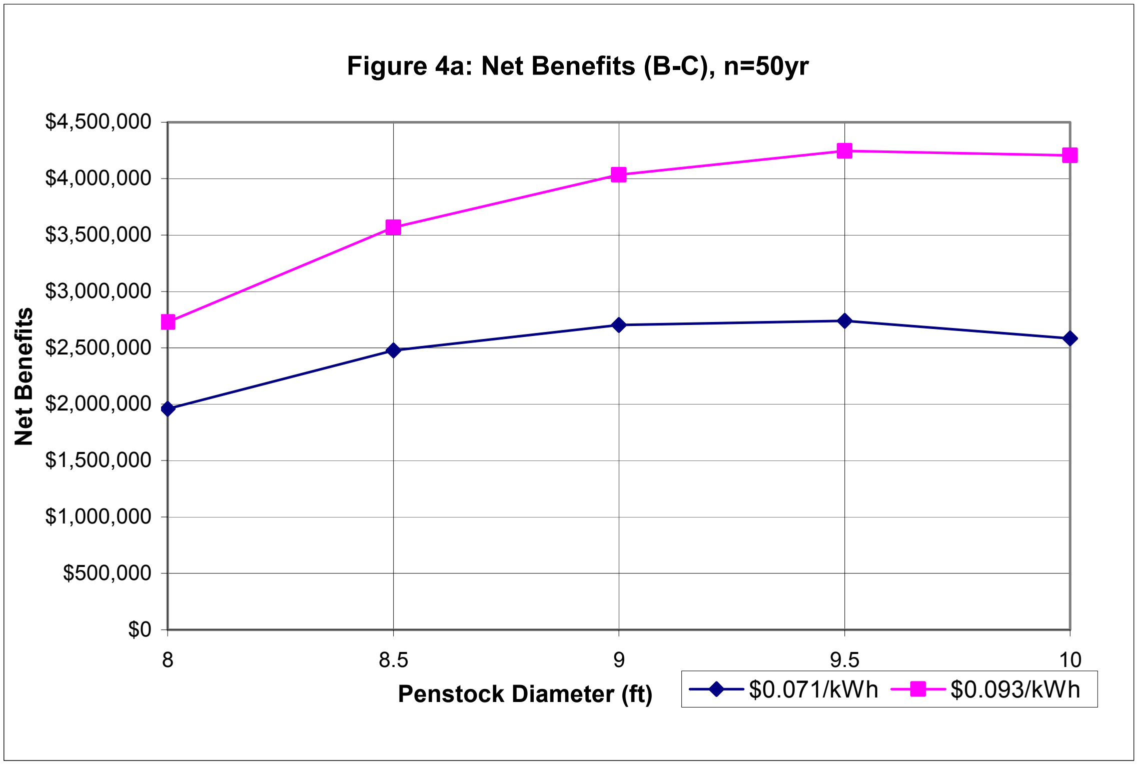


Figure 4a: Net Benefits (B-C), n=50yr
Net Benefits
$4,500,000
$4,000,000
$3,500,000
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
8
8.5
9
9.5
10
Penstock Diameter (ft)
$0.071/kWh
$0.093/kWh

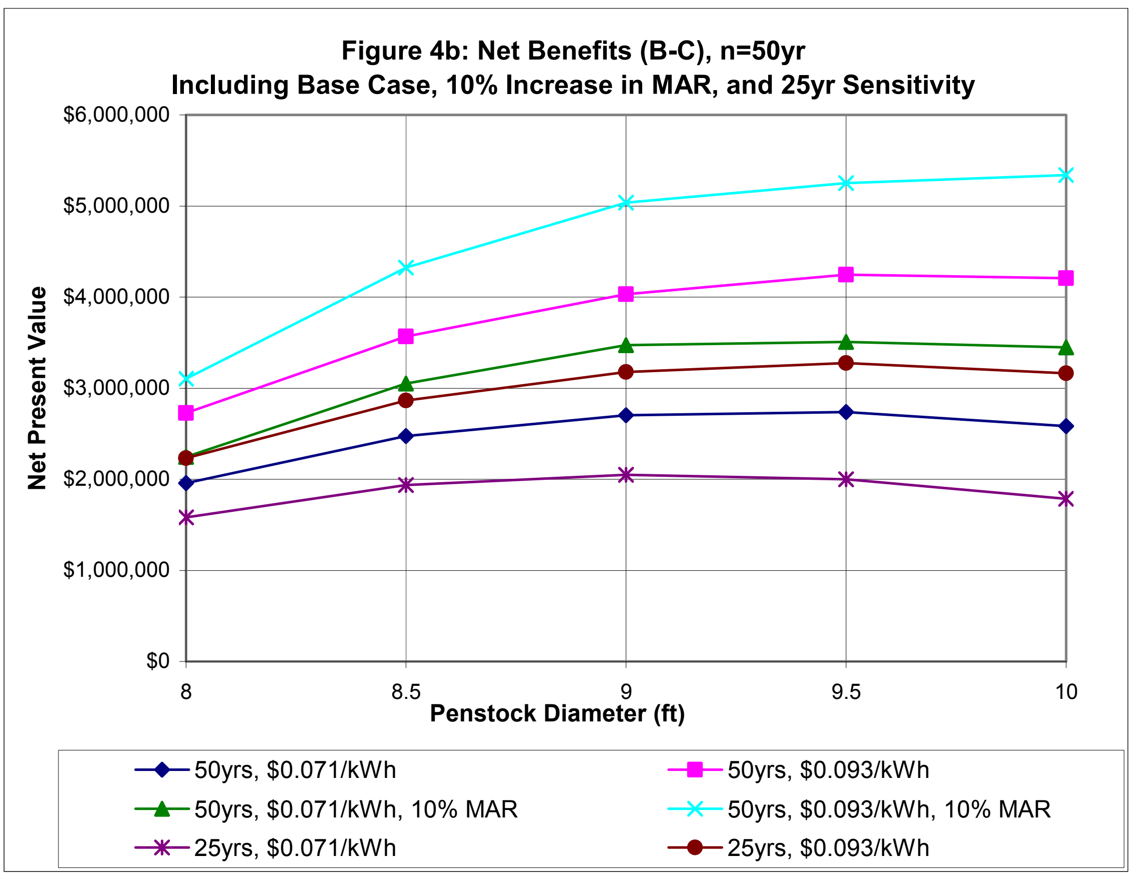


Figure 4b: Net Benefits (B-C), n=50yr
Including Base Case, 10% Increase in MAR, and 25yr Sensitivity
Net Present Value
$6,000,000
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000
$0
8
8.5
9
9.5
10
Penstock Diameter (ft)
50yrs, $0.071/kWh
50yrs, $0.093/kWh
50yrs, $0.071/kWh, 10% MAR
50yrs, $0.093/kWh, 10% MAR
25yrs, $0.071/kWh
25yrs, $0.093/kWh

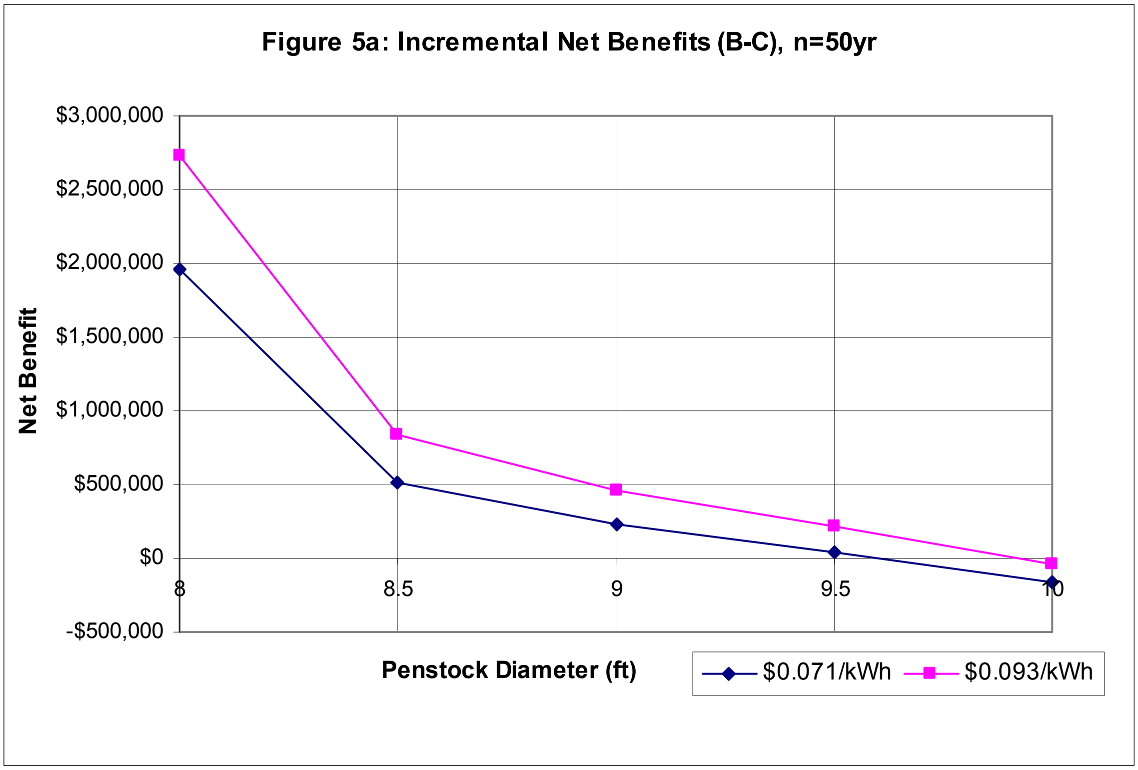


Figure 5a: Incremental Net Benefits (B-C), n=50yr
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
-$500,000
Net Benefit
8
8.5
9
9.5
10
Penstock Diameter (ft)
$0.071/kWh
$0.093/kWh

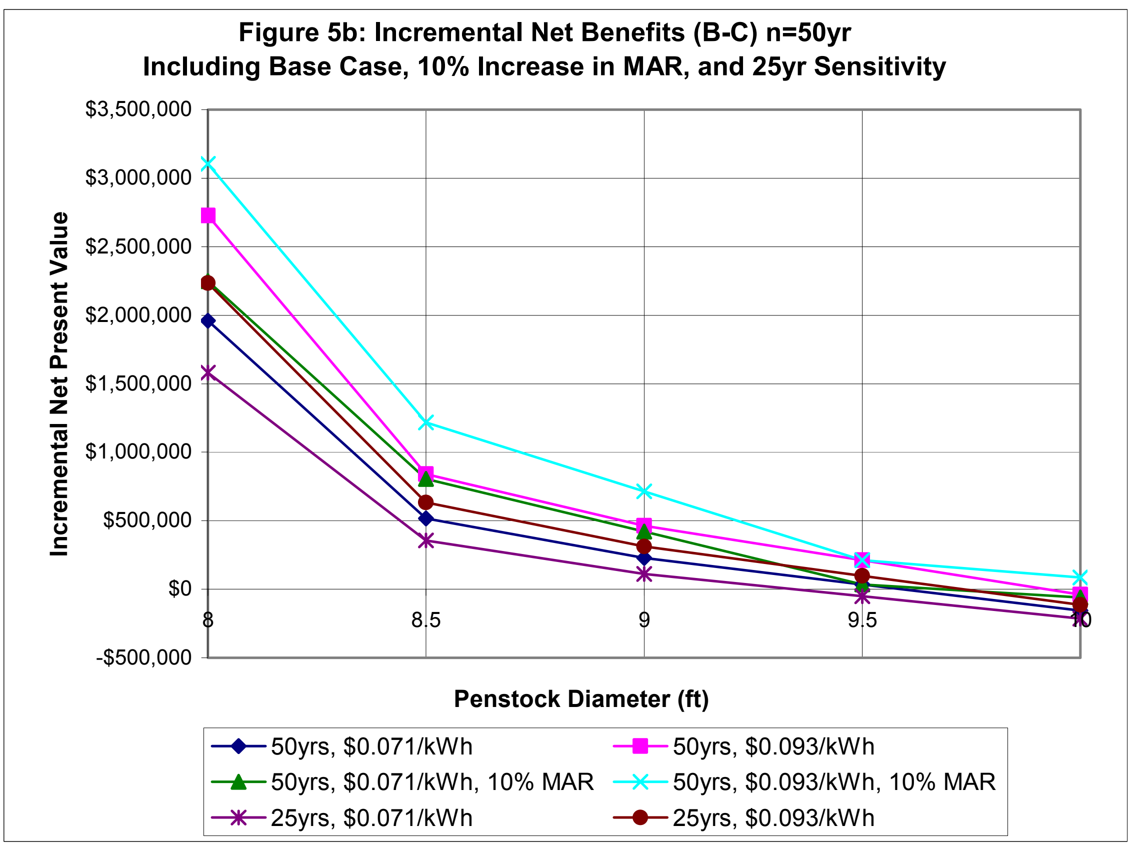


Figure 5b: Incremental Net Benefits (B-C) n=50yr
Including Base Case, 10% Increase in MAR, and 25yr Sensitivity
$3,500,000
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
-$500,000
Incremental Net Present Value
8
8.5
9
9.5
10
Penstock Diameter (ft)
50yrs, $0.071/kWh
50yrs, $0.093/kWh
50yrs, $0.071/kWh, 10% MAR
50yrs, $0.093/kWh, 10% MAR
25yrs, $0.071/kWh
25yrs, $0.093/kWh

Table 1

Results of Economic Analysis

Value of Energy	**$0.071**	**/kWh**				
Diameter (ft)	**7.5**	**8**	**8.5**	**9**	**9.5**	**10**
Average Energy (GWh)	63.5	66.1	67.2	68.0	68.6	69.0
Energy Benefits (above existing)		$2,500,000	$3,558,000	$4,327,000	$4,904,000	$5,289,000
Costs incremental above 7.5ft		$541,154	$1,082,000	$1,623,000	$2,165,000	$2,706,000
Net Benefits (Benefits - Costs)		$1,959,000	$2,476,000	$2,704,000	**$2,739,000**	$2,583,000
Incremental Energy (GWh)		2.6	1.1	0.8	0.6	0.4
Annual Incremental Benefits		$184,600	$78,100	$56,800	$42,600	$28,400
Present worth Incremental Benefits		$2,500,000	$1,058,000	$769,300	$576,900	$384,600
Costs incremental above 7.5ft		$541,154	$541,154	$541,154	$541,154	$541,154
Incremental Net Benefits		$1,959,000	$516,800	$228,100	**$35,750**	-$157,000

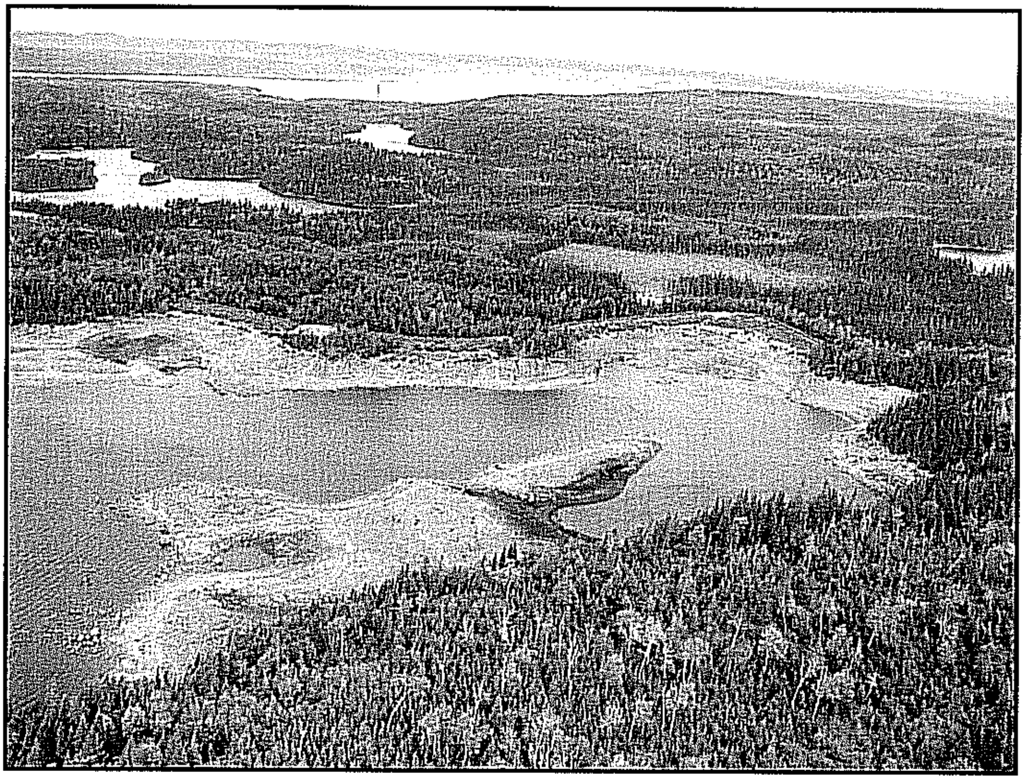
Value of Energy	**$0.093**	**/kWh**				
Diameter (ft)	**7.5**	**8**	**8.5**	**9**	**9.5**	**10**
Average Energy (GWh)	63.5	66.1	67.2	68.0	68.6	69.0
Energy Benefits (above existing)		$3,268,000	$4,651,000	$5,656,000	$6,410,000	$6,913,000
Costs incremental above 7.5ft		$541,154	$1,082,000	$1,623,000	$2,165,000	$2,706,000
Net Benefits (Benefits - Costs)		$2,727,000	$3,569,000	$4,033,000	**$4,245,000**	$4,207,000
Incremental Energy (GWh)		2.6	1.1	0.8	0.6	0.4
Annual Incremental Benefits		$241,300	$102,100	$74,240	$55,680	$37,120
Present worth Incremental Benefits		$3,268,000	$1,383,000	$1,005,000	$754,100	$502,700
Costs incremental above 7.5ft		$541,154	$541,154	$541,154	$541,154	$541,154
Incremental Net Benefits		$2,727,000	$841,800	$463,800	**$212,900**	-$38,500

Note: Discount rate is 7.15% and time is 50 years

Appendix D

Civil Infrastructure Assessment

Rattling Brook Hydro Plant
Civil Infrastructure Assessment



Prepared by:
Tony Chislett, P.Eng

February, 2006

REGISTERED PROFESSIONAL ENGINEERS
GARY L. MURRAY
SIGNATURE
Apr 27/06
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

Page

1.0 General

A complete inspection of the civil infrastructure of the Rattling Brook system was completed in 2005. The purpose of this assessment is to document the condition of existing infrastructure of the system and make recommendations for required improvements.

The total storage volume of all reservoirs in the Rattling Brook system is about 76 million cubic metres, with a drainage basin of 383 km^2. There are a number of dam and flow control structures in the storage reservoirs that comprise the Rattling Brook system. The furthest upstream reservoir, Frozen Ocean Lake, contains an embankment dam, a timber outlet structure and a rockfill overflow spillway. Rattling Lake contains an embankment dam and an adjacent concrete/wooden stoplog spillway. Amy's Lake contains an embankment dam, a concrete outlet structure, and three freeboard dams. The furthest downstream reservoir, the Forebay, contains an embankment dam, a concrete power intake structure, and a rockfill overflow spillway.

2.0 Civil Infrastructure Condition Assessment

2.1 Frozen Ocean Lake

Frozen Ocean Lake is the furthest upstream reservoir within the Rattling Brook system and is comprised of an embankment dam, a rockfill overflow spillway and a timber outlet structure.

2.1.1 Frozen Ocean Lake Dam

Frozen Ocean Lake dam was completely rebuilt in 1988. Major upgrades since that time include riprap improvements in 2001.

Overall the embankment dam is in good condition. The riprap on the upstream face of the dam is well graded with no signs of apparent movement. The downstream face, abutments and crest are all in good condition. At the time of inspection there was no observed evidence of slope instability or overtopping of the dam. Furthermore there was no evidence of seepage through the dam.

The embankment dam is in good condition and no recommendations for improvement are suggested at this time.

2.1.2 Timber Outlet Structure

A complete new outlet structure was installed in 1988. Since that time the concrete sill floor and mechanical equipment for the gate structure was upgraded in 2004.

Overall the timber outlet structure is in good condition. The approach and discharge channels were clear at the time of inspection and there were no apparent deficiencies with regards to the timber structure and abutments.

No recommendations for improvement are suggested at this time.

2.1.3 Frozen Ocean Lake Spillway
The original spillway installed in 1958 was completely rebuilt in 1988. No major upgrades have been carried out since that time.

Overall the spillway is in good condition. The upstream face and crest of the spillway is in good condition. The riprap on the downstream face is well graded with no apparent signs of movement. The abutments are stable with good rockfill protection at the spillway and dam interface. At the time of inspection the approach and outlet channels were clear with no obstructions. Furthermore there was no evidence of seepage through the spillway.

No suggested improvements are recommended at this time.

2.2 Rattling Lake

Rattling Lake site consists of an embankment dam and a concrete and stoplog spillway.

2.2.1 Rattling Lake Dam
Since the commissioning of the site in 1958 major upgrades to Rattling Lake Dam include the replacement of the riprap on the upstream face in 2000.

The upstream face of the dam is in good condition. The riprap is well graded with no indication of movement of the material. No unusual conditions were observed at the abutments. There was a good transition from the embankment sections to the abutments. The crest of the dam is in good condition. At the time of inspection there was no evidence of overtopping or damage observed due to vehicular traffic.

To minimize the amount of vegetation growth on the downstream face of the dam it is recommended the downstream face be re-graded and rockfill be placed over the entire length of the dam.

2.2.2 Rattling Lake Spillway
Rattling Lake Spillway is the main spillway in the Rattling Brook system. Since it's commissioning in 1958, with the exception of replacement of deteriorated stoplogs and other minor upgrades, the spillway is for the most part in its original state. A detailed assessment revealed that it was necessary to replace the spillway as part of the capital works improvements. This detailed assessment is included as Attachment B of this report.

2.3 Amy's Lake

Amy's Lake consists of an embankment dam, a concrete outlet structure and three freeboard dykes.

2.3.1 Amy's Lake Dam
Amy's Lake dam for the most part is in its original state. Other than the replacement of the trash racks in 2000, no major upgrades have been carried out on this structure.

The riprap on the upstream face of the dam is sparse throughout most sections. Some sliding of rockfill into the approach channel was observed. No unusual conditions were observed at the abutments and the crest of the dam appears to be in good condition. No seepage was observed, potentially due to low reservoir levels.

Riprap refurbishment is required on the upstream face of the dam. To prevent sliding of rockfill into the approach channel, it is recommended that the intake be raised by either extending the concrete wing wall or placing large boulders along the channels edge. Furthermore, to minimize vegetation growth, it is recommended that the downstream slope be re-graded and rockfill be placed along the entire length of the dam.

2.3.2 Amy's Control Gate

The control gate at Amy's Lake is the original gate that was installed in 1958. Newfoundland Power intends to implement a water management system at the Rattling Brook facility as part of the capital works improvement. This type of system requires frequent raising and lowering of gates to control the water level to the forebay channel. The current gate installed at Amy's Lake is not suitable for this type of operation. Therefore, it is recommended that the gate at Amy's Lake be replaced with a hydraulic operating gate, suitable to water management operations.

2.3.3 Amy's Concrete Outlet Tunnel

A visual inspection of the exterior and interior of the tunnel was completed. During the internal inspection leakage around the sides and top of the gate was observed as well as normal signs of aging concrete (i.e. exposed aggregate). At the exterior of the discharge channel the concrete retaining wall is showing signs of deterioration (i.e. erosion/weathering). In addition accumulation of rockfill in the discharge channel was observed.

Amy's canal is a man made canal that was constructed in 1958. It is evident that the sides of the canal downstream of the tunnel have failed overtime resulting in an accumulation of rockfill. To eliminate backwater effects at the tailrace it is recommended that the discharge channel be dredged. In addition, to prevent further deterioration of the concrete retaining wall at the exterior of the discharge channel, it is recommended a concrete overlay be implemented.

2.3.4 Amy's Lake Freeboard Dykes

Freeboard Dyke No. 1

No unusual conditions were observed at the abutments and the crest is in good condition with no evidence of overtopping. In addition, at the time of inspection no seepage was observed, potentially due to low reservoir levels.

Freeboard Dyke No.2 and No.3

The riprap on Freeboard Dyke No.3 requires some re-grading.

As part of the Rattling Brook refurbishment project it is recommended that the Freeboard Dyke be upgraded.

2.4 Forebay Dam

The Rattling Brook forebay dam consists of an embankment dam, an intake structure and a rockfill overflow spillway.

2.4.1 Forebay Dam

Since original installation in 1958, major upgrades included riprap improvements completed in 2001.

The riprap on the upstream face of the dam is well graded and shows no signs of movement. The abutments and crest of the dam are in good condition with no evidence of overtopping observed. There was a minimum amount of seepage at the downstream toe running in the penstock right of way.

No recommendations for improvements are suggested at this time.

2.4.2 Forebay Spillway

Major upgrades to the spillway since 1958 include riprap improvements that were completed at the same time as the upgrades to the Forebay dam in 2001.

Both the upstream and downstream face of the spillway is in good condition. Riprap is stable with very few signs of movement. Good riprap protection is evident along the abutment embankments. At the time of inspection the approach and outlet channels were clear with no obstructions.

No recommendations for improvements are suggested at this time.

2.5 Powerhouse Tailrace Tunnel

Since the Rattling Brook facility was placed into service, no upgrades have been completed to the powerhouse tailrace tunnel. An internal inspection of the tunnel was carried out in September 2005. The tunnel is in good condition with minor weathering and spalling of the concrete.

No recommendations for improvements are suggested at this time.

2.6 Access Roads

The access road to Amy’s Lake and Rattling Lake dam is currently in fair to good condition. However before construction begins it is recommended that the road be widened to allow the larger equipment to easily access the various sites.

3.0 Conclusion

Assessments were completed of the civil infrastructure at Rattling Brook including dams, dykes, tunnels, control gates and roads. In summary, the civil infrastructure is in good condition. However, several items require attention to ensure the continued safe and reliable operation.

Based on the findings in this report, the following work is recommended for the Rattling Brook hydro plant system in 2008:

- Replacement of Rattling Lake spillway;
- Upgrades to Amy's Lake dam and Amy's Lake freeboard dam;
- Replacement of Amy's Lake outlet gate;
- Upgrades to Rattling Lake dam; and
- Upgrades to site access roads.

Attachment A

Pictures of Rattling Brook Civil Infrastructure

Figure 1: Aerial Shot of Frozen Ocean Lake Infrastructure

Figure 2: Frozen Ocean Lake Dam

Figure 3: Aerial Shot of Rattling Lake Dam and Spillway

Figure 4: Rattling Lake Dam (Note excessive vegetation on downstream face)

Figure 5: Rattling Lake Dam (Upstream Face)

Figure 6: Aerial Shot of Rattling Lake Spillway

Figure 7: Aerial Shot of Amy's Lake Dam and Outlet

Figure 8: Amy's Lake Dam (Upstream Face)

Figure 9: Amy's Freeboard Dyke No. 1

Figure 10: Amy's Freeboard Dyke No. 3

Figure 11: Aerial Shot of the Forebay Dam

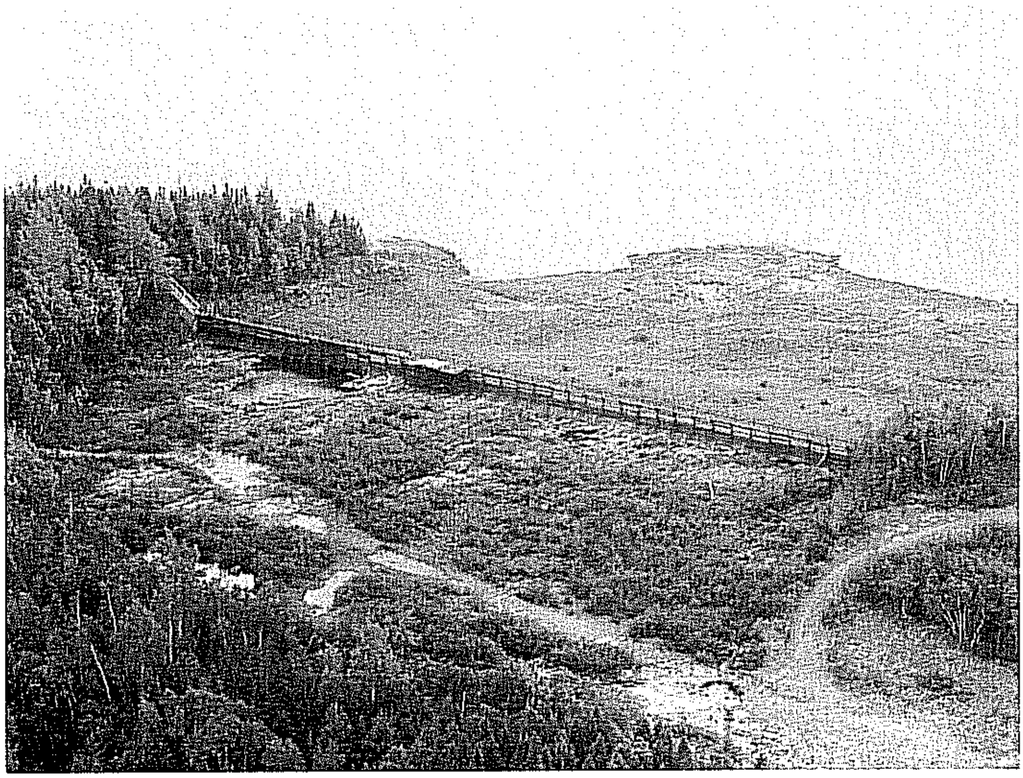
Figure 12: Forebay Dam (Upstream Face)

Figure 13: Forebay Spillway

Attachment B

Rattling Lake Spillway Assessment

Rattling Brook Hydro Plant
Rattling Lake Spillway Assessment



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1.0 General

Rattling Lake Spillway is the main spillway in the Rattling Brook Development and is a High Consequence structure, according to the Canadian Dam Association (CDA) classification system. Since it's commissioning in 1958, with the exception of the replacement of deteriorated stoplogs and other minor upgrades, the spillway is in its original condition.

The purpose of this report is to provide a brief description of the existing Rattling Lake Spillway, document the existing condition of the spillway and assess the existing capacity with respect to spill and stability.

2.0 Rattling Lake Spillway

2.1 Description of Structure

The existing spillway structure was commissioned in 1958. The base of the spillway is a concrete weir that varies in height based on the natural topography of the supporting bedrock. The concrete is anchored to the rock with 20-M dowels. The top of the concrete spillway crest is at elevation 112.78 m.

The spillway elevation is increased to a maximum storage elevation of 115.12 m with 15 wooden stoplogs. The spillway has a total of 42 stoplog bays; 35 bays have a net length of 2.44 m each and 7 bays have a net length of 1.83 m each. The total net length of the spillway openings is 98.15 m. The overall length of the spillway structure between abutments is 107.35 m.

The Full Supply Level (FSL) for the reservoir, based on current operating practice, is 114.91 m, with a storage capacity of 69.2 million cubic metres at FSL. Any reservoir impoundment above the stoplog operating level spills into Rattling Brook downstream. The freeboard, or difference in elevation between the dam crest and maximum storage elevation, is 1.01 m (116.13 m – 115.12 m).

2.2 Existing Operation

During the winter months, the elevation of Rattling and Amy's lakes must be kept at approximately 112.2 m to keep ice from rafting up on the flashboards. This lowered elevation, approximately 2.71 m below FSL, provides sufficient storage to enable Rattling Brook hydroelectric plant to operate efficiently during the winter months, and provides capacity for the high inflows during spring run-off.

During periods when excessive spill events are anticipated, the stoplogs that form the existing structure are manually removed by plant operations staff.

Due to the inefficient operation of this type of structure some energy is spilled that could otherwise be utilized for energy production. The value of the energy is difficult to quantify but is considered to be significant.

2.3 Assessment of the Structure

As part of Newfoundland Power's Dam Safety Program, an inspection of the Rattling Lake Spillway was conducted in 2005 to assess and document the current condition of the structure. Additional input to the structure's assessment was compiled through a review of available documentation.

2.3.1 Dam Safety Inspection Reports

Regularly scheduled dam safety inspections have identified that the spillway and its structural components are showing signs of deterioration. Observations that were made concerning the spillway during the regular scheduled inspections are as follows:

- Concrete crest continues to show signs of deterioration due to weathering and aging. Exposed aggregate and spalling was observed throughout.
- Walkway timbers are showing continuing signs of deterioration and should be replaced in some locations.
- On the downstream end of the spillway there is a significant amount of fractures in the bedrock foundation along the downstream toe. Undercutting is evident throughout the concrete and bedrock interface.

2.3.2 Dam Safety Review

In 2001, AMEC conducted a Dam Safety Review of the Rattling Brook Development. Based on their assessment, Rattling Lake dam was categorized as a High Consequence structure, according to the Canadian Dam Association (CDA) classification system. Within the scope of the dam safety study, a review of the Rattling Lake spillway flood discharge capacity was investigated. Simulations showed that the lifting of stoplogs during flood flows would have to be maintained possibly up to 50 hours, in order to achieve the required discharge capacity of the spillway. In the event that an operator could not remove the stoplogs during times of extreme flow, there is an increased possibility of downstream flooding or dam failure at Rattling Brook.

Due to the configuration and design of the existing spillway, removal of the stoplogs is a labour intensive and potentially hazardous activity for the plant operations staff.

2.3.3 Flood and Dam Break Study

In 2002, AMEC conducted a Flood and Dam Break Study for the Rattling Brook system. In the event that the plant staff is unable to remove the stoplogs during an extreme flood event, and as a result dam failure at Rattling Lake was to occur, the locations judged to be vulnerable are:

- Trans Canada Highway Bridge crossing Rattling Brook
- Route 351 Bridge crossing Rattling Brook
- Rattling Brook powerhouse. Damage to the powerhouse will likely cease power production.
- Rattling Brook substation located near the powerhouse. Damage to the substation will mean loss of power to the town of Norris Arm.

The report indicates that the failure of these structures could damage the bridges and buildings in the vicinity of the Rattling Brook development.

In accordance with the Canadian Dam Association (CDA) guidelines, Rattling Lake dam is classified as having high consequences in the event of a failure. The normal practice for a high consequence structure is to use an Inflow Design Flood (IDF) somewhere between a 1,000 year return flood to the Probable Maximum Flood (PMF). However, based on the risks posed at the bridges, AMEC recommends upgrading the IDF return period for the Rattling Lake spillway from a 1,000 year flood to a 10,000 year flood.

2.3.4 Analysis of Existing Structure
Due to the importance of the spillway in the Rattling Brook development, the condition and age of the structure, a preliminary stability evaluation was performed by Newfoundland Power to assess the structural integrity of the spillway.

All loading cases were considered with anchors extending into the rock foundation, each instance being examined for overturning about the toe of the concrete weir and sliding of the concrete over the underlying rock. In addition, the location of the resultant force was checked to ensure that no tension is induced at the structure and foundation interface.

Because minimal upgrades were completed on the structure since its original installation in 1958, assumptions were made regarding the capacity of the structural components of the spillway system. To perform all applicable checks it was assumed that the strength of both the bracing system and rock anchor dowels was reduced to 75% and 50% of their original capacity.

Based on the preliminary analysis, and the stated assumptions, the spillway structural acceptance criteria for sliding stability is marginal at 75% of the brace and rock anchor's original capacity and it does not meet acceptance criteria when the capacity of the brace and rock anchor system is reduced to 50% of its original capacity.

3.0 Conclusions and Recommendations

3.1 Conclusions

Stability
Based on the stability analysis performed, for the stated assumptions, Rattling Lake spillway does not satisfy industry standard performance criteria. Both sliding and overturning stability were considered. Stability of the structure is dependent on bracing and anchoring systems, which provide some measure of resistance, but should not be relied upon for ongoing stability under long-term service conditions.

Flood Discharge Capacity
The spillway design flood cannot be safely passed with stoplogs in place. Provision for adequate discharge capacity and freeboard requirements at Rattling Lake is largely dependent on stoplog

removal operations. This requires a labour intensive effort from plant operations staff for a prolonged period.

Operation of Stoplogs
Under the current arrangement, stoplogs are typically removed during periods of high inflows in order to provide adequate spillway discharge capacity. The manual stoplog removal process is a hazardous operation, and requires diligent job planning to ensure worker safety is not compromised. External factors, including extreme flood conditions and the inability to access the site may prevent the execution of stoplog removal operations, thus jeopardizing dam safety.

3.2 Recommendations

It is recommended that Newfoundland Power replace the existing stoplog spillway structure at Rattling Brook in 2008. The new structure will be designed to provide adequate discharge capacity under extreme flood conditions, while satisfying freeboard requirements. When evaluating various rehabilitation alternatives, primary consideration must be given to operating features under extreme flood conditions. Preliminary assessments of viable alternatives are in the order of $1.5 million dollars. Alternatives will be evaluated and a recommendation on the appropriate structure design will be undertaken prior to the 2008 Capital Budget Application.

Attachment A

Rattling Lake Spillway Photos

Figure 1: Rattling Lake Spillway (Aerial View)

Figure 2: Undercutting of Concrete/Bedrock Interface

Figure 3: Fractured Brace Foundation

Figure 4: Deteriorated Walkway Timbers & Operation Staff's "Removal" System

Figure 5: Rattling Lake Spillway (Winter Conditions)

Figure 6: Rattling Lake Spillway (Spill Conditions)

Figure 7: Rattling Lake Spillway (Spill Conditions)

Appendix E

Electrical Equipment Site Assessment

Rattling Brook Hydroelectric Plant
Electrical Equipment Site Assessment

Revised March 2005

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1.0 General

The Rattling Brook hydroelectric development went into service in December 1958. The generating station contains two vertical shaft Francis turbines connected to separate generators each with an original rating of 7500 kVA.

Generating unit no. 2 experienced an in-service failure of the windings and underwent a stator rewind in 2002. A planned rewind of generating unit no. 1 was completed in November 2004.

In 1994, the Rattling Brook generating station was placed under remote control from the System Control Centre in St. John's. With the exception of these major electrical projects, the electrical plant remains in original condition.

In February 2005, a site assessment was completed to determine which electrical and mechanical components of the development require refurbishment or replacement.

2.0 AC Distribution

The existing 120/240V 3-phase AC service panel (figure 1) is located in a cell in the existing switchgear line up. This equipment is original to the plant and replacement breakers are no longer available. With additional loading from the proposed plant upgrading and the addition of new heating and ventilating equipment, this panel will no longer have sufficient capacity. It is preferred to locate the AC panel away from the switchgear line-up to provide ease of access for wiring future circuits.

Figure 1 - AC Distribution

3.0 Station Service

There are currently two station services connected to the 6900 volt generator bus. The original plant station service located in the switchgear cabinet consists of three 25 kVA 240 volt secondary transformers, with one transformer low voltage winding tapped to provide 120 volt secondary voltage. The second station service transformer was installed to supply the former control centre building located on this site. This service consists of a 150 kVA three-phase transformer with a 120/208 volt secondary. With the installation of new electrical equipment, it will be necessary to change the voltage of the existing plant station service transformer to satisfy the voltage requirements of the new equipment and increase transformer capacity to accommodate the additional load. A redundant station service, consisting of a normal supply and an emergency supply, will be installed to ensure the availability of this critical black start plant. This will require modification to the outside distribution substation.

4.0 DC Distribution


Figure 2 - DC Distribution

The DC distribution panel (figure 2) is original to the plant and has no spare breaker positions for additional circuits. Additional breaker positions will be required to accommodate the various electronic components to be included in the governor and unit control panels. Additional DC circuits are also required for the motor actuators associated with the new valves to be installed as part of the plant mechanical upgrade. Due to its age, and lack of spare capacity it is recommended that the DC distribution panel be replaced.

5.0 Battery Plant and Charger


Figure 3 - Battery Bank

The battery bank (figure 3) was installed in 1996 and is in good condition. The battery charger is 21 years old and the supply of spare parts has been exhausted. During the inspection its condition was assessed and the charger requires replacement. The battery bank and the charger are located in the same room as the switchgear instead of in a separate battery room. The plant refurbishment will include the construction of a separate battery room to house the battery bank.

6.0 Generators


Figure 4 – Termination Cabinet

Generator No. 2 and Generator No. 1 were rewound in 2002 and 2004 respectively. No additional work is required on the generator windings. The temperature signals from the resistance temperature devices installed in the stator windings during the rewinds will be monitored by the new control system. The existing terminal blocks in the generation terminal cabinet will be replaced with resistance temperature device terminal blocks.

7.0 Excitation Systems

The exciters on both generators are original equipment installed in 1958.

Generator No. 1 exciter stator, rotor and brush gear were cleaned and painted by General Electric during the stator rewind completed in 2004. The winding impedance is good so no additional work is required on the Generator No. 1 exciter as part of this project with the exception of the installation of brush gear temperature sensors. Similarly, the Generator No. 2 exciter was cleaned and painted during the 2002 generator stator rewind. The winding impedance is poor and it is recommended the exciter be overhauled and rewound as part of this project.

Both units have Brown Boveri voltage regulators (figure 5) with mechanical operating mechanisms and have been manufacturer discontinued. These units will be replaced with digital voltage regulators.

The Field Breakers (figure 6) on both units are original to the 1958 installation, are obsolete and lack a sufficient number of auxiliary contacts required by the PLC control system being installed. New field breakers will be installed in the new switchgear lineup. The power cables from the exciters to the generators via the field breaker are also original to the plant and will be replaced as they are at the end of their service life.

Figure 5 - Voltage Regulator

Figure 6 - Field Breaker

8.0 Switchgear

The generator and incoming breakers are original units installed in 1958. The potential transformers (PT) and current transformers (CT) are integral to the switchgear and are original equipment installed in 1958. The PT and CT winding insulation appear brittle due to age. They must be replaced due to the critical role this equipment plays in the electrical protection of the generators.

The existing switchgear design was based upon two incoming breakers fed from two separate power transformers. In 2002, the two original transformers were replaced with a single power transformer. The two original incoming breakers and associated power cables are connected in parallel feeding the new power transformer. A replacement switchgear design will connect the

6900-volt bus to the power transformer with a single incoming breaker and dual set of power cables capable of carrying the total maximum current of both generators.

Another issue to be addressed with the switchgear is the combining of the breaker protection and control with the generator sequencing, monitoring and control functions in a single panel. Replacement of generator control is best done in concert with the switchgear replacement since the proposed design incorporates both functions into a single panel.

9.0 Power Cables

The power cables from the generator termination cabinets to the switchgear are the original 1000 MCM paper insulated lead covered (PILC) cables with pitch filled pothead terminations. PILC cables typically have a long life expectancy. However, these cables are susceptible to stress fractures if the insulation is subjected to movement following years of resting in a fixed position. It will not be possible to relocate these cables to new switchgear cubicles without severely damaging the insulation. Therefore the power cables and terminations will need to be replaced as a result of the planned switchgear replacement.

Figure 7 - Unit No. 1 Switchgear Cable Terminations

Figure 8 - Unit No. 1 Generator Cable Terminations

10.0 Generator Grounding

Both generators currently have their stator windings star point solidly connected to ground, which in the event of a phase to ground fault will subject the windings to the electrical stresses of the total available fault current. Industry best practices involve the installation of a small transformer between the winding star point and ground creating a high impedance path for fault current. This will significantly reduce the available fault current resulting in reduced electrical and mechanical stresses on the generators under fault conditions. It is recommended that the high impedance ground design be implemented, and related ground fault protection improvements be completed.

The termination cabinets attached to the generators do not have space for the grounding transformers. Modifications will have to be made to accommodate mounting the grounding transformers on top of the existing termination cabinets.

11.0 Protective Relays

Protective relaying systems provide protection to equipment and personnel during abnormal loading or fault conditions. Thus protective relaying functions are a critical component and must be sufficient to protect generating units and other electrical equipment against all harmful conditions that may develop. The evaluation of the protective relays considers the age of the relay, its reliability, and its ability to address changes in protection standards since the plant was placed in service.

The existing generator protection for both generating unit no. 1 and no. 2 is provided through obsolete electromechanical relays consisting of the following:

- 40 Loss of field protection
- 49 Stator thermal protection
- 51N Neutral overcurrent
- 87G Differential protection
- 87S Split phase protection
- 51V Voltage restrained overcurrent

Over the past 50 years improvements in generator protection have been developed and the following additional protection is recommended:

- 59N Over voltage relay for ground faults
- 64F Voltage relay for rotor ground faults
- 46 Stator unbalanced current protection
- 81U/81O Under/over-frequency protection
- 27/59 Under/overvoltage
- 24 Volts/Hz protection
- 32 Reverse power protection
- 50/27 Dead machine protection
- 27N 100% stator earth fault protection
- 78 Pole slip protection
- 51 Overcurrent protection

It is recommended that the existing generator protective relays be replaced with modern digital generator protective relays to provide all of the above functions, as well as additional functions. These relays will provide the ground fault protection improvements in conjunction with the recommended grounding transformers in Section 10.0. Improved generation protection reduces stresses due to electrical faults and in turn extends the life of the generator.

The existing plant power transformer protection will be upgraded for consistency with the standard protection and control scheme for generating plant applications.

The existing 66 kV high voltage bus at Rattling Brook substation does not have it own primary high speed protection. It is presently protected by time delayed overcurrent protection on the incoming transmission lines. A high voltage bus differential protection relay will be installed to bring the 66 kV bus protection up to standard. This bus differential scheme will require the addition of current transformers on the high voltage side of the distribution power transformer. The new relay will provide bus current differential protection and backup phase overcurrent protection for all equipment feeding into the bus.

Rattling Brook substation is presently serviced by two 66 kV transmission lines. The existing protection on these lines is a combination of overcurrent and impedance relaying. These relays are of the same vintage as other units operated by Newfoundland Power that have failed to operate correctly under fault conditions. It is recommended that these obsolete electromechanical relays be replaced with modern digital distance line protection relays. The new relays will provide improved line protection with both impedance protection and overcurrent protection, which will also improve coordination with other protection devices. The transmission line protection standard application will be applied to these lines.

12.0 Alarm Annunciation

Industrial computer human-machine interfaces will be installed in the unit control panels to provide improved alarm indication and functionality. The annunciator panel currently located in the switchgear line up is antiquated and will be removed from service.

13.0 Governor Interface

The original Woodward Type HR hydraulic governors still in service on both generating units have been reliable and have no outstanding maintenance issues. However, the original equipment manufacturer advises they will no longer manufacture replacement parts for these units after July 1, 2008. Initially this raised concerns regarding the future maintenance of these units. Newfoundland Power has since determined that parts, service and training for Woodward governors are provided by a number of third-party companies.

More advanced control of the governor load and droop setpoints is required to implement a PLC controlled water management system and remote black starting of the units. With the present configuration of the governors the speed reference setpoint feedback cannot be obtained and the starting gate limit and droop settings cannot be controlled. The Woodward governors consist of two sections, the power piston that provides the force necessary to operate the wicket gates under load, and the control head that provides regulation to the power piston. A number of suppliers can provide an electronic control head that replaces the existing mechanical control column down to the relay valve that initiates the action of the power piston. The fly ball governor head, pilot valve assembly, and mechanical restoring linkages are all removed. The existing hydraulic power piston assembly is retained, along with the relay valve, servomotor, handwheel, and gate operating linkages. The life extension of the power piston assembly will require reconditioning of all seals, bushings and other components that have deteriorated through the previous 48 years of service.

14.0 Plant Control

Although this plant is remotely controlled and monitored, remote control functions are limited. Intervention by a local or SCADA operator is required to start and stop both units at this plant. Adjusting the load for efficient operation requires manual input from an operator and frequent adjustments. At present, there is no automation with respect to water management and the automatic setting of loads. The addition of programmable logic controllers ("PLC") will provide improved local and remote monitoring and control functionality and facilitate the implementation of a variety of control modes to ensure the efficient operation of the plant and utilization of available water. To provide the required processing power and reliability, PLCs will be utilized to control each generator, common plant functions such as heating and ventilation, forebay water level monitoring, Amy's gate monitoring and control and synchronizing.

The synchronizer (figure 9) is original to the plant and is based on vacuum tube technology making parts difficult to obtain. It will be replaced with modern digital synchronizers as part of the upgraded unit control panel.

Figure 9 - Existing Synchronizer

15.0 Instrumentation

The companion mechanical assessment report that was completed at the same time as this electrical assessment report has identified condition monitoring devices that are antiquated and need to be replaced. These devices are original to the 1958 plant construction. The devices have alarm contacts that operate when a predetermined alarm level has been exceeded and the typical response to the contact closure is to trip the unit off line.

Upgrading the plant control to PLC technology provides the capability to continuously monitor the state of the various mechanical subsystems. The operating condition of these bearings, cooling water, windings and other mechanical equipment can be recorded and trends identified before any damage occurs. To provide this capability the antiquated condition monitoring devices must be replaced with modern devices that provide a scaled analog quantity in addition to the trip contact.

The following condition monitoring devices will be replaced as part of the electrical and mechanical refurbishment. The justification for this work is found in Appendix F, *Mechanical Site Assessment* report.

- Speed Switch
- Vibration Sensors
- Bearing Temperatures Sensors
- Pit Flood Sensors

- Stator Temperature Sensors
- Brush Gear Temperature Sensors
- Scroll Case Pressure Gauge
- Wicket Gate Position Transducer
- Bearing Oil Level Sensors

16.0 Bearing Cooling Water Control

The bearing cooling water system is comprised of a water filter, pressure-reducing valve, manual control valve, inlet control solenoid, flow meter, cooling coil and discharge solenoid. Inlet and drain valves with partial automated control are currently in place for both units. Flow monitoring and valve controlled solenoids have been installed to provide protection and control. This system will be integrated into the new PLC control system. Proper control of the system will reduce cooling coil wear, extending the life of the system and reducing the potential for release of petroleum products into the environment.

A detailed assessment of the bearing cooling water system including the condition of the piping and valves is included in Appendix F, *Mechanical Site Assessment* report.

17.0 Heating and Ventilation

There are anti-condensation heaters installed on each generating unit. The building ventilation louvers are original equipment and are pneumatically operated. Additional generator pit heating is required to adequately control condensation. Presently only the generator gallery temperature is monitored.

Heating and ventilation control equipment will be upgraded to interface with the unit control PLCs. Temperatures will be monitored in the generator gallery, turbine pit and valve pit and humidity monitored in the generator gallery. The PLC will use building ambient temperature and humidity inputs to control the operation of the exhaust fans, louvers, generator winding heater, infrared turbine heaters, infrared valve pit heaters and anti-condensation heaters. A manual override of the heating and ventilation control system will be provided to permit operator intervention. A high building temperature alarm will be initiated when a specified ambient temperature is exceeded.

A detailed assessment of the dampers, louvers, actuators and fans is included in Appendix F, *Mechanical Site Assessment* report.

18.0 Forebay Water Level Monitoring and Control

The forebay and Amy's Gate water level probes and transducers are older technology installed in 1987. This equipment will be replaced with new 4 to 20 mA water level transducers and new control cabinets will be installed at the forebay, Amy's gate and in the plant with a small PLC at the forebay. Both sites will communicate with the PLC at the plant via a new fibre optic cable.

One of the unit PLCs will use the water level signals to control the water management system including the control of Amy's gate. The water management system will optimize the efficiency of the plant by controlling the load on both units based upon the water level, inflow, wicket gate position and control mode setpoints. In addition high level (spill) and low level alarms will be initiated when specified water levels are exceeded.

19.0 Forebay Line

The 12.5 kV forebay distribution line was built in 1958. The line was rebuilt in 1980 with penta treated poles and untreated cross arms. Inspection of the line indicates that while the treated poles are in reasonably good condition and may have an extended life of 20 to 25 years, the cross arms and insulators are deteriorated and require replacement. The cross arms are untreated and at 25 years have exposed wood rot. As well many of the cross arms are badly cracked which greatly reduces the structural strength of the entire line. The insulators are older and many are the two piece porcelain type which are prone to failure and have been replaced throughout the system.

This forebay line is used to operate gates which control water levels for operation of the plant. It is also used as the carrier for the communications cable for monitoring these levels. Thus the line is an integral part of the infrastructure required to maintain the plant operations. The forebay line will be upgraded to correct the noted deficiencies.

20.0 Substation

Rattling Brook substation was built in 1958 as a 66 kV transmission switching substation and as a 12.5 kV distribution substation. The distribution substation contains one power transformer (T4) with a capacity of 2.2 MVA at 12.5 kV. The substation directly services approximately 674 customers in the Norris Arm area. In the transmission substation there are two 66 kV transmission lines terminated in the high voltage bus. These are transmission lines 101L to Grand Falls substation and 102L to Gander substation.

The substation has a 4.16 kV bus connected to the 66kV bus through a single transformer (T1) rated at 20 MVA. The 4.16 kV bus connects the power output from the generating station to the transmission and distribution substations.

The existing substation is wood pole construction. The current 12.5 kV distribution bus has non-standard clearances, materials and hardware. The existing substation bus does not have adequate space to accommodate the addition of a new station services transformer required for the new plant switchgear (reference section 3.0). Also, an emergency station service taken from the 12.5 kV distribution bus is required for the plant. Section 11.0 identifies protective relaying deficiencies and recommends protection improvements for the transmission lines, transformer and high voltage bus. The substation site is too small to facilitate the installation of a Portable Substation for transformer maintenance or emergency situations and needs to be enlarged. For these reasons the existing substation needs to be upgraded to current standards, enlarged and modified to provide both normal and emergency station services.

21.0 Communications

Communications systems at Rattling Brook collect information on site at the facility and sends data back to the System Control Centre in St. John's. The communications systems will be upgraded to improve the reliability of the plant and to meet other project objectives such as retirement of the old Control Centre building.

Present System

Two 25 pair figure eight copper communications cables are used to provide water level indication, gate control and gate position from both the forebay and Amy's Lake intake structures back to the plant. The water level indications are used to manage the day to day operation of the plant and to manage the water storage levels. The condition assessment of the plant communications cables indicated that the various cable pairs range from good to poor condition, with some cable pairs no longer intact. Table 1 shows the percentages of pairs in-service, spare and failed.

Table 1
Rattling Brook Communications Cable Assessment
(%)

Cable Section	In-Service	Spare	Failed
Plant to Forebay	40	32	28
Forebay to Amy's	55	27	18

Metallic communication cables are prone to failure caused by voltage gradients on the cable pairs induced by ground potential rises ("GPR"). The GPR effect is common in the utility environment where cables connect the substation ground grid where a fault current may be present to a remote location where the effects of the ground fault are not present. Hence a potential difference exists and a current will flow through the cable. Faulty cable pairs can cause controls to operate incorrectly and errors in reporting of forebay levels.

Proposed Cable System

Reliable operation of the forebay communications, monitoring and control systems contributes greatly to plant production efficiencies. A fibre optic based communications system is proposed to replace the copper communications. The fiber optic cable is not impacted by GPR effects and associated voltage gradients causing analog signal loss. New electronic fibre interface equipment will be installed to transfer signals from the forebay equipment to the plant PLC system.

22.0 Recommendations

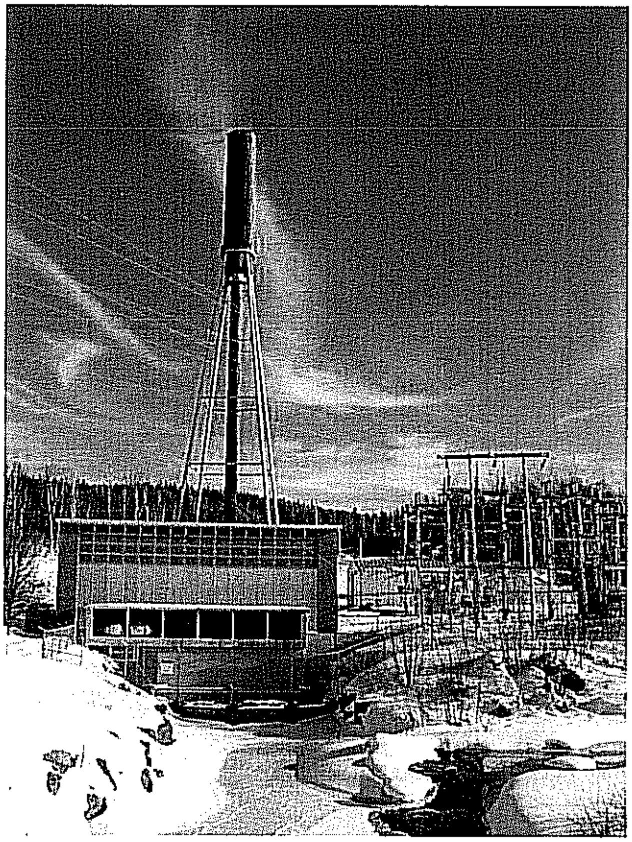
The following upgrades are recommended to be completed in 2007:

1. Replace AC distribution panel and provide new normal and emergency station service
2. Replace DC distribution panel and build battery room
3. Rewind the exciter on unit no. 2
4. Replace the switchgear and generator power cables
5. Replace the Field Breakers and voltage regulators on both units
6. Upgrade protective relay technology for both generators
7. Install generator ground protection on both units
8. Expand the existing substation, improving clearances and modify structures to accommodate station services
9. Install new protection panels for the transformer, two transmission lines and 66 kV bus
10. Refurbish governors and equip with electronic control units
11. Install new unit control panels (PLC) and interface with instrumentation for both units
12. Upgrade to plant and equipment heating and ventilation systems
13. Upgrade the existing forebay 12.5 kV distribution line
14. Replace forebay communication cable and water level monitoring equipment

Appendix F

Mechanical Site Assessment

Rattling Brook Hydro Plant
Mechanical Site Assessment



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1.0 General

The purpose of this report is to document the existing condition of the mechanical equipment at the Rattling Brook hydro plant and to make recommendations for required improvements to extend the life and improve the reliability and efficiency of the plant.

For the most part, the existing mechanical equipment was originally installed when the plant was constructed in 1958. The only notable mechanical upgrade was the replacement of the two turbine runners in 1986-87.

2.0 Equipment Condition Assessment

Site visits were conducted in February 2005 to inspect and assess the condition of the various components and systems including the main and bypass valves, turbines, generators, bearings and related instrumentation, bearing cooling water systems, governors, compressed air system, and powerhouse heating and ventilation.

Additional input to the equipment assessment was compiled through a review of available documentation including: historical inspection and assessment reports; recent maintenance history; outage reports; drawings; and manufacturer's information including maintenance manuals. Discussions were also held with Rattling Brook plant operations personnel regarding maintenance history, issues and recommendations.

2.1 Main Inlet (Butterfly) Valves and Associated Equipment

2.1.1 Main Inlet Valves

The main inlet valve for each unit is a 57 inch butterfly valve manufactured by Vancouver Iron Works (Baldwin-Lima-Hamilton) in 1958. The two identical valves are water actuated and each has a Dresser Coupling dismantling joint, located upstream.

The existing main inlet valves have experienced leaks and related problems. Attempts were made to mitigate these issues however none resulted in long term success. The valves currently leak and make it unsafe to access the scroll case without having to dewater the penstock.

Figure 1- Main Valve

During the site visit, a series of pressure and load rejection tests were carried out. These tests were conducted to determine the pressure differential across the butterfly valves. The maximum pressure loss across each valve was measured to be approximately 3 psi. This pressure loss is approximately three times that which would be typical of a modern butterfly valve. Assuming an annual plant production of 76 GWh after plant refurbishment and a cost of energy of $0.07/kwh, the replacement costs were justifiable.

Both butterfly valves will be replaced. Due to the high cost and long delivery of non-standard 57 inch butterfly valves and dismantling joints, it will be more cost effective to replace the existing with new standard sized 60 inch equipment and make any necessary modifications to accommodate the slight increase in diameter. The new electric valve actuators will operate on standard 125 VDC.

2.1.2 Drain and Bypass Valves

Each system has a 6 inch manual drain valve (figure 2) and a 6 inch manual bypass gate valve (figure 3). All valves are original equipment with the exception of the water actuated bypass valve on unit no. 2 which was replaced in 2001 and is in good condition.

Since both actuated bypass valves are water operated via the same system as the butterfly valves, their replacement will occur at the same time and the new actuators will also be the standard 125 VDC electric actuators.

Based on age and anticipated service life, the manually operated bypass and drain valves will be replaced.

Figure 2 - Drain Valve

Figure 3 - Bypass Valve

2.1.3 Valve Actuators

The existing butterfly and bypass valves for each unit are water actuated via a 2 inch 5-way control valve as shown in figure 4. Both 5-way control valves were refurbished in 2004 however, the original piping remains. Manual operation of the valves was at one time possible by means of a hand pump circuit and auxiliary water supply, but this system is no longer functional.

This system will be decommissioned and the valve actuators replaced with 125 VDC electric actuators.

Figure 4 - Valve Actuator

2.1.4 Valve Control Panel

The control panel for the valves has been modified since its initial installation however the controls for both units are obsolete. The controls for unit no. 2 have only the "main valve closed" indicator light currently operational. The controls for unit no. 1 are original equipment and no indicator lights are working. This control panel will be replaced.

Figure 5 - Valve Control Panel (exterior)

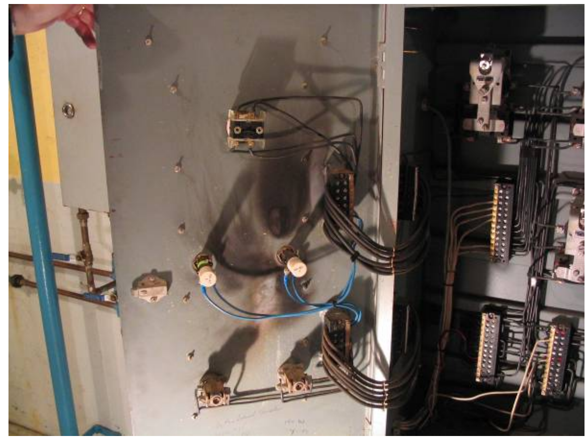


Figure 6 – Valve Control Panel (interior)

2.2 Turbine

During the site visit, it was difficult to conduct an internal inspection of the turbines because of the excessive leakage past the two main inlet butterfly valves. On both units, when the scroll case access hatch was opened (figure 7), the field of view was clouded by the significant spray of water originating around the butterfly valve disc. To mitigate this problem the drain valve was opened and a plywood barricade was placed downstream of the butterfly and drain valves. Even with this barricade in place, there was still a considerable amount of water interfering with the inspection.

Figure 7 – Scroll Case Access Hatch

Prior to this inspection, the most recent documented internal inspection of the turbines was conducted in 1998. The scope of that inspection included the runner, wicket gates and seals, scroll case, and the main inlet butterfly valves of both units.

There is no mention of wicket gate or wicket gate pin and bushing replacements in any of the historical records for either unit. Nor is there mention of the replacement of any of the pins and bushings on any of the other linkages between the governor and the turbine. While it is assumed that this is all original equipment, there currently appears to be little or no lost motion in any of the linkages. As well, since the gate clearances appear uniform and since there seems to be little leakage past the wicket gates, there will be no need to replace this equipment in the immediate future.

It is recommended that a thorough inspection of each turbine be completed during the 2007 plant outage. This inspection should confirm the current schedule for complete turbine overhauls in five to seven years on both units, with one unit undergoing a turbine overhaul in 2012 and the second unit in 2013. Previous overhauls were completed in 1986-87.

2.2.1 Unit No. 1

In 1987, the unit no. 1 turbine runner was replaced with a new Allis-Chalmers runner. During that overhaul, shaft pitting was identified and repairs were made at a local machine shop. As well, the stainless steel gland sleeve was found to be badly worn and was repaired. Severe cavitation was noted in the area of the scroll case head cover and discharge ring seal. This cavitation was also identified as a problem in 1968 and at that time was repaired with Devcon. By 1987, much of that material had washed away and the area was sandblasted and built up, this time using Mazel molecular metal.

Currently, the runner (figure 8) is in good condition. There is some evidence of minor cavitation in essentially the same location on each of the blades.

All but two wicket gates are in good condition. These two gates are located near the 2nd and 3rd stay vanes, counting from the area near the scroll case access hatch. These gates will be repaired as a temporary measure until the unit is overhauled in about 2012.

Figure 8 – Turbine Blades Unit No. 1

Heal-to-toe clearance between the gates is currently less than 0.002”, on the five gates that were measured. There is less than 0.0015” between the top surfaces of the gates and the upper facing plate and approximately 0.015” to 0.018” between the bottom surfaces of the gates and the lower facing plate. Overall, clearances are approximately equal on all gates and there is minimal leakage through the gates into the draft tube area. There has been no change in the wicket gate clearances since the 1998 inspection report.

The upper and lower facing plates appear to be uniform across their surfaces and are in reasonably good condition.

The shaft gland packing on the unit was completely replaced in 2004 and the scroll case air vent valve was replaced in 1999.

2.2.2 Unit No. 2

In 1986, the unit no. 2 turbine runner was replaced with a new Allis-Chalmers runner. The runner is currently in good condition (figure 9). There is some evidence of minor cavitation in essentially the same location on each of the blades. There is no cause for concern at this time.

Figure 9 – Turbine Blades Unit 2

All wicket gates, but one, are in good condition. Like on unit no. 1, this gate is located near the 2nd and 3rd stay vanes, counting from the area near the scroll case access hatch. These gates will be repaired as a temporary measure until the unit is overhauled in 2013.

Heal-to-toe clearance between the gates is less than 0.002" on the five gates that were measured. There is less than 0.0015" between the top surfaces of the gates and the upper facing plate and approximately 0.015" to 0.020" between the bottom surfaces of the gates and the lower facing plate. Overall, clearances are approximately equal on all gates and there is very little leakage through the gates into the draft tube area. There has been no change in the wicket gate clearances since the 1998 report.

The upper and lower facing plates appear to be uniform across their surfaces and in reasonably good condition.

The scroll case air vent valve on this unit is original equipment (figure 10). Given the age and condition of this equipment, and the fact that identical equipment on unit no. 1 of the same vintage has already required replacement, this valve will be replaced.

Figure 10 – Scroll Case Air Vent

2.3 Generator

2.3.1 Unit No. 1

The generator stator on unit no. 1 was rewound in 2004 and the exciter received a minor overhaul that included cleaning and painting. In addition new leads, brackets, and insulators were installed on the exciter. Electrically the exciters tests results were good.

Figure 11 – Generator Gallery

During the rewind project, the braking system was overhauled and air lines were replaced with all new flexible high pressure lines, the brake cylinders were overhauled, and all new brake pads were installed.

2.3.2 Unit No. 2

The generator stator on unit no. 2 was rewound in 2002 and the exciter received a minor overhaul that included cleaning and painting. In addition new leads, brackets, and insulators were installed on the exciter. Electrically the exciters tests results were poor and it is recommended that the exciter be overhauled and rewound as part of this project.

The braking system on this unit has not had any recent upgrades or maintenance other than replacement of the brake pads. Based on the present service life and condition of the system, an overhaul will be completed on the brake cylinders and the existing air lines will be replaced with new flexible high pressure lines.

2.4 Bearings & Bearing Instrumentation

The current assessment of the bearings includes a high-level evaluation of the condition of the bearings on each unit with a more detailed review of the bearing instrumentation and other related equipment.

2.4.1 Bearings

The most recent oil analysis reports for each bearing were reviewed and do not indicate any significant issues requiring immediate action. However, previous inspections have identified some issues on unit no. 1 that require repair. The thrust bearing insulation has been breached and has the potential to cause deterioration of the bearing and must be repaired. The thrust pad springs are no longer within the specified tolerance and require replacement. On the turbine bearing, delamination of the babbit surface from the shell has been noted and has resulted in minor surface damage on the bearing itself. This bearing will be re-babbitted as part of the turbine overhaul in 2012.

Figure 12 – Bearing Oil Level Switch

2.4.2 Bearing Oil Level Instrumentation
The existing oil level switches on the bearings (figure 12) provide alarm contacts only. These will be replaced with new sensors that are also capable of transmitting an analog signal to the unit PLC.

2.4.3 Bearing Temperature Instrumentation
Currently, only the bearing shell temperatures are being measured on both units, not the temperatures of the bearing surface. Measurement of bearing surface temperature wherever possible is superior to measurement of bearing shell temperature as it more precisely measures the temperature of the contact surface. Bearing surface temperature measurement is critical to improve bearing condition monitoring and to improve the response time when problems occur. Therefore, all bearing temperature instrumentation will be relocated and/or replaced as described below.

Unit No. 1

The temperature of each bearing shell is measured with a capillary tube temperature thermal bulb (figure 13). These will be replaced since they are contact only and there is no analog signal which can be transmitted to the PLC.

Unit No. 2

Much of the instrumentation on unit no. 2 has been upgraded in recent years and is tied to the existing unit PLC.

There are currently eight temperature thermocouples (two per: turbine, lower guide, upper guide, and thrust bearing) tied to the plant PLC. However, these thermocouples currently measure bearing shell temperature only and all eight will be relocated to measure bearing surface temperatures.

Figure 13 – Bearing Temperature Switch

2.4.4 Vibration Monitoring
Vibration monitoring is a critical piece of information that identifies growing problems with a dynamic mechanical system. As large machines rotate at high speed their motion should be constant and very stable. As problems develop the equilibrium that exists within the rotating machine is disturbed and vibrations develop. Continuous condition monitoring with vibration sensors identify when these problems begin and allow the engineer an opportunity to correct the problem before it leads to an equipment failure.

There is no vibration monitoring equipment installed on unit no. 1. It is recommended that vibration monitoring be installed on this unit.

The vibration monitoring equipment on unit no. 2 is the type of technology used by the Company for installations that do not use PLC control systems. The system does not provide the operator with real-time data to aid in identifying potential problems with the generator. The existing vibration equipment on unit no. 2 will be replaced with PLC compatible equipment. The existing equipment is still functional, and will be retained as spares for in-service equipment remaining in older installations.

2.5 Bearing Cooling Water Systems

The assessment of the bearing cooling water systems includes a high-level evaluation of the condition of the bearing cooling coils on each unit with a more detailed review of the cooling water piping, and other related equipment.

2.5.1 Bearing Cooling Coils

Table 1 shows the most recent cooling coil replacements.

Table 1
Cooling Coil Replacements

Cooling Coil	**Unit No. 1 Year Replaced**	**Unit No. 2 Year Replaced**
Upper guide thrust bearing	2000	2000
Lower guide bearing	2000	2000
Turbine Bearing	1999	1998

In the latest revision of Newfoundland Power's Environmental Management System (EMS) Plant Operating Guidelines, it is recommended that such cooling coils be replaced every 15 years. This recommendation is based on historical operating experience and will be followed to minimize the risk to the environment due to an oil spill. Using these guidelines, no replacement is required at this time.

2.5.2 Cooling Water Piping

The bearing cooling water system was originally part of a much larger system designed to supply water not only for bearing cooling, but also for an exterior fire hydrant, a sump pit eductor pump, a hot water tank (for plant domestic water), an office building (former control centre) domestic water, and a tap located on a plant exterior wall. As a result there is a complex, interconnected network of water piping and fittings in the turbine area.

Problems related to system deterioration have been well documented, particularly in recent years, as the cause of many unscheduled plant outages. The entire cooling water system will be redesigned and replaced to better suit the application.

Figure 14 – Twin Strainer

The existing twin strainer (figure 14) is original 1958 vintage equipment and has caused problems in recent years. It supplies both bearing cooling water systems as well as other water systems that are no longer in use.

To clean the existing strainer, as is periodically required, both hydro units must be shut down. This strainer will be replaced.

There are solenoid valves (figure 15) and flow meters on the cooling water lines for each bearing and oil level switches on each bearing oil reservoir. This system is designed to control the flow of cooling water when the generator is operating. In addition it monitors the oil level in the bearing oil reservoir. By closely monitoring water flow and oil levels, the system can detect if water is leaking into the bearing reservoir and can stop the flow of water, preventing the release of oil into the environment.

Figure 15 – Solenoid Valve

The solenoid valves were installed on unit no. 1 in 2000 and at that time some of the original bearing cooling water piping was replaced with new copper piping. Similar work was carried out on unit no. 2 at the same time. Experience has shown that the service life of this particular make and model of solenoid valve is limited and therefore all the cooling water solenoid valves will be replaced with more robust equipment.

The flow meters were installed, and associated copper piping replaced, on both units in 2001. However, the flow meters on Unit no. 2 have since been replaced with a newer type. All flow meters are contact only and all appear to be operational. However, experience has shown that the type of flow meters on Unit no. 1 frequently provide erroneous readings and therefore will be replaced.

There currently is no measurement of inlet cooling water temperature. Monitoring equipment will be installed for the purpose of trending bearing temperatures relative to bearing cooling water temperatures.

Cooling water is also directed to the shaft gland seal. Because of the condition and age of this cooling water piping on both units (original 1958 vintage) it will be replaced. The flow meters on this system will be replaced for the same reasons stated above for the flow meters on Unit no. 1.

2.5.3 Other Related Equipment

During normal operation, the 5-way valves drain water into their respective sumps whenever the butterfly valves are opened or closed. This water then drains through concrete embedded pipes to the main plant sump. Water is also piped to the main sump from the discharge of the turbine gland seal cooling water systems on each unit.

The sump is also utilized whenever the draft tube is drained for maintenance and to collect water should there be a leak from the main valves, turbine head cover, draft tube door, or any of the other water piping in the turbine area.

The sump is continuously dewatered by a water operated eductor pump. This pump is original equipment and has frequently required repairs in recent years. Since it has reached the end of its useful life, it will be replaced.

The sump also has an electric pump, which is currently started and stopped by float switches whenever the eductor pump does not have the capacity to handle inflows or has failed. While this electric pump is original equipment, it has not been used extensively because it was manually operated only until recently when the float switches were installed to permit automatic operation. This pump will be removed from service and thoroughly inspected and overhauled if necessary to ensure continued reliable operation.

In addition to the float switches, there is a high water level switch located in the sump which is used to trigger an alarm. These float switches and the high level switch will be connected to the plant PLC to facilitate annunciation of alarms, to initiate unit shut-down sequences, and to facilitate the protection of electrical equipment in the turbine and valve pit areas.

The vast majority of the piping system associated with this sump is original equipment and will be replaced due to its corroded condition.

2.6 Governor

Mechanically, both Woodward governors (figure 16) at Rattling Brook are in good condition and have operated reliably. Despite the fact that Woodward no longer supports its product to any great extent, parts, service, and training are now available from non-OEM providers.

The governors at Rattling Brook will be mechanically overhauled as part of the upgrades recommended in the Electrical Equipment Assessment Report. The functionality of the governors in terms of unit control capabilities is also found in this report.

Figure 16 – Woodward Governor

2.7 Compressed Air System

The central air compressor supplies the braking system on each unit as well as the actuators for the air intake and recirculation operable dampers. This compressor (figure 17) is original 1958 vintage equipment and will be replaced.

Upgrades will also be completed on the entire compressed air system, which is also original equipment. This includes replacement of the piping, valves, regulator, filters, separators, gauges, and related equipment.

Figure 17 – Air Compressor

2.8 Powerhouse Heating and Ventilation

The Rattling Brook powerhouse has a system of air inlet and recirculation dampers for building heating and cooling. Three exhaust fans are also located inside the powerhouse to facilitate cooling.

2.8.1 Air Inlet and Recirculation Operable Dampers and Fixed Louvers

Horizontally, there is approximately 30 inches between the recirculation (interior) dampers and the air inlet (exterior) dampers. Vertically, the top of the recirculation damper is located at approximately the same elevation as the bottom of the air inlet damper.

The recirculation and air inlet dampers are all actuated by the same pneumatic actuators and interconnected linkages.

Recirculation (Interior) Operable Dampers

The recirculation dampers are located on the interior plant wall just above the generator floor level. They are original equipment and will be replaced. The exterior frame openings are approximately 84 inches long by 64 inches high for three of the dampers and 51 inches long by 64 inches high for one of the dampers. The four dampers each have 9 inches horizontal, parallel blades in a 6 inch deep frame. These dampers are deteriorated and will be replaced.

Air Inlet (Exterior) Operable Dampers

The six air inlet dampers (figure 18) each have 9 inch horizontal, parallel blades in a 6 inch deep frame. The inside of each frame opening measures approximately 80½ inches long by 66 inches high. These dampers are badly corroded and require replacement.

Figure 18– Air Inlet Dampers

Exterior Fixed Louvers

The six fixed louvers (figure 19) are located immediately outside air inlet dampers within the same building openings. As such, the overall dimensions of each louver match that of the air inlet dampers. Each louver has 9 inch horizontal, parallel blades in a 6 inch deep frame. The louvers also have an exterior bird screen with ¼ inch openings. This equipment is badly corroded and requires replacement.

Figure 19 – Exterior Louvers

Access

Access to the air inlet dampers is via a small access hatch on the generator floor level behind the air compressor. Inside the hatch is a small wooden ladder leading to wooden planks that run along the length of the six operable dampers. These planks are located at a considerable height since the opening extends downward beyond the recirculation dampers to openings at the turbine floor level. To improve employee safety, improved access ladders and platforms will be installed.

<u>Actuation and Controls</u>
Some upgrades have taken place on the actuation and controls system for the intake and recirculation dampers. While the actuators were upgraded, they still leak considerably (resulting in greater than normal cut in cycles of the air compressor) and will be replaced with new electric actuators. The single thermostat that controls the operation of the dampers was replaced during the upgrade. However, the system will now be tied into the plant PLC system to consolidate control and the thermostat will be replaced with a combined thermostat / humidistat to meet current standards and to provide the required control functionality. The new design will maximize the energy efficiency of the plant, limiting the amount of cooling outside air to times when the plant is operating at full capacity.

2.8.2 Building Exhaust Fans

Two of the 1.5 hp building exhaust fans, located at each end of the plant building are original equipment. These fans are in good condition with operable back draft dampers and bird screens. The additional 15 hp exhaust fan, which was installed in 1993, is in good working condition and is equipped with a functional back draft damper and a bird screen. The nameplate information on all three fans indicates that all are suitable for operation at 208 Volts.

Figure 20 – Building Exhaust Fans

At present each fan is controlled by a dedicated thermostat, each with a slightly different temperature set point. These thermostats will be replaced and the fan control system will now be tied into the plant PLC system to improve energy efficiency.

The walkway around the exhaust fans is in good condition however, it would be safer for plant operations personnel if there were access ladders leading up to the walkways. Such ladders will be installed.

2.8.3 Heating Equipment

There are a number of wall mounted heaters located throughout the powerhouse. As well, there are anti-condensation heaters mounted directly beneath the generator windings.

There are no heaters on the turbine floor or in the valve pits. Presently portable heaters are used in these locations when required. Permanent heaters will be installed at these locations.

3.0 Recommendations

Based on the existing condition of the mechanical equipment at the Rattling Brook hydro plant, a number of improvements are required. These recommendations have been grouped by the timeframe in which they should be completed.

3.1 Year 2007

- Replace butterfly valves and water actuated bypass valves on both units with new 125VDC actuated valves and controls.
- Replace drain valves on both units.
- Replace valve control panels.
- Complete repairs on the deteriorated wicket gates.
- Replace unit no. 2 scroll case air vent valve.
- Overhaul unit no. 2 exciter.
- Overhaul unit no. 2 generator brake system.
- Complete bearing instrumentation upgrades (oil level, temperature, etc.) on both units.
- Install vibration monitoring equipment on both units.
- Upgrade bearing cooling water system including piping, strainers, solenoid valves and flow meters.
- Upgrade sump dewatering system including pumps, piping and controls.
- Mechanically overhaul the power pistons on both governors.
- Replace compressed air system.
- Upgrade powerhouse ventilation.
- Upgrade heating systems.
- Replace air intake louvers.

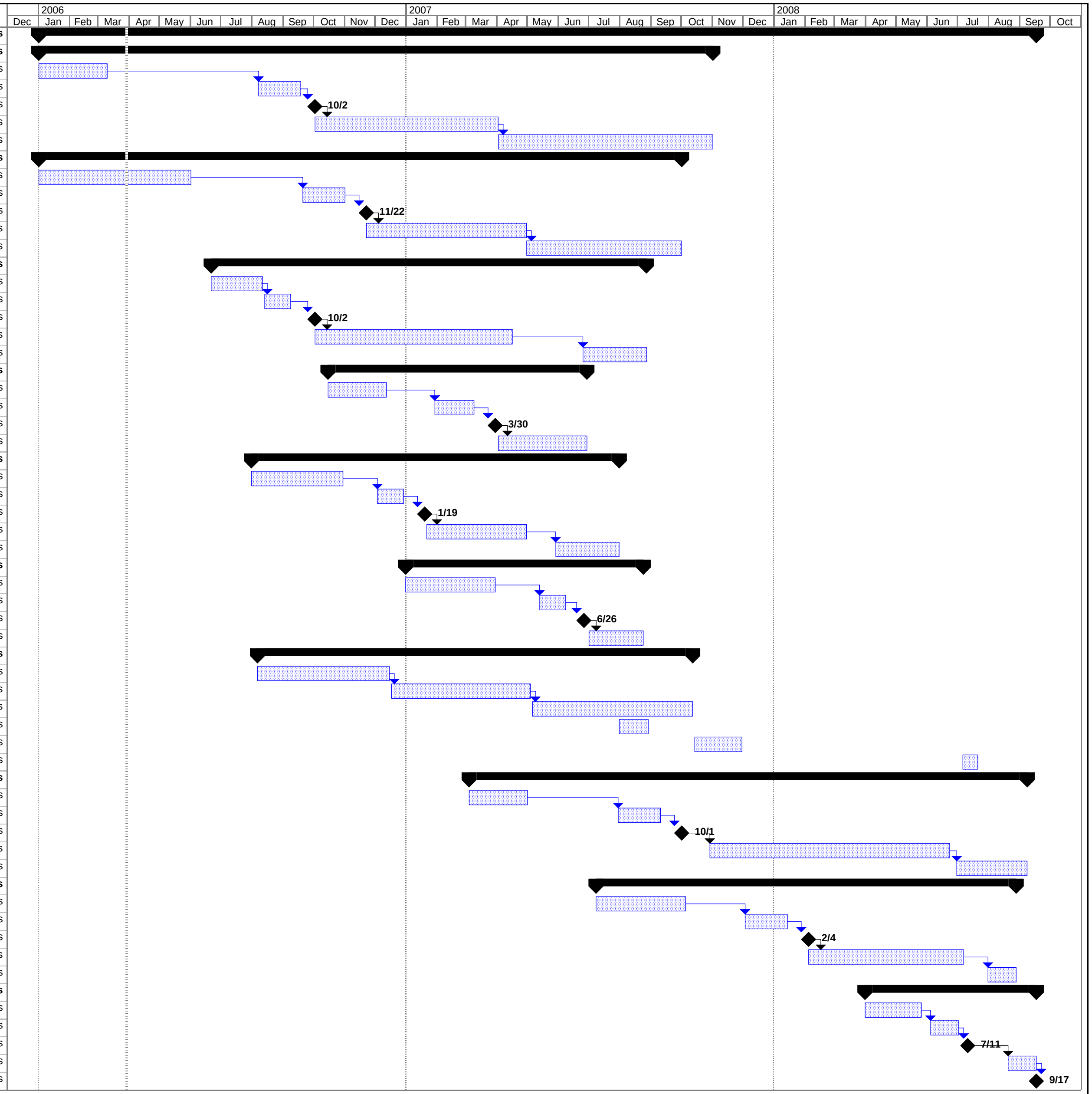
3.2 Years 2012 – 2013

- Overhaul both turbines and replace wicket gates if necessary.

Appendix G

Project Schedule

ID		Task Name	Start	Finish	Duration
1		**Project Management**	**Mon 1/2/06**	**Wed 9/17/08**	**708 days**
2		**Penstock Replacement**	**Mon 1/2/06**	**Thu 11/1/07**	**479 days**
3		Design	Mon 1/2/06	Fri 3/10/06	50 days
4		Tender	Tue 8/8/06	Mon 9/18/06	30 days
5		Award	Mon 10/2/06	Mon 10/2/06	0 days
6		Fabrication	Tue 10/3/06	Mon 4/2/07	130 days
7		Installation	Tue 4/3/07	Thu 11/1/07	153 days
8		**Surge Tank Rehabilitation**	**Mon 1/2/06**	**Mon 10/1/07**	**456 days**
9		Design	Mon 1/2/06	Thu 6/1/06	109 days
10		Tender	Thu 9/21/06	Wed 11/1/06	30 days
11		Award	Wed 11/22/06	Wed 11/22/06	0 days
12		Fabrication of External Riser	Thu 11/23/06	Mon 4/30/07	113 days
13		Construction	Tue 5/1/07	Mon 10/1/07	110 days
14		**Main Valve Replacement**	**Thu 6/22/06**	**Mon 8/27/07**	**308 days**
15		Design	Thu 6/22/06	Fri 8/11/06	37 days
16		Tender	Mon 8/14/06	Fri 9/8/06	20 days
17		Award	Mon 10/2/06	Mon 10/2/06	0 days
18		Fabrication/Delivery of Valve	Tue 10/3/06	Mon 4/16/07	140 days
19		Installation	Tue 6/26/07	Mon 8/27/07	45 days
20		**Powerhouse Extension**	**Mon 10/16/06**	**Fri 6/29/07**	**185 days**
21		Design	Mon 10/16/06	Tue 12/12/06	42 days
22		Tender	Tue 1/30/07	Fri 3/9/07	29 days
23		Award	Fri 3/30/07	Fri 3/30/07	0 days
24		Construction	Tue 4/3/07	Fri 6/29/07	64 days
25		**Mechanical System Upgrades**	**Tue 8/1/06**	**Tue 7/31/07**	**261 days**
26		Design	Tue 8/1/06	Mon 10/30/06	65 days
27		Tender	Mon 12/4/06	Fri 12/29/06	20 days
28		Award	Fri 1/19/07	Fri 1/19/07	0 days
29		Fabrication/Procurement	Mon 1/22/07	Mon 4/30/07	71 days
30		Installation	Wed 5/30/07	Tue 7/31/07	45 days
31		**Substation Upgrades**	**Mon 1/1/07**	**Fri 8/24/07**	**170 days**
32		Design	Mon 1/1/07	Fri 3/30/07	65 days
33		Tender	Mon 5/14/07	Fri 6/8/07	20 days
34		Award	Tue 6/26/07	Tue 6/26/07	0 days
35		Construction	Mon 7/2/07	Fri 8/24/07	40 days
36		**Electrical, Protection & Controls Upgrades**	**Mon 8/7/06**	**Fri 10/12/07**	**310 days**
37		Design	Mon 8/7/06	Fri 12/15/06	95 days
38		Fabrication/Procurement	Mon 12/18/06	Fri 5/4/07	100 days
39		Installation	Mon 5/7/07	Fri 10/12/07	115 days
40		Forebay, Distribution & Communication Line	Wed 8/1/07	Wed 8/29/07	21 days
41		Commissioning	Mon 10/15/07	Fri 11/30/07	35 days
42		Access Road Upgrade	Mon 7/7/08	Mon 7/21/08	11 days
43		**Rattling Lake Spillway Replacement**	**Mon 3/5/07**	**Mon 9/8/08**	**396 days**
44		Design	Mon 3/5/07	Tue 5/1/07	42 days
45		Tender	Tue 7/31/07	Mon 9/10/07	30 days
46		Award	Mon 10/1/07	Mon 10/1/07	0 days
47		Fabrication of Spillway	Tue 10/30/07	Mon 6/23/08	170 days
48		Installation	Tue 7/1/08	Mon 9/8/08	50 days
49		**Amy's Outlet Gate Replacement**	**Mon 7/9/07**	**Thu 8/28/08**	**299 days**
50		Design	Mon 7/9/07	Fri 10/5/07	65 days
51		Tender	Tue 12/4/07	Mon 1/14/08	30 days
52		Award	Mon 2/4/08	Mon 2/4/08	0 days
53		Fabrication/Procurement	Tue 2/5/08	Mon 7/7/08	110 days
54		Installation	Fri 8/1/08	Thu 8/28/08	20 days
55		**Rattling Brook/Amy's Dam Upgrade**	**Tue 4/1/08**	**Wed 9/17/08**	**122 days**
56		Design	Tue 4/1/08	Mon 5/26/08	40 days
57		Tender	Thu 6/5/08	Wed 7/2/08	20 days
58		Award	Fri 7/11/08	Fri 7/11/08	0 days
59		Construction	Thu 8/21/08	Wed 9/17/08	20 days
60		Project Completion	Wed 9/17/08	Wed 9/17/08	0 days



Project: Project1.mpp
Date: Wed 3/29/06

Task | Split | Progress | Milestone | Summary | Project Summary | External Tasks | External Milestone | Deadline

Appendix H

Feasibility Analysis

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1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Rattling Brook hydroelectric development. The continued long-term operation of the Rattling Brook hydroelectric development is reliant on the completion of capital improvement in 2007 and 2008. Planned improvements include replacement of the woodstave penstock, switchgear, main valves, spillway, plant controls and protection, and refurbishment of the surge tank, substation and governors.

With substantial investment required in the near-term to permit the continued reliable operation of this plant, an economic analysis of this development was completed. The analysis includes all costs and benefits for the next 50 years to determine the levelized cost of energy from the plant.

2.0 Capital Costs

All significant capital expenditures for the hydroelectric development over the next 50 years have been identified. The majority of these expenditures are planned for 2007 and 2008 with the remaining expenditures planned for future years. The capital expenditures required to maintain the safe and reliable operation of the facilities are summarized in Table 1.

Table 1
Hydroelectric Development
Capital Expenditures

Year	**(000s)**
2007	$18,820
2008	2,080
2012	350
2013	350
2025	2,000
2030	2,000
2032	1,500
Total	**$27,100**

The total capital expenditure of all of the projects listed above is $27,100,000. A more comprehensive breakdown of capital costs is provided in Attachment A.

3.0 Operating Costs

Operating costs for this hydroelectric system are estimated to be in the order of $282,000 per year. This estimate is based primarily upon recent historical operating experience. The operating cost represents both direct charges for operations and maintenance at this plant as well as indirect costs such as those related to managing the environment, safety, dam safety inspections, and staff training. A summary of operating costs is provided in Attachment B.

The annual operating cost also includes a water power rental rate of $0.80 per MWh. This fee is paid annually to the Provincial Department of Environment and Conservation (Water Resources Management Division) based on yearly hydro plant production. Such a charge is not reflected in the historical annual operating costs for the Rattling Brook development. Therefore, an adjustment is applied to account for the associated increased operating expenses on a go-forward basis.

Penstock and surge tank maintenance has accounted for a portion of the operating costs of this plant in recent years. Future operating costs have been estimated to include a reduction of $10,000 per year to reflect the penstock and surge tank rehabilitation initiatives.

4.0 Benefits

The estimated long-term normal production at this plant under present operating conditions is 69.8 GWh per year. This estimate is based on the results of the Water Management Study completed by SGE Acres in 2005 and adjusted for actual average production and practical operations.

Some of the capital improvement projects will result in decreased energy losses, and subsequent increases in capacity and generation. In particular, it is anticipated that a newly constructed 2.9 metre diameter steel penstock will significantly reduce head loss. The replacement of the main valves will also reduce head loss and increase production. The annual energy generation is expected to increase from 69.8 GWh to 76.0 GWh per year and the plant capacity will increase from 11.2 MW to 14.1 MW.

5.0 Lost Production

The downtime associated with the 2007 capital works at this plant will result in a higher amount of spill from the system compared to a normal operating year. It is anticipated that the potential spill may be in the order of 38.2 GWh which is approximately $1.8 million[1] in increased purchased power costs. Therefore, the analysis assumed production at Rattling Brook of 30.2 GWh in 2007 and 76.0 GWh per year thereafter.

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1 Based on the current rate of 4.7 cents/kWh. However, the financial impact on purchased power expense may increase if the wholesale rate from Newfoundland and Labrador Hydro increases.

There are accounting options for dealing with the lost production such as expensing, deferring and amortizing the cost. The Company plans to present its proposal on accounting for lost production in its next general rate application.

6.0 Financial Analysis

An overall financial analysis of combined costs and benefits has been completed using the levelized cost of energy approach. The levelized cost of energy is representative of the revenue requirement to support the combined capital and operating costs associated with the development.

The estimated levelized cost of energy from the Rattling Brook plant over the next 50 years is 2.9 cents per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Rattling Brook can be produced at a significantly lower price than the cost of replacement energy, assumed to come from Newfoundland and Labrador Hydro's Holyrood thermal generating station. Incremental energy from the Holyrood thermal generating station is estimated to cost 7.1 cents per kWh in the short term (assuming $45.00[2] per barrel), with an associated levelized cost of 8.8[3] cents per kWh.

The future capacity benefits of the continued availability of Rattling Brook hydro plant have not been considered in this analysis. If factored into the feasibility analysis, the financial benefit associated with system capacity would further support the viability of continued plant operations.

7.0 Recommendation

The results of this feasibility analysis show that the continued operation of the Rattling Brook hydroelectric development is economically viable. Investing in the life extension of facilities at Rattling Brook guarantees the availability of low cost energy to the Province. Otherwise the annual production of nearly 69.8 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station. Newfoundland Power should proceed with this project in 2007. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

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[2] Newfoundland and Labrador Hydro's forecast fuel price submitted in response to request for information PUB 13 NLH for their application for 1 percent sulphur fuel recovery costs through the RSP.

[3] 50-year levelized using escalation factors based on the Conference Board of Canada GDP deflator, December 13, 2005.

Attachment A
Summary of Capital Costs

Rattling Brook Feasibility Analysis
Summary of Capital Costs
(000s)

Description	2007	2008	2012	2013	2025	2030	2032
Civil							
Plant Civil Refurbishment	$13,720						
Dams, spillways and gates		$2,080					
Amy's Tunnel Upgrade						$1,500	$500
Amy's Intake					$1,500		
Mechanical							
Plant Mechanical Refurbishment	1,117						
Unit No. 1 Turbine Overhaul			$350				
Unit No. 2 Turbine Overhaul				$350			
Unit No. 1 Replacement Runner					500		
Unit No. 2 Replacement Runner						500	
Governor Upgrades							500
Electrical							
Plant Electrical Refurbishment	2,740						
Substation Upgrade	578						
Controls Upgrade							500
Project Management							
IDC	350						
Project Management and Insurance	315						
Annual Totals ($2007)	**$18,820**	**$2,080**	**$350**	**$350**	**$2,000**	**$2,000**	**$1,500**
Total Life Capital Cost ($2007)	**$27,100**						
Lost Production	**$1,833**						

Attachment B
Summary of Operating Costs

Rattling Brook Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs

Year	Amount
2001	$254,000
2002	210,216
2003	270,429
2004	207,114
2005	213,495
Average	**$231,051**

5-Year Average Operating Cost	$231,051
Water Power Rental Rate[1]	60,800
Reduced Future Penstock Maintenance	- 10,000
Total Forecast Annual Operating Cost	$281,851

1 ($0.80/MWh * 76,000 MWh/yr)

Attachment C
Calculation of Levelized Cost of Energy

Weighted Average Incremental Cost of Capital **7.15%**

Present Worth Year **2007**

YEAR	Generation Hydro 49.26 yrs 8% CCA	Generation Hydro 49.26 yrs 30% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr)
2007	6,385,000	12,434,000	1,105,439	2,114,851	0	-3,220,290	-3,005,403	-3,005,403	4.288	2.899
2008	2,080,000	0	409,697	286,079	0	-695,776	-606,018	-3,611,421	0.926	2.899
2009	0	0	890,543	290,942	0	-1,181,485	-960,399	-4,571,820	1.573	2.899
2010	0	0	1,258,769	295,888	0	-1,554,657	-1,179,413	-5,751,233	2.070	2.899
2011	0	0	1,511,836	300,918	0	-1,812,754	-1,283,447	-7,034,680	2.414	2.899
2012	379,283	0	1,721,673	305,432	0	-2,027,105	-1,339,440	-8,374,120	2.699	2.899
2013	384,972	0	1,866,319	310,013	0	-2,176,333	-1,342,085	-9,716,206	2.898	2.899
2014	0	0	1,932,607	314,664	0	-2,247,271	-1,293,356	-11,009,561	2.992	2.899
2015	0	0	1,979,436	319,384	0	-2,298,819	-1,234,739	-12,244,301	3.061	2.899
2016	0	0	2,005,620	324,174	0	-2,329,795	-1,167,874	-13,412,174	3.102	2.899
2017	0	0	2,016,988	329,037	0	-2,346,025	-1,097,536	-14,509,710	3.124	2.899
2018	0	0	2,017,649	333,973	0	-2,351,622	-1,026,742	-15,536,452	3.131	2.899
2019	0	0	2,010,505	338,982	0	-2,349,487	-957,359	-16,493,811	3.128	2.899
2020	0	0	1,997,614	344,067	0	-2,341,680	-890,507	-17,384,318	3.118	2.899
2021	0	0	1,980,437	349,228	0	-2,329,665	-826,820	-18,211,138	3.102	2.899
2022	0	0	1,960,020	354,466	0	-2,314,486	-766,619	-18,977,757	3.082	2.899
2023	0	0	1,937,112	359,783	0	-2,296,896	-710,026	-19,687,783	3.058	2.899
2024	0	0	1,912,258	365,180	0	-2,277,438	-657,033	-20,344,816	3.033	2.899
2025	2,630,168	0	2,148,439	370,658	0	-2,519,097	-678,256	-21,023,072	3.354	2.899
2026	667,405	0	2,128,161	376,218	0	-2,504,379	-629,298	-21,652,370	3.335	2.899
2027	0	0	2,089,046	381,861	0	-2,470,907	-579,456	-22,231,827	3.290	2.899
2028	0	0	2,064,532	387,589	0	-2,452,121	-536,678	-22,768,505	3.265	2.899
2029	0	0	2,038,415	393,403	0	-2,431,817	-496,719	-23,265,224	3.238	2.899
2030	2,833,438	0	2,293,740	399,304	0	-2,693,044	-513,371	-23,778,595	3.586	2.899
2031	0	0	2,201,071	405,293	0	-2,606,364	-463,693	-24,242,288	3.471	2.899
2032	2,189,309	0	2,394,605	411,373	0	-2,805,978	-465,895	-24,708,183	3.736	2.899
2033	0	0	2,318,404	417,543	0	-2,735,948	-423,954	-25,132,137	3.643	2.899
2034	0	0	2,293,673	423,806	0	-2,717,480	-392,994	-25,525,131	3.618	2.899
2035	0	0	2,266,784	430,163	0	-2,696,948	-363,998	-25,889,129	3.591	2.899
2036	0	0	2,237,915	436,616	0	-2,674,531	-336,886	-26,226,015	3.561	2.899
2037	0	0	2,207,228	443,165	0	-2,650,393	-311,568	-26,537,583	3.529	2.899
2038	0	0	2,174,870	449,813	0	-2,624,683	-287,957	-26,825,539	3.495	2.899
2039	0	0	2,140,977	456,560	0	-2,597,537	-265,962	-27,091,502	3.459	2.899
2040	0	0	2,105,672	463,408	0	-2,569,080	-245,496	-27,336,997	3.421	2.899
2041	0	0	2,069,070	470,359	0	-2,539,429	-226,470	-27,563,467	3.381	2.899
2042	0	0	2,031,274	477,415	0	-2,508,689	-208,799	-27,772,266	3.340	2.899
2043	0	0	1,992,381	484,576	0	-2,476,957	-192,401	-27,964,667	3.298	2.899
2044	0	0	1,952,479	491,845	0	-2,444,323	-177,197	-28,141,864	3.255	2.899
2045	0	0	1,911,648	499,222	0	-2,410,870	-163,109	-28,304,973	3.210	2.899
2046	0	0	1,869,963	506,711	0	-2,376,674	-150,066	-28,455,039	3.165	2.899
2047	0	0	1,827,493	514,311	0	-2,341,804	-137,998	-28,593,037	3.118	2.899
2048	0	0	1,784,299	522,026	0	-2,306,325	-126,838	-28,719,875	3.071	2.899
2049	0	0	1,740,441	529,856	0	-2,270,298	-116,525	-28,836,400	3.023	2.899
2050	0	0	1,695,972	537,804	0	-2,233,776	-107,000	-28,943,400	2.974	2.899
2051	0	0	1,650,940	545,871	0	-2,196,811	-98,208	-29,041,607	2.925	2.899
2052	0	0	1,605,390	554,059	0	-2,159,449	-90,095	-29,131,703	2.875	2.899
2053	0	0	1,559,364	562,370	0	-2,121,734	-82,615	-29,214,318	2.825	2.899
2054	0	0	1,512,900	570,806	0	-2,083,705	-75,720	-29,290,038	2.775	2.899
2055	0	0	1,466,033	579,368	0	-2,045,400	-69,368	-29,359,407	2.724	2.899
2056	0	0	1,418,795	588,058	0	-2,006,853	-63,519	-29,422,926	2.672	2.899
2057	0	0	1,371,215	596,879	0	-1,968,095	-58,136	-29,481,062	2.621	2.899
2058	0	0	1,323,322	605,832	0	-1,929,155	-53,183	-29,534,245	2.569	2.899
2059	0	0	1,275,141	614,920	0	-1,890,061	-48,628	-29,582,874	2.517	2.899
2060	0	0	1,226,693	624,144	0	-1,850,837	-44,442	-29,627,315	2.464	2.899
2061	0	0	1,178,002	633,506	0	-1,811,508	-40,595	-29,667,910	2.412	2.899
2062	0	0	1,129,085	643,008	0	-1,772,094	-37,062	-29,704,972	2.360	2.899
2063	0	0	1,079,962	652,654	0	-1,732,615	-33,818	-29,738,790	2.307	2.899
2064	0	0	1,030,648	662,443	0	-1,693,092	-30,841	-29,769,631	2.254	2.899
2065	0	0	981,160	672,380	0	-1,653,539	-28,111	-29,797,742	2.202	2.899
2066	0	0	931,510	682,466	0	-1,613,975	-25,607	-29,823,350	2.149	2.899
2067	0	0	881,712	692,703	0	-1,574,414	-23,313	-29,846,663	2.096	2.899
2068	0	0	831,777	703,093	0	-1,534,871	-21,211	-29,867,873	2.044	2.899
2069	0	0	781,718	713,640	0	-1,495,357	-19,286	-29,887,159	1.991	2.899
2070	0	0	-605,313	724,344	0	-119,031	-1,433	-29,888,592	0.158	2.899
2071	0	0	331,965	735,209	0	-1,067,174	-11,988	-29,900,580	1.421	2.899
2072	0	0	403,321	746,237	0	-1,149,558	-12,052	-29,912,631	1.531	2.899
2073	0	0	388,605	757,431	0	-1,146,036	-11,213	-29,923,844	1.526	2.899
2074	0	0	373,818	768,793	0	-1,142,611	-10,434	-29,934,278	1.521	2.899
2075	0	0	337,978	780,324	0	-1,118,303	-9,530	-29,943,808	1.489	2.899
2076	0	0	318,088	792,029	0	-1,110,117	-8,829	-29,952,637	1.478	2.899
2077	0	0	320,335	803,910	0	-1,124,244	-8,345	-29,960,982	1.497	2.899
2078	0	0	306,615	815,968	0	-1,122,584	-7,776	-29,968,758	1.495	2.899
2079	0	0	292,850	828,208	0	-1,121,058	-7,248	-29,976,006	1.493	2.899
2080	0	0	279,043	840,631	0	-1,119,674	-6,756	-29,982,762	1.491	2.899
2081	0	0	265,197	853,240	0	-1,118,438	-6,298	-29,989,060	1.489	2.899
2082	0	0	251,316	866,039	0	-1,117,355	-5,872	-29,994,932	1.488	2.899
2083	0	0	237,401	879,030	0	-1,116,431	-5,476	-30,000,407	1.487	2.899
2084	0	0	223,457	892,215	0	-1,115,672	-5,107	-30,005,514	1.486	2.899
2085	0	0	209,485	905,598	0	-1,115,083	-4,763	-30,010,278	1.485	2.899
2086	0	0	195,487	919,182	0	-1,114,669	-4,444	-30,014,722	1.484	2.899
2087	0	0	181,465	932,970	0	-1,114,435	-4,147	-30,018,868		

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax : Income tax expense reflects a statutory income tax rate of 36.12% including surtax of 1.12%.

Operating Costs: Operating costs were assumed to be $281,851 escalated yearly using the GDP Deflator for Canada
Labor is based on union agreements.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	5.44%	2.99%
Common Equity	45.00%	9.24%	4.16%
Total	**100.00%**		**7.15%**

CCA Rates:

Class	Rate	Details
1	4.00%	All generating, transmission, substation and distribution equipment not otherwise noted.
17	8.00%	Expenditures related to the betterment of electrical generating facilities.
43.1	30.00%	Equipment designed to produce energy in a more efficient way.

Escalation Factors: Conference Board of Canada GDP deflator, December 13, 2005

2007 Capital Budget Application
Electrical System Handbook
Hydroelectric Generation

March 2006

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

Newfoundland Power's annual capital budgets focus on a relatively large number of electrical system assets through which the Company delivers service to its customers. Accordingly, the material filed in support of annual capital budgets is necessarily technical in nature.

With its 2006 Capital Budget Application, Newfoundland Power filed a document referred to as the *Electrical System Handbook*. This handbook was provided to assist the reader in better understanding the electrical network and how Newfoundland Power's 2006 capital budget related to that network.

Accompanying the 2007 Capital Budget Application, this document, the *Electrical System Handbook Hydroelectric Generation,* focuses in more detail on the infrastructure and equipment that comprises a typical small hydroelectric plant. This version of the handbook is provided to assist the reader in better understanding the technical terminology used in the assessment of hydro plants. It is appropriate to present this material at this time as a considerable amount of information is being provided to justify the Rattling Brook Hydro Plant refurbishment.

2.0 Typical Small Hydroelectric Development

Hydroelectric generating plants capture the kinetic energy of falling water to generate electricity. A turbine converts the kinetic energy from the falling water to mechanical energy and the generator converts the mechanical energy into electrical energy. The turbine and generator are installed either in, or adjacent to, dams or use a penstock to carry the pressurized water to the powerhouse.

The power generating capacity of a hydroelectric plant is primarily a function of (i) the flow rate of the water and (ii) the hydraulic head which is the elevation difference through which the water falls. From an energy conversion perspective, hydro power is very energy efficient; more than double that of conventional thermal power plants.

The equipment associated with hydroelectric plants is well developed, relatively simple in design and very reliable. As very little heat is involved in the process to generate electricity in a hydroelectric plant, the equipment has a long life and malfunctions are rare. The service life of a hydroelectric plant is well in excess of 50 years at which time refurbishments can be carried out to extend the life even further.

A typical small hydroelectric development can be described in two parts, the civil infrastructure external to the plant and the electrical and mechanical equipment internal to the plant. Figure 1 shows a schematic of the civil infrastructure for a typical small hydroelectric development.

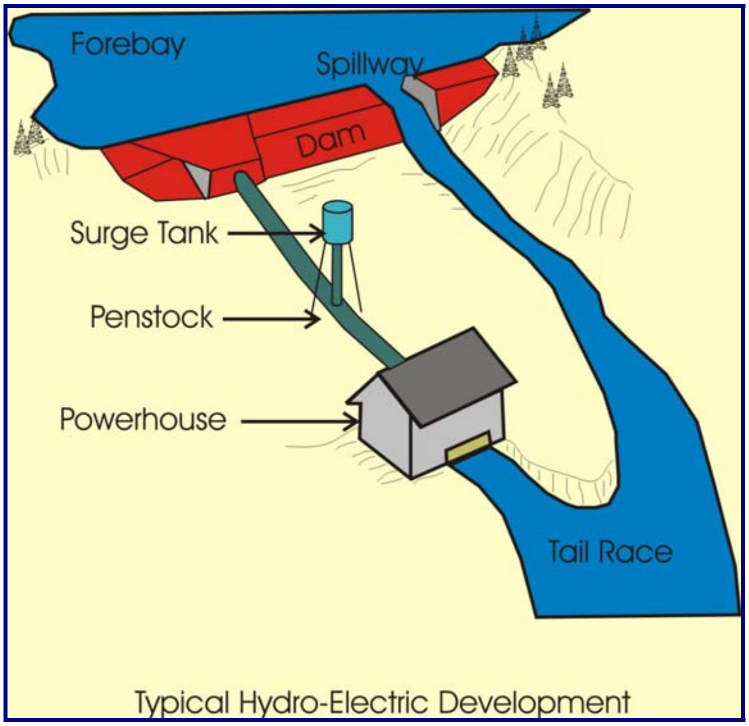

Figure 1

The civil infrastructure is comprised of dams, spillways, control structures, surge tanks and a penstock or canal to direct the flow of water to a powerhouse. Once at the powerhouse the water passes through the turbine spinning it with enough force to generate electricity. The water then exits the powerhouse and flows into a tailrace.

The main electrical and mechanical equipment comprises the generator and turbine. Other equipment such as switchgear, governors and valves are required to operate and protect the generator and turbine.

3.0 Civil Infrastructure

Typically, small hydroelectric developments are run of the river type installations with very little storage. Newfoundland Power operates 23 small hydroelectric developments, some of which have small reservoirs for storing water. Dams, spillways and control structures comprise the reservoir civil infrastructure.

Dams and Spillways

Dams are used to create a reservoir to store water and to develop the necessary water pressure known as hydraulic head. There are a variety of different types of dams used in small hydroelectric developments. The most common types are earth fill dams, rock fill dams, and concrete gravity dams.

Spillways are required to ensure that water elevations inside the reservoir do not exceed safe levels. Spillways allow for the controlled release of water to regulate reservoir water elevations without damaging the down stream habitat. To avoid damage, the excess water must be safely discharged over the dam. Carefully designed overflow passages are incorporated into dams as part of the overall structure. These overflow passages are known as spillways.

An intake structure including trashracks and a gate provide the entrance for the water into the penstock. The trashracks ensure that large solid objects such as wood or ice do not enter the penstock. Trashracks are made up of one or more panels, fabricated from a series of evenly spaced parallel metal rods. The intake gates can be opened or closed to control water flow. Automatic closure of the intake gate may happen when a generator emergency stop is initiated. These gates are also used to seal off the penstock when it needs to be drained for inspections and maintenance. The intake is generally built of reinforced concrete and is an integral part of a dam structure.

Penstock and Surge Tank

The penstock carries the water from the intake structure downstream to the power house. Penstocks, which carry the water under pressure, can be made of steel, fibreglass, plastics, concrete or wood.

The water pressure in the penstock must be maintained at safe levels under all operating conditions. One of the most common ways to regulate penstock pressure is through the use of a surge tank. The surge tank must be elevated above the penstock such that it can support a column of water equal to the maximum design pressure for the penstock. If there is no surge tank, the turbine must be fitted with a large pressure relief value to accomplish the same functionality.

Powerhouse

The powerhouse contains the turbine(s) and most of the electrical and mechanical equipment used to generate power. Figure 2 shows a schematic of a typical powerhouse.

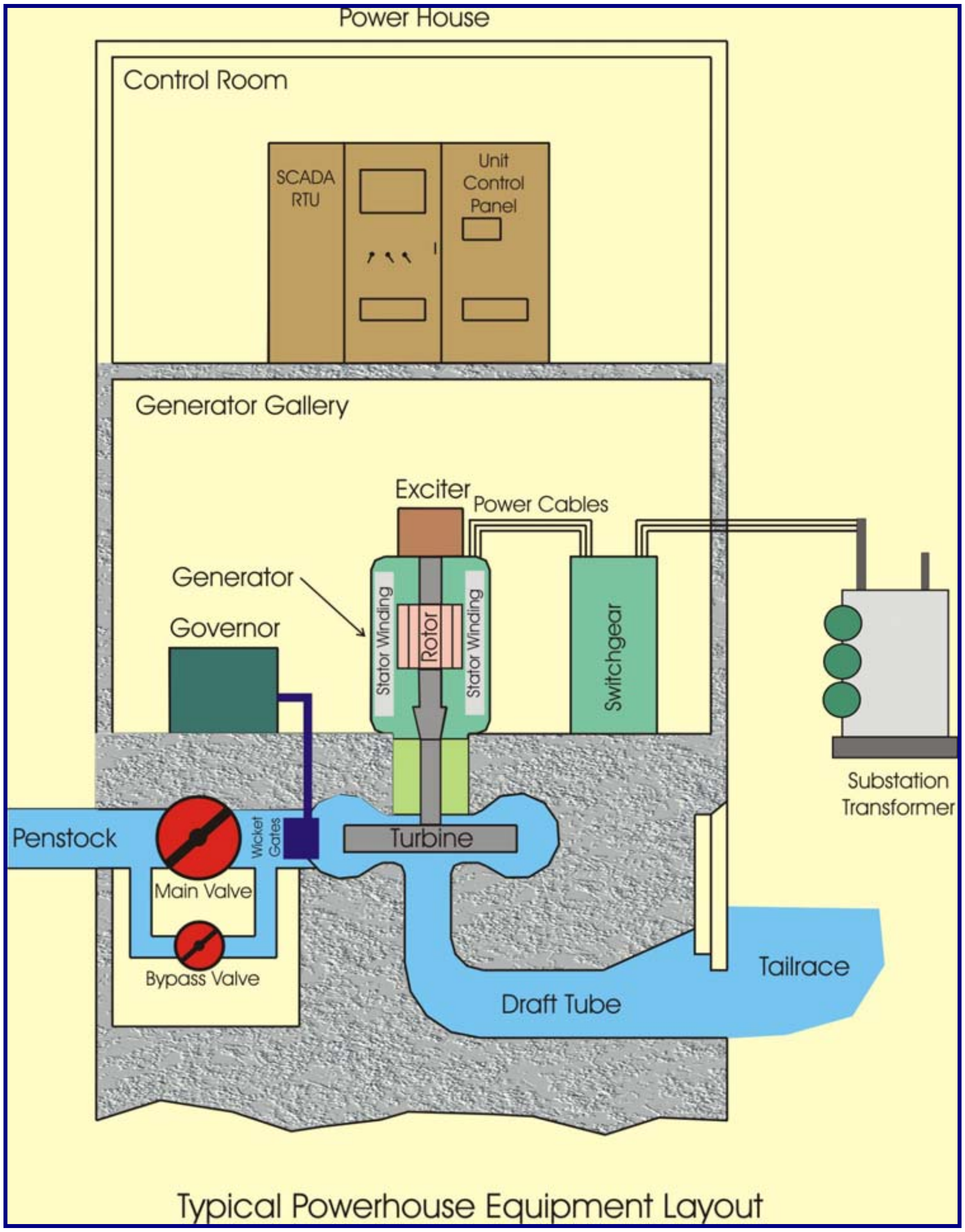

Figure 2

4.0 Mechanical Equipment

The primary mechanical components of a small hydroelectric plant are the main valve, draft tube, turbine and runner. In some locations the energy from the water can support more than one generator. In this case the powerhouse may have more than one operating generator.

In addition to the primary mechanical components identified above, other mechanical equipment consists of valves, pneumatic and hydraulic power components, governors, lubrication and cooling water systems.

Valves

The penstock is attached to a main valve at the entrance to the powerhouse. This valve is necessary to stop the flow of water when the plant is shutdown or when maintenance of the turbine is being preformed. Typically the main valve has a large diameter similar to the penstock. In a small hydroelectric plant the valve diameter is typically between one and two metres in diameter.

The main valve is normally accompanied by a bypass valve and occasionally a drain valve. The bypass valve's function is to divert water past the main valve prior to opening, thereby equalizing pressure on both sides of the main valve to reduce the strain associated with opening such a large valve. The drain valve is normally a manual valve that is used to drain the penstock for maintenance.

Governor

The governor can be a powerful piece of hydraulic or electric equipment controlled by a speed feedback from the generator. The governor's function is to keep the water flow to the turbine under control by adjusting the position of the wicket gates. Wicket gates regulate the water flow by adjusting the amount of force the water places on the turbine. If the generator starts to slow down, the governor opens the gates to create a greater force on the turbine. If the generator starts to speed up the governor closes the gates to reduce the force on the turbine. The regulation of the gates is intended to maintain an electrical frequency of 60.0 cycles per second.

Turbine

The turbine is a rotary engine that converts the energy from the water that is forced through the wicket gates to rotational motion. The turbine is then coupled to the generator through a series of shafts. The generator rotor converts the rotational motion into a rotating electric field. The generator stator windings convert the rotating electric field into electricity.

When the water leaves the turbine it passes through the draft tube on the way to the tailrace. The tailrace carries the water from the powerhouse back to the river system or ocean.

Bearings

With these large generators rotating at 600 revolutions per minute (rpm), there are a number of bearings employed to keep the unit stable. These bearings require lubrication and water cooling to overcome the heat from friction on the bearing surfaces.

5.0 Electrical Equipment

There are typically three large pieces of electrical equipment in each small hydroelectric plant; a power transformer, generator and the switchgear.

Power Transformer

The power transformer is normally located in a substation adjacent to the hydro plant. It transforms the generator output voltage from low levels such as 6,900 volts up to transmission line voltages of tens and hundreds of thousands of volts for transmission to large load centers that require the power.

Generator

Generators consist of two parts - the rotor and the stator windings. The rotor is coupled to the turbine and rotates when water is flowing through the turbine. An electromagnetic field is placed on the rotor through slip rings and brushes. As the electromagnetic field rotates, its lines of flux cross the stator windings creating an electric current.

Switchgear

The switchgear includes a generator breaker for switching power from the generator onto the grid. It also includes the potential and current transformers for metering and protection. Depending upon the equipment design the switchgear may also include the station service transformer, generator protection relays and generator field breaker.

Protection and Control

Modern small hydroelectric generators are controlled using programmable logic controllers (PLC) that are assembled into unit control panels. These unit control panels also house the synchronizer, voltage regulator and operator interface. Some designs will include all unit protection and metering in the unit control panel. The PLC monitors all feedback from the generator and turbine, accepts input from the operator interface, checks for trip conditions from instrumentation and protection devices, and in some designs determines the appropriate load for the generator.

6.0 Ancillary Systems

In addition to the main electrical and mechanical equipment there are ancillary systems that are required to carry out various critical functions. These ancillary systems ensure that the equipment operates safely and provides reliable service over its life. These ancillary systems include cooling water, lubrication, ventilation, heating, station service and DC power.

7.0 Newfoundland Power's Hydroelectric Facilities

Newfoundland Power operates 23 hydroelectric facilities across the province with 32 individual generators. These generators range in size from the largest - Mobile at 12 MW and the smallest - Port Union at 0.26 MW. Typically these plants predate the time in the 1960s when the provincial electrical grid was established. These plants were constructed to operate on small isolated electrical systems serving the communities in the immediate vicinity of the facility. As a result most are synchronous generators with black start capability.

In all cases penstocks are used to connect the plant to the water supply. Pre-1960s, woodstave construction was the most cost effective solution for providing the penstock requirements.

Today these plants are well maintained and remotely monitored and controlled by the Newfoundland Power System Control Center. Most employ water management schemes to ensure that the plants are operated at the most efficient load setting determined in consultation with hydrology consultant SGE Acres Limited. The plants have relatively low operating cost thereby allowing them to be highly efficient and low cost providers of electricity to the provincial grid.

Appendix A

Glossary

Glossary

This glossary does not aim to be exhaustive, but gives a few definitions of terms that frequently are used in the technical assessments provided in the Capital Budget Application.

Black Start
Black starting a generator is a term that is used when a generator is started without the presence of an established power grid. On an isolated system the first generator coming on line is black started, while all subsequent generators are synchronized to the first generator's voltage and frequency.

Dam
Civil engineering work (earth, concrete, rocks) that is constructed to provide a barrier to the flow of water to redirect that water to the intake of a hydroelectric installation. Storage dams store water for a future electricity demand.

Draft Tube
Low pressure part of reaction turbines (Kaplan, Francis) situated downstream of the runner. The draft tube is meant to reduce the speed of water at the turbine outlet, so as to recover a part of the kinetic energy. A water conduit, which can be straight or curved depending upon the turbine installation, that maintains a column of water from the turbine outlet and the downstream water level.

Efficiency
Value that expresses the transformation degree of one form of energy into another. For instance, a mechanical turbine efficiency of 90% means that 90% of the energy from the water is transformed into mechanical energy.

Freeboard
Vertical distance between the water surface elevation and the lowest elevation of the top of the containment structure.

Fly-Wheel
Massive metallic disc coupled with the turbine shaft to limit the rotational acceleration and deceleration of the turbine. It is used in a small isolated network to improve the regulation precision of a very responsive generator.

Forebay
Used to impound water immediately upstream from a dam or hydroelectric plant intake structure.

Francis Turbine
Type of turbine that has a submerged fixed blade design. The water flow to the turbine is varied by controlling the wicket gates.

Generator
Machine that converts mechanical energy into electrical energy

Governor
A piece of mechanical equipment attached to a turbine intended to regulate generator speed by manipulating flow rates into the turbine. Feedback is provided for generator speed to a control section of the governor, which in turn provides control signals to the power section of the governor.

Head Losses
Energy losses due to stream directions changes, frictions on the penstock walls, obstacles (for instance the grids or valves), etc.

High Head
Power plants that operate with a high difference in elevation from the turbine to the intake that can reach several hundreds of meters.

Hydroelectricity
Electricity generated by transforming the hydraulic energy of a river or body of water into mechanical energy and then into electrical energy by a turbine and a generator. It is a renewable and non-polluting energy with high energy efficiency.

Intake
The entry point of water into a penstock for delivery to a hydroelectric plant turbine.

Kaplan
Type of turbines that has a submerged variable pitch blade propeller design. The water flow to the turbine is varied by controlling the pitch of the propeller blades.

Low Head
Power plants that operate with a lesser difference in elevation from the turbine to the intake that can reach only several meters.

Pelton
Turbines used in high head installations are of the impulse type design, the most common of which is the Pelton wheel turbine. The runner of the impulse turbine spins in air and is driven by a high speed water jet.

Penstock
A pressurized pipe that transports water from the forebay intake gate to the hydroelectric power plant.

Trashrack
A steel grill placed across the entrance of the intake to remove any floating object from entering the penstock and damaging either the pipe or turbine runner.

Reservoir
A body of water which is impounded by one or more dams, inclusive of its banks and shores.

Runner
The rotating part of the turbine that converts the energy of falling water into mechanical energy.

Run-Of-River Power Plant
Hydroelectric power plant that uses the natural discharges of the river without any possibility of water storage.

Scroll Case
A spiral-shaped steel intake guiding the flow into the wicket gates located just prior to the turbine.

Small Hydroelectric Plant
The classification of a small hydroelectric plant is regionally based; generally they are installations with a rated output power less than 10 MW are considered within this classification.

Speed No Load Condition
The generator must rotate at synchronous speed with voltages that match in amplitude, phase and frequency those on the power grid before it is safe to connect the energized generator.

Springline
An imaginary horizontal reference line located at mid-height, or halfway point, of a circular conduit, penstock, or tunnel. In the case of a penstock it is located at the maximum horizontal dimension of the pipe.

Spillway
Weir, channel, conduit, tunnel, gate or other structure designed to permit water discharge from the reservoir.

Synchronous Generator
A synchronous generator comes equipped with an integral excitation system that is powered by the plant DC system. A synchronous generator can be black started and operated isolated from the main power grid.

Surge Tank
A structure attached to a penstock in the vicinity of the power house whose purpose is to regulate pressure in the penstock, and to prevent water hammer due to abrupt changes to flow.

Tailrace
A channel that allows the return of the turbined water to the river or ocean.

Turbine
Hydraulic machine which transforms hydraulic energy into rotational mechanical energy.

Transformer
Electrical device meant to modify voltage (such as 230, 400, 6,000 Volts) in order to make it compatible with the network to which it is connected (for example 66,000 Volts).

Wicket Gates
Adjustable gates that control the flow of water to the turbine passage.