NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

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DELIVERED BY HAND

July 11, 2008

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 2009 Capital Budget Application

A. 2009 Capital Budget Application

Enclosed are the original and 8 copies of Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") 2009 Capital Budget Application (the "Application") and supporting materials (the "Filing").

The Application and Filing outlines proposed 2009 capital expenditures totalling $61,571,000 and 2009 leases of $11,000 per year. In addition, the Application seeks approval of a 2007 rate base in the amount of $793,703,000.

B. Compliance Matters

B.1 Board Orders

In Order No. P.U. 27 (2007) (the "2008 Capital Order"), the Board required specific information to be filed with the Application. The Filing complies with those requirements of the 2008 Capital Order.

In Order No. P.U. 35 (2003) (the "2004 Capital Order"), the Board 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.

Telephone: (709) 737-5859 *Email: palteen@newfoundlandpower.com* *Fax: (709) 737-2974*

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. *2009 Capital Budget Plan*: this is filed in compliance with the 2004 Capital Order;

2. *2008 Capital Expenditure Status Report*: this is filed in compliance with the 2008 Capital Order;

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

B.2 The Guidelines

In the October 2007 Capital Budget Application Guidelines (the "Guidelines"), the Board outlined certain directions on how to define and categorize capital expenditures. Although compliance with the Guidelines necessarily requires the exercise of a degree of judgment, the Filing, in the Company's view, complies with the Guidelines while remaining reasonably consistent and comparable with past filings.

Section 3 of the *2009 Capital Budget Plan* provides a breakdown of the overall 2009 Capital Budget by definition, classification, costing method and materiality segmentation as described in the Guidelines.

C. 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 review 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.

D. 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.
2009 Capital Budget Application
Filing Contents

Application

Supporting Materials

Generation

Substations

Transmission

Distribution

Information Systems

Deferred Charges

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 2009 Capital Budget of $61,571,000; and

(b) fixing and determining its average rate base for 2007 in the amount of $793,703,000

2009 Capital Budget Application

NEWFOUNDLAND POWER
A FORTIS COMPANY

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 2009 Capital Budget of $61,571,000; and
(b) fixing and determining its average rate base for 2007 in the amount of $793,703,000

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 2009 Capital Budget in the amount of $61,571,000 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 2009. 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 2009 capital expenditures, by project, which comprise Newfoundland Power's 2009 Capital Budget.

4. Schedule C to this Application is a list of leases in excess of $5,000 per year which Newfoundland Power proposes to proceed with in 2009.

5. Schedule D 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 2009 Capital Budget but will not be completed in 2009.

6. The proposed expenditures as set out in Schedules A, B, C and D 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.

7. Schedule E to this Application shows Newfoundland Power's actual average rate base for 2007 of $793,703,000.

8. Communication with respect to this Application should be forwarded to the attention of Ian Kelly, Q.C. and Gerard M. Hayes, Counsel to Newfoundland Power.

9. 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 2009 of the improvements and additions to its property in the amount of $61,571,000 as set out in Schedules A and B to the Application;

   (b) pursuant to Section 41 of the Act, approving Newfoundland Power's lease of improvements to its property in the amount of $11,000 per year as set out in Schedule C to the Application; and

   (c) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2007 in the amount of $793,703,000 as set out in Schedule E to the Application.

DATED at St. John's, Newfoundland and Labrador, this 11th day of July, 2008.

NEWFOUNDLAND POWER INC.

Ian Kelly, Q.C. and Gerard M. Hayes
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 2009 Capital Budget of \$61,571,000; and
(b) fixing and determining its average rate base for 2007 in the amount of \$793,703,000

AFFIDAVIT

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

1. That I am President & Chief Executive Officer 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 11th day of July, 2008, before me:

Barrister

Earl Ludlow

2009 CAPITAL BUDGET SUMMARY

Asset Class	**Budget (000s)**
1. Generation - Hydro	$ 8,899
2. Generation - Thermal	100
3. Substations	7,172
4. Transmission	4,507
5. Distribution	30,178
6. General Property	835
7. Transportation	2,255
8. Telecommunications	350
9. Information Systems	3,725
10. Unforeseen Allowance	750
11. General Expenses Capitalized	2,800
Total	**$ 61,571**

2009 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
1. Generation - Hydro		
Rocky Pond Plant Refurbishment	$ 6,517	2
Facility Rehabilitation	1,917	4
Raise Rose Blanche Spillway to Increase Production	465	6
Total – Generation - Hydro	**$ 8,899**	
2. Generation - Thermal		
Facility Rehabilitation Thermal	$ 100	9
Total – Generation – Thermal	**$ 100**	
3. Substations		
Substations Refurbishment and Modernization	$ 4,102	12
Replacements Due to In-Service Failures	1,729	14
Horse Chops Transformer Replacement	1,341	16
Total - Substations	**$ 7,172**	
4. Transmission		
Transmission Line Rebuild	$ 4,507	19
Total - Transmission	**$ 4,507**	

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

2009 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
5. Distribution		
Extensions	$ 8,786	22
Meters	1,127	24
Services	2,373	27
Street Lighting	1,646	30
Replace Mercury Vapour Street Lights	806	33
Transformers	6,406	35
Reconstruction	3,229	37
Rebuild Distribution Lines	3,541	39
Relocate/Replace Distribution Lines for Third Parties	622	42
Distribution Reliability Initiative	1,266	44
Feeder Additions for Growth	244	47
Allowance for Funds Used During Construction	132	49
Total - Distribution	**$ 30,178**	
6. General Property		
Tools and Equipment	$ 691	52
Additions to Real Property	144	54
Total - General Property	**$ 835**	
7. Transportation		
Purchase Vehicles and Aerial Devices	$ 2,255	57
Total - Transportation	**$ 2,255**	

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

2009 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
8. Telecommunications		
Replace/Upgrade Communications Equipment	$ 135	60
Fibre Optic Circuit Replacement	215	62
Total - Telecommunications	**$ 350**	
9. Information Systems		
Application Enhancements	$ 1,438	65
System Upgrades[2]	679	67
Personal Computer Infrastructure	409	69
Shared Server Infrastructure	700	72
Network Infrastructure	149	74
Vehicle Mobile Computing Infrastructure	350	76
Total – Information Systems	**$ 3,725**	
10. Unforeseen Allowance		
Allowance for Unforeseen Items	$ 750	79
Total – Unforeseen Allowance	**$ 750**	
11. General Expenses Capitalized		
General Expenses Capitalized	$ 2,800	81
Total – General Expenses Capitalized	**$ 2,800**	

[1] Project descriptions can be found in Schedule B at the page indicated.
[2] Includes the Microsoft Enterprise Agreement; included as a multi-year project in Schedule D of this application.

2009 CAPITAL PROJECTS: MULTI-YEAR

Capital Project	2009	2010	2011
Microsoft Enterprise Agreement[3]	$200,000	$200,000	$200,000

[3] The Microsoft Enterprise Agreement is a multi-year project included in Schedule D of this application.

GENERATION - HYDRO

Project Title: **Rocky Pond Plant Refurbishment (Pooled)**

Project Cost: **$6,517,000**

Project Description

This Generation Hydro project is a major refurbishment of the Company's Rocky Pond Hydroelectric Generating Plant. This refurbishment project will require major upgrades to the civil, electrical and mechanical systems of the plant in 2009. The components requiring replacement or refurbishment include the woodstave penstock, generator windings, governor controls and main valve. Also included in the project is the replacement of the forebay line providing both electricity and communications to the forebay intake gate.

Details on the proposed expenditures are included in ***1.2** Rocky Pond Hydro Plant Refurbishment*.

A fire originating in the switchgear at Rocky Pond plant in July 2005 caused considerable damage to the facility. During the 8 month shutdown the switchgear, protection and control panels, battery bank and battery charger, and all AC/DC panels and wiring were replaced.

This is a major plant refurbishment which involves a combination of inter-dependent and related components. This refurbishment will be completed in 2009 and is clustered with the Rocky Pond substation refurbishment included in the Substations Refurbishment and Modernization project to minimize plant downtime and maximize efficiencies.

Justification

The Rocky Pond Hydroelectric Generating Plant was commissioned in 1942 and, with the exception of the upgrades resulting from the 2005 fire, consists mainly of original equipment. The normal annual plant production is approximately 14.1 GWh of energy, or about 3.3 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. The intake gate and guides are original to the 1942 construction and are in poor condition. Replacement of the intake gate and guides is necessary for the dewatering of the penstock and to ensure worker safety downstream of the gate.

The mechanical assessment identified problems with the main valve seal and as a result a constant flow of high pressure water leaks around the valve when the unit is shut down. This leakage prevents safe access to the scroll case for workers when the penstock remains watered. The generator windings are at the end of their life while the hydraulic governor controls are obsolete and manufacturer discontinued.

A feasibility analysis of projected capital and operating expenditures for the Rocky Pond Hydroelectric Generating Plant has determined the levelized cost of energy from the plant over the next 50 years to be 4.67 cents per kilowatt-hour, which is significantly less than the cost of replacement energy at Holyrood.[1]

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2009 to 2013.

Table 1
Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$6,080	-	-	-
Labour – Internal	39	-	-	-
Labour – Contract	-	-	-	-
Engineering	192	-	-	-
Other	206	-	-	-
Total	**$6,517**	**-**	**-**	**$6,517**

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.

[1] Incremental energy from the Holyrood thermal generating station is estimated at 10.63 cents per kWh for 2009 (based upon $67.00 per barrel of No. 6 fuel from Hydro's fuel price projection dated March 31, 2008), with associated levelized cost of 12.84 cents per kWh over 25 years and 13.90 cents per kWh over 50 years.

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

Project Cost: **$1,917,000**

Project Description

This Generation Hydro 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 project includes the following items:

- Refurbishment of 5 hydro dams and spillways;
- Equipment replacements due to in-service failures;
- Upgrade plant revenue metering;
- Horsechops protection and control systems; and
- Engineering for Seal Cove runner replacement.

Details on 2009 proposed expenditures are included in ***1.1*** *2009 Facility Rehabilitation*.

The replacement or rehabilitation of deteriorated components at individual plants is 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 plants range in age from 9 to 108 years old. These facilities provide energy to the Island Interconnected 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 generation facilities in a safe, reliable and environmentally compliant manner.

The Company's hydro generation facilities produce a combined normal annual production of 425.8 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 676,000 barrels of fuel annually. At oil prices of $67.00 per barrel, this translates into approximately $45 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 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$ 1,397	-	-	-
Labour – Internal	193	-	-	-
Labour – Contract	-	-	-	-
Engineering	280	-	-	-
Other	47	-	-	-
Total	**$ 1,917**	**$3,900**	**$17,601**	**$23,418**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2004	2005	2006	2007	2008F
Total	$1,909	$2,283	$1,234	$780	$3,290[1]

[1] Includes protection and control system upgrades at Cape Broyle and runner replacement at Hearts Content.

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.

Project Title: **Raise Rose Blanche Spillway to Increase Production (Other)**

Project Cost: **$465,000**

Project Description

The Rose Blanche Brook hydroelectric development is located on the southwest coast of the Island of Newfoundland, near the community of Rose Blanche. It is Newfoundland Power's newest hydroelectric development and was placed into service in 1998. The normal annual production of the plant is approximately 20.7 GWh of energy, or about 4.9 % of Newfoundland Power's total hydroelectric system.

Since the construction of the development in 1998, average spill at the Rose Blanche development has been estimated at approximately 6.3 GWh annually. Increasing the amount of storage in the development will reduce the amount of spilled water and result in increased energy production.

The project will increase the annual production of Rose Blanche hydroelectric plant by increasing the elevation of the spillway. Increasing the height of the spillway at Rose Blanche hydroelectric development by 1.16m will result in an additional 0.9 GWh of energy.

Details on the proposed expenditures are included in ***1.3*** *Rose Blanche Spillway*.

Justification

Newfoundland Power operates 23 hydroelectric plants in 19 developments across the province. The annual normal production of these developments is 425.8 GWh which is less than 10% of Newfoundland Power customers' electricity requirements. Operating these generating facilities efficiently reduces the need for additional, more expensive, generation.

Increasing energy production at Newfoundland Power's existing hydroelectric plants would replace energy produced at Hydro's Holyrood thermal generating plant. At oil prices of approximately $67.00 per barrel, an additional 0.9 GWh of hydroelectric production translates into approximately $96,000 in annual fuel savings.

The estimated levelized cost of raising the spillway at Rose Blanche by 1.16m is 4.06 cents per kWh. This energy is lower in cost than energy from sources such as a new hydroelectric development or additional Holyrood thermal generation[2].

This project is justified upon those future energy savings.

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2 Incremental energy from the Holyrood thermal generating station is estimated at 10.63 cents per kWh for 2009 (based upon $67.00 per barrel of No. 6 fuel from Hydro's fuel price projection dated March 31, 2008), with associated levelized cost of 12.84 cents per kWh over 25 years and 13.90 cents per kWh over 50 years.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	365	-	-	-
Labour – Internal	5	-	-	-
Labour – Contract	-	-	-	-
Engineering	50	-	-	-
Other	45	-	-	-
Total	**$ 465**	-	-	**$465**

Costing Methodology

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

Future Commitments

This is not a multi-year project.

GENERATION - THERMAL

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

Project Cost: **$100,000**

Project Description

This Generation Thermal project is necessary for the replacement or rehabilitation of deteriorated thermal plant components that are identified through routine inspections, operating experience and engineering studies.

The replacement or rehabilitation of deteriorated components at individual plants is 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 maintains 43.5 MW of thermal generation consisting of gas turbine and diesel units. These units are generally used to provide emergency generation, both locally and for the interconnected system, and to facilitate scheduled maintenance.

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

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013.

Table 1

Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$ 60	-	-	-
Labour – Internal	20	-	-	-
Labour – Contract	-	-	-	-
Engineering	15	-	-	-
Other	5	-	-	-
Total	**$ 100**	**$100**	**$575**	**$775**

Costing Methodology

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

Table 2 **Expenditure History** **(000s)**					
Year	**2004**	**2005**	**2006**	**2007**	**2008F**
Total	**$142**	**$135**	**-**	**$37**	**$100**

The process of estimating the budget requirement for facilities rehabilitation of thermal generating facilities is on a 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.

SUBSTATIONS

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

Project Cost: **$4,102,000**

Project Description

This Substations Refurbishment and Modernization project is a continuation of work started in 2007 as a result of the *Substation Strategic Plan*. The work included in this project is consistent with this plan. An update to the *Substation Strategic Plan* is included in ***2.1** Substation Refurbishment and Modernization*.

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.

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 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	2009	2010	2011 – 2013	Total
Material	$1,799	-	-	-
Labour – Internal	771	-	-	-
Labour – Contract	292	-	-	-
Engineering	860	-	-	-
Other	380	-	-	-
Total	**$4,102**	**$5,121**	**$18,279**	**$27,502**

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	**2004**	**2005**	**2006**	**2007**	**2008F**
Total	**$2,168**	**$2,072**	**$2,107**	**$2,364**	**$2,555**

The Company has 130 substations varying in age from six 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: **$1,729,000**

Project Description

This Substation project is necessary to replace substation equipment that is retired due to storm damage, lightning strikes, vandalism, 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.

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 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$1,219	-	-	-
Labour – Internal	360	-	-	-
Labour – Contract	-	-	-	-
Engineering	80	-	-	-
Other	70	-	-	-
Total	**$1,729**	**$1,767**	**$5,523**	**$9,019**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2004	2005	2006	2007	2008F
Total	$1,284	$1,194	$1,273	$2,134	$2,100

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. The increase in expenditures is largely attributable to the effects of inflation on utility construction materials[1], and an increase in the number of failures experienced.

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] Section 3.1 of the Capital Plan discusses the impact of inflation on Newfoundland Power's capital budget.

Project Title: **Horse Chops Transformer Replacement (Other)**

Project Cost: **$1,341,000**

Project Description

This Substation project involves replacement of the power transformer and associated substation modifications at the Horse Chops hydroelectric plant.

Capital expenditures are necessary to address identified deficiencies at the Horse Chops hydroelectric plant. The report titled *Horsechops Power Transformer Replacement* provides detailed information on the project.

This project involves the replacement of the 57 year old power transformer at the Plant and the relocation of the Plant substation to accommodate the new transformer.

Justification

The Horsechops hydroelectric plant provides 41.8 GWh of energy per year or approximately 9.8% of Newfoundland Power's annual production.

On March 10, 2008, oil analysis carried out as part of the routine maintenance of the transformer revealed high concentrations of combustible hydrocarbon gases including acetylene in the transformer oil. On April 3, 2008, analysis of a second oil sample confirmed the earlier results. Four additional oil samples taken on April 21, 2008, May 13, 2008, May 22, 2008 and June 2, 2008 have all confirmed the earlier results.

The transformer has been in service for approximately 57 years, and has operated under full load for most of that time. In light of the high cost associated with rewinding the transformer, including the cost of replacement of accessory equipment, and the improved efficiency of a new transformer, the purchase of a new unit is the recommended alternative.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013.

Table 1 **Project Cost** **(000s)**				
Cost Category	**2008**	**2009**	**2010 - 2012**	**Total**
Material	$1,052	-	-	-
Labour – Internal	62	-	-	-
Labour – Contract	-	-	-	-
Engineering	74	-	-	-
Other	153	-	-	-
Total	**$1,341**	-	-	**$1,341**

Costing Methodology

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.

TRANSMISSION

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

Project Cost: **$4,507,000**

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 ($2,912,000).

   Proposed 2009 transmission line rebuilding work will take place on sections of 110L and 111L. Transmission lines 110L and 111L are located on the Bonavista Peninsula and experienced damage during the December 2007 storm resulting in extended outages for customers. 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 ($1,595,000).

Transmission line rebuilds and replacements to address identified deficiencies are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

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.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013. Appendix A of ***3.1** Transmission Line Rebuild* details the transmission line rebuilds planned for each year.

Table 1 **Project Expenditures** **(000s)**				
Cost Category	**2009**	**2010**	**2011 - 2013**	**Total**
Material	$ 1,545	-	-	-
Labour – Internal	354	-	-	-
Labour – Contract	2,004	-	-	-
Engineering	166	-	-	-
Other	438	-	-	-
Total	**$ 4,507**	**$7,327**	**$22,524**	**$34,358**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period. Annual expenditures are a function of the number of lines rebuilt, distance covered and the construction standard used in the design.

Table 2 **Expenditure History** **(000s)**					
Year	**2004**	**2005**	**2006**	**2007**	**2008F**
Total	**$2,061**	**$2,651**	**$4,456**	**$4,440**	**$4,958**

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: **$8,786,000**

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 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$2,835	-	-	-
Labour – Internal	2,101	-	-	-
Labour – Contract	2,719	-	-	-
Engineering	901	-	-	-
Other	230	-	-	-
Total	**$8,786**	**$8,708**	**$24,650**	**$42,144**

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 2009.

Table 2
Expenditure History and Unit Cost Projection

Year	**2004**	**2005**	**2006**	**2007**	**2008F**	**2009B**
Total Exp. (000s)	**$ 8,406**	**$ 7,962**	**$11,136**	**$ 9,285**	**$ 8,730**	**$ 8,786**
Adjusted Cost (000s)[1]	$ 9,982	$ 9,174	$ 8,882[2]	$ 8,596[2]	$ 8,730	$ -
New Customers	4,294	4,149	3,952	3,941	3,827	3,962
Unit Cost ($/customer)[1]	$ 2,325	$ 2,211	$ 2,248	$ 2,181	$ 2,281	$ 2,217

[1] 2008 Dollars.
[2] Excludes expenditure for extensions to cottage areas.

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, are expressed in current-year dollars ("Adjusted Cost") using the Statistics Canada Distribution Systems Price Index.[1] The Adjusted Costs 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 adjusted 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.

[1] Section 3.1 of the *2009 Capital Plan* discusses the impact of inflation on Newfoundland Power's capital budget.

Project Title: **Meters (Pooled)**

Project Cost: **$1,127,000**

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 2009.

Table 1
2009 Proposed Meter Acquisition

Program	Number of Meters
Energy Only Domestic Meters	9,917
Other Energy Only and Demand Meters	1,226

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.

No expenditure has been explicitly budgeted for the installation of automated meter reading ("AMR") technology. However, AMR meters will be installed where it is determined that the higher cost is justified by the savings provided in 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 2009 and a projection of expenditures through 2013.

Table 2 Project Expenditures (000s)				
Cost Category	**2009**	**2010**	**2011 - 2013**	**Total**
Material	$991	-	-	-
Labour – Internal	113	-	-	-
Labour – Contract	23	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$1,127**	**$1,168**	**$4,002**	**$6,297**

Costing Methodology

Table 3 shows the annual expenditures for the most recent five-year period, as well as a projection for 2009.

Table 3 Expenditure History and Unit Cost Projection							
Year	**2004**	**2005**	**2006**	**2007**	**2008F**	**Avg**	**2009B**
Meter Requirements							
New Connections	4,294	4,149	3,952	3,941	3,827		3,962
GROs/CSOs	8,544	12,399	13,371	3,546	14,500		5,509
Other	1,064	2,175	1,677	1,667	1,779		1,672
Total	13,902	18,723	19,000	9,154	20,106		11,143
Meter Costs							
Actual (000s)	$1,297	$1,342	$1,463	$1,154	$1,394		$1,127
Adjusted[1] (000s)	$1,466	$ 924[2]	$1,026[2]	$1,194	-		-
Unit Cost[1]	$105	$83[2]	$89[2]	$130	$69	$95	$101

1 2008 dollars.

2 Excludes two groups of meters which failed compliance sampling testing as required by Measurement Canada in 2005 and 2006.

The project cost for meters is calculated on the basis of historical data. Historical annual expenditures over the most recent five-year period, including the current year, are expressed in current year dollars ("Adjusted Meter Costs") using the Statistics Canada Distribution Systems Price Index. The adjusted costs are divided by the total meter requirements in each year to derive the annual meter cost in current-year dollars ("Unit Cost"). The average of these costs, with unusually high and low data excluded, is adjusted by the GDP Deflator for Canada before being multiplied by forecast 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: **$2,373,000**

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 service 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 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$ 714	-	-	-
Labour – Internal	1,317	-	-	-
Labour – Contract	115	-	-	-
Engineering	199	-	-	-
Other	28	-	-	-
Total	**$2,373**	**$2,368**	**$6,853**	**$11,594**

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 2009.

Table 2

Expenditure History and Unit Cost Projection
New Services

Year	2004	2005	2006	2007	2008F	2009B
Total (000s)	**$ 1,659**	**$ 1,894**	**$ 1,863**	**$ 1,949**	**$ 1,784**	**$ 1,951**
Adjusted Cost (000s)[1]	$ 1,953	$ 2,159	$ 2,056	$ 2,028	$ 1,784	-
New Customers	4,294	4,149	3,952	3,941	3,827	3,962
Unit Cost ($/customer)[1]	$ 455	$ 520	$ 520	$ 515	$ 571	$ 489

[1] 2008 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") using the Statistics Canada Distribution Systems Price index. The Adjusted Costs are 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 adjusted 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 2009.

Table 3

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

Year	2004	2005	2006	2007	2008F	2009B
Total	**$349**	**$339**	**$399**	**$472**	**$402**	**$422**
Adjusted Cost[1]	$411	$386	$440	$491	$402	

[1] 2008 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: **$1,646,000**

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 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$ 891	-	-	-
Labour – Internal	586	-	-	-
Labour – Contract	127	-	-	-
Engineering	25	-	-	-
Other	17	-	-	-
Total	**$1,646**	**$1,623**	**$4,833**	**$8,102**

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 2009.

Table 2

Expenditure History and Unit Cost Projection
New Street Lights

Year	**2004**	**2005**	**2006**	**2007**	**2008F**	**2009B**
Total (000s)	**$ 1,020**	**$ 1,363**	**$ 1,131**	**$ 977**	**$ 1,014**	**$ 1,045**
Exclusions[1] (000s)	-	$ 380	-	-	475	-
Adjusted Cost (000s)[2]	$ 1,251	$ 1,164	$ 1,286	$1,026	$ 985	-
New Customers	4,294	4,149	3,952	3,941	3,827	3,962
Unit Cost ($/cust.)[2]	$ 291	$ 281	$ 325	$ 260	$ 257	$ 258

[1] Exclusions in 2005 reflect the unusually high quantity of new Street Lights installed for the City of St. John's.
[2] 2008 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, are expressed in current-year dollars ("Adjusted Cost") using the Statistics Canada Distribution Systems Price Index . The Adjusted Costs 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 adjusted 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 2009.

Table 3

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

Year	**2004**	**2005**	**2006**	**2007**	**2008F**	**2009B**
Total	**$379**	**$489**	**$451**	**$1,112**	**$446**	**$601**
Exclusions[1]	-	70	-	140	-	-
Adjusted Cost[2]	$465	$496	$513	$1,020	-	-

[1] Exclusions in 2005 & 2007 reflect the Company's program replacement of underground wiring for streetlights in the St. John's area at a cost of $70,000 and $140,000 respectively.

[2] 2008 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: **Replace Mercury Vapour Street Lights (Pooled)**

Project Cost: **$806,000**

Project Description

This Distribution project involves the replacement of existing Mercury Vapour (“MV”) street light fixtures with the more energy efficient High Pressure Sodium (“HPS”) fixtures. There are approximately 7,000 MV street lights in service. Collectively, they have the potential to reduce the energy consumption attributable to street lighting by 2,184 MWh on an annual basis.

At the present time approximately 540 MV street lights fail in service each year, and are replaced by HPS street lights. This project proposes to replace the 7,000 remaining MV street lights over a 3-year period. The project is principally driven by the energy savings realized by the replacement of the MV street light with a HPS street light.

Details on the proposed expenditures are included in ***4.2** Energy Efficient Street Lights*.

Justification

Replacing the 7,000 MV street lights over the 3 year period as proposed will reduce both power purchase and maintenance cost associated with these street lights. The economic analysis completed in report ***4.2** Energy Efficient Street Lights* indicates that the project as proposed provides approximately $626,000 in net benefit over the next 20 years when compared to the current practice of replacing street lights through normal attrition. The levelized cost of energy for this project is 5.65 cents per kWh. [1]

[1] Incremental energy from the Holyrood thermal generating station is estimated at 10.63 cents per kWh for 2009 (based upon $67.00 per barrel of No. 6 fuel from Hydro’s fuel price projection dated March 31, 2008), with associated levelized cost of 12.84 cents per kWh over 25 years and 13.90 cents per kWh over 50 years.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	**2009**	**2010**	**2011 - 2013**	**Total**
Material	$ 385	-	-	-
Labour – Internal	387	-	-	-
Labour – Contract	-	-	-	-
Engineering	17	-	-	-
Other	17	-	-	-
Total	**$ 806**	**$581**	**$581**	**$1,968**

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.

Project Title: **Transformers (Pooled)**

Project Cost: **$6,406,000**

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.

Transformer 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 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$6,406	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$6,406**	**$6,513**	**$20,156**	**$33,075**

Costing Methodology

Table 2 shows the annual expenditures for the most recent five-year period, as well as an estimate for 2009.

Table 2
Expenditure History and Budget Estimate
(000s)

Year	2004	2005	2006	2007	2008F	2009B
Total	**$5,449**	**$4,976**	**$5,643**	**$6,992**	**$7,010**	**$6,406**
Adjusted Cost[1]	$7,046	$6,197	$5,866	$6,379	$6,010	-

[1] 2008 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, are expressed in current-year dollars ("Adjusted Cost") using the Statistics Canada Distribution Systems Price Index. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada 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: **$3,229,000**

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 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$ 764	-	-	-
Labour – Internal	1,300	-	-	-
Labour – Contract	729	-	-	-
Engineering	326	-	-	-
Other	110	-	-	-
Total	**$ 3,229**	**$4,612**	**$13,853**	**$21,694**

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 2009.

Table 2

Expenditure History and Budget Estimate
(000s)

Year	2004	2005	2006	2007	2008F	2009B
Total	**$2,420**	**$2,898**	**$2,989**	**$3,563**	**$3,295**	**$3,229**
Adjusted Cost[1]	$2,841	$3,291	$3,282	$3,193	$3,129	-

[1] 2008 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, are expressed in current-year dollars ("Adjusted Cost") using the Statistics Canada Distribution Systems Price Index. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada 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: **$3,541,000**

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 2009 includes feeder improvements on 43 of the Company's 303 feeders.

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 8,600 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 2009 and a projection of expenditures through 2013.

Table 1 **Project Expenditures** **(000s)**				
Cost Category	**2009**	**2010**	**2011 - 2013**	**Total**
Material	$1,709	-	-	-
Labour – Internal	1,434	-	-	-
Labour – Contract	203	-	-	-
Engineering	27	-	-	-
Other	168	-	-	-
Total	**$3,541**	**$3,622**	**$11,363**	**$18,526**

Costing Methodology

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

Table 2 **Expenditure History** **(000s)**					
Year	**2004**	**2005**	**2006**	**2007**	**2008F**
Total	**$3,382**	**$3,545**	**$2,811**	**$3,249**	**$3,385**

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 observed in 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

[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.

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.

[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: **$622,000**

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 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$ 218	-	-	-
Labour – Internal	199	-	-	-
Labour – Contract	131	-	-	-
Engineering	63	-	-	-
Other	11	-	-	-
Total	**$ 622**	**$797**	**$2,518**	**$3,937**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2004	2005	2006	2007	2008F
Total	**$440**	**$630**	**$1,801**	**$1,604**	**$1,033**
Adjusted Cost[1]	$517	$715	$478[2]	$593[3]	$728[4]

[1] 2008 dollars.
[2] Excludes $999,000 for Persona cross island project.
[3] Excludes $1,520,000 for Persona cross island project.
[4] Excludes $305,000 for Persona cross island project.

The budget estimate is based on historical expenditures. 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, are expressed in current-year dollars ("Adjusted Cost") using the Statistics Canada Distribution Systems Price Index. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada to determine the budget estimate.

To ensure consistency from year to year, expenditures related to past extraordinary requirements are excluded from the calculation. For example, three exclusions for work completed for Persona are identified in the notes to Table 2. For these projects, costs less betterment was recovered from Persona.

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: **Distribution Reliability Initiative (Pooled)**

Project Cost: **$1,266,000**

Project Description

This Distribution project involves the replacement of deteriorated poles, conductor and hardware to reduce both the frequency and duration of power interruptions to the customers served by specific distribution lines. The nature of the upgrading work follows from a detailed assessment of past service problems, knowledge of local environmental conditions (such as salt contamination and wind and ice loading), and engineering knowledge to apply location specific design and construction standards. Options are evaluated to improve reliability performance and project plans are subsequently developed from an engineering analysis.

The 2009 project involves continuation of work on 2 feeders included in the Distribution Reliability Initiative ("DRI") from 2006 and 2008, plus 1 feeder added to the DRI for the first time in 2009.[1]

Table 1 identifies the feeders where upgrading is proposed in 2009. It shows the number of customers affected, and the average unscheduled distribution yearly interruption statistics for the five-year period ending December 31, 2007. These SAIFI[2] and SAIDI[3] statistics exclude planned power interruptions and interruptions due to all causes other than distribution system failure. An analysis of each feeder to be upgraded is contained in report ***4.1** Distribution Reliability Initiative*.

[1] The DRI first included the Glovertown (GLV-02) and Lewisporte (LEW-02) projects in 2006 that were originally planned to be completed over three years. The second year of these projects was postponed from 2007 to 2008 in light of the Rattling Brook Refurbishment project. The Northwest Brook (NWB-02) feeder project is also of 3 years duration, commencing in 2009.

[2] System Average Interruption Frequency Index (SAIFI) calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area. Distribution SAIFI records the average number of outages related to distribution system failure.

[3] System Average Interruption Duration Index (SAIDI) is calculated by dividing the number of customer-outage-hours (e.g., a two hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area. Distribution SAIDI records the average hours of outage related to distribution system failure.

Table 1

Distribution Interruption Statistics
5-Years to December 31, 2007

Feeder	Number of Customers	Distribution SAIFI	Distribution SAIDI
Glovertown (GLV-02)	1,259	3.85	9.07
Lewisporte (LEW-02)	1,390	3.39	8.55
North West Brook (NWB-02)	1,050	3.04	6.58
Company Average	**-**	**1.68**	**2.13**

While the work on different feeders is not inter-dependent, the various components of this project 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 provide reliable electrical service. Customers supplied by these feeders experience power interruptions more often, or of longer duration, than the Company average. Individual feeder projects have been prioritized based on their historic SAIFI and SAIDI statistics.

The distribution reliability initiative project has had a positive impact on the reliability performance of the feeders that have been upgraded.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013.

Table 2

Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$ 611	-	-	-
Labour – Internal	513	-	-	-
Labour – Contract	73	-	-	-
Engineering	9	-	-	-
Other	60	-	-	-
Total	**$1,266**	**$1,431**	**$4,487**	**$7,184**

Cost Methodology

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

Table 3

Expenditure History (000s)

Year	2004	2005	2006	2007[1]	2008F
Total	$763	$1,065	$3,365	-	$1,286

[1] The Distribution Reliability Initiative was suspended in 2007 in light of the Rattling Brook project.

The budget estimate is based on detailed engineering estimates of individual feeder upgrade 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.

Project Title: **Feeder Additions for Growth (Pooled)**

Project Cost: **$244,000**

Project Description

This Distribution project consists of load transfers from an existing feeder in one substation, to a feeder in an adjacent substation, to accommodate load growth without the addition of transformer capacity. There are typically 3 alternatives to deal with a substation transformer that is approaching its design capacity. Alternative 1 is to replace the transformer with a larger capacity unit. Alternative 2 is to add another transformer to the substation. Alternative 3 is to transfer customer load to an adjacent substation that has available transformer capacity.

Alternative 3 is the least cost alternative as it defers the purchase of an additional transformer to a future date.

The work for 2009 involves converting a section of a feeder at Broad Cove Substation from 12.5 kV to 25 kV to allow load transfers to a feeder at Hardwoods Substation.

Justification

The project is justified based on the obligation to provide safe, least cost reliable service.

Forecast and actual peak load conditions and customer growth indicate that this project is warranted in order to maintain the electrical system within recommended guidelines. This project is required to maintain substation transformer loading at Broad Cove Substation within its loading parameters thus deferring the need to replace the power transformer at Broad Cove Substation.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013.

Table 1 **Project Expenditures** **(000s)**				
Cost Category	**2009**	**2010**	**2011 - 2013**	**Total**
Material	$ 51	-	-	-
Labour – Internal	89	-	-	-
Labour – Contract	88	-	-	-
Engineering	11	-	-	-
Other	5	-	-	-
Total	**$ 244**	**$ 282**	**$ 888**	**$ 1,414**

Cost Methodology

The budget estimate is based on detailed engineering estimates of individual feeder 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.

Project Title: **Allowance for Funds Used During Construction (Pooled)**

Project Cost: **$132,000**

Project Description

This Distribution project is an allowance for funds used during construction ("AFUDC") which 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.

Effective January 1, 2008, the Company calculates AFUDC as approved in Order No. P.U. 32 (2007). This method of calculating the AFUDC is the mainstream practice of regulated Canadian utilities and is consistent with the asset rate base method of accounting.

Justification

The AFUDC 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 2009 and a projection of expenditures through 2013.

Table 1

Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	-	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	132	-	-	-
Total	**$132**	**$136**	**$423**	**$691**

Cost Methodology

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

Table 2
Expenditure History and Budget Estimate
(000s)

Year	2004	2005	2006	2007	2008
Total	**$66**	**$73**	**$68**	**$72**	**$132**

The increase in the 2008 forecast and the 2009 budget are based on the change in calculation as approved in Order No. P.U. 32 (2007).

The budget estimate for AFUDC is based on an estimated $1.0 million monthly average of distribution work in progress upon which the interest rate will be applied. The AFUDC rate is applied each month in accordance with Order No. P.U. 32 (2007).

Future Commitments

This is not a multi-year project.

GENERAL PROPERTY

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

Project Cost: **$691,000**

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 ($225,000)*: 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 ($400,000)*: 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 ($66,000)*: This project is the replacement of office furniture that has deteriorated. The Company has approximately 550 regular 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 2009 and a projection of expenditures through 2013.

Table 1

Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$ 691	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$ 691**	**$703**	**$2,180**	**$3,574**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2004	2005	2006	2007	2008F
Total	**$570**	**$693**	**$659**	**$617**	**$690**

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: **$144,000**

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 less than $50,000 each and 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 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$ 115	-	-	-
Labour – Internal	7	-	-	-
Labour – Contract	7	-	-	-
Engineering	8	-	-	-
Other	7	-	-	-
Total	**$ 144**	**$146**	**$452**	**$742**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2004	2005	2006	2007	2008F
Total	**$336**	**$334**	**$150**	**$165**	**$216**
Exclusions	211[1]	224[2]	-	-	85
Adjusted Cost	$125	$110	$150	$165	$131

[1] Includes roof repairs to offices in Gander and Stephenville.
[2] Includes renovations to the Kenmount Road, Topsail Road and Duffy Place buildings.

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 large unplanned additions are excluded from the historical average calculation.

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: **$2,255,000**

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 2009.

Table 1
2009 Proposed Vehicle Replacements

Category	No. of Units
Heavy fleet vehicles[1]	3
Passenger vehicles[2]	38
Off-road vehicles[3]	8
Total	**49**

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

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 vehicles and aerial devices that have reached the end of their useful service lives.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013.

Table 2 **Project Expenditures** **(000s)**				
Cost Category	**2009**	**2010**	**2011 - 2013**	**Total**
Material	$2,193	-	-	-
Labour – Internal	52	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	10	-	-	-
Total	**$2,255**	**$2,467**	**$7,062**	**$11,784**

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

Table 3 **Expenditure History** **(000s)**					
Year	**2004**	**2005**	**2006**	**2007**	**2008F**
Total	**$2,660**	**$2,838**	**$2,751**	**$2,231**	**$2,214**

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: **$135,000**

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 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.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013.

Table 1

Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$ 87	-	-	-
Labour – Internal	3	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	45	-	-	-
Total	**$ 135**	**$ 138**	**$ 426**	**$ 699**

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 2008.

Table 2
Expenditure History
(000s)

Year	**2004**	**2005**	**2006**	**2007**	**2008F**
Total	**$150**	**$102**	**$173**	**$110**	**$104**
Adjusted Cost[1]	$167	$107	$182	$112	-

[1] 2008 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 Statistics Canada Distribution Systems Price Index for the budget year to determine the budget estimate. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada 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.

Project Title: **Fibre Optic Circuit Replacement (Other)**

Project Cost: **$215,000**

Project Description

This Telecommunications project involves the replacement of leased and rented fibre optic communication circuits with fibre optic cables owned and maintained by Newfoundland Power.

The Company has 32 fibre optic systems in service which are a mix of owned, leased and rented facilities.

Newfoundland Power has completed an engineering review of these fibre optic communication circuits. Over the next few years, lease agreements will expire and new agreements for ten year terms will need to be established. Details of the engineering review are found in report ***5.1** Fibre Optic Circuit Replacement* included in the 2008 Capital Budget Application.

Justification

Reliable communications equipment is essential to the provision of safe, reliable electrical service. Replacement of rented facilities with Newfoundland Power owned fibre optic cables is justified by the Net Present Value analysis provided in ***5.1** Fibre Optic Circuit Replacement* included in the 2008 Capital Budget Application.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	2009	2010	2011 - 2013	Total
Material	$ 180	-	-	-
Labour – Internal	35	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$ 215**	**$ 244**	**$ 278**	**$ 737**

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.

INFORMATION SYSTEMS

Project Title: Application Enhancements (Pooled)

Project Cost: $1,438,000

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 2009, some, such as the Customer Service Internet, are custom-developed while others, such as the Great Plains financial management system, are vendor-provided.

The application enhancements proposed for 2009 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*** *2009 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*** *2009 Application Enhancements*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	**2009**	**2010**	**2011 - 2013**	**Total**
Material	$ 180	-	-	-
Labour – Internal	979	-	-	-
Labour – Contract	-	-	-	-
Engineering	34	-	-	-
Other	245	-	-	-
Total	**$1,438**	**$1,400**	**$4,360**	**$7,198**

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

Table 2
Expenditure History
(000s)

Year	**2004**	**2005**	**2006**	**2007**	**2008F**
Total	**$1,313**	**$1,185**	**$1,540**	**$1,353**	**$1,393**

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: **$679,000**

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, to facilitate infrastructure upgrades or to maintain vendor support.

For 2009, the project includes upgrades to database management system software, the Hand Held Meter Reading System and the Avantis Asset Management System.

This project also includes the Microsoft Enterprise Agreement. This Agreement covers the purchase of Microsoft software and provides access to the latest versions of each software product purchased under this agreement. Details on Microsoft Enterprise Agreement are included in *Schedule D* of the 2009 Capital Budget.

Details on 2009 proposed expenditures are included in ***5.2** 2009 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 2009 and a projection of expenditures through 2013.

Table 1

Project Expenditures
(000s)

Cost Category	**2009**	**2010**	**2011 – 2013**	**Total**
Material	$ 210	-	-	-
Labour – Internal	266	-	-	-
Labour – Contract	-	-	-	-
Engineering	13	-	-	-
Other	190	-	-	-
Total	**$ 679**	**$860**	**$2,850**	**$4,389**

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	2004	2005	2006	2007	2008F
Total	$861	$779	$1,017	$679	$545

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

With the exception of the provision for the Microsoft Enterprise Agreement, this is not a multi-year project. Under the terms of the Microsoft Enterprise Agreement, Newfoundland Power would be required, upon termination of the arrangement prior to the end of a 3-year term, to pay the remaining portion of the full 3-year software licensing fee. Approval is therefore requested for the 3-year expenditure of $600,000 associated with the Microsoft Enterprise Agreement, which covers the period 2009 through 2011 inclusive.

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

Project Cost: **$409,000**

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 2009, 128 PCs will be purchased consisting of 96 desktop computers and 32 laptop computers. This project also covers the purchase of additional peripheral equipment such as monitors, mobile devices, and printers to replace existing units that have reached the end of useful life.

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.

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 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 2007 and 2008, as well as the proposed additions and retirements for 2009.

Table 1

PC Additions and Retirements
2007 – 2009

	2007			**2008F**			**2009B**		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	52	52	469	76	76	469	96	96	469
Laptop	40	13	156	28	38	146	32	32	146
Total	**92**	**65**	**625**	**104**	**114**	**615**	**128**	**128**	**615**

Justification

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

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013.

Table 2
Project Expenditures
(000s)

Cost Category	2009	2010	2011 – 2013	Total
Material	$216	-	-	-
Labour – Internal	85	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	108	-	-	-
Total	**$409**	**$400**	**$1,200**	**$2,009**

Costing Methodology

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

Table 3
Expenditure History
(000s)

Year	2004	2005	2006	2007	2008F
Total	**$424**	**$412**	**$380**	**$409**	**$408**

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: **$700,000**

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, disk storage, as well as security upgrades.

For 2009, the project includes replacement of shared servers located in area offices across the province; replacement of the Avantis Asset Management System shared servers; replacement of the shared servers for the Handheld Meter Reading System; and purchase and implementation of shared server infrastructure to ensure data security for mobile computing.

The shared server infrastructure requirements for 2009 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 2009 are provided in ***5.3*** *2009 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 2009 and a projection of expenditures through 2013.

Table 1 **Project Expenditures** **(000s)**				
Cost Category	**2009**	**2010**	**2011 – 2013**	**Total**
Material	$ 387	-	-	-
Labour – Internal	233	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	80	-	-	-
Total	**$ 700**	**$725**	**$2,250**	**$3,675**

Costing Methodology

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

Table 2 **Expenditure History** **(000s)**					
Year	**2004**	**2005**	**2006**	**2007**	**2008F**
Total	**$699**	**$593**	**$493**	**$883**	**$889**

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: **Network Infrastructure (Pooled)**

Project Cost: **$149,000**

Project Description

This Information Systems project involves the addition of network components that provide employees with access to applications and data in order to provide service to customers and to operate efficiently.

Network components such as routers and switches interconnect shared servers and personal computers across the Company, enabling the transport of SCADA data, VHF radio communications, corporate and customer service data. The Company has increased its use of wireless communications technologies in recent years.

For 2009, this project includes the installation of wireless network equipment in the Company's area offices, and the purchase and implementation of network devices to provide network redundancy to guard against hardware failures.

The individual network infrastructure requirements for 2009 are not inter-dependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Justification

The reliability and availability of the network infrastructure is critical to enabling the Company to continue to provide least cost reliable service to customers. The addition of wireless network components will enable employees in Company offices to connect securely to the corporate network from locations anywhere within the building. For example a line crew can access the corporate network from a line truck parked in the building's service bay.

This project is necessary to ensure the continued integrity of Company and customer data. This, in turn, allows the maintenance of acceptable levels of customer service and operational efficiency.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013.

Table 1 Project Expenditures (000s)				
Cost Category	**2009**	**2010**	**2011 – 2013**	**Total**
Material	$ 105	-	-	-
Labour – Internal	34	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	10	-	-	-
Total	**$ 149**	**$150**	**$535**	**$834**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period. No Network Infrastructure expenditures were required in 2006 and 2007.

Table 2 Expenditure History (000s)					
Year	**2004**	**2005**	**2006**	**2007**	**2008F**
Total	**$432**	**$286**	**-**	**-**	**$119**

The budget for this project is based on cost estimates for the individual budget items based on past experiences and pricing.

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: **Vehicle Mobile Computing Infrastructure (Pooled)**

Project Cost: **$350,000**

Project Description

This Information Systems project is necessary to provide mobile computing infrastructure in Company vehicles.

In 2009, 25 ruggedized laptop computers will be purchased and deployed in Company vehicles used by field staff. This project also covers the supporting equipment required to properly install the computers in the vehicles such as ergonomic mounting hardware, and communications equipment.

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

Justification

This project will improve customer service and operational efficiency. As well, this project is justified on the basis of ensuring compliance and ongoing adherence of safety and environmental standards and processes in use by the Company.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013.

Table 2

Project Expenditures
(000s)

Cost Category	2009	2010	2011 – 2013	Total
Material	$225	-	-	-
Labour – Internal	85	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	40	-	-	-
Total	**$350**	**$450**	-	**$800**

Costing Methodology

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

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

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.
2009 Capital Budget
Leases

Lease	Annual Cost	Term
Postage Meter	$11,000	60 Months

Title: **Postage Meter**

Lease Cost: **$11,000/Year**

Project Description

This lease is for the replacement of a postage meter located at Newfoundland Power, 50 Duffy Place. This unit is used to automatically place postage stamps on approximately 500 pieces of Newfoundland Power mail per work day.

Justification

This project is justified on the need to provide employees with the ability to perform outgoing mail services in a timely manner.

Projected Expenditures

The estimated annual cost for the lease of this meter is $11,000 per year for a five-year term. The lease will end in 2013.

Table 1 provides a breakdown of the proposed expenditures for 2009 and a projection of expenditures through 2013.

Table 1
Project Expenditures
(000s)

Cost Category	2009	2010	2011 – 2013	Total
Material	-	-		-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	$11	$11	$33	$55
Total	**$11**	**$11**	**$33**	**$55**

Future Commitments

This is multi-year project, with commitments expected for a lease term of 5 years.

Newfoundland Power Inc.
2009 Capital Budget
Future Required Expenditures

Improvement to Property	Estimated Annual Expenditure	Timing
Microsoft Enterprise Agreement[1]	$200,000	3 Years: 2009 through 2011

[1] Detailed description provided in ***5.2*** *2009 System Upgrades*

Newfoundland Power Inc.
2009 Capital Budget
Rate Base
(000s)

	Historical Data	
	2006	**2007**
Plant Investment	$ 1,186,614	$ 1,239,186
Deduct:		
Accumulated Depreciation	494,851	516,478
Contributions in Aid of Construction	23,142	24,217
Weather Normalization Reserve	(11,808)	(10,516)
Purchase Power Unit Cost Variance Reserve	1,342	1,650
	507,527	531,829
	679,087	707,357
Add - Contributions Country Homes	1,001	1,346
Balance - Current Year	680,088	708,703
Balance - Previous Year	661,172	680,088
Average	670,630	694,396
Deferred Energy Replacement Cost	-	574
Deferred Regulatory Cost	-	8,690
Cash Working Capital Allowance	5,522	6,669
Materials and Supplies	4,510	4,393
Average Deferred Charges	94,338	96,784
Average Unrecognized 2005 Unbilled Revenue	(21,396)	(17,803)
Average Rate Base at Year End	$ 753,604	$ 793,703

2009 Capital Plan

June 2008

Table of Contents

1.0 Introduction

Newfoundland Power's 2009 Capital Plan provides an overview of the Company's 2009 Capital Budget together with an outlook for capital expenditure through 2013.

Newfoundland Power's 2009 Capital Budget totals $61,571,000.

Over the next five years, the Company plans to invest approximately $343 million in plant and equipment. The impact of inflation on utility construction projects and the need for greater transformer capacity over the next 5 years will increase the planned expenditures in generation, transmission, substation and distribution assets through the 2009 to 2013 period.

Approximately 58% of planned expenditures through 2013 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 as a percentage of annual capital expenditure.

2.0 2009 Capital Budget

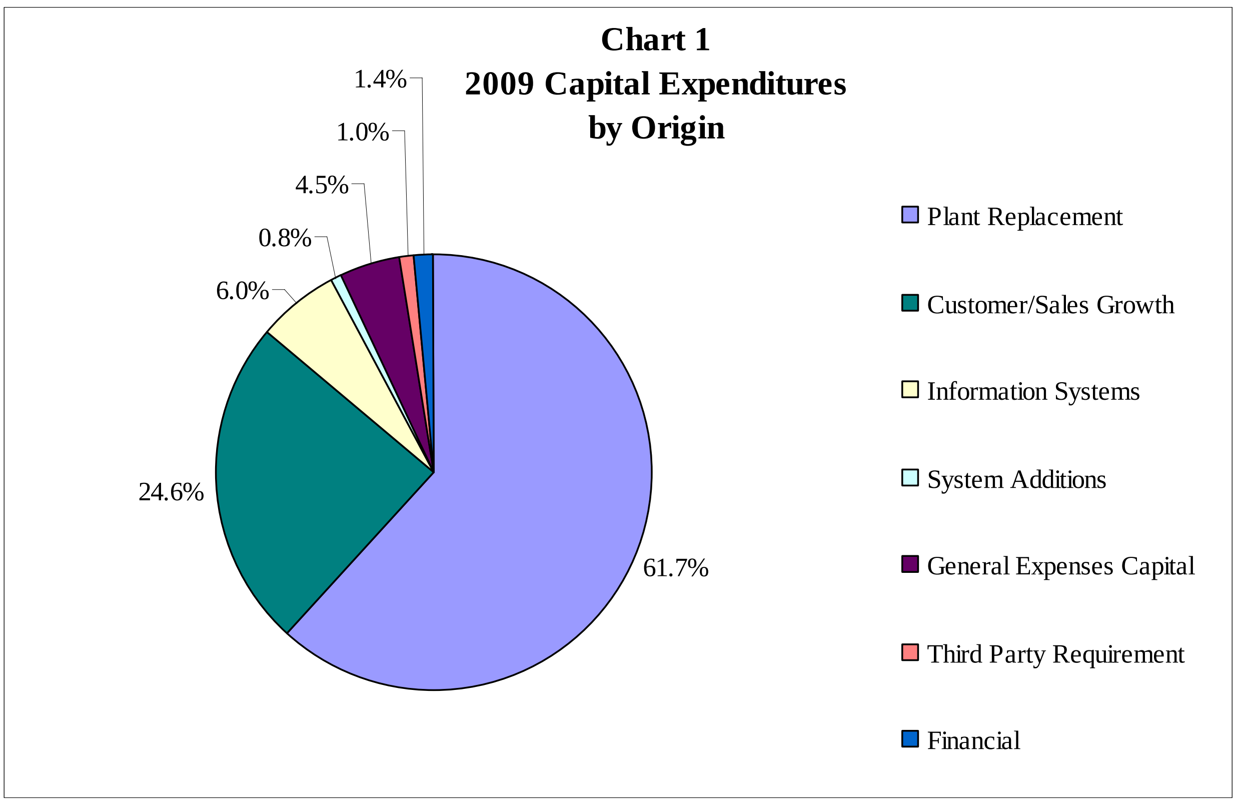
Newfoundland Power's 2009 capital budget is $61,571,000.

This section of the 2009 Capital Plan provides an overview of the 2009 capital budget by origin (root cause) and asset class. In addition, this section summarizes 2009 capital projects by the various categories set out in the Board's October 2007 Capital Budget Application Guidelines.

2.1 2009 Capital Budget Overview

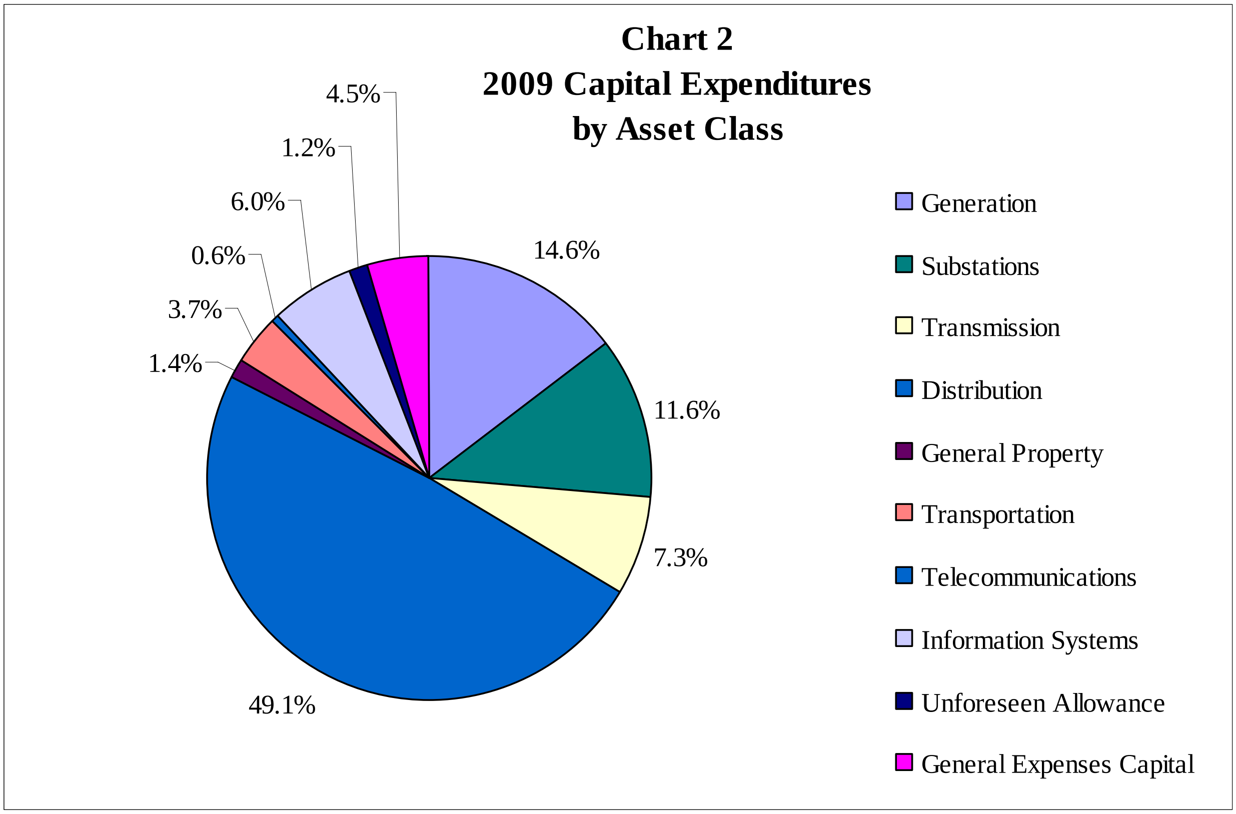
Newfoundland Power's 2009 capital budget contains 34 projects totalling $61,571,000. Between 2004 to 2008, the Company's annual capital program averaged $57.5 million in a range of $48.9 million to $68.5 million.

Chart 1 shows the 2009 capital budget by origin, or root cause.



Approximately 62% of proposed 2009 capital expenditure is related to the replacement of plant. A further 25% of proposed 2009 capital expenditure is required to meet the Company's obligation to provide service to new customers. The remaining 13% of forecast capital expenditures for 2009 relate to information systems, system additions, capitalized general expenses, third party requirements and financial carrying costs (allowance for funds used during construction). 2009 capital expenditures are broadly consistent with the allocation of the capital budget in the past five years.

Chart 2 shows the 2009 capital budget by asset class.



As in past years, Distribution capital expenditure accounts for the greatest percentage of overall expenditure at $30.2 million, or 49% of the 2009 capital budget. Generation capital expenditures account for $9.0 million, or 15% of the 2009 capital budget. Substations and Transmission capital expenditures account for a further $11.7 million, or 19% of the 2009 capital budget.

In 2009, the Company plans to replace the Rocky Pond hydroelectric plant penstock, head gate and main valve along with rewinding the generator stator at an estimated cost of $6.5 million. In 2008 Newfoundland Power has undertaken a study to identify opportunities for increasing production at existing hydroelectric plants. The first of these projects, the *Rose Blanche Spillway* project involves the raising of the spillway dam elevation to increase the storage capacity of the watershed. The increased capacity translates into 900 MWhr of additional energy on an annual basis.

The Horse Chops plant power transformer has reached the end of its service life and requires replacement at a cost of $1.3 million.

Rebuilds on two Bonavista Peninsula transmission lines that were damaged by the December 2, 2007 sleet storm are budgeted at $2.9 million for 2009. The total cost of all transmission line rebuilds for 2009 is $4.5 million.

The replacement of the remaining mercury vapour street lights with high pressure sodium street lights is planned over a three year period starting with a $0.8 million expenditure in 2009. This project is justified by the energy savings resulting from reduced energy consumption associated with more efficient high pressure sodium lamps. Details on this project are included in the report ***4.2*** *Energy Efficient Street Lights*.

2.2 The Capital Budget Application Guidelines

On October 29, 2007, the Board issued Policy No. 1900.6, referred to as the Capital Budget Application Guidelines ("the CBA Guidelines"), providing definition and categorization of capital expenditures for which a public utility requires prior approval of the Board. Newfoundland Power's 2009 capital budget application complies with the CBA Guidelines.

The 2009 capital budget application includes 34 projects as detailed in Schedule A. There are 30 *pooled* projects accounting for 92% of total expenditures. There are 31 *normal* projects accounting for 96% of total expenditures.

2009 Capital Projects by Definition
Table 1 summarizes Newfoundland Power's proposed 2009 capital projects by definition as set out in the CBA Guidelines.

Table 1
2009 Capital Projects
By Definition

Definition	**No.**	**($000s)**
Pooled	28	55,800
Clustered	0	0
Other	6	5,771
Total	**34**	**61,571**

2009 Capital Projects by Classification
Table 2 summarizes Newfoundland Power's proposed 2009 capital projects by classification as set out in the CBA Guidelines.

Table 2
2009 Capital Projects
By Classification

Classification	No.	($000s)
Mandatory	0	0
Normal	29	58,297
Justifiable	5	3,274
Total	**34**	**61,571**

2009 Capital Projects Costing

Table 3 summarizes Newfoundland Power's proposed 2009 capital projects by costing method (i.e., identified need vs. historical pattern) as set out in the CBA Guidelines.

Table 3
2009 Capital Projects
By Costing Method

Method	No.	($000s)
Identified Need	20	31,001
Historical Pattern	14	30,570
Total	**34**	**61,571**

2009 Capital Projects Materiality

Table 4 segments Newfoundland Power's proposed 2009 capital projects by materiality as set out in the CBA Guidelines.

Table 4
2009 Capital Projects
Segmentation by Materiality

Segment	No.	($000s)
Under $200,000	5	660
$200,000 - $500,000	7	2,362
Over $500,000	22	58,549
Total	**34**	**61,571**

3.0 5-Year Outlook

Newfoundland Power's 5-year capital outlook for 2009 through 2013 includes average annual capital expenditures forecast to be $68.7 million. Over the five year period 2004 through 2008, the average annual capital expenditure is expected to be $57.5 million.

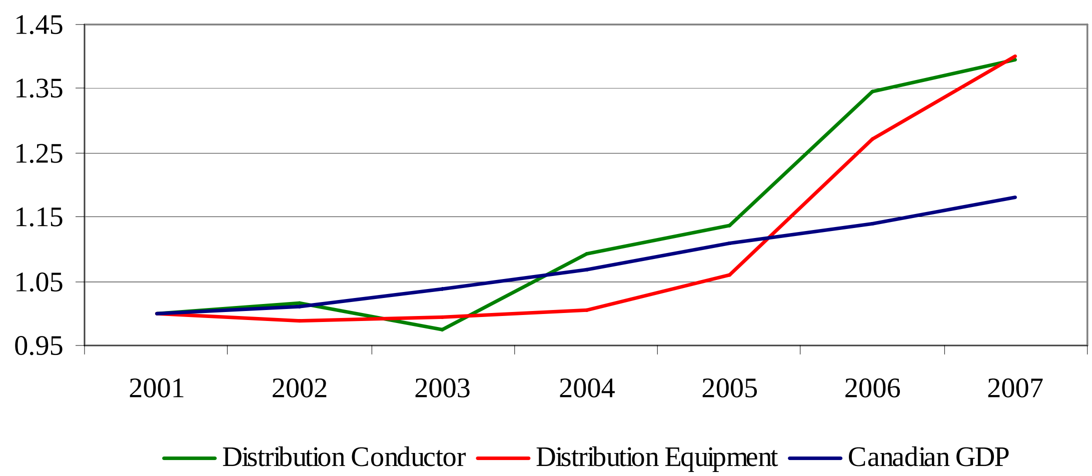
The increase in forecast capital expenditures is related to high levels of inflation for utility equipment and the forecast requirement for additional power transformers for load growth, mobile generation and portable substations.

3.1 Utility Infrastructure Cost

In recent years, Newfoundland Power has experienced increased cost in both material and contract labour associated with constructing utility infrastructure. This experience is consistent with national trends.

Graph 1 compares the cost of distribution conductor and distribution equipment to Canadian gross domestic product ("GDP") for the period 2001 through 2007[1].

Graph 1
Statistics Canada
Electric Utility Distribution System Price Index



Over the period 2001 through 2005, electrical distribution material costs were broadly consistent with overall Canadian GDP. Since 2006, distribution material costs have increased at a materially higher level than Canadian GDP.

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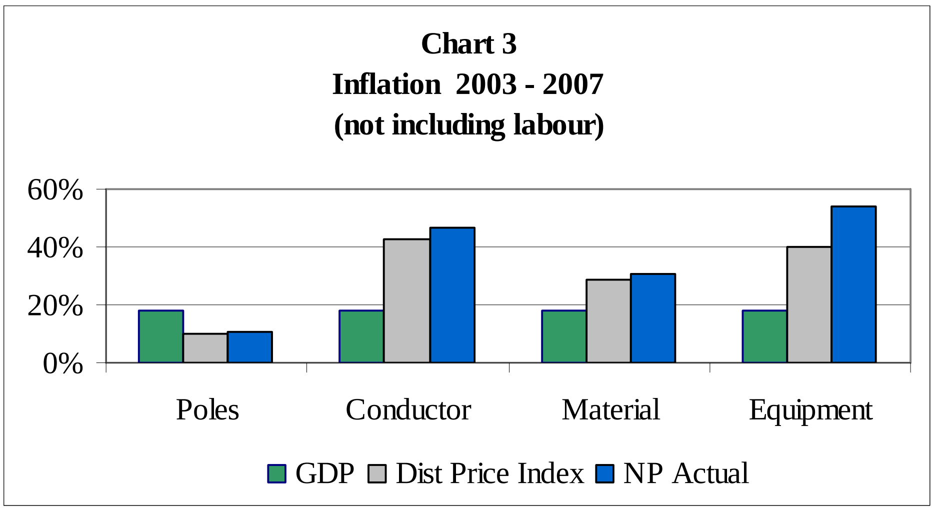
[1] Distribution conductor and equipment cost data taken from the Electric Utility Construction Price Index by Statistics Canada (*Capital Expenditure Price Statistics* catalogue 62-007-X).

These material cost increases are driven largely by the increase in raw material prices used in the manufacture of components required for utility infrastructure projects. Raw materials such as copper and iron are important inputs into manufacturing processes for conductor, transformers and other major equipment used in distribution, substation and transmission infrastructure projects. Raw material prices are being driven by global demand for these commodities, along with rising energy and transportation costs.

Chart 3 compares inflation as reflected in Canadian GDP, the Distribution Price Index[2], and Newfoundland Power's expenses during the period 2003 through 2007 for poles, conductor, other standard material, and equipment used by Newfoundland Power.



Conductor, material and equipment require raw materials such as copper and iron in their manufacture. For these items, inflation associated with the Company's purchases has exceeded the GDP deflator and more closely tracked the Distribution Price Index from Statistics Canada[3].

Material cost inflation impacts Newfoundland Power's capital budgeting. For 2009, costs associated with distribution projects *Extensions, Transformers, Services, Meters* and *Street Lighting* alone have been increased by approximately $2.1 million to better reflect inflationary effects. This should improve the accuracy of these unit cost based estimates and result in actual costs better reflecting budget estimates.

3.2 Capital Expenditures: 2004 - 2013

The Company plans to invest $344 million in plant and equipment during the 2009 through 2013 period. On an annual basis, capital expenditures are expected to average approximately $68.7 million and range from a low of $61.6 million in 2009 to a high of $72.2 million in 2011.

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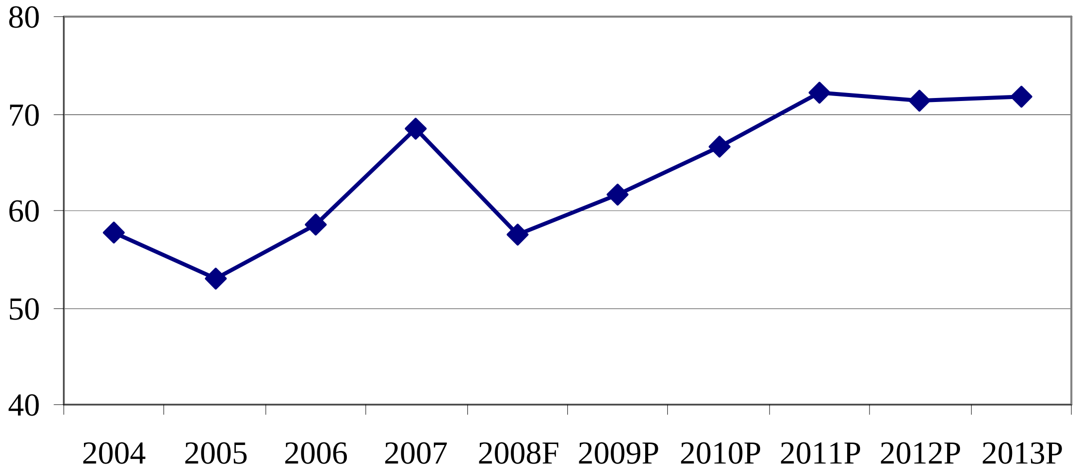
2 The Distribution Price Index is part of the Electric Utility Construction Price Index. See Footnote 1.

3 Variances between Newfoundland Power's actual material cost inflation and the Distribution Price Index reflect local factors such as transportation costs and the exclusive use of higher cost stainless steel pole-mounted transformers.

Graph 2 shows actual capital expenditures for the period 2004 through 2007 and forecast capital expenditure for the period 2008 through 2013.

Graph 2
Capital Expenditures 2004 Actual - 2013 Plan
($000,000)



Overall planned capital expenditures over the 5-year period from 2009 through 2013 are expected to be greater than those in the 5-year period from 2004 through 2008. This is principally the result of inflation in utility infrastructure construction costs; the inclusion of power transformers for load growth; and forecast requirement for mobile generation and a portable substation included in the 5 year plan.

For the 2004 through 2013 period, the replacement of plant has been, and will continue to be, the dominant driver of Newfoundland Power's capital budget, accounting for approximately 58% of total expenditures.

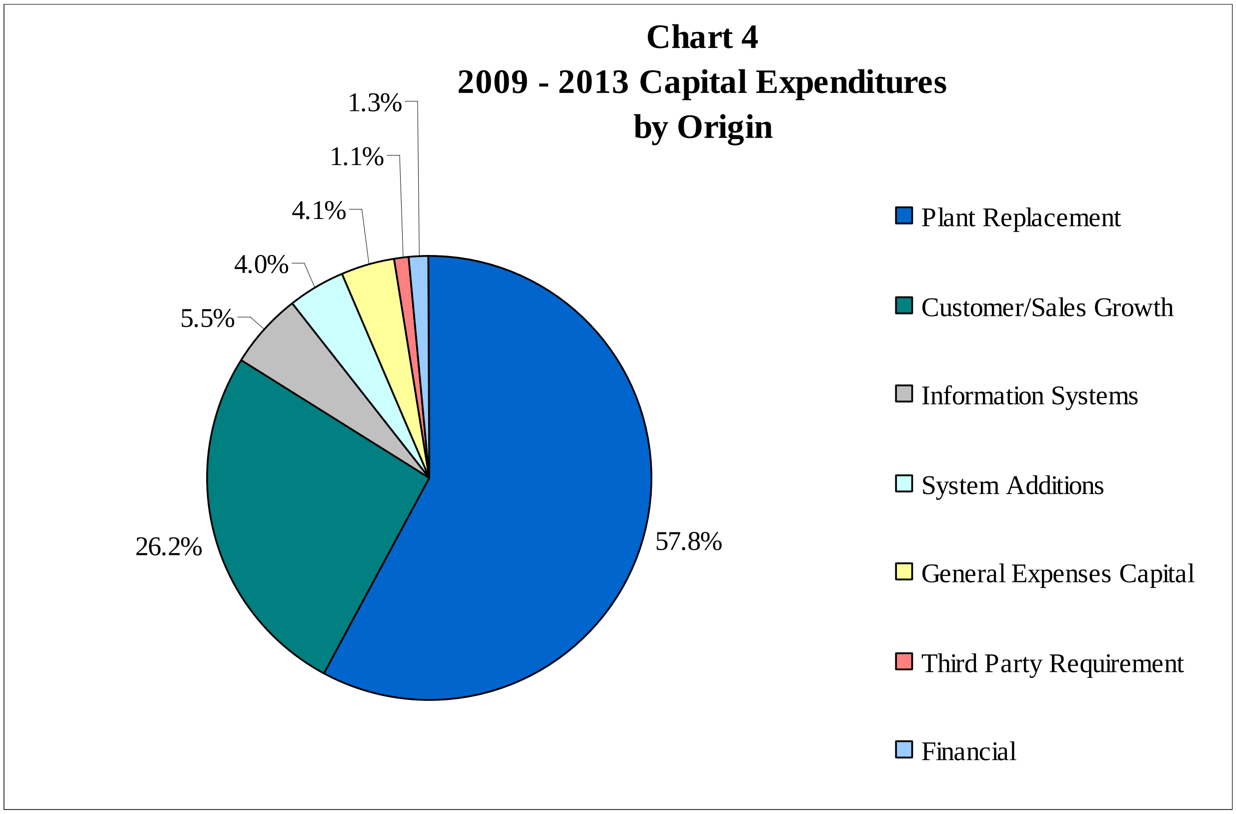
Capital expenditures to meet increases in customer connections and sales will continue to account for approximately 27% of total expenditures.

3.3 2009 – 2013 Capital Expenditures

3.3.1 Overview

The origin of expenditures through the 2009 to 2013 period is broadly consistent with the 2003 through 2007 period.

Chart 4 shows aggregate forecast capital expenditures by origin for the period 2009 through 2013.



Plant replacement accounts for 58% of all planned expenditures over the next five years, followed by customer and sales growth at 26%. The remaining 16% of total capital expenditures for the 2009 through 2013 period relate to a variety of causes including information systems, system additions, third party requirements and financial costs.

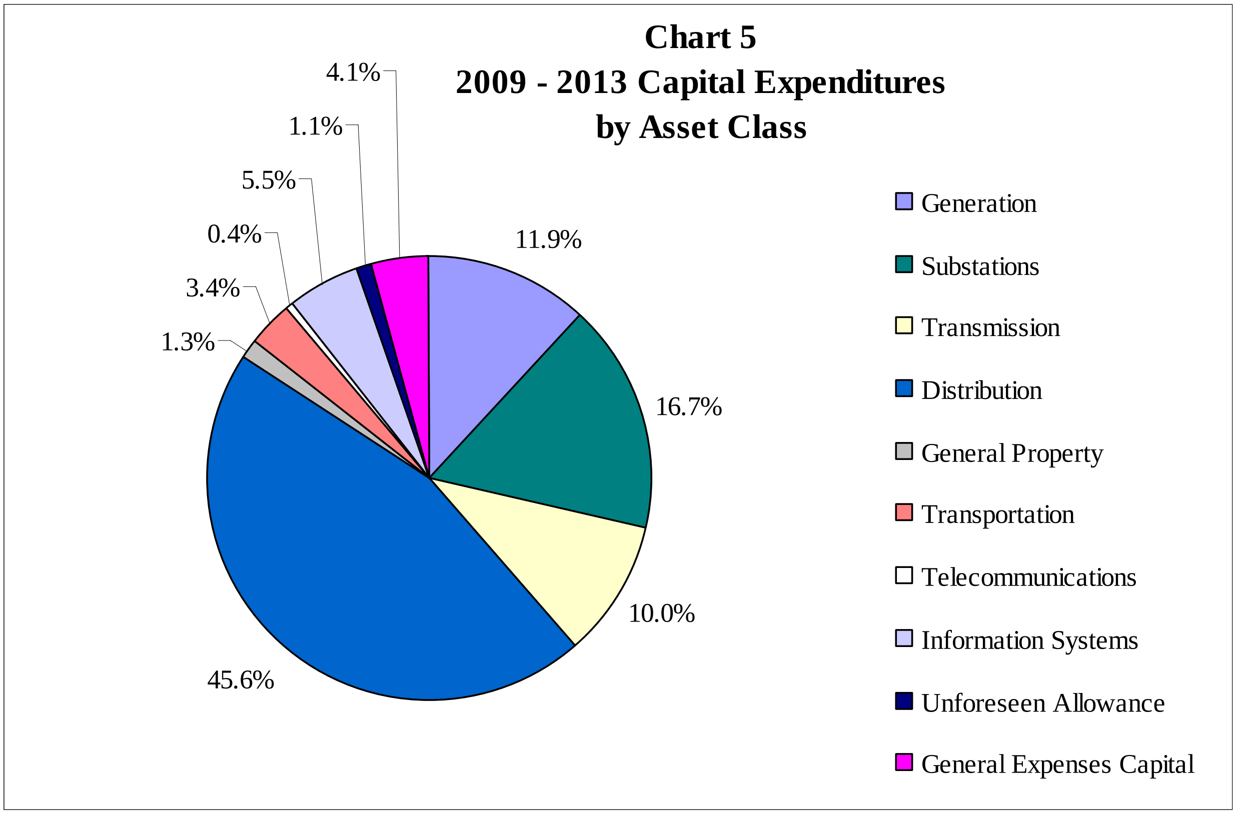


Chart 5 shows aggregate forecast capital expenditures for the period 2009 through 2013 by asset class. Distribution accounts for 46% of all planned expenditures over the next five years, followed by Substations (17%), Generation (12%) and Transmission (10%). The remaining six asset classes account for 15% of total capital expenditures for the 2009 through 2013 period.

A summary of planned capital expenditures for the period 2009 through 2013 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 substations and transmission.

3.3.2 Generation

Generation capital expenditures will average approximately $8.2 million per year from 2009 to 2013, which is comparable to the average of $7.9 million spent between 2004 through 2008.

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 continue to be required over the planning period. Over the next five years, the Company plans to continue the practice adopted in recent years of undertaking major plant refurbishment while also identifying opportunities to increase energy production and reduce losses at existing facilities. Specifically, the following major capital project initiatives are planned:

- In 2009 the refurbishment of the Rocky Pond hydroelectric plant is planned at a cost of $6.5 million as described in *1.2 Rocky Pond Plant Refurbishment*.

- In 2010, the Company plans to refurbish the Rattling Brook spillway and associated dam structures at an estimated cost of $2.6 million. The Company is working with government officials to define the project scope and to secure the appropriate approvals.

- In 2010, the Company plans to upgrade the governors, protection and control systems at the Lookout Brook hydroelectric plant at an estimated cost of $1.5 million.

- In 2011, the Company plans to purchase a 5 MW mobile generator at an estimated cost of $7.0 million. The mobile generator will be used for both emergency generation and to minimize customer outages during planned work.

- In 2012, a refurbishment of the Victoria hydroelectric plant is planned at an estimated cost of $3.0 million.

- In 2012, the Company plans to replace the Hearts Content hydroelectric plant penstock and main valve at an estimated cost of $3.6 million.

- In 2013, a refurbishment of the governors and protection and control systems at the Lockston hydroelectric plant is planned at an estimated cost of $3.0 million.

- In 2013, the runners and wicket gates on two units at the Tors Cove hydroelectric plant are planned for replacement at an estimated cost of $1.1 million.

The Company will bring forward, as part of its annual 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.

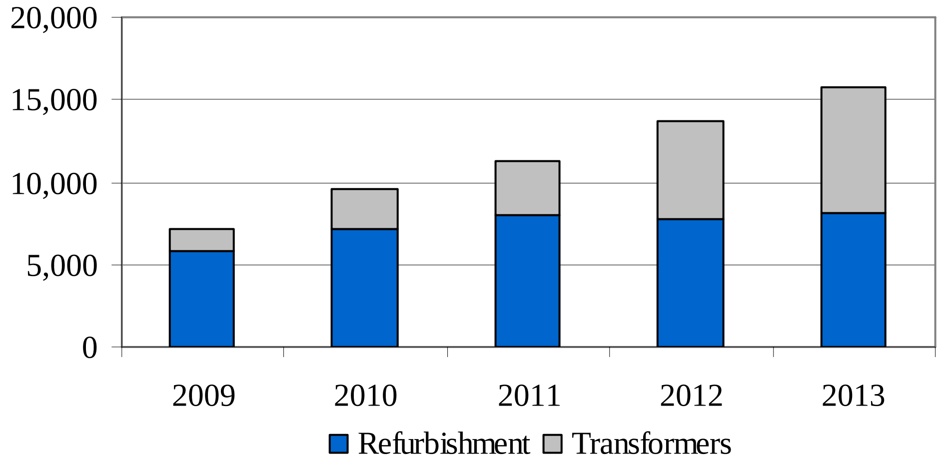
3.3.3 Substations

Substations capital expenditures are expected to average $11.5 million annually over the 2009 through 2013 period which is greater than the average of $5.4 million spent annually between 2004 and 2008. The increase in expenditures is largely attributable to the effects of inflation on utility construction materials and the requirement for additional transformer capacity at six locations across the province to serve increased customer load growth[4].

In each year of the 2009 to 2013 forecast period there is a requirement to purchase at least one large power transformer. In 2009, the power transformer at Horse Chops plant is being replaced as it is at the end of its service life. Starting in 2010 and continuing through 2013 there are requirements for additional transformers to accommodate load growth. In 2013, there is an additional portable substation planned increasing the fleet of portable substations from 3 units to 4 units. The additional portable substation is required to address concerns with the overall increasing age of the Company's in-service power transformers.

Chart 6 shows the impact of the purchase of new transformers on the substations capital plan for the 2009 to 2013 period.

Chart 6
Substations Capital Plan
2009 to 2013
($000)



The Company forecasts a number of significant projects will be required due to system load growth over the planning period. Commencing in 2010 and continuing through 2013 new substation transformers are required for the Humber Valley, Deer Lake, Grand Falls, Clarenville, Lethbridge and Mount Pearl areas. In recent years, at some of these locations, load growth has been addressed through customer load transfers with adjacent substations. Eventually, as customer load continues to grow, more transformer capacity will inevitably be required. The annual Capital Budget applications will include engineering studies detailing the requirements for additional transformers in the years in which they are required.

[4] By comparison, in the period 2004 through 2008, Newfoundland Power installed 1 additional power transformer to serve increased customer load growth. The purchase of transformers to serve customer load growth is in addition to the requirement for transformers to replace aged or deteriorated equipment.

The Company's fleet of portable substations is aging and will require refurbishment over the 5 year period. Refurbishment of portable substation P3 is included in the *2010 Substation Refurbishment and Modernization* project while Portable substation P4 is scheduled for refurbishment in 2011. The Company proposes to purchase another portable substation in 2013. This unit will increase the number of portable substations available in the event of a transformer failure and provide greater flexibility in the scheduling of major planned substation projects.

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 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 the 2007 Capital Budget Application, the Company submitted its 10-year substation strategy in a report titled *Substation Strategic Plan*. The Company intends to follow this approach to preventive capital maintenance that involves the refurbishment and modernization of substation plant and equipment. An update of the strategic plan is included in report ***2.1*** *2009 Substation Refurbishment and Modernization*.

3.3.4 Transmission

Transmission capital expenditures are expected to average $6.9 million annually over the 2009 through 2013 period. This is higher than the average $3.7 million annual expenditure over the 2004 to 2008 period due to inflation and the need to rebuild aging transmission lines.

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 to address these failures. 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 ***3.1** 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. An update of the plan is included in report ***3.1** Transmission Line Rebuild Strategy*.

3.3.5 Distribution

Distribution capital expenditures are expected to remain relatively stable at an average of approximately $31.3 million for the period 2009 to 2013 compared to an average of $29.5 million for the period 2004 to 2008.

The Company operates approximately 9,000 km of distribution lines serving over 233,000 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 5 shows the total capital expenditures associated with the connection of new customers to the system over the next five years.

Table 5
New Customer Connection Cost

	2009	**2010**	**2011**	**2012**	**2013**
New Customer Connections	3,962	3,830	3,657	3,349	3,328
Average Cost/Connection	$3,830	$4,034	$4,190	$4,409	$4,530
Capital Expenditure ($000s)	$15,175	$15,451	$15,323	$14,765	$15,077

Over the 2009 to 2013 period new customer connections are forecast to decrease by 16%. The impact of inflation over the same period increases the average cost per customer connection by 18%. The combined effect of lower new customer connections forecast and inflation is no significant change in total capital expenditures to connect new customers over the period.

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 43 distribution feeders per year over the planning period.

The Distribution *Reconstruction* project involves the replacement of deteriorated or damaged distribution structures and electrical equipment. The project is comprised of small unplanned projects and is estimated using the historical average of the most recent five-year period. The budget estimates for the 2009 to 2013 period also includes an amount to upgrade the underground distribution system along Water Street in downtown St. John's. During the 2008 construction season the City of St. John's will be excavating along Water Street from Waldegrave Street to Hutchings Street, and Harbour Drive from Water Street to Becks Cove. Newfoundland Power will apply to the Board to install civil infrastructure as part of the City's 2008 project.

The amount of Distribution capital expenditure for system load growth is expected to remain relatively constant over the next five years when compared to the previous five years. The majority of the growth continues to be located on the Northeast Avalon Peninsula.

The Company ranks its distribution feeders based on reliability performance and completes in-field assessments of those with the poorest performance statistics. Capital upgrades are performed on the worst performing feeders under a project titled, *Distribution Reliability Initiative*. The projects planned for 2009 involve two feeders in Central Newfoundland where work has been ongoing since 2006 and the addition of a new feeder in the Northwest Brook area.

3.3.6 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 provide backup diesel generation and implement demand/load control at Company buildings.

General Property capital expenditures are expected to average $0.9 million annually over the 2009 through 2013 period which is less than the $1.5 million spent over the 2004 through 2008 period.

3.3.7 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 remain relatively stable at an average of approximately $2.4 million annually over the 2009 through 2013 period compared to an average of $2.5 million spent over the 2004 through 2008 period.

3.3.8 Telecommunications

The Telecommunications asset class includes the replacement or upgrading of various communications systems. These systems contribute to customer service, safety, and 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 remain relatively stable at an average of approximately $0.3 million annually over the 2009 through 2013 period compared to an average of $0.2 million spent over the 2004 through 2008 period.

3.3.9 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 remain relatively stable at an average of approximately $3.8 million annually over the 2009 through 2013 period compared to an average of $3.6 million spent over the 2004 through 2008 period. Forecast capital expenditure in Information Systems in the 2009 and 2013 period do not include expenditure for the eventual replacement of the Company's Customer Service System.

3.3.10 Unforeseen Allowance

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 $0.8 million in each year's capital budget from 2009 through 2013.

3.3.11 General Expenses Capitalized

General Expenses Capitalized 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 Capitalized of $2.8 million is reflected in each year's capital budget from 2009 through 2013.

3.4 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 2009 through 2013.

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 power transformers in the Company's 5-year forecast. Should customer and energy growth vary from forecast the capital expenditure for one or more of these transformers (in the order of $2 million each) may no longer be required in the current 5-year forecast.

The age of the Company's power transformers presents another potential risk to the stability of the capital forecast. In-service failures of power transformers, like the recent losses of the Pierre's Brook and Salt Pond power transformers[5], will necessitate capital expenditures.

An example of a potential large project is the replacement of the Company's Customer Service System ("CSS"), which has been in service since 1991. As the replacement cost of a CSS system could be in the order of $15 million, the Company is taking steps to extend the life of CSS through 2013. The current plan is to replace CSS over a number of years beginning in 2013. However, changing technology and vendor support could conceivably dictate otherwise.

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 assess technological and business developments in metering. Such developments could result in increased capital expenditures in the future.

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5 Replacement of the Pierre's Brook power transformer was approved under Board Order P.U.3 (2008). Replacement of the Salt Pond power transformer was approved under P.U.15 (2002-2003).

Capital expenditures can be impacted by major storms or weather events. In 1984 and 1994, the Company was impacted by sleet storms that resulted in widespread damage and service interruption to customers. On December 2, 2007 a sleet storm in eastern Newfoundland caused widespread power outages on the Bonavista and Avalon Peninsula. The occurrence and costs of severe storms are not predictable.

Appendix A

2009 – 2013 Capital Plan

Newfoundland Power Inc.
2009-2013 Capital Plan
(000s)

Asset Class	**2009**	**2010**	**2011**	**2012**	**2013**
Generation	$8,999	$6,600	$10,555	$8,559	$6,062
Substations	7,172	9,526	11,249	13,697	15,809
Transmission	4,507	7,327	7,221	7,544	7,759
Distribution	30,178	31,841	31,928	30,986	31,693
General Property	835	991	1,005	877	892
Transportation	2,255	2,467	2,585	2,372	2,105
Telecommunications	350	382	418	142	144
Information Systems	3,725	3,985	3,725	3,725	3,745
Unforeseen Allowance	750	750	750	750	750
General Expenses Capitalized	2,800	2,800	2,800	2,800	2,800
Total	**$61,571**	**$66,669**	**$72,236**	**$71,452**	**$71,759**

Newfoundland Power Inc.
2009-2013 Capital Plan
(000s)

GENERATION

Project	2009	2010	2011	2012	2013
Facility Rehabilitation – Hydro	$1,035	$1,425	$1,945	$1,875	$1,812
Facility Rehabilitation - Thermal	100	100	275	150	150
Mobile Governor, Protection and Control	-	-	750	-	-
Horsechops Governor, P&C	947	-	-	-	-
Rattling Brook Plant – Dam Refurbishment	-	2,600	-	-	-
Raise Sandy Lake Elevation	-	-	575	-	-
Rocky Pond Plant Rehabilitation	6,517	-	-	-	-
Rose Blanche Production Increase	400	-	-	-	-
Seal Cove G1 Turbine	-	550	-	-	-
Petty Harbour Surge Tank & Valve	-	425	-	-	-
Lockston Plant Refurbishment	-	-	-	18	3,000
Victoria Hydro Plant Refurbishment	-	-	10	2,950	-
Purchase Portable Generation	-	-	7,000	-	-
Tors Cove Runners and Wicket Gates	-	-	-	16	1,100
Lookout Brook Governors P&C	-	1,500	-	-	-
Hearts Content Penstock	-	-	-	3,550	-
Total - Generation	**$8,999**	**$6,600**	**$10,555**	**$8,559**	**$6,062**

Newfoundland Power Inc.
2009-2013 Capital Plan
(000s)

SUBSTATIONS

Project	2009	2010	2011	2012	2013
Substations Refurbishment & Modernization	$4,102	$5,121	$6,193	$5,857	$6,229
Replacements Due to In-Service Failure	1,729	1,767	1,803	1,840	1,880
Replace Horsechops Transformer	1,341	-	-	-	-
Additions Due to Load Growth	-	2,391	3,253	6,000	2,700
Purchase portable Substation P5	-	-	-	-	5,000
Convert 23L to 66 KV	-	247	-	-	-
Total – Substations	**$7,172**	**$9,526**	**$11,249**	**$13,697**	**$15,809**

Newfoundland Power Inc.
2009-2013 Capital Plan
(000s)

TRANSMISSION

Project	2009	2010	2011	2012	2013
Rebuild Transmission Lines	$2,912	$5,693	$5,548	$5,831	$6,004
Transmission Line Reconstruction	1,595	1,634	1,673	1,713	1,755
Total – Transmission	**$4,507**	**$7,327**	**$7,221**	**$7,544**	**$7,759**

Newfoundland Power Inc.
2009-2013 Capital Plan
(000s)

DISTRIBUTION

Project	2009	2010	2011	2012	2013
Extensions	$8,786	$8,708	$8,518	$7,991	$8,141
Meters	1,127	1,168	1,233	1,323	1,446
Services	2,373	2,368	2,338	2,234	2,281
Street Lighting	2,452	2,204	2,217	1,584	1,613
Transformers	6,406	6,513	6,614	6,714	6,828
Reconstruction	3,229	4,612	4,596	4,583	4,674
Rebuild Distribution Lines	3,541	3,622	3,703	3,786	3,874
Relocations For Third Parties	622	797	818	839	861
Distribution Reliability Initiative	1,266	1,431	1,463	1,495	1,529
Feeder Modifications for Load Growth	244	282	289	296	303
Allowance for Funds Used During Construction	132	136	139	141	143
Total – Distribution	**$30,178**	**$31,841**	**$31,928**	**$30,986**	**$31,693**

Newfoundland Power Inc.
2009-2013 Capital Plan
(000s)

GENERAL PROPERTY

Project	2009	2010	2011	2012	2013
Tools and Equipment	$691	$703	$715	$726	$739
Additions to Real Property	144	146	148	151	153
Stand-By Diesel Generators – Company Buildings	-	142	142	-	-
Total – General Property	**$835**	**$991**	**$1,005**	**$877**	**$892**

Newfoundland Power Inc.
2009-2013 Capital Plan
(000s)

TRANSPORTATION

Project	2009	2010	2011	2012	2013
Purchase Vehicles and Aerial Devices	$2,255	$2,467	$2,585	$2,372	$2,105
Total – Transportation	**$2,255**	**$2,467**	**$2,585**	**$2,372**	**$2,105**

Newfoundland Power Inc.
2009-2013 Capital Plan
(000s)

TELECOMMUNICATIONS

Project	2009	2010	2011	2012	2013
Replace/Upgrade Communications Equipment	$135	$138	$140	$142	$144
Fibre Optic Cable	215	244	278	-	-
Total – Telecommunications	**$350**	**$382**	**$418**	**$142**	**$144**

Newfoundland Power Inc.
2009-2013 Capital Plan
(000s)

INFORMATION SYSTEMS

Project	2009	2010	2011	2012	2013
Application Enhancements	$1,438	$1,400	$1,450	$1,450	$1,460
System Upgrades	679	860	950	950	950
Personal Computer Infrastructure	409	400	400	400	400
Shared Server Infrastructure	700	725	750	750	750
Vehicle Mobile Computing	350	450	-	-	-
Network Infrastructure	149	150	175	175	185
Total – Information Systems	**$3,725**	**$3,985**	**$3,725**	**$3,725**	**$3,745**

Newfoundland Power Inc.
2009-2013 Capital Plan
(000s)

UNFORESEEN ALLOWANCE

Project	2009	2010	2011	2012	2013
Allowance for Unforeseen	$750	$750	$750	$750	$750
Total – Unforeseen Allowance	**$750**	**$750**	**$750**	**$750**	**$750**

Newfoundland Power Inc.
2009-2013 Capital Plan
(000s)

GENERAL EXPENSES CAPITALIZED

Project	2009	2010	2011	2012	2013
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**

2008 Capital Expenditure Status Report

June 2008

NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

2008 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 5 of Order No. P.U. 27 (2007).

Page 1 of the 2008 Capital Expenditure Status Report outlines the forecast variances from budget of the capital expenditures approved by the Board in Order Nos. P.U. 27 (2007) and P.U. 3 (2008). The detailed tables on pages 2 to 13 provide additional detail on capital expenditures in 2008, and also include information on those capital projects approved for 2007 that were not completed prior to 2008.

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 2008 Capital Expenditure Status Report.

Newfoundland Power Inc.

2008 Capital Budget Variances
(000s)

	Approved by Order Nos. P.U. 27 (2007) P.U. 3 (2008)	Forecast	Variance
Generation - Hydro	$3,385	$3,415	$ 30
Generation - Thermal	100	100	0
Substations[1]	5,762	6,822	1,060
Transmission	4,890	5,046	156
Distribution	26,636	30,111	3,475
General Property	977	1,071	94
Transportation	2,214	2,214	0
Telecommunications	224	224	0
Information Systems	3,502	3,564	62
Unforeseen Items	1,150	1,150	0
General Expenses Capitalized	2,800	2,800	0
Total	$51,640	$56,517	$4,877
Projects carried forward from 2007		$768	

[1] Budget includes $886,000 for Pierre’s Brook Power Transformer approved in P.U. 3 (2008).

2008 Capital Expenditure Status Report
(000s)

	Capital Budget			Actual Expenditures			Forecast			
	2007	2008	Total	2007	2008	Total To Date	Remainder 2008	Total 2008	Overall Total	Variance
	A	B	C	D	E	F	G	H	I	J
2008 Projects	$ -	$ 51,640	$ 51,640	$ -	$ 22,788	$ 22,788	$ 33,729	$ 56,517	$ 56,517	$ 4,877
2007 Projects	18,852	-	18,852	17,235	183	17,418	585	768	18,003	(849)
Grand Total	**$ 18,852**	**$ 51,640**	**$ 70,492**	**$ 17,235**	**$ 22,971**	**$ 40,206**	**$ 34,314**	**$ 57,285**	**$ 74,520**	**$ 4,028**

Column A	Approved Capital Budget for 2007
Column B	Approved Capital Budget for 2008
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2007
Column E	Actual Capital Expenditures for 2008
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2008
Column H	Total of Columns E and G
Column I	Total of Columns D and H
Column J	Column I less Column C

2008 Capital Expenditure Status Report
(000s)

Category: Generation - Hydro

Project	Capital Budget 2007 A	Capital Budget 2008 B	Capital Budget Total C	Actual Expenditures 2007 D	Actual Expenditures 2008 E	Actual Expenditures Total To Date F	Forecast Remainder 2008 G	Forecast Total 2008 H	Forecast Overall Total I	Variance J	Notes*
2008 Projects											
Hydro Plants - Facility Rehabilitation	$ -	$ 3,260	$ 3,260	$ -	$ 590	$ 590	$ 2,700	$ 3,290	$ 3,290	$ 30	
Engineering to Increase Plant Production	-	125	125	-	-	-	125	125	125	-	
Total - 2008 Projects	$ -	$ 3,385	$ 3,385	$ -	$ 590	$ 590	$ 2,825	$ 3,415	$ 3,415	$ 30	
2007 Projects											
Rattling Brook Hydro Plant Refurbishment	$ 18,242	$ -	$ 18,242	$ 17,204	$ 143	$ 17,347	$ 46	$ 189	$ 17,393	$ (849)	
Total - Generation Hydro	**$ 18,242**	**$ 3,385**	**$ 21,627**	**$ 17,204**	**$ 733**	**$ 17,937**	**$ 2,871**	**$ 3,604**	**$ 20,808**	**$ (819)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2007
Column B	Approved Capital Budget for 2008
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2007
Column E	Actual Capital Expenditures for 2008
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2008
Column H	Total of Columns E and G
Column I	Total of Columns D and H
Column J	Column I less Column C

2008 Capital Expenditure Status Report
(000s)

Category: Generation - Thermal

	Capital Budget		Actual Expenditures		Forecast				
Project	**2008**	**Total**	**2008**	**Total To Date**	**Remainder 2008**	**Total 2008**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2008 Projects									
Thermal Plants - Facility Rehabilitation	$ 100	$ 100	$ 1	$ 1	$ 99	$ 100	$ 100	$ -	
Total - Generation Hydro	**$ 100**	**$ 100**	**$ 1**	**$ 1**	**$ 99**	**$ 100**	**$ 100**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2008
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2008
Column D	Total of Column C
Column E	Forecast for Remainder of 2008
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2008 Capital Expenditure Status Report
(000s)

Category: Substations

Project	Capital Budget 2008	Capital Budget Total	Actual Expenditures 2008	Actual Expenditures Total To Date	Forecast Remainder 2008	Forecast Total 2008	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2008 Projects									
Substation Refurbishment and Modernization	$ 3,703	$ 3,703	$ 1,547	$ 1,547	$ 1,008	$ 2,555	$ 2,555	$ (1,148)	1
Replacement Due to In-Service Failures	1,340	1,340	433	$ 433	1,667	2,100	2,100	760	2
Convert 403L to 66KV to Reduce Losses	233	233	33	$ 33	233	266	266	33	
Replace Pierre's Brook Power Transformer	486	486	122	$ 122	364	486	486	-	
Wind Farms (Application filed with PUB)	-	-	-	$ -	1,415	1,415	1,415	1,415	3
Total - Substations	**$ 5,762**	**$ 5,762**	**$ 2,135**	**$ 2,135**	**$ 4,687**	**$ 6,822**	**$ 6,822**	**$ 1,060**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2008
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2008
Column D	Total of Column C
Column E	Forecast for Remainder of 2008
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2008 Capital Expenditure Status Report
(000s)

Category: Transmission

	Capital Budget		Actual Expenditures		Forecast				
Project	**2008**	**Total**	**2008**	**Total To Date**	**Remainder 2008**	**Total 2008**	**Overall Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2008 Projects									
Transmission Line Rebuild	$ 4,890	$ 4,890	$ 1,037	$ 1,037	$ 3,921	$ 4,958	$ 4,958	$ 68	
Wind Farms (Application filed with PUB)	-	-	-	-	88	88	88	88	
Total - Transmission	**$ 4,890**	**$ 4,890**	**$ 1,037**	**$ 1,037**	**$ 4,009**	**$ 5,046**	**$ 5,046**	**$ 156**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2008
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2008
Column D	Total of Column C
Column E	Forecast for Remainder of 2008
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2008 Capital Expenditure Status Report
(000s)

Category: Distribution

Project	Capital Budget		Actual Expenditures		Forecast				
	2008	Total	2008	Total To Date	Remainder 2008	Total 2008	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2008 Projects									
Extensions	$ 7,791	$ 7,791	$ 2,858	$ 2,858	$ 5,872	$ 8,730	$ 8,730	$ 939	4
Meters	986	986	500	$ 500	894	$ 1,394	1,394	408	5
Services	2,004	2,004	957	$ 957	1,229	$ 2,186	2,186	182	6
Street Lighting	1,361	1,361	700	$ 700	760	$ 1,460	1,460	99	
Transformers	5,811	5,811	5,793	$ 5,793	1,217	$ 7,010	7,010	1,199	7
Reconstruction	3,129	3,129	1,379	$ 1,379	1,916	$ 3,295	3,295	166	
Trunk Feeders									
Rebuild Distribution Lines	3,385	3,385	942	$ 942	2,443	$ 3,385	3,385	-	
Relocate/Replace Distribution Lines For Third Parties	606	606	559	$ 559	474	$ 1,033	1,033	427	8
Distribution Reliability Initiative	1,286	1,286	1,016	$ 1,016	270	$ 1,286	1,286		
Install Capacitors to Reduce Losses	200	200	12	$ 12	188	$ 200	200		
Interest During Construction	77	77	72	$ 72	60	$ 132	132	55	
Total - Distribution	**$ 26,636**	**$ 26,636**	**$ 14,788**	**$ 14,788**	**$ 15,323**	**$ 30,111**	**$ 30,111**	**$ 3,475**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2008
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2008
Column D	Total of Column C
Column E	Forecast for Remainder of 2008
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2008 Capital Expenditure Status Report
(000s)

Category: General Property

Project	Capital Budget 2007	Capital Budget 2008	Capital Budget Total	Actual Expenditures 2007	Actual Expenditures 2008	Actual Expenditures Total To Date	Forecast Remainder 2008	Forecast Total 2008	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2008 Projects											
Tools and Equipment	$ -	$ 690	$ 690	$ -	$ 67	$ 67	$ 623	$ 690	$ 690	$ -	
Additions to Real Property	-	122	$ 122	-	87	87	$ 129	216	216	94	
Standyby Diesel Generators	-	165	$ 165	-	7	7	$ 158	165	165	-	
Total 2006 General Property	-	977	977	-	161	161	910	1,071	1,071	94	
2007 Projects											
Energy Efficient HVAC System	610	-	$ 610	$ 31	40	71	539	579	610	-	
Total - General Property	**$ 610**	**$ 977**	**$ 1,587**	**$ 31**	**$ 201**	**$ 232**	**$ 1,449**	**$ 1,650**	**$ 1,681**	**$ 94**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2007
Column B	Approved Capital Budget for 2008
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2007
Column E	Actual Capital Expenditures for 2008
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2008
Column H	Total of Columns E and G
Column I	Total of Columns D and H
Column J	Column I less Column C

2008 Capital Expenditure Status Report
(000s)

Category: Transportation

	Capital Budget		Actual Expenditures		Forecast				
Project	2008	Total	2008	Total To Date	Remainder 2008	Total 2008	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2008 Projects									
Purchase Vehicles and Aerial Devices	$ 2,214	$ 2,214	$ 1,247	$ 1,247	$ 967	$ 2,214	$ 2,214	$ -	
Total - Transportation	**$ 2,214**	**$ 2,214**	**$ 1,247**	**$ 1,247**	**$ 967**	**$ 2,214**	**$ 2,214**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2008
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2008
Column D	Total of Column C
Column E	Forecast for Remainder of 2008
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2008 Capital Expenditure Status Report
(000s)

Category: Telecommunications

Project	Capital Budget		Actual Expenditures		Forecast				
	2008	Total	2008	Total To Date	Remainder 2008	Total 2008	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2008 Projects									
Replace/Upgrade Communications Equipment	$ 104	$ 104	$ 25	$ 25	$ 79	$ 104	$ 104	$ -	
Fibre Optic Circuit Replacement	120	$ 120	3	$ 3	$ 117	$ 120	$ 120	$ -	
Total - Telecommunications	**$ 224**	**$ 224**	**$ 28**	**$ 28**	**$ 196**	**$ 224**	**$ 224**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2008
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2008
Column D	Total of Column C
Column E	Forecast for Remainder of 2008
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2008 Capital Expenditure Status Report
(000s)

Category: Information Systems

	Capital Budget		Actual Expenditures		Forecast				
Project	**2008**	**Total**	**2008**	**Total To Date**	**Remainder 2008**	**Total 2008**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2008 Projects									
Application Enhancements	$ 1,389	$ 1,389	$ 637	$ 637	$ 756	$ 1,393	$ 1,393	$ 4	
System Upgrades	487	487	136	136	409	545	545	58	
Personal Computer Infrastructure	408	408	166	166	242	408	408	-	
Shared Server Infrastructure	889	889	257	257	632	889	889	-	
Network Infrastructure	119	119	116	116	3	119	119	-	
Microsoft Enterprise Agreement	210	210	-	-	210	210	210	-	
Total - Information Systems	**$ 3,502**	**$ 3,502**	**$ 1,312**	**$ 1,312**	**$ 2,252**	**$ 3,564**	**$ 3,564**	**$ 62**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2008
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2008
Column D	Total of Column C
Column E	Forecast for Remainder of 2008
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2008 Capital Expenditure Status Report
(000s)

Category: Unforeseen Items

Project	Capital Budget 2008	Capital Budget Total	2008	Total To Date	Forecast Remainder 2008	Forecast Total 2008	Forecast Overall Total	Variance	Notes*
	B	C	E	F	G	H	I	J	
2008 Projects									
Allowance for Unforeseen Items	$ 750	$ 750	$ -	$ -	$ 750	$ 750	$ 750	$ -	
Allowance for Unforeseen Items P.U.3 (2008)	$ 400	$ 400	$ 400	$ 400	$ -	$ 400	$ 400	$ -	
Total - Unforeseen Items	**$ 1,150**	**$ 1,150**	**$ 400**	**$ 400**	**$ 750**	**$ 1,150**	**$ 1,150**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2007
Column B	Approved Capital Budget for 2008
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2007
Column E	Actual Capital Expenditures for 2008
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2008
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2008 Capital Expenditure Status Report
(000s)

Category: General Expenses Capitalized

	Capital Budget		Actual Expenditures		Forecast				
Project	**2008**	**Total**	**2008**	**Total To Date**	**Remainder 2008**	**Total 2008**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2007 Projects									
Allowance for General Expenses Capitalized	$ 2,800	$ 2,800	$ 1,089	$ 1,089	$ 1,711	$ 2,800	$ 2,800	$ -	
Total - General Expenses Capitalized	**$ 2,800**	**$ 2,800**	**$ 1,089**	**$ 1,089**	**$ 1,711**	**$ 2,800**	**$ 2,800**	**$ -**	

* See Appendix A for notes containing variance explanations.

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Column A	Approved Capital Budget for 2008
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2008
Column D	Total of Column C
Column E	Forecast for Remainder of 2008
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

Substations

1. *Substation Refurbishment and Modernization:*
Budget: $3,703,000 Forecast: $2,555,000 Variance: ($1,148,000)

Expenditure associated with Substation Refurbishment and Modernization is expected to be less than originally budgeted due to increased workload in the Replacement Due to In-Service Failures project (item 2 below) and the need to redirect resources to deal with the failure of the Power Transformer at Pierre's Brook.

2. *Replacement Due to In-Service Failures:*
Budget: $1,340,000 Forecast: $2,100,000 Variance: $760,000

Expenditure associated with Replacement Due to In-Service Failures covers the cost of purchasing, refurbishing and installing equipment to replace substation equipment that has either failed or is in imminent danger of failing. Costs can vary significantly depending on the number of failures and the type of equipment that fails.

The purchase cost of Replacement Equipment was budgeted at $615,000 based on historical averages. The current estimate is $850,000. The increase is driven principally by the need to purchase two 138 kV breakers at a cost of $150,000. Unit cost increases driven largely by steel and fuel prices account for the remainder of the increase.

The direct cost associated with emergency In-Service Failures was budgeted at $800,000 based on historical averages. The cost of emergency work completed or in progress at the end of the 1st quarter 2008 was $507,000. Based on these higher than expected expenditures in the 1st quarter of the year it is now estimated that the annual expenditure will be $1,200,000, an increase of $400,000.

The cost of refurbishing equipment was budgeted at $325,000 based on historical averages. However due to the higher than expected equipment failure rate in the first quarter the cost for 2008 is now expected to be $450,000.

3. *Wind Farms*[1]*:*
Budget: $0 Forecast: $1,415,000 Variance: $1,415,000

On May 14, 2008 Newfoundland Power filed an Application with the Board of Commissioners of Public Utilities for capital costs associated with the interconnection of two wind farms to the Island Interconnected system, the first near St. Lawrence on the Burin Peninsula and the second near Fermeuse on the Avalon Peninsula.

[1] Forecast is for the Substation portion of the Wind Farms Application.

Distribution

4. *Extensions :*
Budget: $7,791,000 Forecast: $8,730,000 Variance: $939,000

The original 2008 Capital budget estimate for extensions was based on 3,453 new customer connections. Revised data from the Canada Mortgage and Housing Corporation and the Conference Board of Canada now places the estimate for new customer connections at 3,827. The additional $939,000 is forecast to be principally required to build the infrastructure required to connect the additional customers.

5. *Meters :*
Budget: $986,000 Forecast: $1,394,000 Variance: $408,000

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 2008, Newfoundland Power is required to replace an additional 10,000 meters due to the failure of two groups of meters that were purchased and installed in 1970 and 1990. 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.

6. *Services :*
Budget: $2,004,000 Forecast: $2,186,000 Variance: $182,000

The original 2008 Capital budget estimate for services was based on 3,453 new customer connections at the five year historical cost of $464 per customer. Revised data from the Canada Mortgage and Housing Corporation and the Conference Board of Canada now places the estimate for new customer connections at 3,827. The additional $182,000 is required to provide service to the additional 374 customers.

7. *Transformers :*
Budget: $5,811,000 Forecast: $7,010,000 Variance: $1,199,000

The increase in expenditure associated with purchasing distribution transformers is principally due to an increase in unit cost. Based on the price escalation clause in the transformer purchase agreement the average unit cost for 2008 will increase by 23% over 2007. The price increase is driven largely by increasing steel and fuel prices.

8. *Relocate/Replace Distribution Lines for Third Parties :*
Budget: $606,000 Forecast: $1,033,000 Variance: $427,000

The capital expenditure associated with Relocate/Replace Distribution Lines for Third Parties is required to either upgrade distribution lines to accommodate the placement of additional telecommunications attachments or to relocate lines at the request of a customer. A Contribution in Aid of Construction is a consideration in all cases.

The increase in expenditure in 2008 is driven by continued higher than normal activity associated with upgrades to their systems by the various telecommunications companies. The total cost is now estimated to be $1,033,000. Contributions in Aid of Construction will recover approximately $682,000 or 66% of the total capital cost of this project.

2009 Facility Rehabilitation

June 2008

Prepared by:

Gary K. Humby, P.Eng.

NEWFOUNDLAND POWER
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1.0 Introduction

The 2009 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 plants that provide energy to the Island Interconnected System. Maintaining these generating facilities reduces the need for additional, more expensive, generation.

Items 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 425.8 GWh[1]. The alternative to maintaining these facilities would be to retire them.

The 2009 Facility Rehabilitation project totalling $1,917,000 is comprised of Horsechops Protection, Control and Governor Refurbishment; Hydro Dam Rehabilitation; Generation Equipment Replacements Due to In-Service Failures; Upgrade Plant Revenue Metering; and, Engineering for Seal Cove Runner Replacement.

2.0 Horsechops Protection, Control and Governor Refurbishment

Cost: $947,000

The Horsechops generating plant was commissioned in 1954 and has a nameplate rating of 8.3 MW. The normal annual production from the plant is 43.0 GWhr or approximately 10.1% of Newfoundland Power's annual hydroelectric production.

The plant contains a vertical 10,000 hp Francis turbine manufactured by Dominion Engineering and a Canadian General Electric generator. The unit is automated and controlled remotely through the SCADA system. The plant is connected to the Island Interconnected System at Mobile substation via Newfoundland Power's transmission line 20L.

Major work completed at this facility in recent years includes the installation of a steel surge tank, steel penstock and intake structure and new main inlet valve. The existing protection and control schemes, including the governor, generator protection, voltage regulation and plant control system are obsolete and are in need of modernization.

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[1] Normal annual production was established as 419.6 GWh in the Water Management Study – Hydrology Update prepared by SGE Acres dated August 1, 2005. Normal production was increased by 6.2 GWh as a result of the capacity increase at Rattling Brook to make the revised base normal hydroelectric production to be 425.8 GWh.

2.1 Governor Control System ($127,000)

The existing Woodward Model HR gate shaft governor shown in Figure 1 is the original equipment installed in 1954.[2] The governor is obsolete and the manufacturer no longer supplies replacement parts or offers maintenance support.

This item involves the removal of the hydraulic control portion of the governor and installation of a digital control system to provide enhanced performance and control. The existing power piston is in good condition and will not be replaced. The new governor control makes possible the implementation of a water management algorithm in the plant control system to optimize energy production from the available water in the development.

Figure 1

2.2 Generator Protection ($87,000)

The existing protection system at Horsechops lacks five elements[3] of the minimum protection set.[4] In addition to not meeting the minimum recommended protection level, the existing electromechanical relays have experienced trouble related to age and environmental conditions. The generator ground fault protection requires upgrading. Currently, the generator neutral is solidly bonded to ground exposing the generator winding to high fault current levels. Modern protection designs involve high impedance grounding to minimize the exposure of the generator windings to large fault currents. Continuous conditional monitoring of stator insulation is required to ensure the unit is not remotely started when the windings have high moisture levels.

This item involves the installation of a new protection panel containing digital protection relays and new current transformers. A neutral grounding transformer with secondary resistor will be installed to improve ground fault protection. A neutral contactor will be installed to allow the installation of continuous online monitoring of the stator insulation.

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[2] US Army Core of Engineers indicate typical service life of governor control system to be 15 to 40 years. The Horsechops governor control system is 54 years old.

[3] The existing generator protection does not include residual ground fault 59GN, sensitive ground fault 87GN, rotor ground fault 64F, overvoltage 59 and over/under frequency 81 elements which are recommended for this generator.

[4] Protective relaying systems provide protection to equipment and personnel during abnormal loading or fault conditions. The selection of protection elements for a particular generator will depend upon the equipment design and system configuration.

2.3 Switchgear ($163,000)

The switchgear has been upgraded in recent years with the installation of a new breaker. However, the meters, instruments, wiring and other electrical components are original. The original equipment lacks the accuracy required for metering of the plant, and is vulnerable to insulation breakdown as it continues to age.

Figure 2

Figure 3

Figure 4

This item involves the replacement of the original potential and current transformers (Figure 2 and 3) with more reliable, accurate units. The control switches, meters and associated wiring will also be replaced with new equipment in the generating unit control panel. The power cables (Figure 4) leading from the generator to the switchgear and from the switchgear to the substation will be replaced with 1,000 MCM XLPE cables with slip on terminations.

As a result of fault levels and clearing times at Horsechops there is a high arc flash hazard associated with this switchgear, requiring an arc flash boundary of 5.70 metres. To provide protection from this hazard walls will be constructed to separate the switchgear from the control room and the generator floor.

2.4 Plant Control System ($442,000)

The Horsechops generator is controlled through various electromagnetic relays and switches from the original plant installation. This type of control does not allow for modernization of the plant, including the monitoring of automated water management[5] routines remotely through the SCADA system. The water management system will optimize the efficiency of the plant by controlling unit loading based upon water level, inflow and wicket gate position. Monitoring of the system through SCADA will allow the operator to select water management mode for

[5] Water management is an intelligent system of online monitoring of water levels and subsequent operation of the plant in response to changing water levels.

efficient operation and peak mode when requested to provide maximum generation by Newfoundland Hydro.

The original Brown Boveri AB2/1 voltage regulator unit contains a mechanical operating mechanism that has been manufacturer discontinued. The voltage regulator has corrosion damage making its operation unreliable.

This item involves the installation of a modern programmable logic controller ("PLC") to provide full local and remote plant control. The PLC will interface with existing instrumentation and plant heating/cooling systems to provide an integrated control platform for the plant. As well, resulting control functionality will make possible the implementation of a variety of control modes, including water management and the capability to remotely black start the plant. A gateway data concentrator will provide communications to the SCADA system and access to data from the digital relays and PLC.

2.5 AC and DC Systems ($128,000)

The existing 48-circuit AC distribution panel is 120/240 volt rated and is located in the switchgear. It does not have spare circuits available, and replacement breakers are not available due to the age of the equipment. It will be replaced with a standard 120/208V 60 circuit essential services panel and a 120/208V 60 circuit non-essential services panel located on the switchgear room wall.

Both the normal and emergency services transformers will be replaced. Both transformers are original to the 1954 plant construction. The replacement units will provide a standard voltage rating AC service for the plant to provide improved reliability and ease of replacement in the future.

The 20 circuit DC distribution panel was installed in 1985 and has 11 spare circuits available. The Varta 156 Amp-hour lead acid battery bank was installed in 1992 and the Staticon battery charger was installed in 1986. Typically battery chargers have a 15 year life expectancy while battery banks have a 20 year life expectancy. The DC panel will remain in service and the Staticon battery charger will be replaced. The battery bank will be replaced with gel cell technology to eliminate the requirement for a separate battery room to be constructed.

3.0 Hydro Dam Rehabilitation

Cost: $435,000

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.

This item involves the refurbishment of deteriorated components at various dam structures. The work to be completed includes upstream slope improvements at embankment dams and outlet structure concrete repairs.

Specific work to be completed in 2009 includes:

1. Hearts Content Plant: Packs Pond Riprap ($100,000)
   This item involves improvements to the upstream riprap zone. Recent inspections have shown that the upstream riprap is sparse and does not provide adequate protection for the adjacent and internal embankment zones of the dam.

2. Rocky Pond Plant: Long Pond Dam ($75,000)
   This item involves improvements to the upstream and downstream riprap zone, and erosion protection of the abutment. Recent inspections have indicated that the upstream and downstream slopes of Long Pond Dam require rehabilitation of the protective riprap zone as it is undersized and requires re-grading. In addition, additional erosion protection will be installed at the abutments to protect the dam against further erosion.

3. Seal Cove Plant: Forebay Spillway ($100,000)
   This item involves rehabilitation of the north section of the concrete overflow spillway and the placement of erosion protection along the downstream toe. The concrete on the north section is deteriorating. In particular, excessive cracking, weathered concrete, and exposed rebar and aggregate are evident throughout. In addition, anti-scour and erosion protection will be placed along the downstream toe to prevent undercutting erosion.

4. Rattling Brook Plant: Trashrack Replacement ($60,000)
   This item involves replacement of the trashrack at the intake for the Rattling Brook development. The trashrack is original to the 1958 construction and a recent inspection of the trashrack indicates that it is in poor condition. It is recommended that the trashrack be replaced.

5. Horsechops Plant: Forebay Spillway Rehabilitation ($100,000)
   This item involves the rehabilitation of the forebay spillway at the Horsechops development. Recent inspections indicate that the existing stop log lifting mechanism at this structure is not operable. This lifting mechanism will be replaced and the spillway will be rehabilitated to enhance dam safety performance of the structure under flood conditions.

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.

4.0 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 2004.

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

Year	**2004**	**2005**	**2006**	**2007**	**2008F**
Total	$385	$570[1]	$591[1]	$409	$425

[1] Excludes Rocky Pond rebuild.

Based upon this recent historical information and engineering judgement, $425,000 is estimated to be required in 2009 for replacement of 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.

5.0 Upgrade Plant Metering

Cost: $100,000

Digital meters were initially installed in Newfoundland Power substations and hydroelectric plants to provide data for internal metering purposes including SCADA. With the introduction of the demand energy wholesale rate for electricity the digital meters in the power plants require monthly interrogation by Newfoundland and Labrador Hydro for revenue metering purposes. A number of problems have been experienced with the reliability and integrity of data obtained from the existing meters. The majority of the problems have resulted from errors in the meter's time keeping-function. The meter's internal clocks are inaccurate and drift several seconds per day, making it difficult to synchronize energy readings across all plants.

The combination of data errors and poor time synchronization has caused delays for Newfoundland and Labrador Hydro in compiling the monthly energy bill. In addition, any time data has to be edited, the integrity of that data is questionable.

Newfoundland Power plans to replace 25 of the existing digital meters in 2009 with revenue grade, SCADA capable meters that will provide reliable, accurate metering data to meet the requirements of Newfoundland and Labrador Hydro.

6.0 Engineering for Seal Cove Runner Replacement

Cost: $10,000

Newfoundland Power's Seal Cove hydroelectric generating plant is located approximately 20 kilometres from the City of St. John's along the Conception Bay Highway. The plant was commissioned in 1924 and has a capacity of 3.5 MW. The normal annual production at Seal Cove is approximately 8.5 GWhr or 2.0% of the total hydroelectric production of Newfoundland Power.

The plant has two turbine units: G1 of 1924 vintage with a nameplate capacity of 1.1 MW, and G2 of 1926 vintage with a nameplate capacity of 2.4 MW.

Newfoundland Power has conducted various inspections of the major components of the G1 turbine. These inspections revealed severe deterioration of the turbine runner. The deterioration involves severe cavitation of the runner, as well as corrosion of the wicket gates such that the gates do not operate efficiently through their full range of motion. The extent of damage to the runner blades and wicket gates shown in Figures 5 and 6 is such that the runner is no longer able to operate efficiently and increases the risk of an in-service failure.

Figure 5

Figure 6

Newfoundland Power currently plans to bring forward a capital budget project proposal for the replacement of G1 runner at Seal Cove plant in the 2010 Capital Budget Application. This capital project proposal will require detailed engineering design work to finalize the necessary budget estimates and schedules. Also the detailed design work will allow Newfoundland Power to prepare engineering specifications and tender documents in advance to ensure the project can be completed during the 2010 construction season.

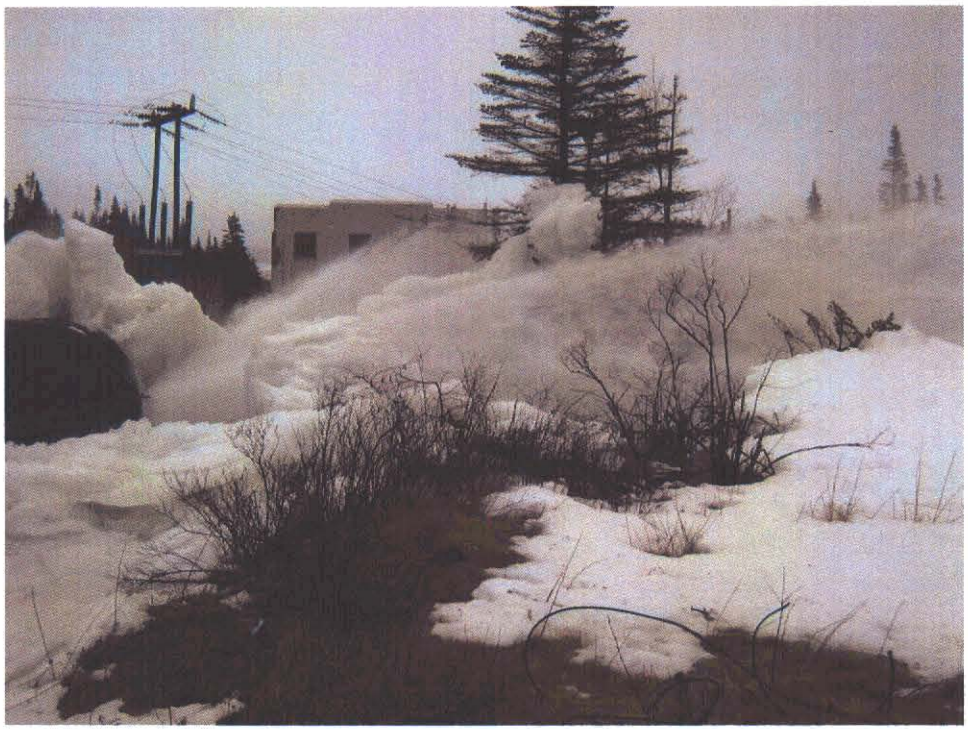
7.0 Recommendations

This project, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable plant operations. A 2009 budget of $1,917,000 for Facility Rehabilitation is recommended as follows:

- $947,000 for Horsechops Protection, Control and Governor Refurbishment;
- $435,000 for Hydro Dam Rehabilitation;
- $425,000 for Generation Equipment Replacements Due to In-Service Failures;
- $100,000 for Upgrade Plant Metering; and
- $10,000 for Engineering for Seal Cove Runner Replacement.

Rocky Pond Hydro Plant Refurbishment

June 2008



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PROVINCE OF NEWFOUNDLAND

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1.0 Introduction

Newfoundland Power's Rocky Pond/Tors Cove development is composed of two generating plants, Rocky Pond and Tors Cove, located on the southern shore of the Avalon Peninsula, approximately 40 km south of the City of St. John's.

Rocky Pond hydroelectric generating plant is located upstream of Tors Cove Pond. The plant was placed into service in 1942 and has a capacity of 3.25 MW under a net head of 32.6 m. The normal annual production at Rocky Pond is approximately 14.1 GWhr or 3.3 % of the total hydroelectric production of Newfoundland Power. The development has provided 66 years of reliable energy production to the Island Interconnected System.

Newfoundland Power has determined that the woodstave penstock has reached the end of its useful life and requires replacement (See Appendix A for pictures of the penstock). In addition, the following work needs to be completed:

- Refurbish intake;
- Replace main valve;
- Rewind generator;
- Implement governor upgrades; and
- Rebuild forebay distribution and communication line.

This project is necessary at this time due to the age and physical condition of the plant assets. The woodstave penstock is 66 years old, is in poor condition and continues to deteriorate. It must be replaced in 2009. The intake gate and gate guides are original to the plant and require replacement.

Replacement of the main valve; governor controls; rebuilding the forebay distribution line and communication cable will improve operation of the plant and provide low cost energy to the Island Interconnected System.

Results of the feasibility analysis conclude that the continued operation of Rocky Pond plant, including the planned replacement and refurbishment project, is economically viable over the long term. This project will allow Newfoundland Power to continue to operate this facility into the future, maximizing the benefits of this renewable resource for its customers.

2.0 Background

Newfoundland Power completed an assessment on the Rocky Pond Development to determine the project scope and verify the budget for the work to be completed. An engineering assessment was completed on the penstock by Hatch[1] in November 2006. This assessment report is included in Appendix B. Appendix C includes the project schedule. Appendix D includes a feasibility analysis of the costs and benefits associated with the project.

[1] Hatch, formerly SGE Acres, is a leading provider of process and business consulting, engineering project and construction management to the energy, mining, metallurgical, manufacturing and infrastructure industries.

Figure 1 below is a map outlining the Rocky Pond/Tors Cove hydroelectric system. Water from upstream reservoirs entering Rocky Pond forebay is stored, spilled, or used for generation at Rocky Pond hydroelectric plant.

Power flow and spill from Rocky Pond forebay enters Tors Cove Pond forebay and is stored, spilled out of the system, or used for generation at Tors Cove hydroelectric plant.

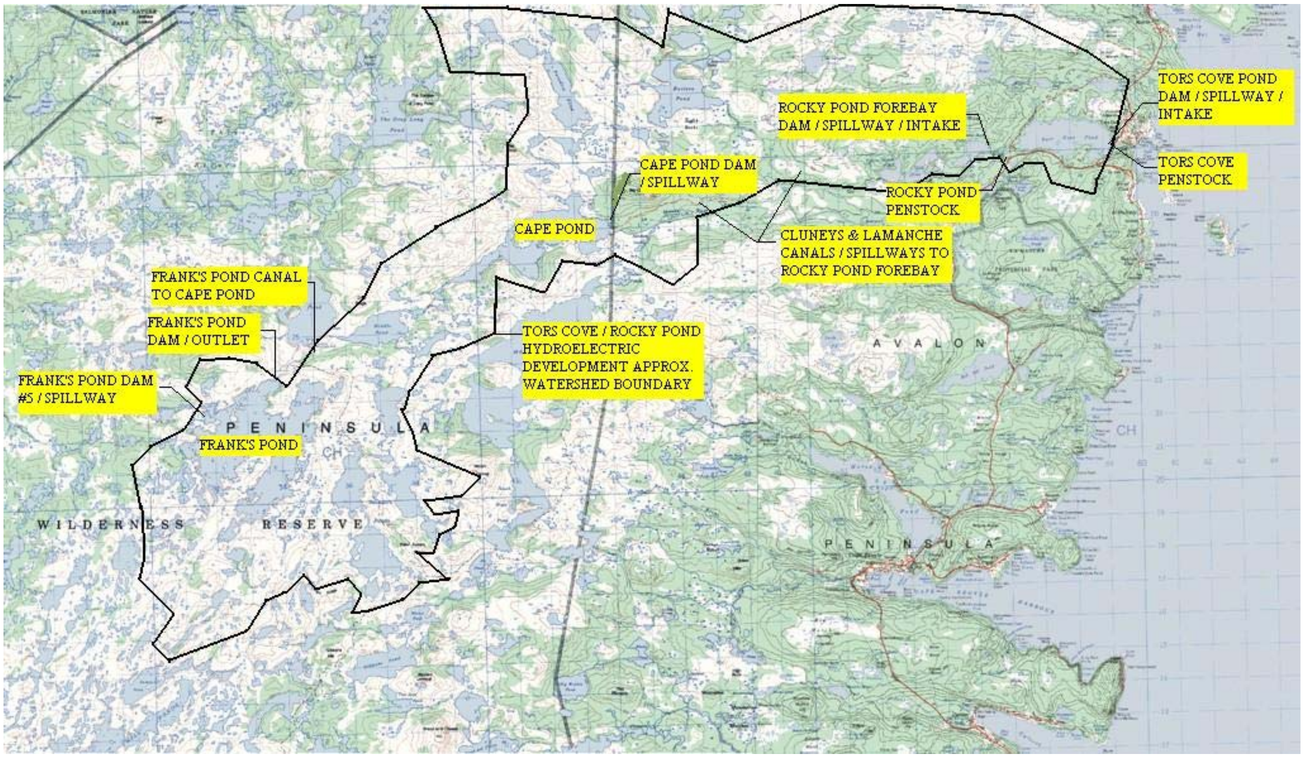


Figure 1

On July 15th, 2005, an electrical fault occurred in the switchgear at Rocky Pond plant resulting in a fire. Rocky Pond plant was shutdown for approximately 8 months to complete the necessary repairs related to the damage caused by the fire.[2]

During the plant shutdown period the following equipment was replaced:

- Switchgear;
- Protection and unit control panels;
- Battery bank and battery charger;
- Communication equipment; and
- All AC/DC circuits.

In addition, the wicket gate bushings were replaced on the turbine and a building extension was constructed to accommodate space requirements for the new equipment.

[2] The majority of this work was funded by insurance. Refer to Order Nos. P.U. 33 (2005) and P.U. 34 (2005).

Other upgrades since the plant was commissioned in 1942 include:
- New crane hoist installed - 1995;
- Runner and wicket gates replaced - 1996;
- New louver system installed - 2003; and
- Plant roof and overhead door replaced - 2006.

No work is required on the above plant equipment at this time as a result of these past upgrades.

An engineering assessment was completed on the penstock in November 2006. Engineering assessments were completed for the remaining systems in 2007 and early 2008. All major components of the Rocky Pond system have been reviewed. Based on the engineering assessment, the project scope and budget have been finalized and presented in this report.

3.0 Civil Works

Engineering assessments have identified the following civil work to be completed:
- Replace the woodstave penstock; and
- Replace the intake gate and gate guides.

The penstock, intake gate and guides are original to plant construction in 1942.

3.1 Penstock

The woodstave penstock is 66 years old and is in poor condition with deterioration along its entire length. The penstock bedding is saturated due to significant leakage from the penstock. There is also a bog located along the upper half of the penstock that appears to be contributing to the saturation of the bedding. Saturation of the penstock bedding has resulted in settlement of the support cradles into the soil bed. In addition several of the support cradles have been undermined by the heavy water flows along the length of the penstock.

The steel bands are heavily corroded in areas of extensive leakage. The woodstaves are also rotting in several areas. This is largely attributable to the settlement of support cradles in the penstock bedding, poor drainage, and lack of ventilation in these areas. In recent years attempts have been made to divert the water flow to improve drainage and ventilation along the penstock. However, the water flow remains excessive and continues to be a contributing factor to the ongoing deterioration of the penstock.

On March 8, 2008, a substantial leak developed in the penstock upstream of the power plant. Water flow from the leak prohibited the repair of the damage with the plant in operation. Therefore, the plant was taken out of service, the penstock dewatered and the leak repaired. A picture of this leak is included as Figure 2, while other pictures of the leak are included in Appendix A.

Figure 2

With the deteriorated condition of the woodstaves, heavily corroded bands, crushed woodstaves, and deteriorated supports there is a concern that the need to de-water the penstock to address major leaks will increase. Recent experience indicates that the Rocky Pond penstock is increasingly unable to withstand de-watering without significant leakage upon re-watering. As a result, every effort is made to avoid de-watering the penstock. Consequently, leaks that cannot be plugged without de-watering may remain unrepaired, as long as the escaping water does not imperil safety or the plant infrastructure itself. Furthermore, the condition of the penstock is such that de-watering during the winter months, if necessary, could make it impossible to return the penstock to service due to the extent of the leakage upon re-watering and the resultant ice build-up. The inability to routinely de-water the penstock for operational reasons constitutes a serious operating limitation on the plant due to the engineering interdependence of the penstock and power plant equipment.

The woodstave penstock has reached the end of its useful life and requires replacement.

The existing penstock does not have an access road adjacent to it. To facilitate the removal and installation of the new penstock an access road will be constructed along the existing penstock.

The construction material options that are being considered for the replacement include steel and fibreglass. It is planned to tender both the steel and the fibreglass options to ensure competitive bidding and proceed with the least cost option that meets all technical and engineering requirements.

3.2 Forebay Intake Structure

The intake gate and gate guides are original to the 1942 construction and are in poor condition. Excessive flows currently bypass the gate when the plant is shutdown and the penstock is dewatered. This prohibits safe access to the intake when the penstock is dewatered to perform regular inspection and maintenance on the intake. It is recommended that the intake gate and gate guides be replaced.

3.3 Civil Infrastructure

Assessments were completed of the civil infrastructure at Rocky Pond/Tors Cove in 2007 as part of Newfoundland Power's Dam Safety program. The assessment included an inspection of all the dams, dykes, spillways and other outlet structures for both developments. Overall the civil infrastructure for the Rocky Pond development is in good condition. However, riprap improvements are required for Rocky Pond Long Pond dam. Refer to the *"Facilities Rehabilitation"* report of Newfoundland Power's 2009 Capital Budget Application for a description of this project.

4.0 Mechanical Works

The majority of the mechanical equipment has been upgraded and/or replaced in recent years with the exception of the main inlet valve and the governor.

4.1 Main Inlet Valve

The main inlet valve at Rocky Pond is a 2,134 mm (84 in) butterfly valve manufactured by Dominion Engineering Works Ltd. (Montreal, Canada) in 1942. The valve is electrically actuated. An internal inspection of the valve performed during a recent plant shutdown revealed that the valve was not sealing properly in the closed position creating a constant flow of high pressure water into the turbine. This leakage prevents safe access to the scroll case without having to dewater the penstock each time work is required on the turbine. The current limitations imposed on the operation of the plant as a result of the need to avoid de-watering the penstock, together with the leaking of the main valves, limit the Company's ability to maintain and service other equipment in the plant.

Typically, the main valve is accompanied by a bypass valve and drain valve. However, the main valve arrangement at Rocky Pond is accompanied by a drain valve only. The drain valve is a manual valve that is used to drain the penstock for maintenance. The function of a bypass valve is to direct 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 lack of a bypass valve puts additional strain on the current main valve arrangement during opening and appears to be a contributing factor to the excessive leakage around the valve seal.

The control panel for the main valve has been modified since its initial installation; however, the controls for the unit are obsolete. This control panel will be replaced.

Based on the age and condition, the main valve, drain valve and associated equipment will be replaced. In addition, a bypass valve will be incorporated into the redesign of the main valve arrangement.

4.2 Governor

The governor is a Woodward Model HR and is original to the plant construction in 1942 (See Figure 3). An assessment of the governor was completed in 2007. Overall the hydraulic power portion of the governor is in good condition but does require a minor mechanical overhaul. The original equipment manufacturer has declared this model of governor to be obsolete and no longer manufactures replacement parts. A number of third party companies provide maintenance support, including parts, but these companies and the utility industry is moving towards replacing the hydraulic control portion of these governors with digital systems that provide enhanced control and feedback capabilities.

Figure 3

An assessment of the governor was completed in 2007. Overall the hydraulic power portion of the governor is in good condition but does require a minor mechanical overhaul. The original equipment manufacturer has declared this governor to be obsolete and no longer manufactures replacement parts. A number of third party companies provide maintenance support, including parts, but these companies and the utility industry is moving towards replacing the hydraulic control portion of these governors with digital systems that provide enhanced control and feedback capabilities.

In 2006 a water management system was implemented into the PLC to optimize loading of the unit. In order to avail of better unit control and operation with the PLC based control system, the governors will be upgraded with a new electronic head similar to the installation at Rattling Brook in 2007.

The hydraulic power portion of the governor is in good condition and will be retained. The hydraulic control portion of the governor, above the relay valve, will be removed and a PLC based digital control system installed. The Woodward Combination Speed Switch will no longer be required to supply speed feedback to the governor so it will be removed, except for the tooth gear, on which new speed sensors will be installed.

The new governor control will provide more precise speed control.

5.0 Electrical Works

5.1 Generator Rewind

Following a fire at Rocky Pond plant in 2005, the majority of the plant's electrical equipment was replaced with the exception of the generator and governor.

The generator at Rocky Pond plant was manufactured by Westinghouse in 1941 and operates at 6.9 kV (See Figure 4). Both the stator and rotor windings are 66 years old and are the oldest windings in service in any of Newfoundland Power's generating plants. Newfoundland Power currently has fifteen generators that operate at 6.9 kV. The average age of these fifteen generators is 35 years. Six of the fifteen generators that operate at 6.9 kV have been rewound. The average winding life of the six units at the time of winding was 46 years.

Figure 4

The generator was dismantled, cleaned and painted by Siemens as part of the rehabilitation of Rocky Pond plant in 2005 and 2006. During this time the rotor and stator windings were inspected by Siemens and appeared to be in fair condition. A more recent inspection of the rotor and stator windings revealed the stator windings are extremely brittle, greatly increasing the probability of an in-service failure. Based upon age and condition and to avoid the possibility of an in-service failure, it is recommended that the generator stator be rewound and the rotor reinsulated as part of this project.

5.2 Forebay Distribution Line

The 12.5 kV forebay distribution line was built in 1942 to provide electricity for the forebay and to provide communications between the plant and forebay. The communications cable is used to monitor and control water levels for operation of the plant. The existing communication cables are made of twisted pair copper conductors and are used to provide water level indication, gate control, and gate position from the forebay intake structure back to the plant. The water level indications are used to manage the operation of the plant and to manage the water storage levels. Therefore the line is an integral part of the infrastructure required to maintain the plant operations.

Figure 5

Inspection of the forebay line indicates that several of the wooden poles have exposed wood rot (See Figure 5). As well, the insulators are old and many are the porcelain type which are prone to failure and have been replaced throughout the system.

To continue efficient operation of the plant, the forebay line will be rebuilt to correct these deficiencies. In addition, the copper communications cable will be replaced with a fibre optic based communication system. This type of system is consistent with previous communication systems installed at other plant locations.

6.0 Project Execution

The refurbishment to the Rocky Pond hydroelectric development is necessary in 2009. The penstock has reached the end of its useful life and requires replacement. The intake structure, main valve, generator and governor are original to the plant construction and require refurbishment and/or replacement to ensure efficient plant operation.

It is estimated that the plant will be out of service for 16 weeks from June to September 2009. It is anticipated that the penstock replacement will take 14 weeks. When the new penstock is re-watered, commissioning will commence and the plant will be back in service within 2 weeks of re-watering.

In order for the project to be completed on schedule the penstock, main valve and governor controls will have to be procured in 2008. The detailed engineering for the penstock, main valve, and governor will be completed in the 3rd quarter of 2008 with the supply contracts for all items tendered and awarded in the 4th quarter.

During the 16 week plant downtime it is estimated, based on normal inflows, that spill at Rocky Pond plant will be minimal, only 1.97 GWh. Water that is spilled from Rocky Pond will be recaptured and used in production at the Tors Cove plant located just downstream. It is anticipated that no spill will occur from Tors Cove plant during this time.

A detailed project schedule is found in Appendix C. Table 1 shows the proposed high level schedule for the project.

Table 1
High-Level Project Schedule

Date	Description
Q3 2008	Complete geotechnical review of existing penstock route
Q4 2008	Complete engineering design of penstock access road
Q4 2008	Tender and award penstock supply contract
Q4 2008	Complete engineering design of main valve
Q4 2008	Tender and award main valve supply
Q4 2008	Tender and award governor controls supply
Q1 2009	Tender and award penstock installation contract
Q2 2009	Construct access road along penstock
Q3 2009	Complete penstock installation
Q3 2009	Refurbish intake structure
Q3 2009	Replace main valve
Q3 2009	Complete generator rewind
Q3 2009	Complete governor upgrades
Q4 2009	Replace forebay distribution and communications line
Q4 2009	Test and commission systems

7.0 Project Cost

The total project cost is estimated at $6.6 million which includes $75,000[3] in 2008 for engineering assessment, design and tendering, followed by $6.5 million in 2009 for penstock and main valve replacement; generator rewind; and upgrades to the intake, governor, and forebay distribution and communication line.

Table 2 provides the project cost breakdown by year and system component.

[3] As approved in the 2008 Capital Budget. Refer to Order No. P.U. 27 (2007).

Table 2
Cost Estimate for Rocky Pond Refurbishment
(000s)

Description	2008	2009
Engineering		
Engineering 2008	$75	
Civil		
Penstock		$4,922
Intake		225
Mechanical		
Main Valve		455
Governor Upgrades		124
Electrical		
Generator Rewind		563
Communications/Distribution Line		75
Project Management		
IDC		90
Project Management		63
Annual Totals	**$75**	**$6,517**

8.0 Feasibility Analysis

Appendix D provides a feasibility analysis for the continued operation of the Rocky Pond 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 Rocky Pond hydroelectric development ensures the continued availability of 14.1 GWhr of energy annually to the Island Interconnected System.

The estimated levelized cost of energy from Rocky Pond over the next 50 years, including the proposed capital expenditures, is 4.67 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 10.63 cents per kWh in the short term (assuming $67.00 per barrel), with an associated levelized cost of 13.90 cents per kWh[4].

[4] Incremental energy from the Holyrood thermal generating station is estimated at 10.63 cents per kWh for 2009 (based upon $67.00 per barrel of No. 6 fuel from Hydro's fuel price projection dated March 31, 2008), with associated levelized cost of 12.84 cents per kWh over 25 years and 13.90 cents per kWh over 50 years.

Appendix A

Pictures of Rocky Pond Penstock

Picture 1: Water Leakage from Penstock

Picture 2: Water Leakage from Penstock

Picture 3: Maintenance Personnel attempting to plug leaks in Penstock

Picture 4: Poor drainage along Penstock

Picture 5: Poor drainage along Penstock

Picture 6: Poor drainage along Penstock

Picture 7: Major Leak Upstream of Powerhouse (March 8th, 2008)

Picture 8: Major Leak Upstream of Powerhouse (March 8th, 2008)

Picture 9: Undermining and Support Settlement into Penstock Bedding

Picture 10: Settlement of Penstock Supports into Bedding

Picture 11: Leakage Repair near Intake

Appendix B

Hatch: Assessment of Rocky Pond Woodstave Penstock

Newfoundland Power
55 Kenmount Road
P.O. Box 8910
St. John's, NL A1B 3P6

Assessment of Rocky Pond Woodstave Penstock

Final Report

H-324668
0
December 2006

Newfoundland Power
Assessment of Rocky Pond Woodstave Penstock

Final Report

Prepared by: Walter Smith | December 2006
Date

Distribution List

H-324668

Table of Contents

1. Introduction

1.1 Authorization

On November 16, 2006, Newfoundland Power engaged Hatch to carry out a visual inspection and prepare a summary report on the condition of woodstave penstock of the company's Rocky Pond Hydroelectric Development. The work was undertaken based on a proposal submitted by Hatch on November 6, 2006.

1.2 Scope of Inspection and Report

The scope of the inspection included a visual inspection to ascertain the general state and condition of the penstock, a summary report describing the condition and findings and inclusion of a subjective opinion of the useful life of the penstock. The penstock is nearing the end of its useful life and non-destructive testing such as wood cores sample testing was deemed unnecessary.

1.3 Background

Available information included four drawings, as follows:

- Intake and Conduit under dam dated April 7, 1942
- Revised W.S. Pipeline Location No. R-4, dated February 17, 1942
- Preliminary profile No. NF-1852, dated January 5, 1942
- Profile- Pipeline Sub-Grade, No. R-8, dated August 5, 1942

The Rocky Pond/Tors Cove Hydroelectric System is located on the southern shore of the Avalon Peninsula and has two generating stations, Rocky Pond and Tors Cove. The facility was commissioned in 1943. The Rocky Pond Generating Station has one unit with an installed capacity of 3.25 MW with a rated head of 32.6 m (107 feet). The local datum centerline elevation of the turbine distributor is 88 m (289 feet). The penstock has an approximate 10 degree curve to the south just downstream of the intake and a 29 degree curve to the north at about 304.8 m (1000 feet) downstream of the intake. The soil bed has 7 slope changes along its length with slopes ranging from 1 degree up to 15 degrees near the powerhouse. The penstock does not contain any anchor blocks or movement joints. The penstock is crossed by a road bridge upstream of the powerhouse.

The 2.29 m (7.5 foot) nominal diameter by 756 m (2480 feet long) woodstave penstock is configured as follows: 716 m (2349 linear feet) of 2.273 m (89½ inch) inside diameter pipe with 66.7 mm (2 5/8 inch) thick staves and 39.9 m (131 linear feet), near the powerhouse, with 2.261 m (89 inch) inside diameter pipe with 79.4 mm (3 1/8 inch) thick staves.

The pipe is banded with approximately 19 mm (¾ inch) diameter steel bands which vary in spacing from approximately 75 mm (3 inches) at the powerhouse to approximately 200 mm (8 inches) at the intake conduit end.

The pipe is supported on timber cradles which contain about 120 degree portion of the pipe. The cradles are constructed out of 150 mm (6 inch) by 200 mm (8 inch) timber.

The timber staves and the cradles are pressure treated with creosote.

The penstock is the original pipeline installed in 1942.

The normal static head at the powerhouse is 290 kPa (42 psi). The highest penstock pressure upon 100% load rejection, measured in 2006, was 586 kPa (85 psi).

2. Inspection

Mr. Walter Smith, P.Eng., of Hatch Energy carried out the visual inspection on November 29, 2006. Mr. Gary Murray, P.Eng., and Ms. Trina Cormier, B. Eng., of Newfoundland Power accompanied Mr. Smith during the inspection. The weather was clear with the temperature at minus 4 Celsius. A series of photographs were taken to record the pipeline condition as it was walked upstream on the south side and downstream on the north.

3. Penstock Condition

3.1 Pipe Condition

The pipeline is leaking significantly along its entire length. This is highlighted by the extensive icing on the trees, bushes shrubs and grass along the entire length.

The soil bed is firm but wet over its entire length. The soil bed drains freely but the drainage water surface is much higher on the pipeline than is normally desirable. The source of the water is believed to be primarily from within the pipeline; however, there is bog along the flat area, on the upper half, which is contributing.

Near the powerhouse, Newfoundland Power has in recent years cut off and diverted approximately 50% of the water flowing from the leakage from the penstock and bog, to the back of the powerhouse. It is now diverted to the south bank of the tailrace. However, there is still too much water to be handled at the pipeline under the repair bay slab to the north side of the tailrace.

The penstock is sagging moderately in some areas due to settlement and/or sinking of the support cradles into the soil bed.

The cradle assemblies exhibit some cracks in the retaining segments. These cracks have been reinforced with steel plates and bolts. A few of the cradle sills or sleepers have been undercut by the heavy flows along either side particularly near the powerhouse end.

The steel bands are heavily corroded especially in the upstream half where there is extensive leakage and little ventilation. In one location there were three bands missing, one which had completely failed due to corrosion.

The staves are significantly deteriorated in several areas and suffer badly from the lack of ventilation due to the cradles sinking into the soil, bush and shrub growth and location of the pipeline bed through an excavated trench, particularly in the upstream half of the pipeline.

The pipeline was constructed without the use of metal end butts resulting in quite a number of split-outs at the end joints of the staves. These are retained by various repair types using steel plates with rubber gaskets or wood slats placed and held by the bands. In some locations the bands have completely failed. This is mainly caused by the lack of keepers (a ridge forming part of the shoe) which are found in the more modern band shoe designs and retain the washer and nut from slipping off. The timber staves also exhibit brooming, flaking, feathering and crushing between the steel bands.

The leaks have been repaired by various methods over the years. Large leaks and end split-outs are contained by placing large plates and rubber gaskets under the bands. At the spring line tapered wedges are driven in. In other areas sod is placed and retained to reduce the leakage.

Creosote has leached out of the wood especially in the flatter areas of the pipeline near the intake dam. The embedded steel thimble is corroded at the intake.

3.2 Photographs

A series of photographs are included in Appendix A.

4. Conclusions and Recommendations

4.1 Conclusions

The Rocky Pond Penstock is approximately 64 years old , is in very poor condition, leaks significantly and is nearing the end of its useful life. The life span for a woodstave penstock can vary and can be up to 60 years in many cases and is dependent on a number of factors: including the design thickness and design hardware, steel quality, timber species and quality, wood treatment quality, the saddle or cradle design, the extent of annual maintenance, and so on. The generating facilities day to day operation, including starts and stops, load changes and the number of times the pipeline is drained and refilled also impact its useful life.

In the case of the Rocky Pond Penstock, it has been favoured by having a moderately low hydraulic head but has been plagued by the poor drainage and ventilation conditions. The cradles support the pipeline over about a 120 degree arc. Modern woodstave pipeline designs have support up to 160 degrees. The higher support level confines the pipe better and results in fewer cycles from round to oval, during day to day operation and during periodic emptying and refilling.

The pipeline poses no obvious threat of sudden collapse or failure. Water loss has not been measured but it could easily be leaking as much as 10% of its carrying capacity or more.

The pipeline bed and its location, largely in an excavation, are preventing proper drainage and ventilation. The result is continued rotting of the timber staves and supports and continued corrosion of the bands and accompanying hardware.

4.2 Recommendations

Based on the condition, extent of deterioration and potential for failure, it is recommended that the penstock be replaced.

Considerations for the replacement should include:

- Improvement in bed support and drainage along its route to ensure adequate ventilation for the new pipeline. This could be accomplished by raising the bed level and/or extensive local drainage ditches and diversions to carry water away from the pipeline and soil bed.
- An access road along its length will be required to re-construct the new pipeline.
- The most cost effective replacement materials.

Interim repair and upkeep recommendations include the following:

- Improve drainage where practical along the soil bed.
- Improve the ventilation near the bottom of the penstock by removal of shrubs and grass. Excavate soil where practical to effect this.
- Drain the submerged area at the intake and at the powerhouse to the extent it is practical to do so.
- Carryout routine leak repair and band tightening.

- Repair undercut cradle components.
- Repair strut and segment split-outs in the cradles.
- Replace missing steel bands.
- Make sure areas of ice build-up do not extend to the point where the pipeline can be jacked up by ice. This can be monitored by occasional inspections by operating staff.
- Treat the timber and woodstaves with wood preservative where deemed necessary.
- Remove debris from the penstock at the road crossing.
- Clean and paint the exposed thimble at the intake.

Appendix A

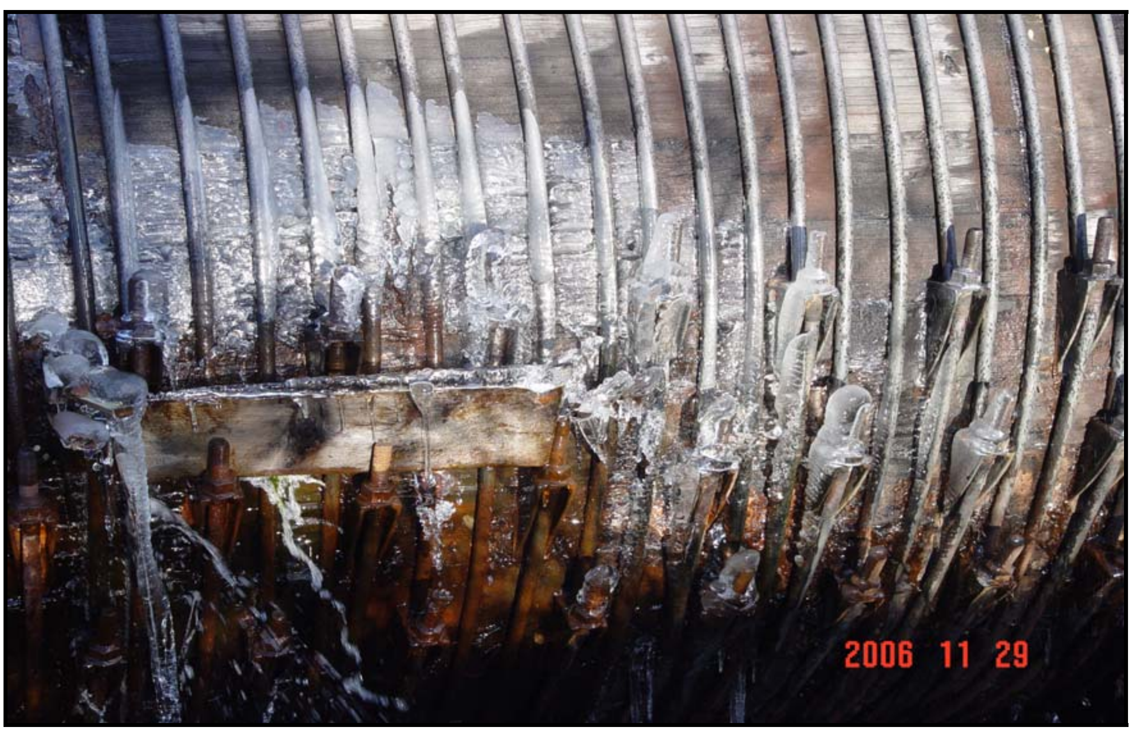
Photographs

A.1 Photographs

Photograph #1 – Soil and concrete on pipe at the road bridge.

Photograph #2 – Wood stave crushing and corroded steel bands near the road bridge. Note there are no nut/washer keepers built into the band hardware.

Photograph #3 – Close view. Note repairs grass and extent of water.



Photograph #4 – Typical repair – wooden board or slat.

Photograph #5 – Use of sod in repair. Note steel band corrosion.

Photograph #6 – Extensive leakage at a repair area.

Photograph #7 – Recent diversion of about half the flow to the south of the tailrace.

Photographs #8 – Band failed due to corrosion.

Photograph #9 – A general view of the two main bends near the intake.

Photograph #10 – Several missing bands at one location near the intake end.

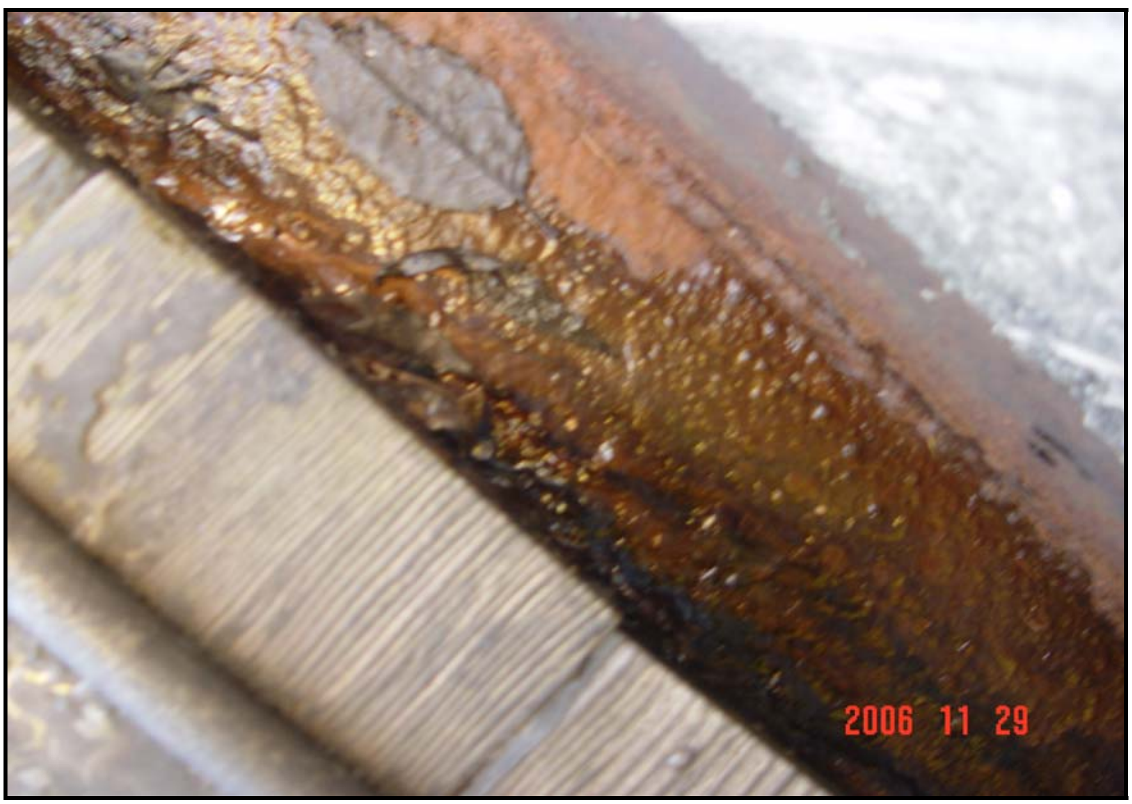
Photograph #11 – Near the intake conduit. Note the wedges near the top steel band connecting hardware.

Photograph #12 – Typical large area repairs with steel plate and rubber gasket.

Photograph #13 – Extensive use of wedges to plug leaks near the intake.

Photograph #14 – Poor drainage and ventilation near the intake conduit.

Photograph #15 – Looking downstream at the intake. Note creosote leached out by the sun.



Photograph #16 – Corroded steel thimble at the intake.

Photograph #17 – Several repairs and poor drainage and ventilation.

Photograph #18 – Split cradle segment.

Photograph #19 – Extensive flows along the pipeline.

Photograph #20 – Close view of corrosion and vegetation at the foundation soil bed.

Photograph #21 – Leakage and lack of ventilation caused by vegetation near the powerhouse.

Photograph #22 – Looking upstream near the powerhouse.

Photograph #23 – Missing steel band near the powerhouse.

Photograph #24 – Poor drainage and ventilation near the powerhouse. Note the undercut cradle sleeper near centre photograph.

Photograph #25 – Significant penstock drainage under the repair bay. View is at the downstream of the powerhouse.

Photograph #26 – Typical corroded steel band button head.

Photograph #27 – Typical corroded steel band button head.

Photograph #28 – Typical un-corroded steel band button head.

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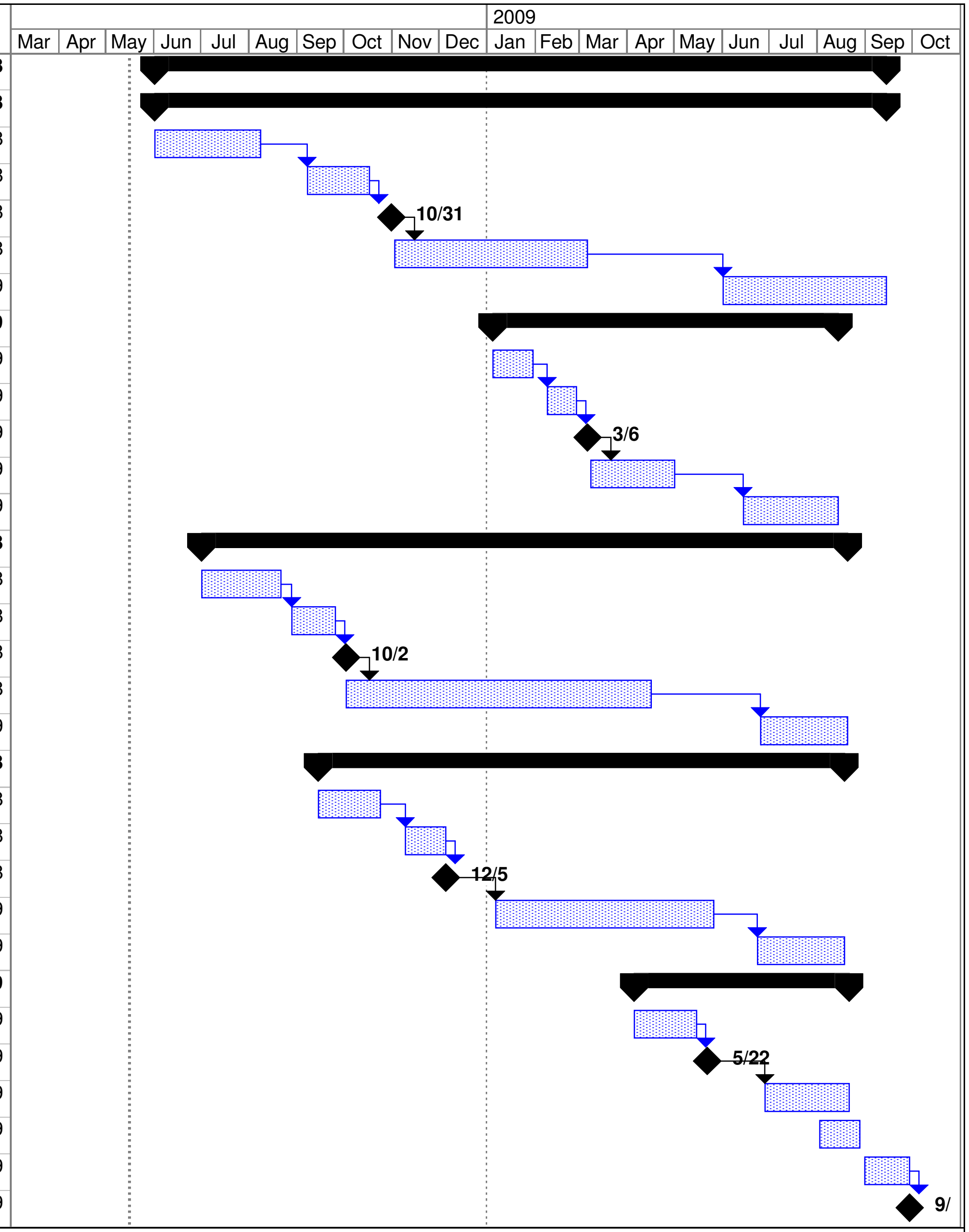
Appendix C

Project Schedule

ID	Task Name	Duration	Start
1	**Project Management**	**336 days**	**Mon 6/2/08**
2	**Penstock Replacement**	**336 days**	**Mon 6/2/08**
3	Design	50 days	Mon 6/2/08
4	Tender	30 days	Mon 9/8/08
5	Award	0 days	Fri 10/31/08
6	Fabrication	90 days	Mon 11/3/08
7	Installation	75 days	Tue 6/2/09
8	**Intake Refurbishment**	**160 days**	**Mon 1/5/09**
9	Design	20 days	Mon 1/5/09
10	Tender	15 days	Mon 2/9/09
11	Award	0 days	Fri 3/6/09
12	Fabrication/Delivery of Gate	40 days	Mon 3/9/09
13	Construction	45 days	Mon 6/15/09
14	**Main Valve Replacement**	**297 days**	**Wed 7/2/08**
15	Design	37 days	Wed 7/2/08
16	Tender	20 days	Fri 8/29/08
17	Award	0 days	Thu 10/2/08
18	Fabrication/Delivery of Valve	140 days	Fri 10/3/08
19	Installation	40 days	Fri 6/26/09
20	**Governor Upgrades**	**242 days**	**Mon 9/15/08**
21	Design	30 days	Mon 9/15/08
22	Tender	20 days	Mon 11/10/08
23	Award	0 days	Fri 12/5/08
24	Fabrication/Delivery	100 days	Wed 1/7/09
25	Installation	40 days	Wed 6/24/09
26	**Generator Rewind**	**100 days**	**Mon 4/6/09**
27	Tender	30 days	Mon 4/6/09
28	Award	0 days	Fri 5/22/09
29	Construction	40 days	Mon 6/29/09
30	Forebay Distribution and Communication Line	20 days	Mon 8/3/09
31	Commissioning	21 days	Tue 9/1/09
32	Project Completion	0 days	Tue 9/29/09



Project: Rocky Pond Refurbishment
Date: Fri 5/16/08

Task | Milestone | External Tasks
Split | Summary | External Milestone
Progress | Project Summary | Deadline

Appendix D

Feasibility Analysis

Table of Contents

1.0 Introduction

This feasibility analysis examines the future viability of Newfoundland Power's Rocky Pond hydroelectric development. The continued long-term operation of the Rocky Pond hydroelectric development is reliant on the completion of capital improvement in 2009. Planned work includes replacement of the woodstave penstock, refurbishment of the intake structure, a generator rewind, replacement of the main valve, as well as upgrading of the governor controls and rebuilding the forebay distribution and communication line.

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 2009 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	Expenditure
2009-2013	$6,937
2014-2018	$710
2019-2023	$277
2024-2028	$585
2029-2031	$175
Total	**$8,684**

The total capital expenditure of all of the projects listed above is $8.7 million. 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 $86,554 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 includes a water power rental rate of $0.80 per MWhr. 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 Rocky Pond development. Therefore, an adjustment is applied to account for the associated increased operating expenses on a go-forward basis.

Penstock maintenance has accounted for a large 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 rehabilitation initiatives.

4.0 Lost Production

The downtime associated with the 2009 capital works at this plant will result in a minimal amount of spill from the system. To minimize spill it has been determined that June to September 2009 would be the most economic time to complete the project. Water that is spilled from Rocky Pond will be recaptured and used in production at the Tors Cove plant located just downstream. It is anticipated that no spill will occur from Tors Cove plant during this time, however spill from Rocky Pond forebay will be in the order of 1.97 GWhr which translates into approximately $173,459[1] in increased purchased power costs.

5.0 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 Rocky Pond plant over the next 50 years is 4.67 cents per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Rocky Pond 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 10.63 cents per kWh in the short term (assuming $67.00 per barrel), with an associated levelized cost of 13.90 cents per kWh[2].

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[1] Based on the current rate of 8.805 cents/kWh. However, the financial impact on purchased power expense may increase if the wholesale rate from Newfoundland and Labrador Hydro increases.

[2] Incremental energy from the Holyrood thermal generating station is estimated at 10.63 cents per kWh for 2009 (based upon $67.00 per barrel of No. 6 fuel from Hydro's fuel price projection dated March 31, 2008), with associated levelized cost of 12.84 cents per kWh over 25 years and 13.90 cents per kWh over 50 years.

The future capacity benefits of the continued availability of Rocky Pond 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.

6.0 Recommendation

The results of this feasibility analysis show that the continued operation of the Rocky Pond hydroelectric development is economically viable. Investing in the life extension of facilities at Rocky Pond guarantees the availability of low cost energy to the Province. Otherwise the annual production of 14.1 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 2009. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

Attachment A
Summary of Capital Costs

Rocky Pond Feasibility Analysis
Summary of Capital Cost
(000s)

Description	2009	2011	2012	2014	2017	2018	2020	2021	2022	2024	2026	2030
Civil												
Penstock	$4,922											
Intake	$225											
Dams, Spillways, Canals, and Gates		$250	$120	$250	$360				$200	$300		
Tailrace						$50						
Roof and Building Upgrades			$50									
Mechanical												
Main Valve	$455											
Governor Upgrades	$124											
Cooling Water												
Ventilation/Compressor						$50						
Electrical												
Stator Rewind/Rotor Reinsulation	$563											
Forebay Line Rebuild	$75											
Protection Upgrade							$30					
PLC Upgrade												$175
Batteries/Charger								$47			$35	
Turbine Overhaul											$250	
Project Mangement												
IDC	$90											
Project Mangement	$63											
Annual Totals ($2009)	**$6,517**	**$250**	**$170**	**$250**	**$360**	**$100**	**$30**	**$47**	**$200**	**$300**	**$285**	**$175**

Attachment B
Summary of Operating Costs

Rocky Pond Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs

Year	Amount
2003	$63,261
2004	58,359
2005	76,980
2006	105,345
2007	122,426
Average	**$85,274**

5-Year Average Operating Cost	85,274
Water Power Rental Rate[1]	11,280
Reduced Future Penstock Maintenance	- 10,000
Total Forecast Annual Operating Cost	$86,554

[1] ($0.80/MWh * 14,100 MWh/yr)

Attachment C
Calculation of Levelized Cost of Energy

Weighted Average Incremental Cost of Capital	7.27%
Escalation Rate	
PW Year	2008

YEAR	**Generation** Hydro 64.4yrs 8% CCA	**Generation** Hydro 64.4yrs 50% CCA	**Capital Revenue Requirement**	**Operating Costs**	**Operating Benefits**	**Net Benefit**	**Present Worth Benefit**	**Cumulative Present Worth Benefit**	**Rev Rqmt (¢/kWhr)**	**Levelized (¢/kWhr) 50 years**	**Rev Rqmt**
2009	**1,594,740**	**4,921,760**	53,270	**86,554**	**0**	-139,824	-130,348	-130,348	0.992	4.667	
2010	**0**	**0**	-161,579	**87,939**	0	73,640	63,997	-66,351	-0.522	4.667	
2011	**257,810**	**0**	309,424	**89,258**	0	-398,682	-322,992	-389,343	2.828	4.667	
2012	**177,940**	**0**	524,899	**90,597**	0	-615,496	-464,849	-854,192	4.365	4.667	
2013	**0**	**0**	611,201	**92,137**	0	-703,338	-495,191	-1,349,383	4.988	4.667	
2014	**270,650**	**0**	674,522	**93,703**	0	-768,226	-504,219	-1,853,601	5.448	4.667	
2015	**0**	**0**	689,049	**95,296**	0	-784,346	-479,910	-2,333,511	5.563	4.667	
2016	**0**	**0**	693,235	**96,916**	0	-790,151	-450,696	-2,784,207	5.604	4.667	
2017	**410,355**	**0**	726,511	**98,661**	0	-825,172	-438,773	-3,222,980	5.852	4.667	
2018	**116,039**	**0**	728,932	**100,437**	0	-829,369	-411,117	-3,634,097	5.882	4.667	
2019	**0**	**0**	721,744	**102,245**	0	-823,988	-380,768	-4,014,865	5.844	4.667	
2020	**36,076**	**0**	717,222	**104,085**	0	-821,307	-353,807	-4,368,671	5.825	4.667	
2021	**57,537**	**0**	713,453	**105,958**	0	-819,412	-329,067	-4,697,738	5.811	4.667	
2022	**249,245**	**0**	725,633	**107,866**	0	-833,499	-312,039	-5,009,778	5.911	4.667	
2023	**0**	**0**	715,019	**109,807**	0	-824,826	-287,865	-5,297,642	5.850	4.667	
2024	**387,448**	**0**	739,148	**111,784**	0	-850,932	-276,849	-5,574,491	6.035	4.667	
2025	**0**	**0**	727,421	**113,796**	0	-841,217	-255,139	-5,829,630	5.966	4.667	
2026	**381,445**	**0**	750,812	**115,844**	0	-866,656	-245,040	-6,074,671	6.146	4.667	
2027	**0**	**0**	738,857	**117,929**	0	-856,787	-225,832	-6,300,503	6.077	4.667	
2028	**0**	**0**	728,988	**120,052**	0	-849,041	-208,623	-6,509,126	6.022	4.667	
2029	**0**	**0**	718,619	**122,213**	0	-840,832	-192,604	-6,701,730	5.963	4.667	
2030	**251,545**	**0**	729,467	**124,413**	0	-853,880	-182,337	-6,884,067	6.056	4.667	
2031	**0**	**0**	717,015	**126,652**	0	-843,667	-167,946	-7,052,013	5.983	4.667	
2032	**0**	**0**	705,966	**128,932**	0	-834,898	-154,937	-7,206,950	5.921	4.667	
2033	**0**	**0**	694,517	**131,253**	0	-825,770	-142,857	-7,349,807	5.857	4.667	
2034	**0**	**0**	682,679	**133,615**	0	-816,295	-131,647	-7,481,455	5.789	4.667	
2035	**0**	**0**	670,578	**136,021**	0	-806,598	-121,267	-7,602,722	5.721	4.667	
2036	**0**	**0**	658,233	**138,469**	0	-796,702	-111,662	-7,714,384	5.650	4.667	
2037	**0**	**0**	645,666	**140,961**	0	-786,627	-102,778	-7,817,161	5.579	4.667	
2038	**0**	**0**	632,893	**143,499**	0	-776,392	-94,565	-7,911,727	5.506	4.667	
2039	**0**	**0**	619,931	**146,082**	0	-766,013	-86,978	-7,998,705	5.433	4.667	
2040	**0**	**0**	606,795	**148,711**	0	-755,506	-79,971	-8,078,676	5.358	4.667	
2041	**0**	**0**	593,499	**151,388**	0	-744,887	-73,503	-8,152,179	5.283	4.667	
2042	**0**	**0**	580,056	**154,113**	0	-734,169	-67,536	-8,219,715	5.207	4.667	
2043	**0**	**0**	566,478	**156,887**	0	-723,365	-62,032	-8,281,747	5.130	4.667	
2044	**0**	**0**	552,775	**159,711**	0	-712,485	-56,958	-8,338,706	5.053	4.667	
2045	**0**	**0**	538,957	**162,586**	0	-701,543	-52,283	-8,390,988	4.975	4.667	
2046	**0**	**0**	525,034	**165,512**	0	-690,546	-47,975	-8,438,964	4.897	4.667	
2047	**0**	**0**	511,014	**168,491**	0	-679,505	-44,009	-8,482,972	4.819	4.667	
2048	**0**	**0**	496,904	**171,524**	0	-668,429	-40,357	-8,523,330	4.741	4.667	
2049	**0**	**0**	482,713	**174,612**	0	-657,325	-36,997	-8,560,327	4.662	4.667	
2050	**0**	**0**	468,446	**177,755**	0	-646,201	-33,906	-8,594,234	4.583	4.667	
2051	**0**	**0**	454,110	**180,954**	0	-635,064	-31,064	-8,625,297	4.504	4.667	
2052	**0**	**0**	439,709	**184,212**	0	-623,921	-28,450	-8,653,747	4.425	4.667	
2053	**0**	**0**	425,250	**187,527**	0	-612,777	-26,048	-8,679,796	4.346	4.667	
2054	**0**	**0**	410,737	**190,903**	0	-601,640	-23,842	-8,703,637	4.267	4.667	
2055	**0**	**0**	396,174	**194,339**	0	-590,513	-21,815	-8,725,452	4.188	4.667	
2056	**0**	**0**	381,565	**197,837**	0	-579,402	-19,954	-8,745,406	4.109	4.667	
2057	**0**	**0**	366,914	**201,398**	0	-568,312	-18,245	-8,763,651	4.031	4.667	
2058	**0**	**0**	352,224	**205,023**	0	-557,247	-16,678	-8,780,329	3.952	4.667	
2059	**0**	**0**	337,499	**208,714**	0	-546,212	-15,239	-8,795,568	3.874	4.667	
2060	**0**	**0**	322,740	**212,471**	0	-535,211	-13,920	-8,809,488	3.796	4.667	
2061	**0**	**0**	307,952	**216,295**	0	-524,247	-12,711	-8,822,200	3.718	4.667	
2062	**0**	**0**	293,136	**220,188**	0	-513,324	-11,603	-8,833,803	3.641	4.667	
2063	**0**	**0**	278,294	**224,152**	0	-502,446	-10,587	-8,844,390	3.563	4.667	
2064	**0**	**0**	263,429	**228,187**	0	-491,615	-9,657	-8,854,047	3.487	4.667	
2065	**0**	**0**	248,542	**232,294**	0	-480,836	-8,805	-8,862,852	3.410	4.667	
2066	**0**	**0**	233,635	**236,475**	0	-470,110	-8,025	-8,870,877	3.334	4.667	
2067	**0**	**0**	218,710	**240,732**	0	-459,441	-7,312	-8,878,189	3.258	4.667	

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects an income tax rate of 33.0%.

Operating Costs: Operating Costs were assumed to be $86,554 escalated yearly using GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55%	5.90	3.25
Common Equity	45%	8.95	4.03
Total	**100%**		**7.27**

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.
43.2	50.00%	Equipment designed to produce energy in a more efficient way.

Escalation Factors: Conference Board of Canada GDP Deflator.

Raise Rose Blanche Spillway to Increase Production

June 2008

Prepared by:

Gary K. Humby, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
GARY K. HUMBY
SIGNATURE
JUL 9/02/2008
DATE
PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

The Rose Blanche Brook hydroelectric development is located on the southwest coast of the Island of Newfoundland, near the community of Rose Blanche. It is Newfoundland Power's newest hydroelectric development and was placed into service in 1998. The normal annual production of the plant is approximately 20.7 GWh of energy, or about 4.9 % of Newfoundland Power's total hydroelectric system.

Since the construction of the development in 1998, average spill at the Rose Blanche development has been estimated at approximately 6.3 GWh annually, consistent with the original design.

A detailed assessment to identify options to reduce spill and increase energy production at Rose Blanche hydroelectric development was carried out by Hatch[1] in September 2003. The detailed assessment report *"Rose Blanche Study of Modifications to Increase Energy"* is included in Appendix A of this report. This report was reviewed and updated by Hatch in May 2008 to reassess the energy benefits and to update the cost estimates for the alternatives to increase energy production. A copy of the updated report is also included in Appendix A of this report.

Increasing the amount of storage in the development will reduce the amount of spilled water and result in increased energy production.

2.0 Background

The Rose Blanche generator has a nameplate capacity of 6.0 MW, powered by two 3.0 MW turbines. The two turbines share a single generator and a single penstock. The rated net head of the generating station is 114.2 m. The total drainage area upstream of the intake is 53 km^2. The only controlled storage in the Rose Blanche system is the forebay, which is relatively small. Rose Blanche is essentially a run-of-river hydroelectric plant. A schematic of the Rose Blanche system is provided in Figure 1.

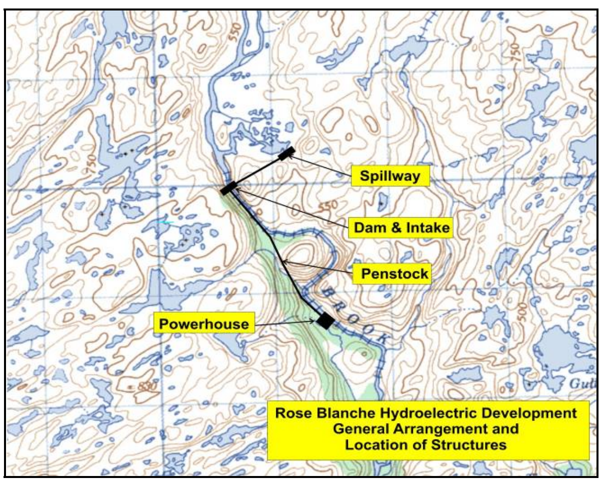

Figure 1

[1] Hatch, formerly SGE Acres, is a leading provider of process and business consulting, engineering project and construction management to the energy, mining, metallurgical, manufacturing and infrastructure industries.

Structures within the Rose Blanche development include the forebay dam, intake and one overflow spillway. The dam is located in a narrow gorge with a maximum height of approximately 30 m and a crest length of 53 m. The intake, located through the left abutment, consists of a reinforced concrete box culvert, steel gate with mechanical lift and a wood frame gatehouse. The spillway is a concrete overflow spillway, located approximately 500 m east of the forebay and is 40 m long. Photos of the system structures are included in Appendix B.

Since the construction of the generating station in 1998, average annual spill at Rose Blanche has been estimated to be 6.3 GWh annually. In 2003 Newfoundland Power engaged Hatch to complete a detailed assessment to identify viable options to reduce spill and increase energy production at the Rose Blanche hydroelectric development. The detailed assessment report *"Rose Blanche Study of Modifications to Increase Energy"* is included in Appendix A of this report. This report was updated by Hatch in May 2008 to reassess the energy benefits and to update the cost estimates for the alternatives proposed. The Hatch report is also included in Appendix A of this report. The detailed assessment includes the identification of alternatives for increasing energy production at Rose Blanche; an estimation of energy benefits associated with each alternative; as well as a review of the relevant flood handing issues, including design flood levels, discharge capacity, freeboard requirements and dam stability.

3.0 Options to Increase Energy Production

Production may be increased within a hydroelectric development through either physical changes or operational changes to the system.

The least cost physical change to the Rose Blanche system that would directly result in an increase in production includes raising the spillway elevation.

Three options considered in raising the spillway elevation include:

- Option 1: Concrete extension on the existing spillway (ogee or rectangular shape);
- Option 2: Flashboards anchored to the existing spillway; and
- Option 3: Inflatable gate on the existing spillway.

Flashboards can present a hazard if not removed in time to pass floods. 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. The Rose Blanche facility is unstaffed and isolated, and it is not feasible to remove and replace flashboards on a frequent basis. For these reasons, the flashboard option was ruled out as an alternative to increase the height of Rose Blanche spillway.

Inflatable gates are more costly than the other alternatives that were evaluated and for this reason were also ruled out as an alternative to increasing the spillway height.

It was determined that the most feasible least cost option to increase the height of the spillway at Rose Blanche is a concrete extension. A concrete extension will enhance spill capacity, requires no user intervention during a flood, no power requirements are necessary and since there are no moving parts minimal maintenance will be required. Two concrete extension options were evaluated; 0.86 m rectangular concrete extension and a 1.16 m ogee concrete extension. Based on the evaluation of both options it was determined that an ogee shape concrete extension is the most feasible option that will provide the largest incremental increase in annual energy output.

The total estimated cost for increasing the height of the existing spillway with an ogee concrete extension is $464,800. The incremental increase in energy output related to raising the spillway is estimated to be 0.9 GWhr for a total annual energy output of 21.6 GWhr.

Increasing the height of the spillway will be completed from July to mid August 2009 when reservoir levels are low. During this construction period the plant will remain in operation. The detailed design will be completed in-house and will commence in the first quarter of 2009.

4.0 Feasibility Analysis

Appendix C of this report provides a feasibility analysis for raising the height of the existing spillway to increase energy output at Rose Blanche. The results of the feasibility analysis show that raising the height of the existing spillway is economical and will result in an additional 0.9 GWh of energy to the Island Interconnected System.

The estimated levelized cost of raising the spillway at Rose Blanche is 4.060 cents per kWh. This energy is lower in cost than energy from sources such as a new hydroelectric development or additional Holyrood thermal generation. Incremental energy from Holyrood thermal generating station is estimated at 10.90 cents per kWh in the short term (assuming $67.00 per barrel), with an associated levelized cost of 13.90 cents per kWh.[2]

5.0 Conclusion

Increasing the height of the spillway at Rose Blanche hydroelectric development will result in an additional 0.9 GWh of energy. The feasibility analysis included in Appendix C verifies the financial viability of completing this project. Based upon the considerations outlined in this report and the attached assessment, the project is recommended to proceed in 2009.

[2] Incremental energy from the Holyrood thermal generating station is estimated at 10.63 cents per kWh for 2009 (based upon $67.00 per barrel of No. 6 fuel from Hydro’s fuel price projection dated March 31, 2008), with associated levelized cost of 12.84 cents per kWh over 25 years and 13.90 cents per kWh over 50 years.

Appendix A

Rose Blanche Study of Modifications to Increase Energy

HATCH™

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May 15, 2008

Mr. G. Humby, P.Eng.
Newfoundland Power
P.O. Box 8910
St. John's, NL
A1B 3P6

Dear Gary:

Subject: Rose Blanche Additional Energy Potential Study (Project Number H-329525)

SGE Acres was engaged by Newfoundland Power (NP) in February 2003 to carry out a study to identify options to increase energy generation at the Rose Blanche Hydroelectric Development. NP recently engaged Hatch in April 2008 to provide an update to that study. The scope of work for the current study follows.

- Review freeboard studies.
- Assessment of additional energy potential.
- Provide cost estimates based on conceptual designs.

The current scope of work does not include conducting an economic analysis and a stability analysis for the proposed options.

1. Freeboard Studies

Freeboard studies conducted in 2003 indicted that the maximum flood level for the development could be increased, thus increasing the head and energy for the facility. These freeboard estimates were based on the U.S. Army Corps of Engineers Shore Protection Manual and these procedures have now been replaced by the Coastal Engineering Manual. Also, the Canadian Dam Association (CDA) has recently revised in 2007 their Dam Safety Guidelines (2007 CDA Guidelines) and have provided procedures for calculating freeboard. The 2003 estimates of required freeboard were reviewed and revised following the methodologies presented in CEM and the 2007 CDA Guidelines. The results of these studies indicate that the required freeboard would not be updated and there are no changes in the 2003 results.

Since the required freeboard is unchanged, the options previously reviewed in 2003 remain valid. NP requested for this study that the following two options from the 2003 study be updated.

- Option #2: Concrete Extension 0.86 m (Broad Crested Weir)
- Option #3: Concrete Extension 1.16 m (Ogee)

It should also be noted that the Dam Classification System has been updated in the 2007 CDA Guidelines. Based on the old guidelines, Rose Blanche has been classified as "HIGH" and been assigned an inflow design flood with an estimated annual exceedance probability (AEP) of 1/1,000. For the purposes of this study, NP has directed Hatch to continue using the 1,000 year flood as the inflow design flood. It is proposed that prior to final design NP undertake to confirm the current dam classification and inflow design flood of Rose Blanche Dam following the 2007 CDA Guidelines.

2. Assessment of Additional Energy Potential

The power and energy model previously set up in 2003 to simulate the energy potential for the Rose Blanche Hydroelectric Development was used for this study to update the additional energy potential. The model was updated to reflect the additional years of available hydrology. The previous estimates in 2003 were based on a hydrological record of 40 years while this study has been updated to 44 years. The following table provides the results of the analysis.

Table 1
Assessment of Additional Energy Potential

Option	Assumed Existing Operation			
	2003 Average Annual Energy (GWh/yr)	2003 Incremental Energy (GWh/yr)	2008 Average Annual Energy (GWh/yr)	2008 Incremental Energy (GWh/yr)
Existing Spillway	23.6	-	23.4	-
Option 2: Concrete Extension 0.86 m	24.3	0.7	24.1	0.7
Option 3: Concrete Extension 1.16 m	24.5	0.9	24.3	0.9

The results indicate that although the estimated average annual energy decreased due to the extra years of flow data added to the hydrological record, the decrease was relative and the incremental energy remains the same. It should be noted that the above results are referenced to assumed existing operation. If at any time NP decide to change the existing operations, these values should be reviewed in light of that change. As an example, the previous study in 2003 assessed the value in changing the operation and indicated that if the reservoir rule curves were changed to a "Low Forebay Target Level" there could be an increase in energy of 0.3 GWh/yr. If this operational change is considered viable to NP and is implemented prior to any physical modifications to the system, it could change the value of incremental energy noted above for each option. Prior to final design of upgrade options NP should consider reviewing the existing reservoir operations and the associated energy benefits.

3. Cost Estimates

Cost estimates were prepared during the work conducted in 2003 and were conceptual only based on preliminary quantity estimates and assumed unit costs. Detailed cost estimates were not prepared and the 2003 cost estimates did not include a review of stability analysis of the alternatives. The cost estimates did not include taxes, owner's costs or design and environmental costs, and it was assumed that construction would not involve any generation losses. For this study, these conceptual cost estimates have been reviewed and updated primarily based on the volume of concrete required, unit costs, engineering and owner cost, contingency, and routine environmental costs. The costs presented in the following tables do not include taxes and it was assumed that construction would not involve any generation losses. A break down in the cost estimates follow.

Table 2
Option 2: Concrete Extension 0.86 m Cost Estimate

Item	Description	Quantity (m^3)	Unit Price ($/ m^3)	Total
1	Reinforced Concrete	100	$1,500	$150,000
2	Dowels in Rock	40	$300	$12,000
			Total Construction Cost	$162,000
			Engineering and Owners Cost (15% of Total Construction Cost)	$24,300
			Contingency (25% of Total Construction Cost)	$40,500
			2008 Total Cost Estimate	***$226,800***

The conceptual cost estimate noted in the 2003 study report for this option was $143,250. The reason for the increase in cost relates to an increase in concrete unit cost and the assumed volume of concrete. The previous cost estimate assumed that the current spillway weir could be used as a part of the new structure; however, this estimate assumes that the new structure would be either built just upstream or downstream of the old structure and the existing weir could not be used for stability issues. During final design a review of stability can be conducted to determine if the existing weir could be included; however, it is felt for the conceptual cost estimate that it not be included at this time.

Table 2
Option 3: Concrete Extension 1.16 m Cost Estimate

Item	Description	Quantity (m^3)	Unit Price (\$/ m^3)	Total
1	Reinforced Concrete	160	$2,000	$320,000
2	Dowels in Rock	40	$300	$12,000
			Total Construction Cost	$332,000
			Engineering and Owners Cost (15% of Total Construction Cost)	$49,800
			Contingency (25% of Total Construction Cost)	$83,000
			2008 Total Cost Estimate	***$464,800***

The conceptual cost estimate noted in the 2003 study report for this option was $421,545. The reason for the increase in cost, albeit slight increase relative to Option 2, relates to an increase in concrete unit cost and the assumed volume of concrete. The 2003 cost estimate assumed that the new spillway would be a "true" ogee shape (meaning the spillway profile would follow the lower nappe). This study has assumed a "simplified" ogee having a 45 degree slope on the downstream end, thus requiring significantly less concrete on the downstream slope. Shaping the crest should still provide the required coefficient for discharge, but eliminate the need for a perfectly shaped spillway. This reduction in volume combined with increased unit costs for concrete approximately offset, thus leading to a cost estimate marginally higher than that provided in 2003.

4. Recommendations

Prior to final design, it is recommended that the following be investigated.

- Confirm Dam Classification and Inflow Design Flood for Rose Blanche Dam in accordance with the 2007 CDA Guidelines.
- Determine potential for existing operations to change, and the impact these changes might have on the potential incremental energy for each option presented in this report. If NP optimized operation of the current system to maximize energy, the incremental energies associated with raising the spillway should be re-evaluated.
- Based on the option selected and final cross sectional design, estimate the potential coefficient of discharge and confirm the spillway sill elevation.

- Detailed cost estimates should be prepared during the design phase that includes stability analysis of alternatives.

Yours very truly,

Robert Woolgar
Manager, Newfoundland and Labrador
Water and Wind Power

RW:smb

File 401.01.03.35.01

SGE Acres

St. John's • Clarenville
Corner Brook • Sydney • Halifax
Moncton • Saint John • Fredericton

September 12, 2003
P14764.00.02

Newfoundland Power
P.O. Box 8910
55 Kenmount Road
St. John's, Newfoundland A1B 3P6

Attention: Mr. G. Humby, P.Eng.

Dear Sir:

Rose Blanche Study of Modifications to Increase Energy

SGE Acres was engaged by Newfoundland Power (NP) in February 2003 to carry out a study to identify options to increase energy generation at the Rose Blanche Brook hydroelectric development. This letter report presents the methodology and final results, conclusions and recommendations for this study. Since submission of the draft report, we have re-run the energy simulations with the full 40-year hydrologic record available and reviewed the cost estimates. The economic analysis has been revised to reflect the new energy and cost estimates.

The scope of work for this study included

- identification of alternatives for increasing energy generation at the Rose Blanche Brook hydroelectric development, including operational changes and physical changes;
- assessment of relevant flood handling issues, including design flood levels, discharge capacity, minimum required freeboard for wind and wave action, and dam stability;
- estimation of energy benefits for each alternative, using a power and energy model;
- preparation of conceptual cost estimates for each alternative;
- comparison of the benefits and costs using selected economic indicators; and
- preparation of a letter report with conclusions and recommendations.

1 System Description

The Rose Blanche Brook hydroelectric development is located on the southwest coast of the Island of Newfoundland, near the community of Rose Blanche. It is NP's newest hydroelectric development and was commissioned in 1998. The Rose Blanche Brook Generating Station has two units with nameplate capacities of 3.0 MW each for a total nameplate capacity of 6.0 MW. The two units share a single generator and a single penstock. The rated net head of the station is 114.2 m. The total drainage area upstream of the intake is 53 km^2. The only controlled storage in the system is the forebay, which has an area of 0.93 km^2 at full supply level (FSL) and is impounded by a 19 m high rockfill dam.

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The spillway channel is located 500 m east of the dam and is cut through bedrock. The spillway consists of a concrete weir 1 m high and 40 m long, which runs across the channel.

A schematic of the system is provided as Figure 1. A schematic of the dam, spillway and forebay levels is provided as Figure 2.

2 Identification of Alternatives

NP has found that the volume of spill at Rose Blanche Brook tends to be large, especially during the spring freshet. Of interest to NP are alternatives to increase the amount of storage in the development, which should reduce the amount of spilled water and result in increased energy generation.

Due to the shape of the forebay and the sheltered location of the dam, there is less wave runup on the dam than expected from information used in the project design studies. This presents an opportunity to increase storage by raising the spillway elevation. Alternatives for raising the spillway elevation include a concrete extension on the existing sill, inflatable crest gates, and flashboards. It was agreed with NP that no feasible opportunities exist to add upstream storage to the system.

Concrete Extension

A concrete extension entails adding concrete to raise the height of the existing weir. The surface of the weir can be sloped or curved (i.e., an ogee shape) to enhance the discharge capacity for a given head. Key advantages of concrete are high resistance to damage, long service life, low maintenance, and relative simplicity of design and construction.

Inflatable Gate

An inflatable gate consists of a reinforced rubber dam body that is inflated with air and anchored along the span to a concrete foundation. Key advantages are the ability to dynamically control the water level and to safely achieve higher forebay levels than possible with a fixed overflow structure.

Inflatable gates, such as the type supplied by Bridgestone, can be controlled automatically via water level sensors. They can be partially deflated to pass spill while maintaining a certain forebay level, or be completely deflated to allow unobstructed passage of extreme flows. Inflatable gates require little maintenance compared to other types of controllable gates. It would however be necessary to construct a concrete pad on which the gate can lie flat while deflated.

Flashboards

Flashboards (assemblages of boards supported by vertical columns anchored to a spillway crest) allow the reservoir level to be raised above a fixed crest level, when the spillway is not needed for passing flows. A disadvantage of flashboards is that they can present a hazard if not removed in time to pass floods. This is a concern where the reservoir is small and the streamflows are flashy, such that levels tend to rise quickly. The Rose Blanche facility is unstaffed and isolated, and it is not feasible to remove and replace flashboards on a frequent basis. Flashboards can be designed to detach automatically under a certain head, but this form of operation is somewhat unreliable, especially where ice pressures can also cause failure. Sudden large discharges can result when flashboards fail and can be hazardous. For these reasons, NP ruled out flashboards as an alternative.

Operational Changes

Generation may be increased through operational changes that reduce spill or increase head. Reducing spill may be achieved by maintaining the forebay at a lower level. This allows high inflows to be stored rather than spilled, but also involves a tradeoff in reduced head. Alternatively, the forebay can be maintained in a full condition in order to maximize head, but spill flows will be larger and more frequent.

NP's form of operation at present is to draw down the forebay prior to the spring freshet, but otherwise apparently to use judgement in running one or two units to maintain a forebay level between FSL and low supply level (LSL) as a compromise between maintaining head and minimizing spill.

Simulation results and NP's experience with the plant indicate a tendency for the forebay level to rise quickly. This finding suggests that inflow forecasting may be a useful tool in optimizing generation at this development. An evaluation of flow forecasting was outside the scope of this study.

3 Flood Handling and Freeboard

Geotechnical and structural engineering reviews done for this study found that dam stability and intake stability are not limiting constraints on the maximum allowable level of the forebay. Consequently, the maximum level is limited only by the minimum required freeboard for the design flood and wind and wave action.

Under the Canadian Dam Association (CDA) Dam Safety Guidelines, the main dam is classified in the HIGH consequence category and is assigned an inflow design flood (IDF) with an estimated annual exceedance probability (AEP) of 1/1,000. The IDF is 500 m^3/s, based on a flood frequency analysis done by NP with data from 1962 to 1997. NP reviewed the analysis and concluded that there was no need to update the flood estimate with more recent data, because there have been no unusual floods since that time.

A maximum forebay level of 166.30 m was selected for flood handling analysis, in agreement with NP. That level is presently the maximum flood level associated with the 1/10,000 AEP event (730 m^3/s). It provides a freeboard of 0.90 m below the crest rail at 167.20 m (assuming no wind and wave action).

The general freeboard requirement for this type of dam in the CDA Guidelines is that 95 percent of the waves shall not overtop the dam, in either the 1/100 AEP wind during the design flood, or the 1/1,000 AEP wind during the highest normal level. To assess the adequacy of the freeboard, SGE Acres carried out a review of expected wind and wave action.

Based on methods in the U.S. Army Corps of Engineers Shore Protection Manual, the effective fetch (for wave runup) was estimated to be 150 m, with a maximum fetch (for wind setup) of 800 m. A wind frequency analysis was then carried out, using an available record of 24 maximum annual winds from 1971 to 2002, as measured by Environment Canada at the Port aux Basques climate station. Winds from the northwest, north and northeast were considered. The 1/100 and 1/1,000 AEP winds were estimated to be 10 km/h and 117 km/h, respectively.

Wind setup and wave runup calculations using the methods proposed by Saville et al. determined that, at a forebay level of 166.30 m, neither the 1/100 nor the 1/1,000 AEP winds produce 95th percentile waves overtopping the dam crest. Therefore, it was concluded that a design flood level of 166.30 m is acceptable.

4 Final List of Alternatives

Limiting the design flood level to 166.30 m, the maximum height of the concrete extension depends on the discharge capacity of the weir, which depends on the shape of the crest. A coefficient of 1.6 was assumed for a broad-crested weir with a horizontal surface. Using the weir equation, this gives a maximum extension of 0.86 m, to 162.36 m.

An ogee crest shape would have a higher coefficient, enabling passage of comparatively higher flows with lesser heads. A coefficient of 1.8 was assumed (slightly less than the theoretical maximum because of the relatively shallow approach depth). The maximum height extension in this case is 1.16 m, to 162.66 m, with an associated gain in storage.

Additional storage above the fixed crest elevation can be provided by an inflatable gate. NP supplied technical and cost information on Bridgestone inflatable gates ranging in size from 2 to 5 m. Extrapolation from these costs showed that it is always cheaper to build a concrete extension than it is to construct a pad and install an inflatable gate of equal height on top of the existing crest. Therefore, any advantage in using an inflatable gate is in combination with a concrete extension, to obtain additional storage above what is achievable with a concrete extension alone. The requirement for a concrete pad means that an ogee form cannot be used; therefore it was assumed that the inflatable gate would be in combination with the 0.86 m concrete extension. A 4 m gate is the largest that can be used, which would allow the forebay to be maintained all the way up to the design flood level of 166.30 m under normal conditions.

The final list of alternatives for analysis was as follows.

Option 1: 0.50 m concrete extension (crest elevation 162.00 m)
Option 2: 0.86 m concrete extension (crest elevation 162.36 m)
Option 3: 1.16 m concrete ogee (crest elevation 162.66 m)
Option 4: Concrete extension with 2 m inflatable gate (inflated elevation 164.36 m)
Option 5: Concrete extension with 3 m inflatable gate (inflated elevation 165.36 m)
Option 6: Concrete extension with 4 m inflatable gate (inflated elevation 166.36 m)

For each option, as well as for the existing development, the energy was estimated for a low, intermediate, and high forebay target level. The target levels represent operational tradeoffs between spill and head, as previously discussed. In this way, the effects of physical and operational changes could be considered at the same time.

Stability analysis of alternatives was outside the scope of this study. Issues that should be addressed in a detailed design study include ice loading, extent of anchoring, and optimization of concrete and reinforcement quantities.

5 Power and Energy Model Results

A power and energy model was used to estimate the energy of each of the options. The Acres Reservoir Simulation Package (ARSP) model of this development was first set up for the Water Management Study, and was also used for the Hydroelectric Systems Strategic Planning Study conducted for NP by Acres International in 2000/2001. Inflow sequences were synthesized from the record of flows at the nearby Environment Canada hydrometric station on Isle aux Morts River (02ZB001). For this study, the model was run first using the 15-year period 1984 to 1998, as used in the Water Management Study, and then with the full 40-year sequence of inflows available (1963 to 2002). The model was run for the base case and the six options for each of three target forebay levels.

The incremental energy was calculated with respect to the base case, which is the simulated long term production for existing physical conditions and current NP plant operating guidelines. The current forebay operating practices are represented in the model by an assumed rule curve (intermediate target level). The energy estimates (using the 40-year inflow sequence) are provided in Table 1. A plot of incremental energy for each spillway option is shown as Figure 3. In each case, the 40-year scenario gave higher average energy than the 15-year scenario, which was presented in the draft report. This is because of a slightly higher average annual flow, and the variability of the distribution of flow over the years.

The results indicate that a high forebay target level to maximize head also increases the amount of spill, and results in less energy than lower target levels. It is better to reduce spill by increasing storage, or making better use of existing storage, than it is to keep the forebay high.

The results also indicate that simply keeping the forebay low, with no physical modifications, results in an incremental average energy of 0.3 GWh/yr compared to assumed present practice. This is consistent with the finding of the Hydroelectric Systems Strategic Planning Study. The associated benefit is similar to the increased energy attainable from building a 0.50 m spillway extension without any change in forebay operation.

Figure 4 compares the simulated forebay levels for low (proposed) and intermediate (assumed existing) target levels. Also shown are actual forebay levels recorded by NP between 2000 and 2003. The levels are plotted as duration curves, showing the proportion of time that elevations are equaled or exceeded. The proposed operation has a lower average level and less frequent submergence of the sides of the forebay.

6 Cost-Benefit Analysis

Energy benefits for each option are shown in Table 2, using an assumed value of energy of $0.050/kWh, a period of 50 years, and discount rates of 5, 7, and 9 percent.

Construction cost estimates for each option are provided in the attached Appendix, and are summarized in Table 3. For the purpose of this exercise, the cost estimates were conceptual only, based on preliminary quantity estimates and assumed unit costs. Detailed cost estimates should be prepared in a design study that includes stability analysis of alternatives. The construction cost estimates do not include taxes, owner's costs or design and environmental costs. Construction is not expected to involve any generation losses. Review of the hydrology and simulation results indicated that spill is rare during the months of July to September, providing ample time to work on the spillway in the dry.

Five economic indicators were used to evaluate the options: benefit, benefit/cost ratio, net benefit, cost of energy, and incremental cost as a function of incremental benefit. The indicators are shown in Tables 4 through 7 and are also plotted in Figures 5 through 9. The analysis was based on the forebay target level for each option that gave the best incremental energy. With the concrete extensions, the most energy was obtained by keeping the forebay as low as possible. With the inflatable gates, an intermediate target level was better.

Figure 5 shows a plot of net present value (NPV) benefit as a function of cost. The diagonal line is the break even line, where the benefit equals the cost. The same values are expressed in a different way in Figure 6 as benefit/cost ratios. For the inflatable gate options, a positive or negative return on investment was sensitive to the discount rate. The highest benefit/cost ratios were obtained for the concrete extensions. The ogee was the least attractive of the extensions. This was related to the cost of the additional concrete necessary to make the improved ogee shape.

Figure 7 shows the NPV net benefit for each option. Again, the sensitivity to discount rate is evident. The 0.86 m concrete extension resulted in the greatest net benefit.

Figure 8 shows the unit cost of energy for each option (the construction cost annualized over the life of the project, divided by the incremental average energy). The least costly energy came from the 0.86 m concrete extension.

Figure 9 shows the incremental benefit as a function of the incremental cost between options; that is, whether or not it is worthwhile to go from one option to the next more expensive option. The plot suggests that although it is worthwhile to extend the concrete weir, it is not worthwhile to add an ogee shape. Although one more foot of storage is gained, the benefit is not enough to offset the additional cost of building the ogee. The plot also indicates that it a positive incremental benefit is realized (at a discount rate not exceeding 5 percent) in building a pad and installing an inflatable gate of up to 3 m. However, inflatable gates are not attractive at higher discount rates.

7 Conclusions

1. For the range of discount rates considered, concrete extensions are economically attractive; the 0.86 m concrete extension resulted in the greatest net benefit and the lowest cost of energy. The inflatable gate options are generally less attractive due to their higher cost. As noted, the costs used in this analysis are construction costs and are not all-inclusive. Total project costs will be higher, therefore reducing net benefits and associated economic indicators.

2. For a design flood level of 166.30 m, the highest concrete spillway extension is 0.86 m above the existing crest, to elevation 162.36 m, assuming a horizontal weir shape. An ogee shape would allow an extension to 162.66 m, but is not economically attractive due to the additional cost.

3. It is more economical to build a concrete extension than it is to install an inflatable gate of equal height on the existing spillway crest. The advantage of an inflatable gate is in allowing the use of storage above the fixed crest elevation of a concrete extension. 4 m is the largest inflatable gate size that can be used with a 0.86 m concrete extension, assuming a design flood level of 166.30 m.

4. There is an opportunity to increase generation by changing current operating practice to keep the forebay low. This will reduce spill and result in an estimated incremental energy of 0.3 GWh/yr compared to current practice. As well, there will be a smaller submerged area of the forebay side slopes, on average. In general, increasing storage or making better use of existing storage provides a superior opportunity to increase generation than does keeping the forebay high in an attempt to maximize head.

5. The stability of the existing main dam is not a limiting constraint in raising the spillway elevation. The maximum level of the forebay is limited by dam freeboard requirements. Under the CDA Guidelines, a maximum forebay level of 166.30 m (0.90 m below the dam crest rail) provides adequate freeboard for wind and wave action, in both design flood and normal operating conditions.

8 Recommendations

1. To maximize generation with the existing facilities, NP should change its current plant operating guidelines to run the units with all available water and keep the forebay low.

2. NP should consider raising the concrete spillway by 0.86 m.

3. NP should carry out a detailed analysis, including engineering design, stability analysis and detailed cost estimates of alternatives. The analysis should optimize the design, considering the cost of capital and the value of energy.

4. If physical changes are implemented, NP should carry out a water management analysis to determine the optimal forebay levels to maximize generation.

5. NP should consider inflow forecasting to help optimize generation at this development.

We trust that this report meets your requirements. Please call is you have any questions regarding this analysis, or if we can be of further assistance.

Yours very truly,

Susan Richter

MR:sjc

S. H. Richter, M.Eng., P.Eng.
Senior Hydrotechnical Engineer

Attachments

Table 1

Power and Energy Model Results

Option	Full Supply Level (m)	Assumed Existing Operation			Low Forebay Target Level			High Forebay Target Level		
		Avg. Ann. Energy (GWh)	Increm. Energy (GWh)	Average Spill (m^3/s)	Avg. Ann. Energy (GWh)	Increm. Energy (GWh)	Average Spill (m^3/s)	Avg. Ann. Energy (GWh)	Increm. Energy (GWh)	Average Spill (m^3/s)
Existing Spillway	161.50	23.6	0.0	0.536	23.9	0.3	0.468	21.0	-2.6	0.886
1) Conc. extension 0.50 m	162.00	24.0	0.4	0.489	24.2	0.6	0.437	21.2	-2.4	0.867
2) Conc. extension 0.86 m	162.36	24.3	0.7	0.462	24.4	0.8	0.416	21.4	-2.2	0.854
3) Conc. extension (ogee) 1.16 m	162.66	24.5	0.9	0.441	24.5	0.9	0.400	21.5	-2.1	0.844
4) Conc. ext. + 2 m inflatable gate	164.30	25.3	1.7	0.348	25.2	1.6	0.326	22.1	-1.5	0.791
5) Conc. ext. + 3 m inflatable gate	165.30	25.8	2.2	0.304	25.6	2.0	0.286	22.5	-1.1	0.760
6) Conc. ext. + 4 m inflatable gate	166.30	26.2	2.6	0.263	26.0	2.4	0.249	22.9	-0.7	0.730

Note: Incremental energy is referenced to existing spillway with existing operation (23.6 GWh).

Table 2

Energy Benefits

Option	FSL (m)	Increm. Energy (GWh)	Annual Benefit $0.050/kWh	Net Present Value Benefits n = 50 years		
				i = 5%	i = 7%	i = 9%
1) Conc. extension 0.50 m	162.00	0.6	$ 30,000	$ 547,678	$ 414,022	$ 328,850
2) Conc. extension 0.86 m	162.36	0.8	$ 40,000	$ 730,237	$ 552,030	$ 438,467
3) Conc. extension (ogee) 1.16 m	162.66	0.9	$ 45,000	$ 821,517	$ 621,034	$ 493,276
4) Conc. ext. + 2 m inflatable gate	164.30	1.7	$ 85,000	$1,551,754	$1,173,063	$ 931,743
5) Conc. ext. + 3 m inflatable gate	165.30	2.2	$ 110,000	$2,008,152	$1,518,082	$1,205,785
6) Conc. ext. + 4 m inflatable gate	166.30	2.6	$ 130,000	$2,373,270	$1,794,097	$1,425,019

Table 3

Cost Estimates

Option	FSL (m)	Construction Cost	Annualized Cost n = 50 years		
			i = 5%	i = 7%	i = 9%
1) Conc. extension 0.50 m	162.00	$ 111,105	$ 6,086	$ 8,051	$ 10,136
2) Conc. extension 0.86 m	162.36	$ 143,250	$ 7,847	$ 10,380	$ 13,068
3) Conc. extension (ogee) 1.16 m	162.66	$ 421,545	$ 23,091	$ 30,545	$ 38,456
4) Conc. ext. + 2 m inflatable gate	164.30	$ 1,112,535	$ 60,941	$ 80,614	$ 101,493
5) Conc. ext. + 3 m inflatable gate	165.30	$ 1,629,975	$ 89,285	$ 118,108	$ 148,698
6) Conc. ext. + 4 m inflatable gate	166.30	$ 2,304,525	$ 126,234	$ 166,986	$ 210,235

Table 4

Benefit/Cost Ratio

Option	FSL (m)	i = 5%	i = 7%	i = 9%
1) Conc. extension 0.50 m	162.00	4.93	3.73	2.96
2) Conc. extension 0.86 m	162.36	5.10	3.85	3.06
3) Conc. extension (ogee) 1.16 m	162.66	1.95	1.47	1.17
4) Conc. ext. + 2 m inflatable gate	164.30	1.39	1.05	0.84
5) Conc. ext. + 3 m inflatable gate	165.30	1.23	0.93	0.74
6) Conc. ext. + 4 m inflatable gate	166.30	1.03	0.78	0.62

Table 5

NPV Net Benefits

Option	FSL (m)	i = 5%	i = 7%	i = 9%
1) Conc. extension 0.50 m	162.00	$ 436,573	$ 302,917	$ 217,745
2) Conc. extension 0.86 m	162.36	$ 586,987	$ 408,780	$ 295,217
3) Conc. extension (ogee) 1.16 m	162.66	$ 399,972	$ 199,489	$ 71,731
4) Conc. ext. + 2 m inflatable gate	164.30	$ 439,219	$ 60,528	-$ 180,792
5) Conc. ext. + 3 m inflatable gate	165.30	$ 378,177	-$ 111,893	-$ 424,190
6) Conc. ext. + 4 m inflatable gate	166.30	$ 68,745	-$ 510,428	-$ 879,506

Table 6

Cost of Energy

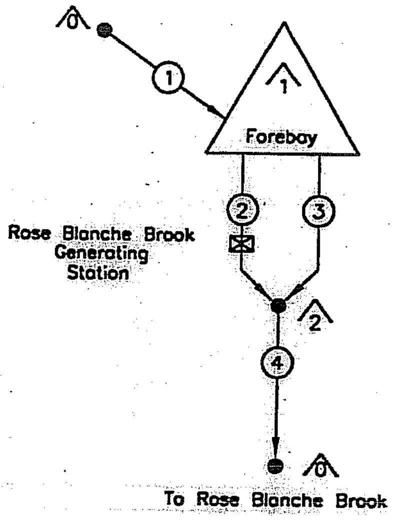
Option	FSL (m)	i = 5%	i = 7%	i = 9%
1) Conc. extension 0.50 m	162.00	$ 0.010	$ 0.013	$ 0.017
2) Conc. extension 0.86 m	162.36	$ 0.010	$ 0.013	$ 0.016
3) Conc. extension (ogee) 1.16 m	162.66	$ 0.026	$ 0.034	$ 0.043
4) Conc. ext. + 2 m inflatable gate	164.30	$ 0.036	$ 0.047	$ 0.060
5) Conc. ext. + 3 m inflatable gate	165.30	$ 0.041	$ 0.054	$ 0.068
6) Conc. ext. + 4 m inflatable gate	166.30	$ 0.049	$ 0.064	$ 0.081

Table 7

Incremental Cost vs. Incremental Benefit

Option	Incremental Cost	Incremental Benefit		
		i = 5%	i = 7%	i = 9%
Concrete extensions				
1) Conc. extension 0.50 m	$ 111,105	$ 547,678	$ 414,022	$ 328,850
2) Conc. extension 0.86 m	$ 32,145	$ 182,559	$ 138,007	$ 109,617
3) Conc. extension (ogee) 1.16 m	$ 278,295	$ 91,280	$ 69,004	$ 54,808
Inflatable Gates				
4) Conc. ext. + 2 m inflatable gate	$ 969,285	$ 821,517	$ 621,034	$ 493,276
5) Conc. ext. + 3 m inflatable gate	$ 517,440	$ 456,398	$ 345,019	$ 274,042
6) Conc. ext. + 4 m inflatable gate	$ 674,550	$ 365,119	$ 276,015	$ 219,234

Note: Option 4 incremented to Option 2



CHANNELS

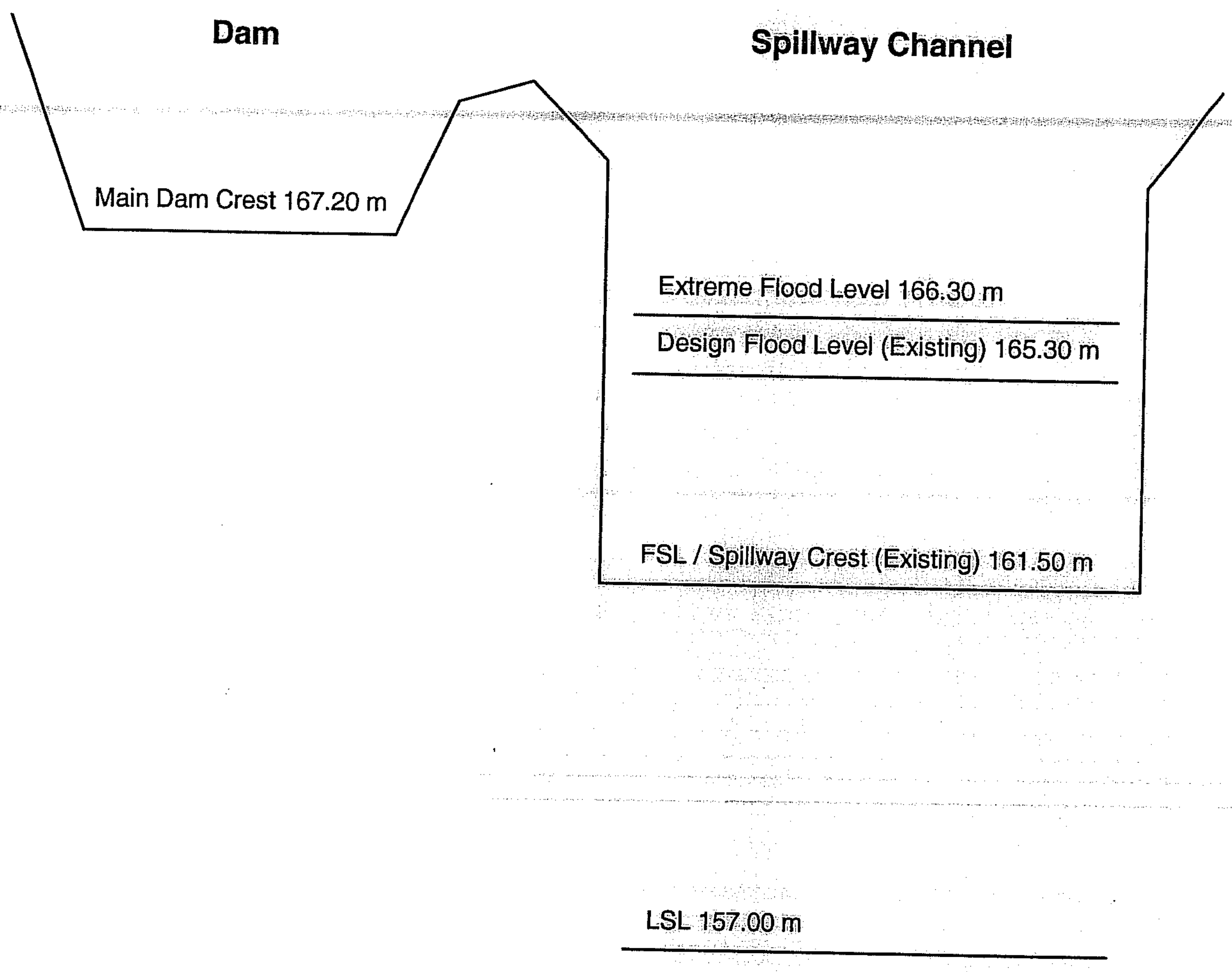
1 — Rose Blanche Brook Inflow
2 — Rose Blanche Brook Power Flow
Units #1 and #2
3 — Rose Blanche Brook Spill
4 — Rose Blanche Brook Total Outflow

RESERVOIRS / NODES

0 — Source / Sink
1 — Rose Blanche Brook Forebay
2 — Rose Blanche Brook Total Outflow

SGE Acres

Figure 1
System Schematic
Rose Blanche Study of Modifications to Increase Energy
Newfoundland Power



SGE Acres

Figure 2
Schematic of Operating Levels
Rose Blanche Study of Modifications to Increase Energy
Newfoundland Power

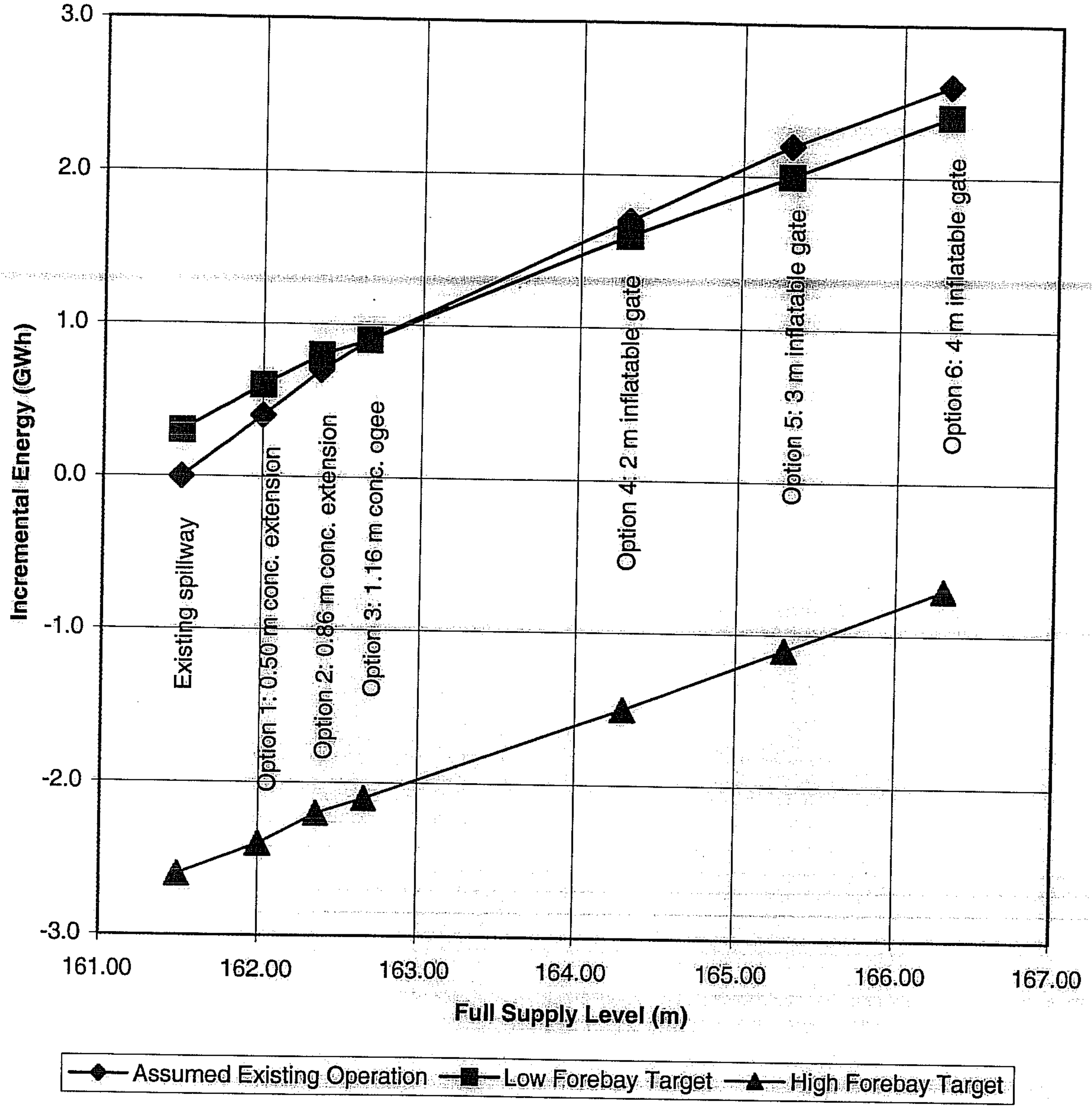


Figure 3
Incremental Energy
Rose Blanche Study of Modifications to Increase Energy
Newfoundland Power

SGE Acres

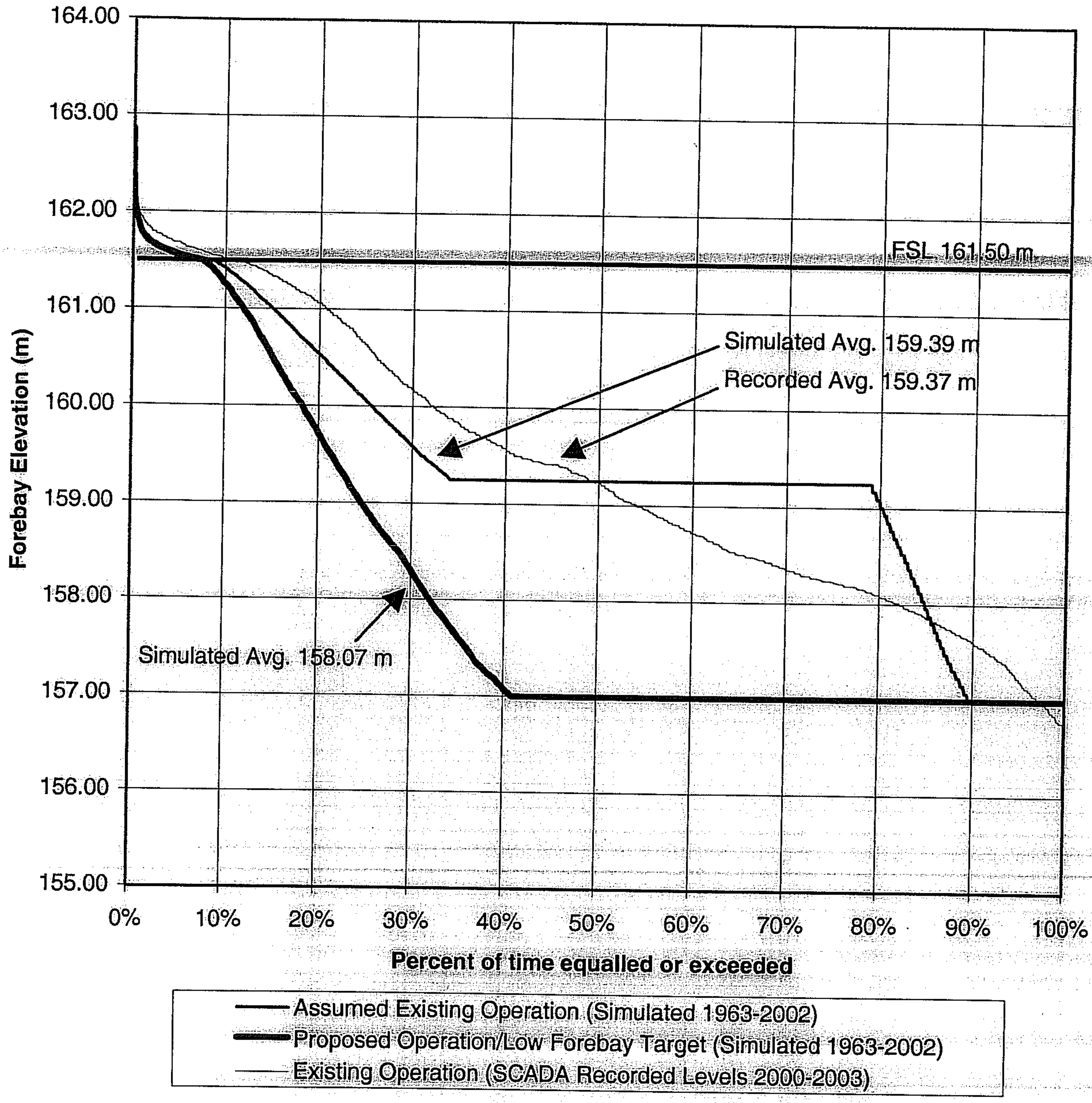


Figure 4

Forebay Elevation - Duration Curves

Rose Blanche Study of Modifications to Increase Energy

Newfoundland Power

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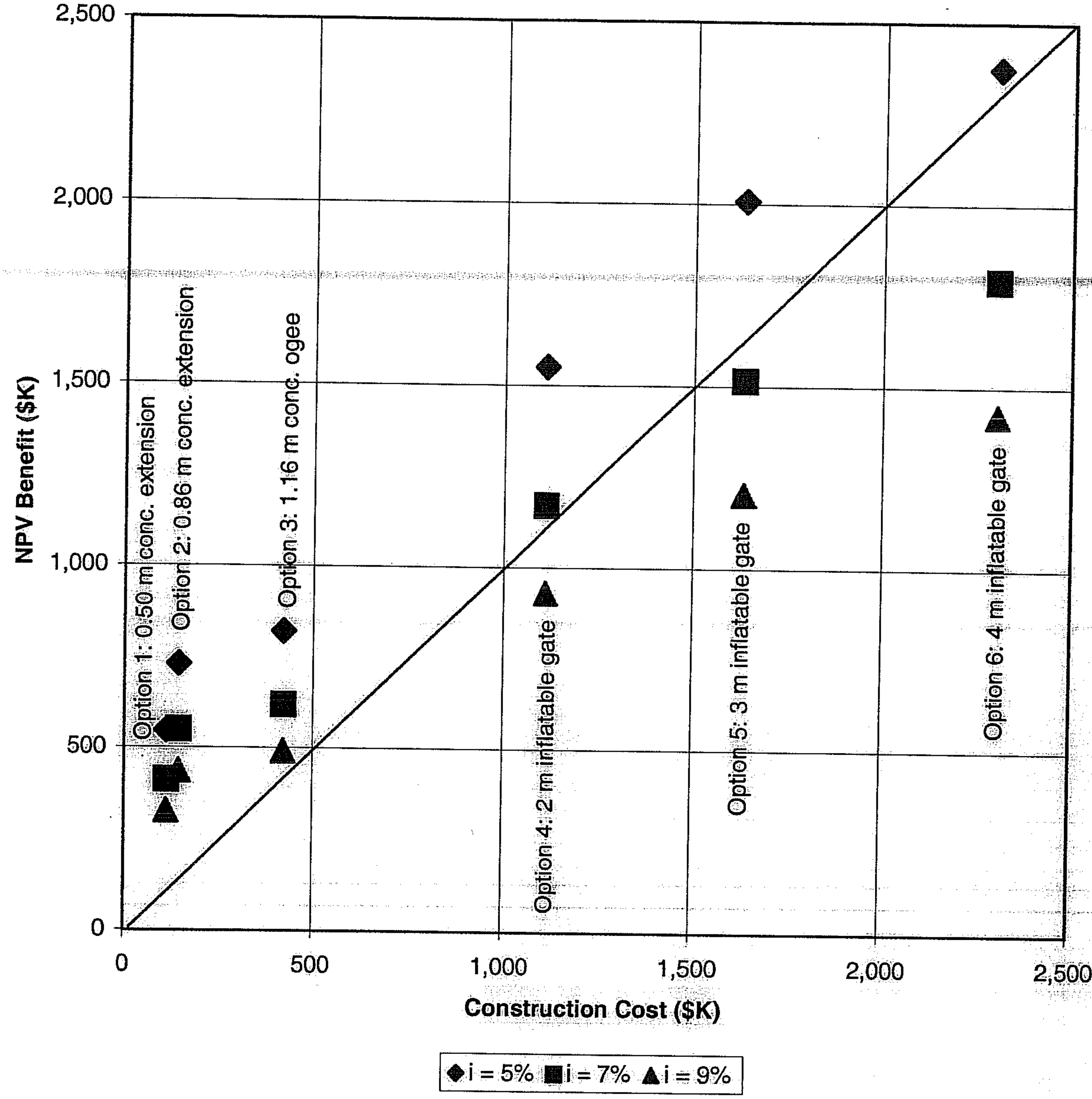


SGE Acres

Figure 5
Benefit and Construction Cost
Rose Blanche Study of Modifications to Increase Energy
Newfoundland Power

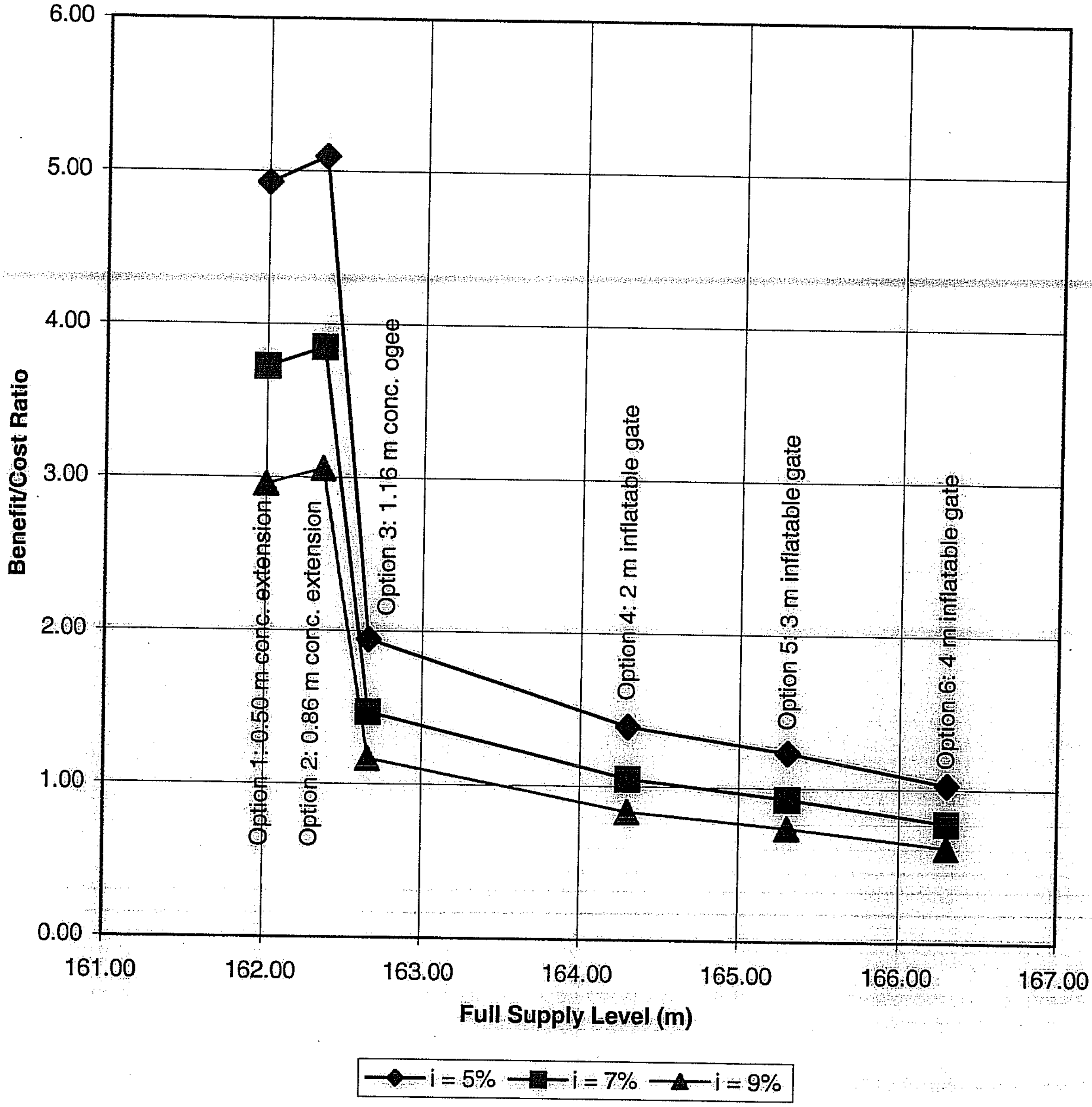


Figure 6
Benefit/Cost Ratio
Rose Blanche Study of Modifications to Increase Energy
Newfoundland Power

SGE Acres

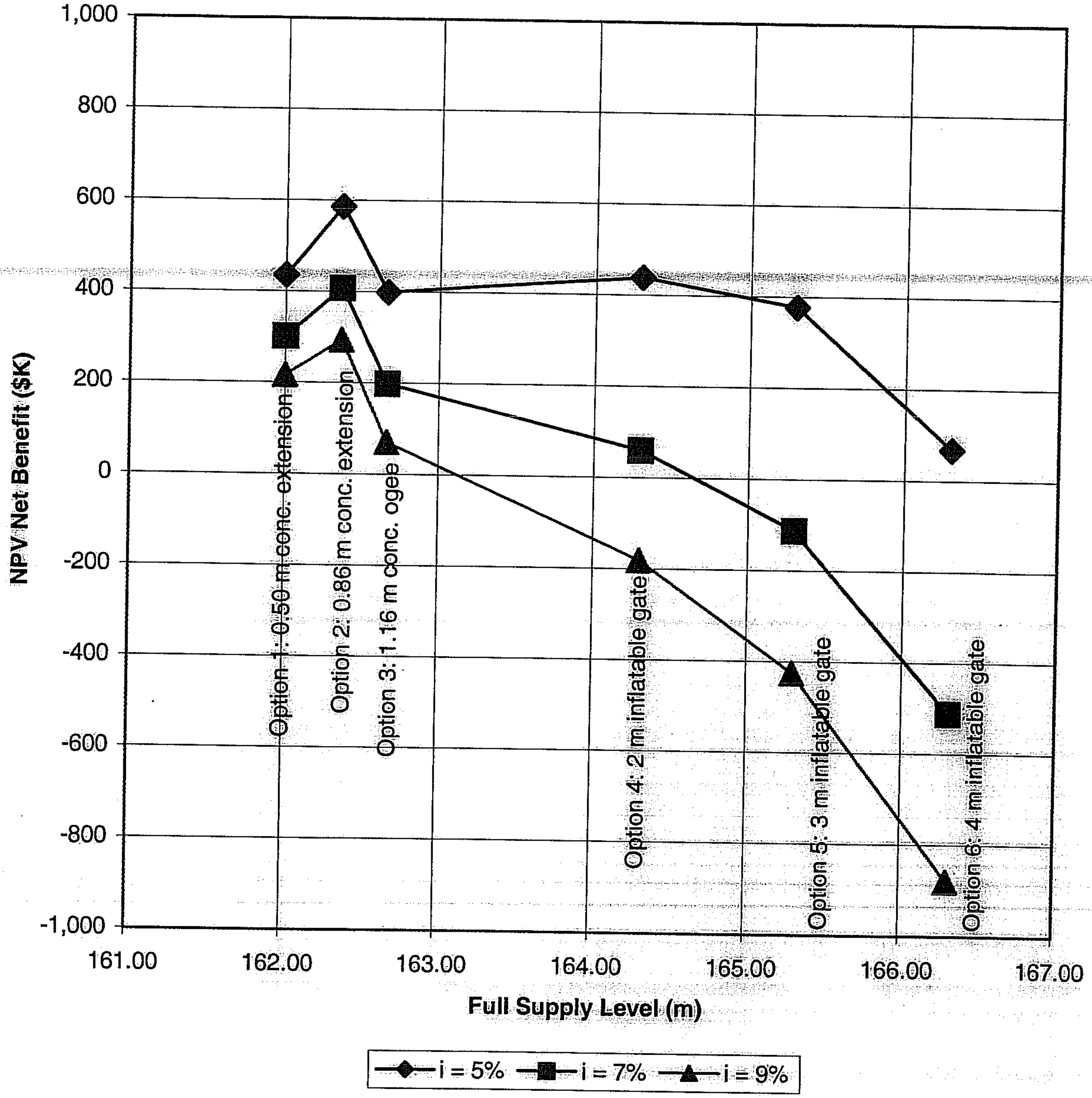
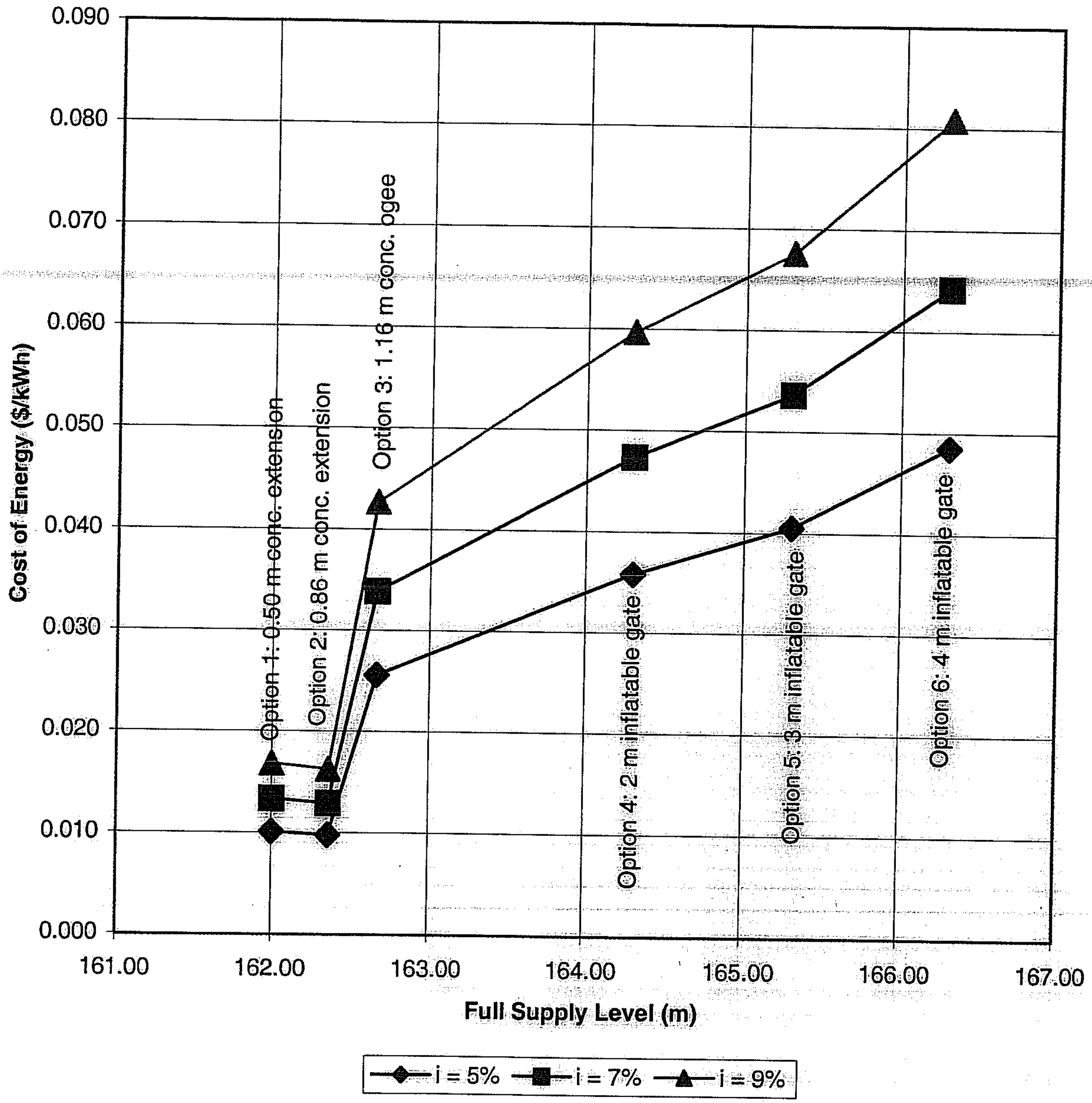


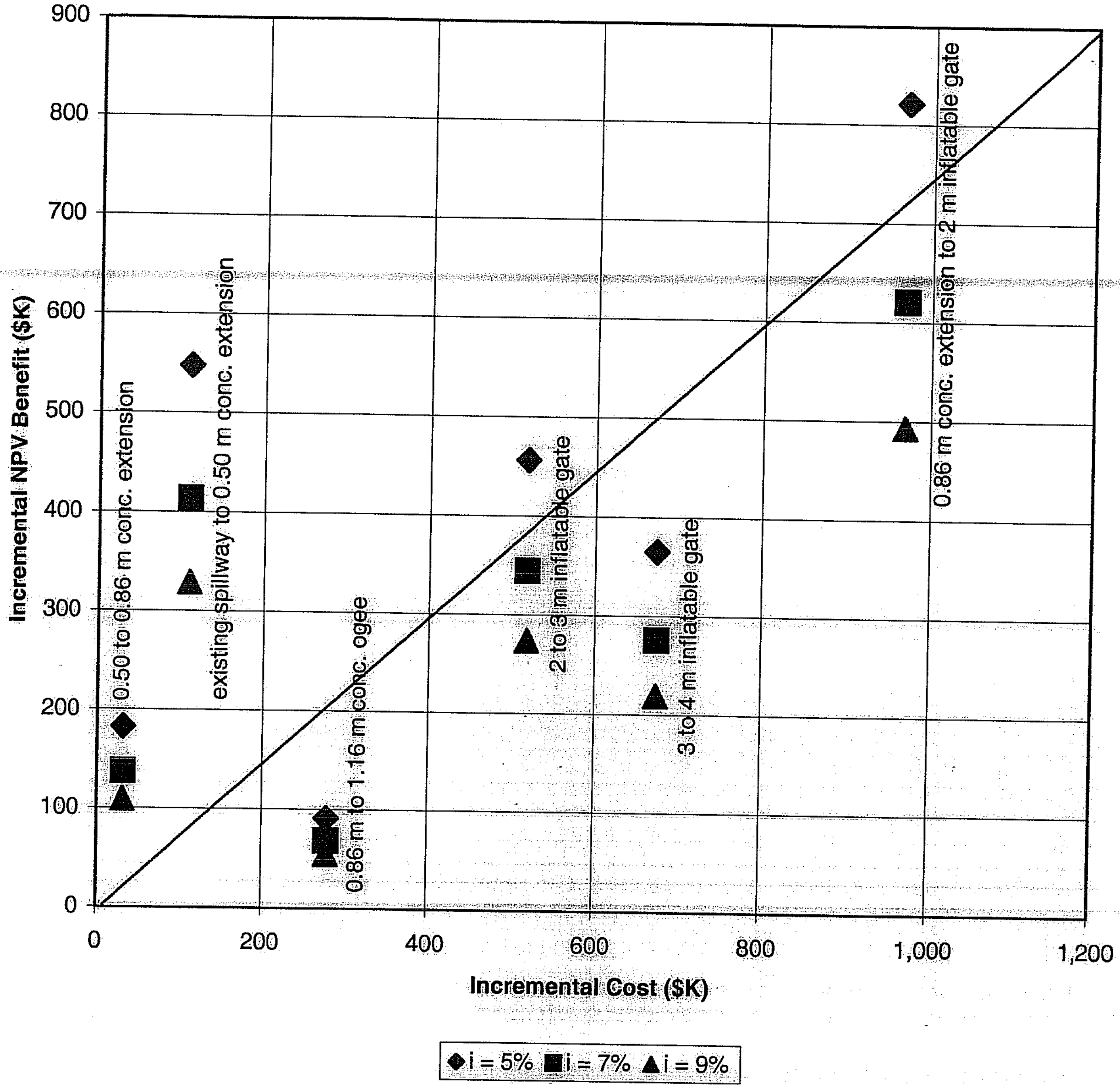
Figure 7
Net Benefit
Rose Blanche Study of Modifications to Increase Energy
Newfoundland Power

SGE Acres



SGE Acres

Figure 8
Cost of Energy
Rose Blanche Study of Modifications to Increase Energy
Newfoundland Power



SGE Acres

Figure 9

Incremental Benefit and Incremental Cost

Rose Blanche Study of Modifications to Increase Energy

Newfoundland Power

Rose Blanche Option 1

Priced Bills of Quantities - Unit Price Contract

0.50m Concrete Extension

Item No		Description	Quantity	Unit	Unit Price	Amount	Section Totals	Description
1		**Temporary Construction Facilities & Project Indirects**						
	.1	Engineer's / Owner's site office & services	1	LS	$7,250.00	$7,250.00		one inspector and services
	.3	Temporary Power/Services	1	LS	$4,000.00	$5,000.00		
	.5	Miscellaneous	1	LS	$3,000.00	$3,000.00		
		Sub-Total Item 1					$15,250.00	
2		**Contractors' Accommodation / Mobilization**						
	.1	Contractors' accommodation & subsistence costs	1	LS	$10,250.00	$10,250.00		
	.2	Mobilization / Demobilization	1	LS	$15,000.00	$15,000.00		
		Sub-Total Item 2					$25,250.00	
3		**Construction Works**						
	.1	**Excavation**						
	.12	Downstream of Structure	10	m^3	$25.00	$250.00		
	.13	Upstream of Structure	10	m^3	$25.00	$250.00		
		Sub-Total Item 3					$500.00	
4	.14	**Concrete**						
	.143	Weir						
		Concrete Roughing	33	m^3	$550.00	$18,150.00		20% extra for Wasteage
		Concrete Anchoring/Pumping/Grouting	125	sq.m	$200.00	$25,000.00		
			160	ea	$50.00	$8,000.00		
		Sub-Total Item 4					$51,150.00	
5	0.1	**Fill and Compact**						
	0.12	Spillway	25	m3	$17.50	$437.50		
		Sub-Total Item 5					$437.50	
		Sub-Total					$92,587.50	
6	0.1	**Contingency**						
		Construction Contingency	1	L.S.			$18,517.50	
		Total Construction Costs					$111,105	

Rose Blanche Option 2

Priced Bills of Quantities - Unit Price Contract

0.86m Concrete Extension

Item No		Description	Quantity	Unit	Unit Price	Amount	Section Totals	Description
1		**Temporary Construction Facilities & Project Indirects**						
	.1	Engineer's / Owner's site office & services	1	LS	$14,150.00	$14,150.00		
	.3	Temporary Power/Services	1	LS	$5,000.00	$5,000.00		
	.5	Miscellaneous	1	LS	$3,300.00	$3,300.00		
		Sub-Total Item 1					$22,450.00	
2		**Contractors' Accommodation / Mobilization**						
	.1	Contractors' accommodation & subsistence costs	1	LS	$10,950.00	$10,950.00		
	.2	Mobilization / Demobilization	1	LS	$15,000.00	$15,000.00		
		Sub-Total Item 2					$25,950.00	
3		**Construction Works**						
	.1	**Excavation**						
	.12	Downstream of Structure	12	m^3	$25.00	$300.00		
	.13	Upstream of Structure	12	m^3	$25.00	$300.00		
		Sub-Total Item 3					$600.00	
4	.14	**Concrete**						
	.143	Weir						
		Concrete Roughing	67	m^3	$550.00	$36,850.00		20% extra for Wasteage
		Concrete Anchoring/Pumping/Grouting	125	sq.m	$200.00	$25,000.00		
			160	ea	$50.00	$8,000.00		
		Sub-Total Item 4					$69,850.00	
5	0.1	**Fill and Compact**						
	0.12	Spillway	30	m3	$17.50	$525.00		
		Sub-Total Item 5					$525.00	
		Sub-Total					$119,375.00	
6	0.1	**Contingency**						
		Construction Contingency	1	L.S.			$23,875.00	
		Total Construction Costs					$143,250	

Rose Blanche Option 3
Priced Bills of Quantities - Unit Price Contract
1.16m Concrete Extension

Item No		Description	Quantity	Unit	Unit Price	Amount	Section Totals	Description
1		**Temporary Construction Facilities & Project Indirects**						
	.1	Engineer's / Owner's site office & services	1	LS	$22,600.00	$22,600.00		
	.3	Temporary Power/Services	1	LS	$10,000.00	$10,000.00		
	.5	Miscellaneous	1	LS	$6,000.00	$6,000.00		
		Sub-Total Item 1					$38,600.00	
2		**Contractors' Accommodation / Mobilization**						
	.1	Contractors' accommodation & subsistence costs	1	LS	$20,000.00	$20,000.00		
	.2	Mobilization / Demobilization	1	LS	$20,000.00	$20,000.00		
		Sub-Total Item 2					$40,000.00	
3		**Construction Works**						
	.1	**Excavation**						
	.13	Upstream of Existing Structure	36	m^3	$25.00	$900.00		
	.14	Downstream of Existing Structure	10	m^3	$50.00	$500.00		
		Sub-Total Item 3					$1,400.00	
4	.14	**Concrete**						
	.143	Weir						
		Concrete Roughing	296	m^3	$800.00	$236,800.00		20% extra for Wasteage
		Concrete Anchoring/Pumping/Grouting	125	sq.m	$200.00	$25,000.00		
			160	ea	$50.00	$8,000.00		
		Sub-Total Item 4					$269,800.00	
5	0.1	**Fill and Compact**						
	0.12	Spillway	85	m3	$17.50	$1,487.50		
		Sub-Total Item 5					$1,487.50	
		Sub-Total					$351,287.50	
6	0.1	**Contingency**						
		Construction Contingency	1	L.S.			$70,257.50	
		Total Construction Costs					$421,545	

Rose Blanche Option 4

Priced Bills of Quantities - Unit Price Contract

Concrete Extension with 2m Inflatable Gate

Item No.		Description	Quantity	Unit	Unit Price	Amount	Section Totals	Description
1		**Temporary Construction Facilities & Project Indirects**						
	.1	Engineer's / Owner's site office & services	1	LS	$32,350.00	$32,350.00		
	.3	Temporary Power/Services	1	LS	$10,000.00	$10,000.00		
	.5	Miscellaneous	1	LS	$6,000.00	$6,000.00		
		Sub-Total Item 1					**$48,350.00**	
2		**Contractors' Accommodation / Mobilization**						
	.1	Contractors' accommodation & subsistence costs	1	LS	$23,000.00	$23,000.00		
	.2	Mobilization / Demobilization	1	LS	$20,000.00	$20,000.00		
		Sub-Total Item 2					**$43,000.00**	
3		**Construction Works**						
	.1	**Excavation**						
	.13	Upstream of Existing Structure	33	m^3	$25.00	$825.00		
	.14	Downstream of Existing Structure	10	m^3	$50.00	$500.00		
		Sub-Total Item 3					$1,325.00	
4	.14	Concrete						
	.143	Weir	305	m^3	$550.00	$167,750.00		20% extra for Wasteage
		Concrete Roughing	125	sq.m	$200.00	$25,000.00		
		Concrete Anchoring/Pumping/Grouting	160	ea	$50.00	$8,000.00		
		Sub-Total Item 4					$200,750.00	
5	0.1	Fill and Compact						
	0.12	Spillway	85	m3	$17.50	$1,487.50		
		Sub-Total Item 5					**$1,487.50**	
6	0.1	**Rubber Gate**						
		Rubber Dam	1	LS	$460,000.00	$460,000.00		
		Gate House	1	LS	$34,000.00	$34,000.00		
		Electrical Power	1.50	km	$52,000.00	$78,000.00		
		Installation of Rubber Dam	1	LS	$37,000.00	$37,000.00		
		Concrete end Walls	16	m3	$800.00	$12,800.00		Include: Rock anchoring.
		Pump House Slab	13	m3	$800.00	$10,400.00		
		Sub-Total Item 6						
							$632,200.00	
		Sub-Total					**$927,112.50**	
6	0.1	**Contingency**						
		Construction Contingency	1	L.S.			**$185,422.50**	
		Total Construction Costs					**$1,112,535**	

Rose Blanche Option 5

Priced Bills of Quantities - Unit Price Contract

Concrete Extension with 3.0m Inflatable Gate

Item No.		Description	Quantity	Unit	Unit Price	Amount	Section Totals	Description
1		Temporary Construction Facilities & Project Indirects						
	.1	Engineer's / Owner's site office & services	1	LS	$32,350.00	$32,350.00		
	.3	Temporary Power/Services	1	LS	$10,000.00	$10,000.00		
	.5	Miscellaneous	1	LS	$6,000.00	$6,000.00		
		Sub-Total Item 1					$48,350.00	
2		Contractors' Accommodation / Mobilization						
	.1	Contractors' accommodation & subsistence costs	1	LS	$23,000.00	$23,000.00		
	.2	Mobilization / Demobilization	1	LS	$20,000.00	$20,000.00		
		Sub-Total Item 2					$43,000.00	
3		Construction Works						
	.1	Excavation						
	.13	Upstream of Existing Structure	50	m^3	$25.00	$1,250.00		
	.14	Downstream of Existing Structure	10	m^3	$50.00	$500.00		
		Sub-Total Item 3					$1,750.00	
4	.14	Concrete						
	.143	Weir						
		Concrete Roughing	450	m^3	$550.00	$247,500.00		20% extra for Wasteage
		Concrete Anchoring/Pumping/Grouting	125	sq.m	$200.00	$25,000.00		
			160	ea	$50.00	$8,000.00		
		Sub-Total Item 4					$280,500.00	
5	0.1	Fill and Compact						
	0.12	Spillway	75	m3	$17.50	$1,312.50		
		Sub-Total Item 5					$1,312.50	
6	0.1	Rubber Gate						
		Rubber Dam	1	LS	$800,000.00	$800,000.00		
		Gate House	1	LS	$34,000.00	$34,000.00		
		Electrical Power	1.50	km	$52,000.00	$78,000.00		
		Installation of Rubber Dam	1	LS	$37,000.00	$37,000.00		
		Concrete end Walls	30	m3	$800.00	$24,000.00		include. Rock anchoring
		Pump House Slab	13	m3	$800.00	$10,400.00		
		Sub-Total Item 6					$983,400.00	
		Sub-Total					$1,358,312.50	
6	0.1	Contingency						
		Construction Contingency	1	L.S.			$271,662.50	
		Total Construction Costs					$1,629,975	

Rose Blanche Option 6

Priced Bills of Quantities - Unit Price Contract

Concrete Extension with 4.0m Inflatable Gate

Item No		Description	Quantity	Unit	Unit Price	Amount	Section Totals	Description
1		Temporary Construction Facilities & Project Indirects						
	.1	Engineer's / Owner's site office & services	1	LS	$32,350.00	$32,350.00		
	.3	Temporary Power/Services	1	LS	$10,000.00	$10,000.00		
	.5	Miscellaneous	1	LS	$6,000.00	$6,000.00		
		Sub-Total Item 1					$48,350.00	
2		Contractors' Accommodation / Mobilization						
	.1	Contractors' accommodation & subsistence costs	1	LS	$23,000.00	$23,000.00		
	.2	Mobilization / Demobilization	1	LS	$20,000.00	$20,000.00		
		Sub-Total Item 2					$43,000.00	
3		Construction Works						
	.1	Excavation						
	.13	Upstream of Existing Structure	67	m^3	$25.00	$1,675.00		
	.14	Downstream of Existing Structure	10	m^3	$50.00	$500.00		
		Sub-Total Item 3					$2,175.00	
4	.14	Concrete						
	.143	Weir	600	m^3	$550.00	$330,000.00		20% extra for Wasteage
		Concrete Roughing	125	sq.m	$200.00	$25,000.00		
		Concrete Anchoring/Pumping/Grouting	160	ea	$50.00	$8,000.00		
		Sub-Total Item 4					$363,000.00	
5	0.1	Fill and Compact						
	0.12	Spillway	75	m3	$17.50	$1,312.50		
		Sub-Total Item 5					$1,312.50	
6	0.1	Rubber Gate						
		Rubber Dam	1	LS	$1,260,000.00	$1,260,000.00		
		Gate House	1	LS	$34,000.00	$34,000.00		
		Electrical Power	1.50	km	$52,000.00	$78,000.00		
		Installation of Rubber Dam	1	LS	$37,000.00	$37,000.00		
		Concrete End Walls	54	m3	$800.00	$43,200.00		include rock anchoring
		Pump House Slab	13	m3	$800.00	$10,400.00		
		Sub-Total Item 6					$1,462,600.00	
		Sub-Total					$1,920,437.50	
6	0.1	Contingency						
		Construction Contingency	1	L.S.			$384,087.50	
		Total Construction Costs					**$2,304,525**	

Appendix B

Photos of Rose Blanche Development

Picture 1: Main Dam

Picture 2: Existing Concrete Overflow Spillway

Picture 3: Spillway Channel

Picture 4: Spill Conditions

Appendix C

Feasibility Analysis

Table of Contents

1.0 Introduction

This feasibility analysis was completed by Newfoundland Power to determine the most feasible alternative to reduce spill and increase the energy production at Newfoundland Power's Rose Blanche hydroelectric development.

The capital costs and energy benefits utilized for each alternative to complete the analysis were provided by Hatch based on their research and experience in hydroelectric system modelling including experience designing and constructing these types of structures. The capital costs and energy benefits were used to determine the levelized cost of the energy for each alternative.

The results of the analysis are presented in this report.

2.0 Capital Costs and Energy Benefits

Two options were assessed to determine the most feasible alternative to increase the energy production at Rose Blanche hydro development. For each option the capital cost and the energy benefit was estimated by Hatch and is summarized in Table 1.

Table 1
Capital Costs and Energy Benefits

Option	Capital Cost (000's)	Energy Benefit (GWh)
0.86 m concrete extension (rectangular)	$227	0.7
1.16 m concrete extension (ogee)	$465	0.9

3.0 Financial Analysis

An overall financial analysis of combined capital costs and energy benefits has been completed for both options using the levelized cost of energy approach. The results of this analysis are included in Attachment A. The levelized cost of energy is representative of the revenue requirement to support the capital costs associated with increasing the elevation of the spillway at Rose Blanche.

The estimated levelized cost for each option is summarized in Table 2.

Table 2
Levelized Cost

Option	Levelized Cost (cents/kWh)
0.86 m concrete extension (rectangular)	2.547
1.16 m concrete extension (ogee)	4.060

4.0 Recommendation

The results of the feasibility analysis show that the levelized cost for both options are lower than energy from sources such as a new hydroelectric development or additional Holyrood thermal generation. Incremental energy from Holyrood thermal generating station is estimated at 10.63 cents per kWh in the short term (assuming $67.00 per barrel), with an associated levelized cost of 13.90 cents per kWh.[1]

Based on these results it is recommended that Newfoundland Power proceed with the 1.16 m concrete extension to increase the height of the spillway at Rose Blanche. The expected new annual energy output at Rose Blanche is 21.6 GWhr.

[1] Incremental energy from the Holyrood thermal generating station is estimated at 10.63 cents per kWh for 2009 (based upon $67.00 per barrel of No. 6 fuel from Hydro's fuel price projection dated March 31, 2008), with associated levelized cost of 12.84 cents per kWh over 25 years and 13.90 cents per kWh over 50 years.

Attachment A
Calculation of Levelized Cost of Energy

Option 1 - 0.86 m Concrete Extension

Weighted Average Incremental Cost of Capital	7.27%
Escalation Rate	
PW Year	2008

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized (¢/kWhr) 50 years	Rev Rqmt
2009	**226,800**	**0**	19,572	**0**	**0**	-19,572	-18,245	-18,245	2.796	2.547	
2010	**0**	**0**	18,414	**0**	0	-18,414	-16,003	-34,248	2.631	2.547	
2011	**0**	**0**	18,778	**0**	0	-18,778	-15,213	-49,462	2.683	2.547	
2012	**0**	**0**	19,017	**0**	0	-19,017	-14,362	-63,824	2.717	2.547	
2013	**0**	**0**	19,122	**0**	0	-19,122	-13,463	-77,287	2.732	2.547	
2014	**0**	**0**	19,188	**0**	0	-19,188	-12,594	-89,881	2.741	2.547	
2015	**0**	**0**	19,219	**0**	0	-19,219	-11,760	-101,641	2.746	2.547	
2016	**0**	**0**	19,218	**0**	0	-19,218	-10,962	-112,602	2.745	2.547	
2017	**0**	**0**	19,186	**0**	0	-19,186	-10,202	-122,804	2.741	2.547	
2018	**0**	**0**	19,127	**0**	0	-19,127	-9,481	-132,286	2.732	2.547	
2019	**0**	**0**	19,042	**0**	0	-19,042	-8,800	-141,085	2.720	2.547	
2020	**0**	**0**	18,935	**0**	0	-18,935	-8,157	-149,242	2.705	2.547	
2021	**0**	**0**	18,805	**0**	0	-18,805	-7,552	-156,794	2.686	2.547	
2022	**0**	**0**	18,656	**0**	0	-18,656	-6,984	-163,778	2.665	2.547	
2023	**0**	**0**	18,488	**0**	0	-18,488	-6,452	-170,231	2.641	2.547	
2024	**0**	**0**	18,304	**0**	0	-18,304	-5,955	-176,186	2.615	2.547	
2025	**0**	**0**	18,105	**0**	0	-18,105	-5,491	-181,677	2.586	2.547	
2026	**0**	**0**	17,891	**0**	0	-17,891	-5,058	-186,735	2.556	2.547	
2027	**0**	**0**	17,664	**0**	0	-17,664	-4,656	-191,391	2.523	2.547	
2028	**0**	**0**	17,425	**0**	0	-17,425	-4,282	-195,673	2.489	2.547	
2029	**0**	**0**	17,175	**0**	0	-17,175	-3,934	-199,607	2.454	2.547	
2030	**0**	**0**	16,915	**0**	0	-16,915	-3,612	-203,219	2.416	2.547	
2031	**0**	**0**	16,646	**0**	0	-16,646	-3,314	-206,533	2.378	2.547	
2032	**0**	**0**	16,368	**0**	0	-16,368	-3,038	-209,571	2.338	2.547	
2033	**0**	**0**	16,082	**0**	0	-16,082	-2,782	-212,353	2.297	2.547	
2034	**0**	**0**	15,789	**0**	0	-15,789	-2,546	-214,899	2.256	2.547	
2035	**0**	**0**	15,490	**0**	0	-15,490	-2,329	-217,228	2.213	2.547	
2036	**0**	**0**	15,184	**0**	0	-15,184	-2,128	-219,356	2.169	2.547	
2037	**0**	**0**	14,872	**0**	0	-14,872	-1,943	-221,299	2.125	2.547	
2038	**0**	**0**	14,555	**0**	0	-14,555	-1,773	-223,072	2.079	2.547	
2039	**0**	**0**	14,234	**0**	0	-14,234	-1,616	-224,688	2.033	2.547	
2040	**0**	**0**	13,908	**0**	0	-13,908	-1,472	-226,160	1.987	2.547	
2041	**0**	**0**	13,578	**0**	0	-13,578	-1,340	-227,500	1.940	2.547	
2042	**0**	**0**	13,244	**0**	0	-13,244	-1,218	-228,718	1.892	2.547	
2043	**0**	**0**	12,907	**0**	0	-12,907	-1,107	-229,825	1.844	2.547	
2044	**0**	**0**	12,566	**0**	0	-12,566	-1,005	-230,830	1.795	2.547	
2045	**0**	**0**	12,223	**0**	0	-12,223	-911	-231,741	1.746	2.547	
2046	**0**	**0**	11,877	**0**	0	-11,877	-825	-232,566	1.697	2.547	
2047	**0**	**0**	11,529	**0**	0	-11,529	-747	-233,313	1.647	2.547	
2048	**0**	**0**	11,178	**0**	0	-11,178	-675	-233,987	1.597	2.547	
2049	**0**	**0**	10,825	**0**	0	-10,825	-609	-234,597	1.546	2.547	
2050	**0**	**0**	10,471	**0**	0	-10,471	-549	-235,146	1.496	2.547	
2051	**0**	**0**	10,114	**0**	0	-10,114	-495	-235,641	1.445	2.547	
2052	**0**	**0**	9,756	**0**	0	-9,756	-445	-236,086	1.394	2.547	
2053	**0**	**0**	9,396	**0**	0	-9,396	-399	-236,485	1.342	2.547	
2054	**0**	**0**	9,036	**0**	0	-9,036	-358	-236,843	1.291	2.547	
2055	**0**	**0**	8,673	**0**	0	-8,673	-320	-237,164	1.239	2.547	
2056	**0**	**0**	8,310	**0**	0	-8,310	-286	-237,450	1.187	2.547	
2057	**0**	**0**	7,946	**0**	0	-7,946	-255	-237,705	1.135	2.547	
2058	**0**	**0**	7,580	**0**	0	-7,580	-227	-237,932	1.083	2.547	
2059	**0**	**0**	7,214	**0**	0	-7,214	-201	-238,133	1.031	2.547	
2060	**0**	**0**	6,847	**0**	0	-6,847	-178	-238,311	0.978	2.547	
2061	**0**	**0**	6,479	**0**	0	-6,479	-157	-238,468	0.926	2.547	
2062	**0**	**0**	6,110	**0**	0	-6,110	-138	-238,606	0.873	2.547	
2063	**0**	**0**	5,741	**0**	0	-5,741	-121	-238,727	0.820	2.547	
2064	**0**	**0**	5,371	**0**	0	-5,371	-106	-238,833	0.767	2.547	

Option 2 - 1.16 m Concrete Extension

Weighted Average Incremental Cost of Capital	7.27%
Escalation Rate	
PW Year	2008

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized (¢/kWhr) 50 years	Rev Rqmt
2009	**464,800**	**0**	40,110	**0**	**0**	-40,110	-37,392	-37,392	4.457	4.060	
2010	**0**	**0**	37,738	**0**	0	-37,738	-32,796	-70,188	4.193	4.060	
2011	**0**	**0**	38,484	**0**	0	-38,484	-31,178	-101,366	4.276	4.060	
2012	**0**	**0**	38,973	**0**	0	-38,973	-29,434	-130,800	4.330	4.060	
2013	**0**	**0**	39,188	**0**	0	-39,188	-27,591	-158,390	4.354	4.060	
2014	**0**	**0**	39,324	**0**	0	-39,324	-25,810	-184,201	4.369	4.060	
2015	**0**	**0**	39,388	**0**	0	-39,388	-24,100	-208,301	4.376	4.060	
2016	**0**	**0**	39,385	**0**	0	-39,385	-22,465	-230,765	4.376	4.060	
2017	**0**	**0**	39,320	**0**	0	-39,320	-20,908	-251,673	4.369	4.060	
2018	**0**	**0**	39,199	**0**	0	-39,199	-19,431	-271,104	4.355	4.060	
2019	**0**	**0**	39,025	**0**	0	-39,025	-18,034	-289,138	4.336	4.060	
2020	**0**	**0**	38,804	**0**	0	-38,804	-16,716	-305,854	4.312	4.060	
2021	**0**	**0**	38,539	**0**	0	-38,539	-15,477	-321,331	4.282	4.060	
2022	**0**	**0**	38,233	**0**	0	-38,233	-14,313	-335,644	4.248	4.060	
2023	**0**	**0**	37,890	**0**	0	-37,890	-13,224	-348,868	4.210	4.060	
2024	**0**	**0**	37,512	**0**	0	-37,512	-12,205	-361,072	4.168	4.060	
2025	**0**	**0**	37,103	**0**	0	-37,103	-11,253	-372,325	4.123	4.060	
2026	**0**	**0**	36,665	**0**	0	-36,665	-10,367	-382,692	4.074	4.060	
2027	**0**	**0**	36,200	**0**	0	-36,200	-9,542	-392,234	4.022	4.060	
2028	**0**	**0**	35,711	**0**	0	-35,711	-8,775	-401,009	3.968	4.060	
2029	**0**	**0**	35,199	**0**	0	-35,199	-8,063	-409,071	3.911	4.060	
2030	**0**	**0**	34,666	**0**	0	-34,666	-7,403	-416,474	3.852	4.060	
2031	**0**	**0**	34,114	**0**	0	-34,114	-6,791	-423,265	3.790	4.060	
2032	**0**	**0**	33,545	**0**	0	-33,545	-6,225	-429,490	3.727	4.060	
2033	**0**	**0**	32,959	**0**	0	-32,959	-5,702	-435,192	3.662	4.060	
2034	**0**	**0**	32,358	**0**	0	-32,358	-5,219	-440,411	3.595	4.060	
2035	**0**	**0**	31,744	**0**	0	-31,744	-4,773	-445,183	3.527	4.060	
2036	**0**	**0**	31,117	**0**	0	-31,117	-4,361	-449,544	3.457	4.060	
2037	**0**	**0**	30,479	**0**	0	-30,479	-3,982	-453,527	3.387	4.060	
2038	**0**	**0**	29,829	**0**	0	-29,829	-3,633	-457,160	3.314	4.060	
2039	**0**	**0**	29,170	**0**	0	-29,170	-3,312	-460,472	3.241	4.060	
2040	**0**	**0**	28,502	**0**	0	-28,502	-3,017	-463,489	3.167	4.060	
2041	**0**	**0**	27,826	**0**	0	-27,826	-2,746	-466,235	3.092	4.060	
2042	**0**	**0**	27,142	**0**	0	-27,142	-2,497	-468,732	3.016	4.060	
2043	**0**	**0**	26,451	**0**	0	-26,451	-2,268	-471,000	2.939	4.060	
2044	**0**	**0**	25,753	**0**	0	-25,753	-2,059	-473,059	2.861	4.060	
2045	**0**	**0**	25,050	**0**	0	-25,050	-1,867	-474,926	2.783	4.060	
2046	**0**	**0**	24,341	**0**	0	-24,341	-1,691	-476,617	2.705	4.060	
2047	**0**	**0**	23,627	**0**	0	-23,627	-1,530	-478,147	2.625	4.060	
2048	**0**	**0**	22,908	**0**	0	-22,908	-1,383	-479,530	2.545	4.060	
2049	**0**	**0**	22,185	**0**	0	-22,185	-1,249	-480,779	2.465	4.060	
2050	**0**	**0**	21,458	**0**	0	-21,458	-1,126	-481,904	2.384	4.060	
2051	**0**	**0**	20,728	**0**	0	-20,728	-1,014	-482,918	2.303	4.060	
2052	**0**	**0**	19,994	**0**	0	-19,994	-912	-483,830	2.222	4.060	
2053	**0**	**0**	19,257	**0**	0	-19,257	-819	-484,649	2.140	4.060	
2054	**0**	**0**	18,517	**0**	0	-18,517	-734	-485,382	2.057	4.060	
2055	**0**	**0**	17,775	**0**	0	-17,775	-657	-486,039	1.975	4.060	
2056	**0**	**0**	17,030	**0**	0	-17,030	-586	-486,626	1.892	4.060	
2057	**0**	**0**	16,284	**0**	0	-16,284	-523	-487,148	1.809	4.060	
2058	**0**	**0**	15,535	**0**	0	-15,535	-465	-487,613	1.726	4.060	
2059	**0**	**0**	14,784	**0**	0	-14,784	-412	-488,026	1.643	4.060	
2060	**0**	**0**	14,032	**0**	0	-14,032	-365	-488,391	1.559	4.060	
2061	**0**	**0**	13,278	**0**	0	-13,278	-322	-488,713	1.475	4.060	
2062	**0**	**0**	12,522	**0**	0	-12,522	-283	-488,996	1.391	4.060	
2063	**0**	**0**	11,765	**0**	0	-11,765	-248	-489,244	1.307	4.060	
2064	**0**	**0**	11,008	**0**	0	-11,008	-216	-489,460	1.223	4.060	

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects an income tax rate of 33.0%.

Operating Costs: Operating Costs were assumed to be $86,554 escalated yearly using GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55%	5.90	3.25
Common Equity	45%	8.95	4.03
Total	**100%**		**7.27**

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.
43.2	50.00%	Equipment designed to produce energy in a more efficient way.

Escalation Factors: Conference Board of Canada GDP Deflator.

2009 Substation Refurbishment and Modernization

June 2008

Prepared by:

G. Richard Spurrell, P.Eng.

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1.0 Substation Modernization and Refurbishment Strategy

Newfoundland Power's (the "Company") substations serve a critical role in providing service to its customers. The Company's substation maintenance program and the *Substation Modernization and Refurbishment* project ensures reliable, least cost power is provided to customers in a safe and environmentally responsible manner.

In the 2007 Capital Budget Application, the Company submitted its *Substation Strategic Plan*. This plan outlined a structured approach for the overall refurbishment and modernization of its substations that will be coordinated with ongoing major equipment maintenance and replacement activities. The substation plan coincides with the maintenance cycle for major substation equipment. This coordination minimizes customer service interruptions and improves productivity.

In preparation of annual capital budgets, substations are assessed with particular consideration given to the physical condition of core infrastructure and equipment. Due to changing priorities, ongoing reliability issues, inspection and asset condition data, the scheduling of work in a particular substation in a given year may be altered.

The current five-year forecast for the Refurbishment and Modernization Capital Plan is shown in Appendix A.

2.0 Substation Modernization and Refurbishment 2009 Projects

Since the filing of the 2008 Capital Budget Application in June of 2007, three significant substation projects have arisen. The replacement of the Pierre's Brook power transformer[1] came about as the result of an in-service failure of the 66 year old unit. The other two projects have come about as Newfoundland Hydro has entered into power purchase agreements with two wind energy proponents that involve interconnection of two wind farms to the Company's substations at St. Lawrence and Fermeuse[2]. Newfoundland Hydro and the wind energy proponents have requested the interconnection with Newfoundland Power to occur in 2008.

None of these three projects were included in the original substation capital work plan for 2008. Newfoundland Power completes most of the design and engineering for substation projects in house. Resources are allocated based upon anticipated workload. The significant unexpected 2008 increase in workload required a re-evaluation of project priorities. To accommodate the work required by these projects Newfoundland Power deferred 5 projects originally included in the 2008 capital budget to the 2009 capital budget. The *Substation Strategic Plan* has been altered to accommodate these changes.

Table 1 is a summary of the Substation Refurbishment and Modernization projects planned in 2009 for nine substations, including the 5 projects carried forward from 2008.

---

1 Project approved in Board order P. U. 3 (2008)

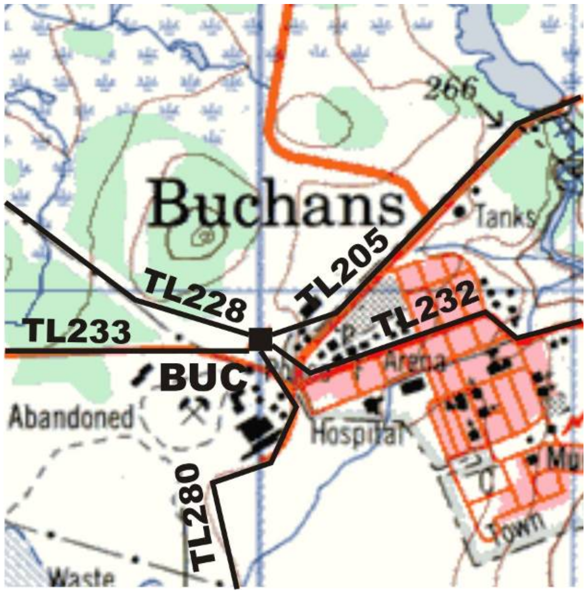
2 Application for supplemental approval filed on May 14, 2008.

Table 1 2009 Substation Projects (000s)	
Substation	**Budget**
Buchans (BUC)	$201
Clarenville (CLV)	530
Doyles (DOY)	125
Gander (GAN)	602
Grand Falls (GFS)	646
Kings Bridge (KBR)	1,258
Kelligrews (KEL)	137
Oxen Pond (OXP)	161
Rocky Pond (ROP)	442
Total	**$4,102**

The following pages outline the capital work required in each substation.

2.1 Buchans Substation ($201,000)

Buchans substation is a joint Newfoundland and Labrador Hydro and Newfoundland Power substation. Newfoundland Power's portion of the substation consists of the equipment to terminate its two 12.5 kV distribution feeders. The substation serves approximately 700 customers in the Buchans area. Buchans BUC-01 feeder also connects Abitibi Price's 2.0 MW hydro plant on Buchans Lake to the Island Interconnected System.

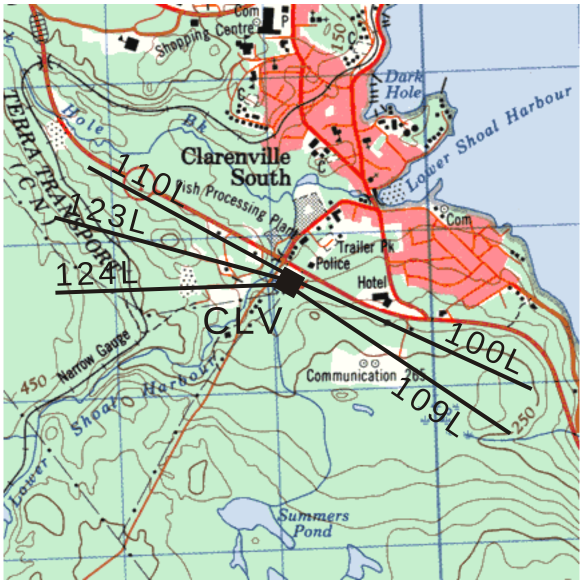


Buchans Substation Location

Maintenance records and on-site engineering assessment show that the 12.5 kV equipment is in good condition with no signs of deterioration. The two reclosers will be replaced and an RTU installed to automate the feeders for remote control.

2.2 Clarenville Substation ($530,000)

Clarenville substation was built in 1966 as a transmission switching station for the Bonavista Peninsula and also as a 12.5 kV distribution substation for the Clarenville area. The substation contains two power transformers (T1 & T2). Transformer T1 is a 138 kV to 66 kV, 25 MVA transformer serving the Bonavista Peninsula. T2 is a 138 kV to 12.5 kV, 20 MVA power transformer serving approximately 2,000 customers in the Clarenville area through three 12.5 kV feeders.



Clarenville Substation Location

There are four 138 kV transmission lines and one 66 kV transmission line terminated in the substation. The 138 kV transmission lines are 100L to Sunnyside substation, 109L to Northwest Brook substation, 124L to Port Blandford substation and 123L to Catalina substation. The 66 kV transmission line is 110L to Milton substation.

Maintenance records and on-site engineering assessments show that the 138 kV and 12.5 kV steel structures and concrete foundations are in good condition with no sign of deterioration. The 66 kV wood pole structure is also in good condition. The power transformers are in good condition with no signs of deterioration.

Clarenville Substation

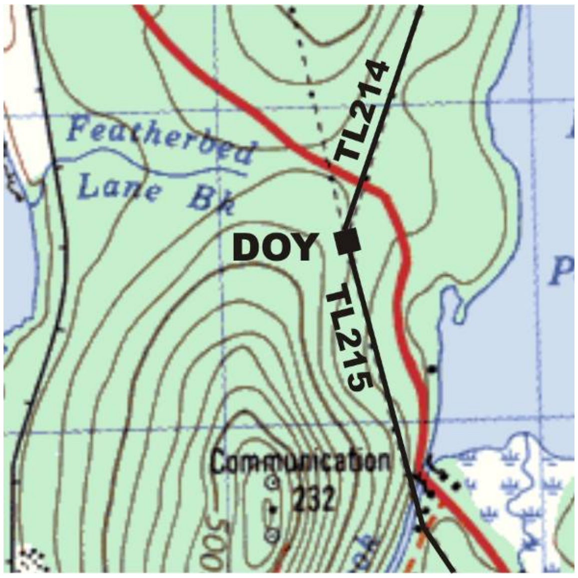
The lightning arrestors on the transformers are silicon carbide and require replacement with metal oxide arrestors. Small animal protection will be installed on the 12.5 kV equipment and bus.

The three 12.5 kV feeders will have relaying replaced and be automated to allow remote control from the System Control Centre. The transmission line relaying on 100L and 109L will be replaced as this relaying is in excess of 40 years old. The transmission line relaying on 123L and 124L will be replaced and consolidated on one panel to provide space in the control room for the feeder panels and the communications equipment. To facilitate continuity of service, a by-pass switch will be installed across the breaker on line 110L. Installation of the bypass switch will enable the breaker to be taken out of service for maintenance without disruption of service to customers.

66 kV Breaker By-pass Switch To Be Installed On 110L

2.3 Doyles Substation ($125,000)

Doyles substation is a joint Newfoundland and Labrador Hydro and Newfoundland Power substation. Newfoundland Power's portion of the substation consist of the distribution power transformer T2 and the 25 kV distribution equipment for the 25 kV bus and feeder. The single feeder serves approximately 1,550 customers in the Doyles area.

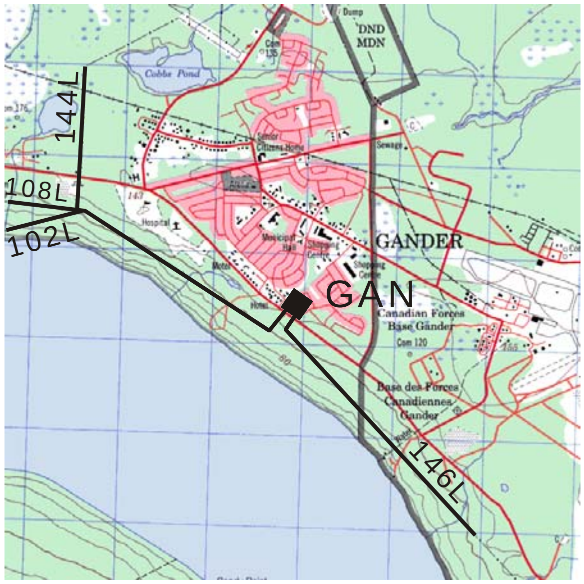


Doyles Substation Location

Maintenance records and on-site engineering assessment shows that the 25 kV equipment is in good condition with no signs of deterioration. The recloser will be replaced and an RTU installed to automate the feeder for remote control.

2.4 Gander Substation ($602,000)

Gander substation was built in 1959 as a distribution substation and over the years has developed into a major transmission and distribution substation. The substation contains one 138 kV to 66 kV, 27 MVA (T2) power transformer, one 138 kV to 12.5 kV, 20 MVA (T1) power transformer and three single phase 66 kV to 6.9 kV, 1.6 MVA (T3) power transformers for providing a ground reference for the 66 kV transmission system. The substation directly serves approximately 1,600 customers in the Gander area through four 12.5 kV feeders.



Gander Substation Location

There are two 138 kV transmission lines terminated in the substation, transmission lines 144L to Cobb's Pond substation and 146L to Gambo substation. There are also two 66 kV transmission lines terminated in the substation, transmission lines 102L to Roycefield substation and 108L to Gander Bay substation.

Maintenance records and on-site engineering assessments show that the 138 kV and 12.5 kV steel structures and 66 kV wood pole structures are in good condition with no signs of deterioration.

Most concrete foundations are in good condition with no signs of deterioration. However, four of the 138 kV structure foundations, one breaker foundation and transformer T3's foundation will require refurbishment.

138 kV Structure Foundation

Transformer T3 Foundation

Power transformers T1 and T2 are in good condition with no obvious signs of deterioration.

Tap changer controllers have a service life of approximately 25 years. Transformer T1 will have the tap changer controls replaced. The lightning arrestors on the high side of transformer T2 are silicon carbide and require replacement with metal oxide arrestors. The grounding transformer T3 (three single phase units) is over 40 years old. Radiators have been cut off and capped due to leaking and there are leaks around the gauge wells of the transformers. These transformers will be replaced with a three phase unit.

The switches in the substation are in good condition with the exception of one 138 kV bus tie switch which is inoperable. This switch will be replaced.

The four 12.5 kV feeders will have relaying replaced and automated to allow remote control from the System Control Centre. The relaying on 146L is over 40 years of age and will be replaced.

2.5 Grand Falls Substation ($646,000)

Grand Falls substation was built in 1959 as a 66 kV to 4.16 kV distribution substation. Today it is a 66 kV transmission substation as well as a 4.16 kV distribution substation. The substation contains one distribution power transformer (T5) with a capacity of 8.4 MVA at 4.16 kV.

Grand Falls Substation Location

This substation directly serves approximately 1,400 customers in the Grand Falls area through four 4.16 kV metal clad switchgear feeders. In the substation there are two 66 kV transmission lines terminated on the high voltage bus. These are transmission lines 105L to Sandy Brook substation and a 66 kV tie line to New Grand Falls substation located on the north side of the TCH.

Maintenance records and on-site engineering assessments show that the 66 kV wood pole structures are in poor condition. The structures are fifty years old with significant signs of deterioration. The structures are leaning considerably and switches will not stay in alignment. The wood pole structures will be replaced with a steel box structure.

Grand Falls Substation 66 kV Wood Pole Structures (Leaning)

The transformer concrete foundation is in good condition with no signs of deterioration. The 4.16 kV switchgear building is of steel construction and is in good condition with no signs of deterioration.

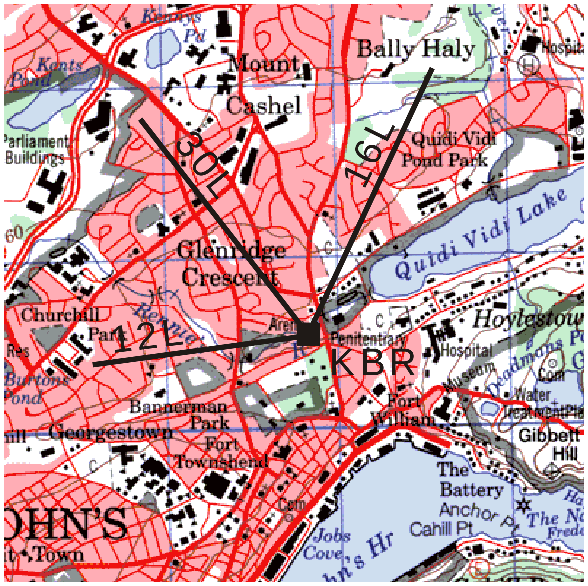
The switchgear building houses the 4.16 kV equipment for the four 4.16 kV feeders, the transmission line protection panels and the 125 V DC battery bank, in one room. A battery room will be constructed for the 125 V DC battery bank and a wall constructed to separate the protection panels from the switchgear to increase personnel safety while working in the building.

Grand Falls - Single Room Switchgear& Control Building

2.6 King's Bridge Substation ($1,258,000)

King's Bridge substation was built in the 1940's as a 33 kV substation. Today it is a 66 kV transmission substation as well as a 4.16 kV and 12.5 kV distribution substation. The substation contains three distribution power transformers (T1, T2 and T3) with a combined capacity of 20 MVA at 4.16 kV and 25 MVA at 12.5 kV.

The substation directly serves approximately 5,500 customers in the King's Bridge Road and Empire Avenue East area of St. John's through eight 4.16 kV metal clad switchgear feeders and four 12.5 kV metal clad switchgear feeders. In the substation there are three 66 kV transmission lines terminated on the high voltage bus. These are transmission lines 12L to Memorial substation, 16L to Pepperrell substation and 30L to Ridge Road substation.



King's Bridge Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV steel structures 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 a 66 kV structure foundation and transformer T2 foundation which will be refurbished.


Concrete Structure Foundation

Kings Bridge substation currently has two buildings, a 12.5 kV switchgear building in the upper yard and a 4.16 kV switchgear building in the lower yard. The 12.5 kV switchgear building installed in 1977 is of steel construction and is showing significant signs of deterioration. This building houses the 12.5 kV equipment for the four 12.5 kV feeders from the substation. This building requires replacement in 2009.

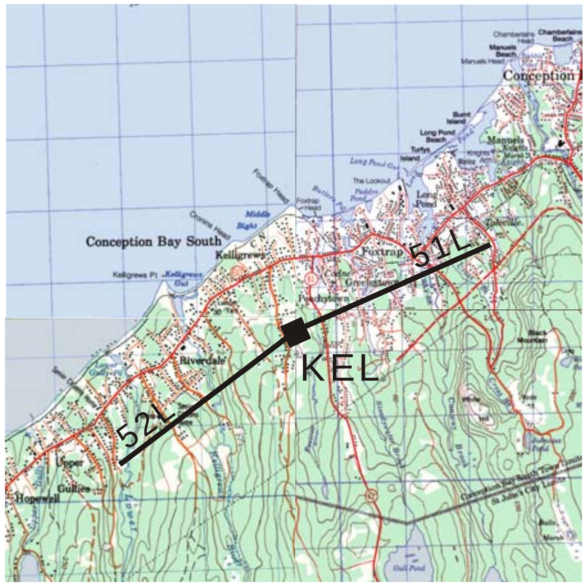

12.5 kV Switchgear Building

The 4.16 kV switchgear building houses the eight 4.16 kV feeders and the transmission line protection panels. These eight feeders and the four 12.5 kV feeders will have relaying replaced and be automated to allow remote control from the System Control Centre. Due to location, the 12.5 kV switchgear replacement building is too small to provide for a separate control room for increased worker safety and there is not enough room in the other existing building to locate it. Therefore, a new control building will be built to accommodate these panels.

The three power transformers are in good condition with no signs of deterioration. The power cables on the two 4.16 kV transformers are 35 years old and require replacement in 2009.

2.7 Kelligrews Substation ($137,000)

Kelligrews substation was built in 1977 as a 12.5 kV distribution substation. The distribution substation contains one power transformer (T1) with a capacity of 15 MVA. The substation directly serves approximately 2,600 customers in the Kelligrews and Upper Gullies areas through two 12.5 kV feeders. There are two 66 kV transmission lines terminated in the substation, transmission lines 51L to Chamberlains substation and 52L to Seal Cove substation.



Kelligrews Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV and 12.5 kV steel structures are in good condition with no signs of deterioration. The concrete structure and equipment foundations are in good condition with no signs of deterioration. The 66 kV and 12.5 kV bus and insulators are also in good condition with no signs of deterioration.

The 25 kV potential transformer shows significant deterioration due to rusting and will be replaced.

25 kV Potential Transformer

The control building is in good condition but the roof shows significant signs of deterioration due to rusting and will be replaced.

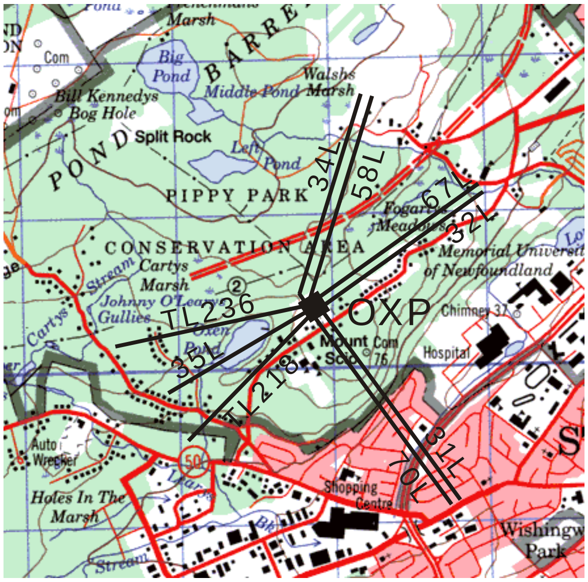
Control Building Roof Deterioration

The power transformer is in good condition with no signs of deterioration. The lightning arrestors on the transformer are silicon carbide and require replacement with new metal oxide arrestors. The power cables connecting the transformer to the low voltage bus are nearing the lifespan of 35 years and require replacement with overhead conductor in 2009.

2.8 Oxen Pond Substation ($161,000)

Oxen Pond substation was built in 1966 as an infeed substation to the City of St. Johns. Today it is one of two major 230 kV in-feed substations serving the City of St. John's and surrounding communities. Newfoundland Power's section of Oxen Pond substation contains one distribution power transformer (T1) and seven 66 kV transmission lines.[3] The distribution transformer T1 has a capacity of 13.3 MVA at 12.5 kV. The substation directly serves approximately 1,150 customers in the Thorburn Road and Mount Scio Road area of St. John's through one 12.5 kV feeder. The seven 66 kV transmission lines terminated on the high voltage bus are 31L and 70L to Stamps Lane substation, 32L and 67L to Ridge Road substation, 34L and 58L to Virginia Waters substation, and 35L to Kenmount substation.

[3] Oxen Pond substation is owned by Newfoundland and Labrador Hydro.



Oxen Pond Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV steel structures are in good condition with no signs of deterioration. The majority of the concrete foundations are in good condition with no signs of deterioration except the foundation on 34L breaker which is deteriorated and requires replacement and one of the foundations for the 12.5 kV steel columns which has some of the anchor bolts rusted off. These will be replaced. Replacement of the structure foundation will require the dismantling and re-assembly of the 12.5 kV structure.

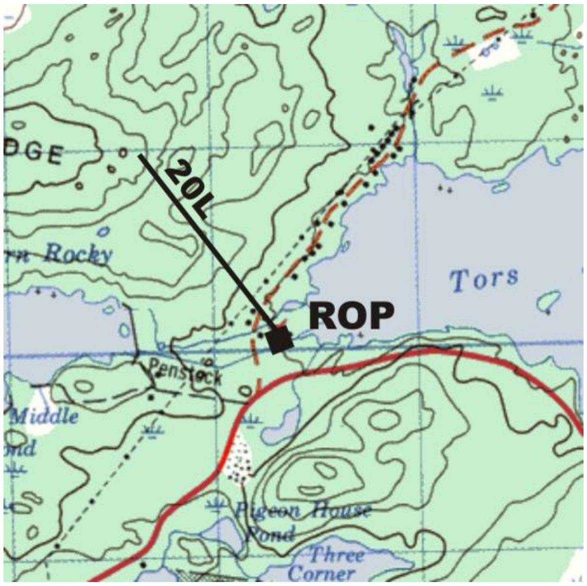

34L Breaker Foundation

The 12.5 kV feeder will have relaying replaced and be automated to allow remote control from the System Control Centre.

Power transformer T1 is in good condition with no obvious signs of deterioration. The lightning arrestors on the transformers are silicon carbide and require replacement with metal oxide arrestors.

2.9 Rocky Pond Substation ($442,000)

Rocky Pond substation was built in 1942 as a generation substation for the 3.75 MVA Rocky Pond hydroelectric plant. The substation contains one power transformer T1 which has a capacity of 4 MVA at 6.9 kV. The station ties the plant into the system via the 66 kV transmission line 20L from Mobile substation. The plant is undergoing a major refurbishment in 2009, including the replacement of the penstock which now passes through the existing substation. The substation will be rebuilt during the 16 week plant outage in 2009.



Rocky Pond Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV wood pole structure shows significant signs of deterioration and safety clearances are not adequate. The wood stave penstock also runs through the existing substation.

Existing Substation – Penstock Inside Yard - Inadequate Clearances

A new substation with both 66 kV and 6.9 kV steel structures will be constructed adjacent to the existing substation. The new substation will also have room to accommodate a portable substation in the event of a power transformer failure.

Appendix A

Substation Refurbishment and Modernization Plan
Five-Year Forecast 2009 to 2013

Substation Refurbishment and Modernization Plan
Five-Year Forecast
2009 to 2013
(000s)

2009		2010		2011		2012		2013	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
BUC	$201	BHD	$128	ABC	$481	BLA	$186	BVS	$671
CLV	530	FRN	544	BVA	693	BRB	905	BIG	344
DOY	125	GAL	431	CAR	493	GBS	737	BFS	734
GAN	602	HCT	691	GIL	152	HGR	1570	GAM	847
GFS	646	NCH	623	GLN	273	HBS	180	GBY	199
KBR	1258	NGF	488	MAS	395	HAR	182	GPD	216
KEL	137	P335	372	MKS	481	P135	430	ISL	131
OXP	161	PAB	303	NHR	464	SPR	279	MOL	372
ROP	442	SPO	446	P435	471	TBS	794	NWB	746
		STX	160	SCR	581	TWG	186	SPF	624
		VIC	713	STV	369	VIR	264	TRP	1069
		MISC	222	SUN	508	MISC	144	WBC	276
				WAL	382				
				WAV	234				
				MISC	216				
Total	**$4,102**		**$5,121**		**$6,193**		**$5,857**		**$6,229**

Note: SUB: Substation - Refer to the Electrical System handbook included with the 2006 Capital Budget Application for three letter substation designations. P135, P335 and P435 are the designations for the portable substations.

MISC: Small projects of less than $100,000 each in a number of different substations.

Horse Chops Plant
Power Transformer Replacement

June 2008

Prepared by:

Jack Casey, P.Eng.

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1.0 Introduction

The Horse Chops hydroelectric plant (the "Plant") is located 56 kilometres south of St. John's on the Southern Shore of the Avalon Peninsula near the community of Cape Broyle, upstream of Cape Broyle Pond. The plant was placed into service in 1953 with a capacity of 8.3 MW under a net head of 85.3 metres. The plant produces 41.8 GWH of energy annually, representing 9.8% of Newfoundland Power's total hydroelectric production. The Plant is connected to the Island Interconnected System at Mobile substation via Newfoundland Power's transmission line 20L.

This project involves the replacement of the 57 year old power transformer (the "Transformer") at the Plant, and the expansion of the Plant substation to accommodate the new transformer.

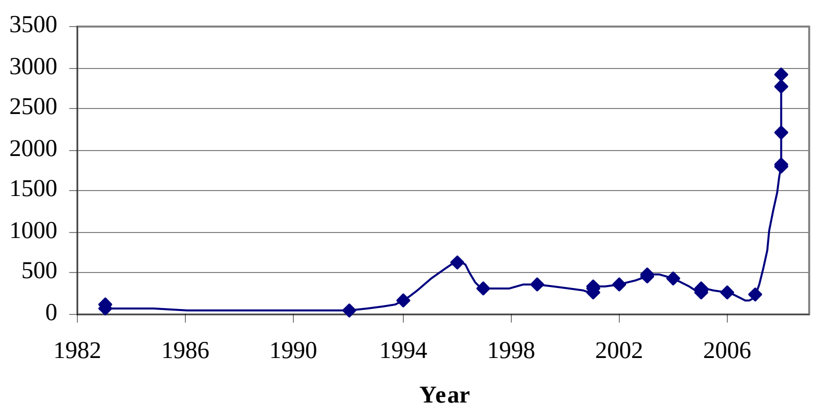
2.0 Background

The Transformer, company number 200165, was manufactured by Reliance Electric in 1951. The 57 year old transformer is an 8.0 MVA unit that increases the voltage of energy produced at the Plant from 6.9 kV to 66 kV for transmission to Mobile substation.

On March 10, 2008, oil analysis carried out as part of the routine maintenance of the Transformer revealed high concentrations of combustible hydrocarbon gases including acetylene in the transformer oil. On April 3, 2008, analysis of a second oil sample confirmed the earlier results. Three additional oil samples taken on April 21, 2008, May 13, 2008, and May 22, 2008 have all confirmed the earlier results.

Graph 1 shows the 26 year history of transformer gas analysis for the Transformer. The graph includes the total of all hydrocarbon gasses in parts per million (ppm) present in the transformer oil at the time of sampling. Appendix A includes graphs showing the individual gas contributions to the total gas profile.

Graph 1
HCP Transformer Gas Analysis
Total Hydrocarbon Gasses
(ppm)



The presence of hydrocarbon gasses indicates overheating of oil in the transformer. The clearest indication of internal trouble in a power transformer is the presence of acetylene[1]. Acetylene is produced when hydrocarbons are exposed to heat caused by electric arcing of the current carrying materials immersed within the transformer oil. Other combustible hydrocarbon gasses such as hydrogen, methane, ethylene, and ethane are not normally present in a healthy transformer.

On May 27, 2008, the Transformer was de-energized and a diagnostic inspection was completed. The inspection did not reveal a cause for the increase in hydrocarbon gas levels in the transformer oil. The Transformer has since been reenergized with the plant operating at reduced load.

Based on the oil analysis reports, it is concluded that the windings in the Transformer have deteriorated to the point where an internal fault could occur at any time. Failure of the Transformer in this manner, particularly when levels of combustible gases in the insulating oil are high, could be catastrophic. Possible consequences include personal injury to plant personnel, and significant property damage to the Plant resulting in the Plant being out of service for an extended period.

The recent oil analysis reports were provided to the Company's transformer consultant who is recommending replacement of the Transformer at "the earliest convenient opportunity"[2].

3.0 Transformer Aging

Large power transformers are a critical component of the electrical system. The replacement of power transformers involves a considerable amount of time and expense and requires particular attention to maximize their service life[3].

The Company has an industry best practice maintenance program in place for its transformer assets. This includes oil sampling and dissolved gas analysis by external laboratories. However, in-service failures of plant and equipment are unavoidable. Factors that impact the service life of power transformers include[4]:

> **Calendar Age**, can have an effect on the mechanical strength of the transformers insulation materials and hence the transformers ability to withstand short circuit forces that are commonplace in the electrical system.
>
> **Operating History**, including the operational loading experience of the unit will impact its service life. In the case of generating plant transformers when energized these units are typically loaded at or near their design maximum.

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1 *Monitoring and Managing Transformer Risks*, Published by AON Limited of London, England, 2007.
2 Included as Appendix C to this report
3 Newfoundland Power filed a report titled *"The Implications of and Response to a Unit Failure"* in its 2002 application for Supplemental Capital Expenditures related to the failure of its Salt Pond substation transformer.
4 *Life Cycle Management of Utility Transformer Assets*, the Hartford Steam Boiler Inspection and Insurance Company, 2002

Operating Environment, including the level of exposure to system faults and frequent switching operations may lead to thermal or mechanical degradation of the transformer.

Failure History, of the unit under consideration or similar units of the same vintage and manufacturer.

Oil Testing History, involving an analysis of the transformer oil's chemical and physical characteristics over time to establish the baseline performance of the unit.

4.0 Transformer Replacement

The only alternatives available to address a deteriorated power transformer are: (1) a complete refurbishment, or rewind, of the existing transformer, and (2) replacement with a new unit.

In a rewind, the internal components of the transformer, including the steel core and the insulated copper windings, are disassembled. The windings and insulation are discarded and replaced with new material. A basic rewind of a three-phase power transformer, consisting of replacing the windings and gaskets and repainting the transformer tank, typically costs approximately half of the cost of a replacement transformer.

In the case of an older transformer, such as the one at Horse Chops, a rewind could also involve replacement of ancillary equipment such as bushings, radiators, valves, gauges and control equipment. It is also possible that the transformer core would have to be replaced. Additional cost would be incurred addressing any of these issues.

A replacement transformer would be constructed to current standards, and would be more energy efficient than the existing unit. The cost of core and copper losses for a 1950s vintage transformer may be twice that of a new transformer[5].

The Transformer has been in service for 57 years, and has operated under full load for most of that time. Considering the unfavourable economics associated with a rewind, and the advantages of improved efficiency provided by a new transformer, the recommended course of action is to purchase a new transformer rather than rewind the existing unit.

The replacement of the Transformer will require capital expenditures additional to those required for the purchase of the replacement unit. The existing substation will be relocated to accommodate the new transformer.

5.0 Plant Transformers

The Company's 23 hydroelectric plants range in age from 9 to 108 years old. These facilities provide low cost energy to the Island Interconnected System. Maintaining these generating facilities reduces the need for additional, more expensive, generation. The power transformers at

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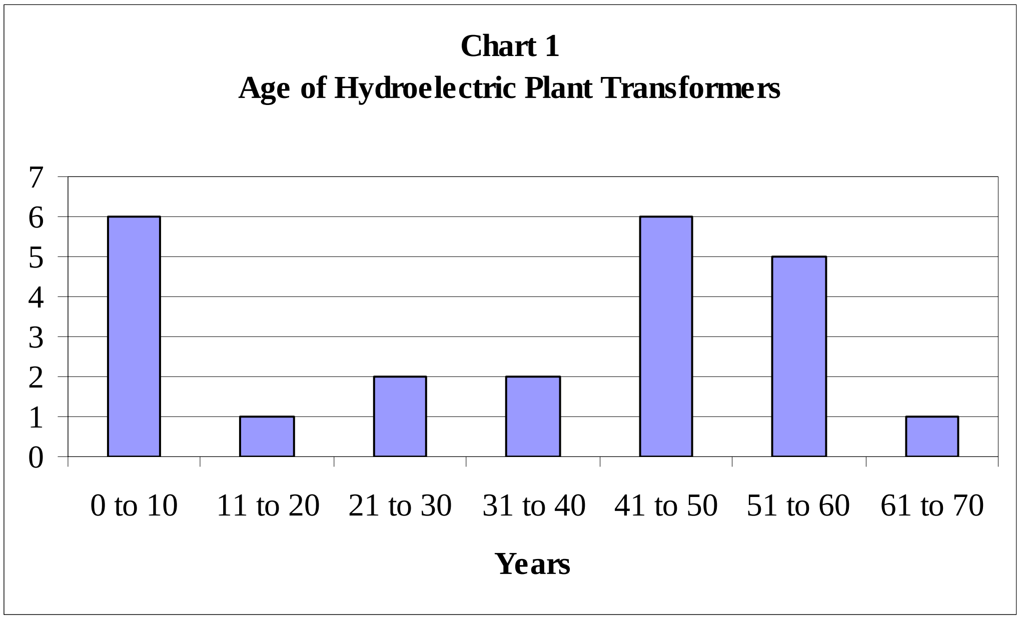
[5] *Life Cycle Management of Utility Transformer Assets*, the Hartford Steam Boiler Inspection and Insurance Company, 2002 page 14

the 23 hydroelectric plants range in age up to 66 years. Chart 1 shows the distribution in age of hydroelectric plants power transformers.



The Company has 6 transformers in excess of 50 years of age, with an additional 6 transformers between 41 and 50 years old. The 6 transformers that are over 50 years old include units at Rocky Pond, Mobile, Tors Cove, Horse Chops, and 2 units at Lockston.

In June 2007 the power transformer at Pierre's Brook plant was taken out of service due to dissolved gas test results that indicated the unit had reached the end of its service life. At that time the Pierre's Brook transformer was 66 years old. The Pierre's Brook transformer is being replaced with a new unit in 2008.

The Company has increased the frequency of inspections and oil sampling on the plant transformers over 50 years of age. Inspections and oil sampling will be completed semi-annually, as opposed to the current practice of annual inspections. The failure of both the Pierre's Brook and Horse Chops transformers indicate that the calendar age, high load factor, and frequent on/off cycling of plant transformers has established that these units will require replacement before power transformers in the distribution and transmission systems.

6.0 Project Description

This project involves the replacement of the Transformer, and modifications to the existing substation to accommodate the replacement transformer.

The replacement transformer cannot be accommodated in the current location due to inadequate clearances. The existing transformers close proximity to the plant building increases the risk of a transformer fire destroying the entire facility. A site approximately 20 metres from the existing substation will be cleared and fenced, for the new substation.

7.0 Project Cost

The current estimate to complete all work associated with the replacement of the Transformer, including the purchase of the new transformer, is $1,341,000. Table 1 provides a detailed breakdown of the total project cost.

Table 1
Project Cost

Description	Estimate ($)
Material	1,052,000
Internal Labour	62,000
Engineering	74,000
Other	153,000
Total	**1,341,000**

8.0 Project Schedule

The Plant is currently operating at reduced load. It is important that the Transformer be replaced in a timely manner so that full production is restored as soon as possible. The order for the replacement transformer will be placed once approval has been received from the Board, and delivery of the unit is expected in early 2009. The purchase price of the transformer, including acceptance testing, is estimated at $800,000. The remaining $541,000 is required to construct the new substation and install the transformer.

The relocation of the Horse Chops substation, and the installation of the replacement transformer and associated work, are scheduled to commence in April 2009 and will take approximately 8 weeks to complete. The entire project is scheduled to be completed in June 2009.

9.0 Concluding

The Transformer has reached the end of its service life. It is necessary that the Transformer be replaced with a new unit, and that the modifications to the existing substation be completed as described in this report.

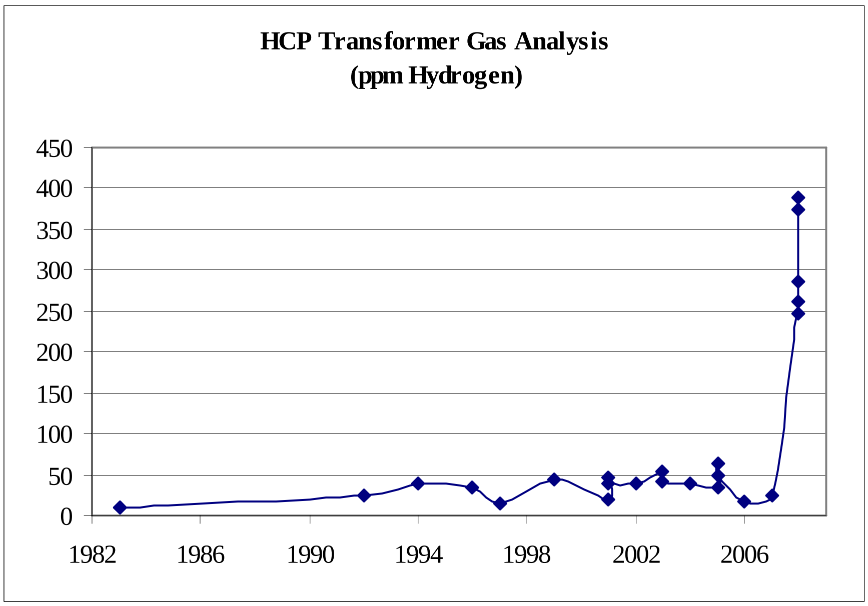
Appendix A

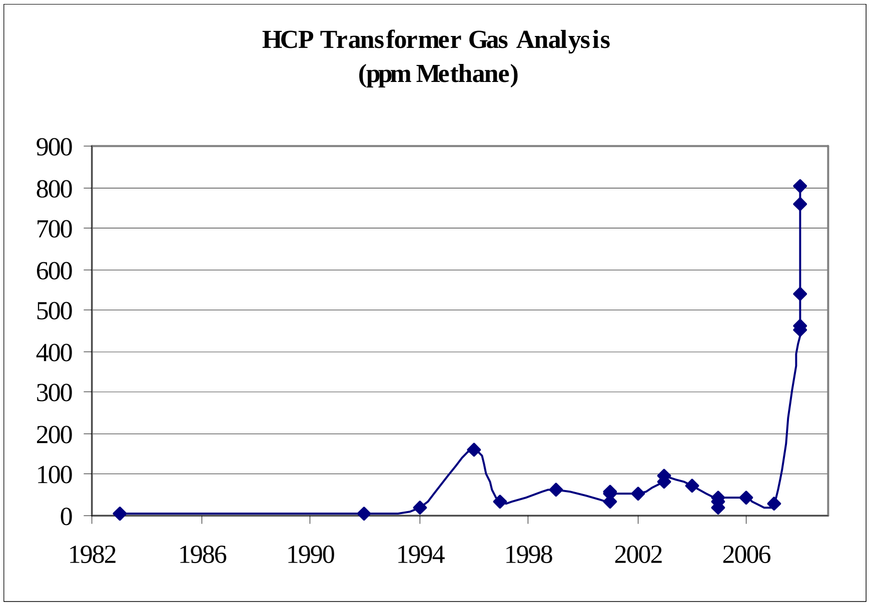
Transformer Oil Analysis

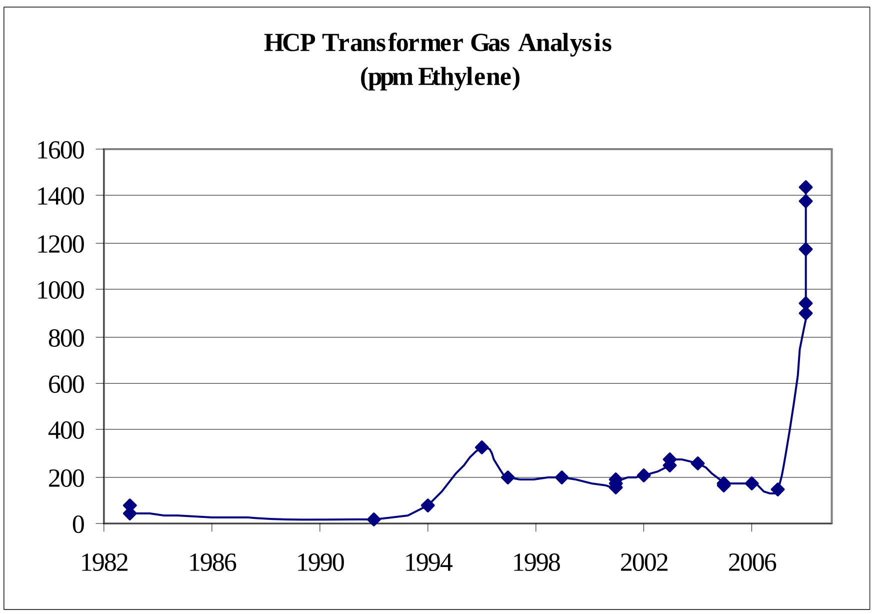
Transformer Oil Analysis

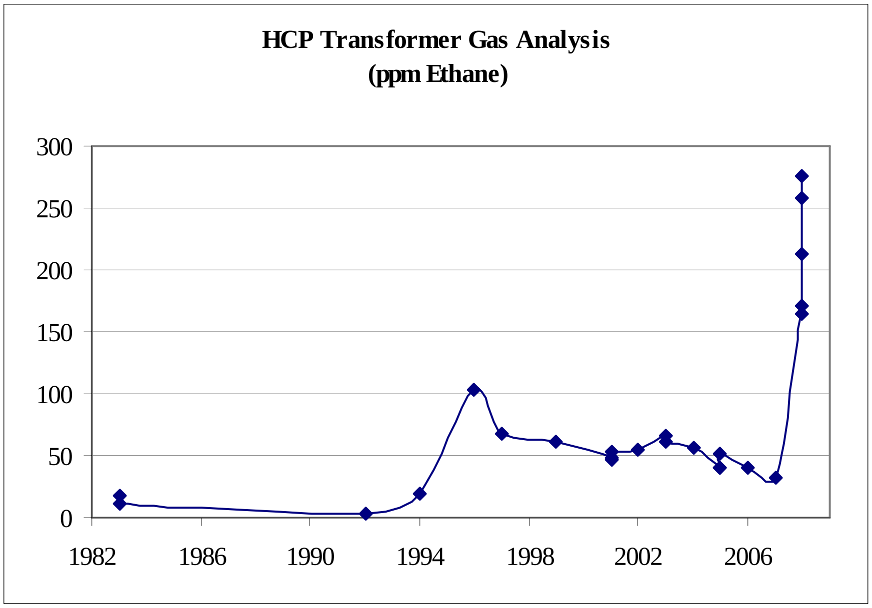
The graphs included are the results of oil analysis completed on power transformer 200165, manufactured by Reliance Electric in 1951. The 57 year old transformer is an 8.0 MVA unit, located at Horse Chops hydroelectric plant.

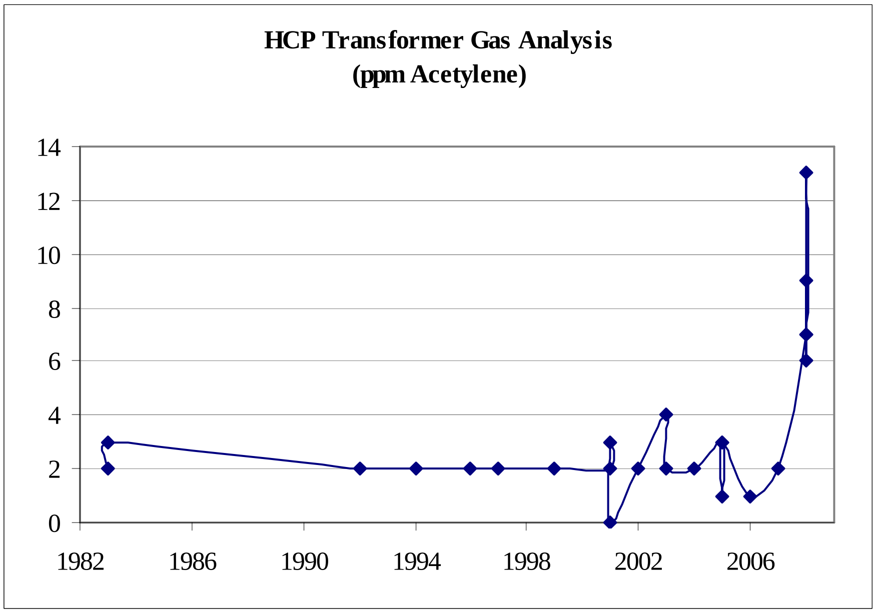
The following graphs show the hydrocarbon gas concentrations present in the transformer insulating oil in parts per million ("ppm"). The graphs cover the period from 1982 to present, and demonstrate the performance of the unit over time. In all cases the unit was performing reasonably well until most recently. Some gassing did occur in the 1996 time period, causing the unit to be closely monitored, but the gas levels eventually returned to normal.




HCP Transformer Gas Analysis
(ppm Methane)
900
800
700
600
500
400
300
200
100
0
1982
1986
1990
1994
1998
2002
2006


HCP Transformer Gas Analysis
(ppm Ethylene)
1600
1400
1200
1000
800
600
400
200
0
1982
1986
1990
1994
1998
2002
2006


HCP Transformer Gas Analysis
(ppm Ethane)
300
250
200
150
100
50
0
1982
1986
1990
1994
1998
2002
2006


HCP Transformer Gas Analysis
(ppm Acetylene)
14
12
10
8
6
4
2
0
1982
1986
1990
1994
1998
2002
2006

Appendix B

Transformer Condition Assessments

Transformer Condition Assessment

The attached reports are the results of oil analysis completed on power transformer, Company number 200165, manufactured by Reliance Electric in 1951. The 57 year old transformer is an 8.0 MVA unit, located at Horse Chops hydroelectric plant.

The first report was provided after a scheduled maintenance procedure was completed on March 10, 2008. The report includes history back to June 2005 in addition to the current analysis. The report recommended a "retest within 60 days to confirm condition."

The cause for concern and need for retest is based upon a significant increase in the incidence of combustible gases, specifically hydrogen, methane, ethane, ethylene and acetylene. Typically, only trace amounts of these gases would be present (tens of parts per million) which is consistent with amounts recorded in previous years. The report identifies high temperatures, arcing and cellulose insulation decomposition as probable causes for the significant increase indentified.

The second test conducted on April 3, 2008 produced results similar to the test conducted 3 weeks earlier. A further retest was completed 18 days later. This third report on April 21, 2008 produced similar results, with a recommendation that the unit be removed from service for investigation and analysis. The fourth report on May 13, 2008 was completed with similar results.

In addition to the Transformer Assessment reports, a dissolved gas analysis report was completed on oil samples taken on May 22, 2008.

The five reports are included in Appendix B.

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Transformer Condition Assessment

TM

Date : 03-24-2008

Glenn Samms
Newfoundland Power
P.O. Box 8910
55 Kenmount Road
St. John's, NF A1B 3P6

Location : HorseChops
Bank & Phase : HCP-T1
Serial Number : TP 1050
Manufacturer : Reliance
Date Mfgd : 1951
Size (kVA) : 8000
Rating kV: 66

Report Number : 5018976
Fluid volume : 2400 G
Fluid type : Mineral Oil
Preservation :
Cooling : ONS
Core & coil wt. : 13636
Impedance :

		Sample Date :	3/10/2008	3/15/2007	4/11/2006	9/21/2005	6/24/2005
		Laboratory No. :	5018976	5014266	5010463	5009323	5008686
		Container No. :	10049	7521	1100	2143	685
		Temperature :	10	45	34		50
H2	Hydrogen	(ppm) :	262	24	16	49	63
CH4	Methane	(ppm) :	451	29	43	42	18
C2H6	Ethane	(ppm) :	171	32	41	51	41
C2H4	Ethylene	(ppm) :	900	144	174	174	165
C2H2	Acetylene	(ppm) :	7	2	1	3	1
CO	Carbon monoxide	(ppm) :	670	604	673	836	611
CO2	Carbon dioxide	(ppm) :	9843	7228	8154	9330	7037
N2	Nitrogen	(ppm) :	91198	76942	78431	83001	78062
O2	Oxygen	(ppm) :	17394	14323	3755	24118	26155
		Total (ppm) :	120896	99328	91288	117604	112144
		TDCG (ppm) :	2461	835	948	1155	890
		SHL (%) :	5.78	9.97	10.44	9.46	8.49
		ETCG (% in blanket) :	1.07	0.58	0.66	0.73	0.61
Particles		5 to 15 um :	1331300	201740	8661410	33430	1077445
Particles		15 to 25 um :	126650	30530	1526290	3855	187745
Particles		25 to 50 um :	10050	9660	472240	1420	54150
Particles		50 to 100 um :	0	310	22070	180	2925
Particles		> 100 um :	0	5	1050	15	65
D1533	Moisture	(ppm) :	26	29	30	27	49
D1816	Dielectric BV	(kV) :	18	31	26	32	
D974	Acid Number	(mg KOH/g) :	0.083	0.068	0.064	0.062	
D971	Interfacial Tension	(dynes/cm) :	22.1	20.1	23.4	28.3	
D1500	Color Number	:	<1.0	<1.5	2.0	2.0	
D924	Power Factor	:	0.032	0.029	0.031	0.024	
D2668	Oxidation Inhibitor	(%) :	<0.010	0.086	0.022	0.010	0.042
5 HMF	5 hydroxymethyl-2-furaldehyde	(ppm) :	<0.010	<0.010	0.125	<0.010	<0.010
2 FAL	2 furaldehyde	(ppm) :	0.635	0.123	0.633	0.161	0.447
2 ACF	2 acetylfuran	(ppm) :	0.049	0.070	<0.010	<0.010	<0.010
5 MEF	5 methyl-2-furaldehyde	(ppm) :	<0.010	<0.010	0.024	<0.010	0.038
2 FOL	2 furfurol	(ppm) :	<0.010	<0.010	<0.010	0.038	0.391
	Estimated DP	:	479-488	636-692	462-488	627-658	447-531

Transformer Condition Assessment Diagnostic Evaluation

TCA Assessment : 4 ID: 200165 Sampler: J. Emberley

Sampling Interval : Retest within 60 days to confirm condition and trend results.

Operating Procedure : Consider treatment to remove particles and oxidation products.Monitor for heating and arcing activity. Paper is reduced to 40% tensile streng

Comments : Heating at higher temperatures and arcing are indicated. Cellulose may be involved.

Field Comments : Fluid oxidation is advancing. Dielectric is reduced.

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Transformer Condition Assessment ™

Glenn Samms
Newfoundland Power
P.O. Box 8910
55 Kenmount Road
St. John's, NF A1B 3P6

Location :	HorseChops	Date :	04-17-2008
Bank & Phase :	HCP-T1	Report Number :	5019136
Serial Number :	TP 1050	Fluid volume :	2400 G
Manufacturer :	Reliance	Fluid type :	Mineral Oil
Date Mfgd :	1952	Preservation :	
Size (kVA) :	8000	Cooling :	ONS
Rating kV:	66	Core & coil wt. :	13636
		Impedance :	

		Sample Date :	4/3/2008	3/10/2008	3/15/2007	4/11/2006	9/21/2005
		Laboratory No. :	5019136	5018976	5014266	5010463	5009323
		Container No. :	10038	10049	7521	1100	2143
		Temperature :	43	10	45 34		
H2	Hydrogen	(ppm) :	248	262	24	16	49
CH4	Methane	(ppm) :	463	451	29	43	42
C2H6	Ethane	(ppm) :	165	171	32	41	51
C2H4	Ethylene	(ppm) :	943	900	144	174	174
C2H2	Acetylene	(ppm) :	13	7	2	1	3
CO	Carbon monoxide	(ppm) :	596	670	604	673	836
CO2	Carbon dioxide	(ppm) :	8373	9843	7228	8154	9330
N2	Nitrogen	(ppm) :	85100	91198	76942	78431	83001
O2	Oxygen	(ppm) :	25585	17394	14323	3755	24118
		Total (ppm) :	121486	120896	99328	91288	117604
		TDCG (ppm) :	2428	2461	835	948	1155
		SHL (%) :	5.67	5.78	9.97	10.44	9.46
		ETCG (% in blanket) :	1.02	1.07	0.58	0.66	0.73
Particles		5 to 15 um :	550960	1331300	201740	8661410	33430
Particles		15 to 25 um :	98345	126650	30530	1526290	3855
Particles		25 to 50 um :	23405	10050	9660	472240	1420
Particles		50 to 100 um :	1670	0	310	22070	180
Particles		> 100 um :	25	0	5	1050	15
D1533	Moisture	(ppm) :	26	26	29	30	27
D1816	Dielectric BV	(kV) :	25	18	31	26	32
D974	Acid Number	(mg KOH/g) :	0.075	0.083	0.068	0.064	0.062
D971	Interfacial Tension	(dynes/cm) :	22.1	22.1	20.1	23.4	28.3
D1500	Color Number	:	<1.5	<1.0	<1.5	2.0	2.0
D924	Power Factor	:	0.043	0.032	0.029	0.031	0.024
D2668	Oxidation Inhibitor	(%) :	0.021	<0.010	0.086	0.022	0.010
5 HMF	5 hydroxymethyl-2-furaldehyde	(ppm) :	<0.010	<0.010	<0.010	0.125	<0.010
2 FAL	2 furaldehyde	(ppm) :	0.558	0.635	0.123	0.633	0.161
2 ACF	2 acetylfuran	(ppm) :	<0.010	0.049	0.070	<0.010	<0.010
5 MEF	5 methyl-2-furaldehyde	(ppm) :	<0.010	<0.010	<0.010	0.024	<0.010
2 FOL	2 furfurol	(ppm) :	<0.010	<0.010	<0.010	<0.010	0.038
	Estimated DP	:	504	479-488	636-692	462-488	627-658

Transformer Condition Assessment Diagnostic Evaluation

TCA Assessment : Potential 4* ID: 200165 Sampler: W.England
Sampling Interval : Resample within 14 days to continue trending and monitoring condition.
Operating Procedure : Conduct further testing to determine location of heating/arcing activity. Paper is reduced to 50% tensile strength.
Comments : Heating at higher temperatures and arcing is indicated.
Field Comments : Fluid condition is within acceptable in-service parameters with the exception of high particle load.

TJ H2b ANALYTICAL SERVICES INCORPORATED

Transformer Condition Assessment ™

Date : 04-25-2008

Glenn Samms	Location : HorseChops	Report Number : 5019253
Newfoundland Power	Bank & Phase : HCP-T1	Fluid volume : 2400 G
P.O. Box 8910	Serial Number : TP 1050	Fluid type : Mineral Oil
55 Kenmount Road	Manufacturer : Reliance	Preservation :
St. John's, NF A1B 3P6	Date Mfgd : 1952	Cooling : ONS
	Size (kVA) : 8000	Core & coil wt. : 13636
	Rating kV: 66	Impedance :

		Sample Date :	4/21/2008	4/3/2008	3/10/2008	3/15/2007	4/11/2006
		Laboratory No. :	5019253	5019136	5018976	5014266	5010463
		Container No. :	10062	10038	10049	7521	1100
		Temperature :	18.6	43	10	45	34
H2	Hydrogen	(ppm) :	285	248	262	24	16
CH4	Methane	(ppm) :	539	463	451	29	43
C2H6	Ethane	(ppm) :	213	165	171	32	41
C2H4	Ethylene	(ppm) :	1176	943	900	144	174
C2H2	Acetylene	(ppm) :	6	13	7	2	1
CO	Carbon monoxide	(ppm) :	632	596	670	604	673
CO2	Carbon dioxide	(ppm) :	8216	8373	9843	7228	8154
N2	Nitrogen	(ppm) :	91327	85100	91198	76942	78431
O2	Oxygen	(ppm) :	27138	25585	17394	14323	3755
		Total (ppm) :	129532	121486	120896	99328	91288
		TDCG (ppm) :	2851	2428	2461	835	948
		SHL (%) :	5.55	5.67	5.78	9.97	10.44
		ETCG (% in blanket) :	1.06	1.02	1.07	0.58	0.66
Particles		5 to 15 um :	433610	550960	1331300	201740	8661410
Particles		15 to 25 um :	30420	98345	126650	30530	1526290
Particles		25 to 50 um :	1825	23405	10050	9660	472240
Particles		50 to 100 um :	45	1670	0	310	22070
Particles		> 100 um :	0	25	0	5	1050
D1533	Moisture	(ppm) :	33	26	26	29	30
D1816	Dielectric BV	(kV) :	20	25	18	31	26
D974	Acid Number	(mg KOH/g) :	0.076	0.075	0.083	0.068	0.064
D971	Interfacial Tension	(dynes/cm) :	24.8	22.1	22.1	20.1	23.4
D1500	Color Number	:	<1.5	<1.5	<1.0	<1.5	2.0
D924	Power Factor	:	0.026	0.043	0.032	0.029	0.031
D2668	Oxidation Inhibitor	(%) :	0.061	0.021	<0.010	0.086	0.022
5 HMF	5 hydroxymethyl-2-furaldehyde	(ppm) :	<0.010	<0.010	<0.010	<0.010	0.125
2 FAL	2 furaldehyde	(ppm) :	0.759	0.558	0.635	0.123	0.633
2 ACF	2 acetylfuran	(ppm) :	0.074	<0.010	0.049	0.070	<0.010
5 MEF	5 methyl-2-furaldehyde	(ppm) :	<0.010	<0.010	<0.010	<0.010	0.024
2 FOL	2 furfurol	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
	Estimated DP	:	454-466	504	479-488	636-692	462-488

Transformer Condition Assessment Diagnostic Evaluation

TCA Assessment : 4 ID: 200165 Sampler: W. England

Sampling Interval : Retest within 30 days.

Operating Procedure : Plan to remove frm service for additional testing, investigation and analysis. Paper is reduced to 40% tensile strength.

Comments : Heating and arcing is indicated. Possibly at a contact or connector.

Field Comments : Fluid condition is within acceptable in-service parameters.

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Transformer Condition Assessment ™

Glenn Samms
Newfoundland Power
P.O. Box 8910
55 Kenmount Road
St. John's, NF A1B 3P6

Location : HorseChops
Bank & Phase : HCP-T1
Serial Number : TP 1050
Manufacturer : Reliance
Date Mfgd : 1951
Size (kVA) : 8000
Rating kV: 66

Date : 05-29-2008
Report Number : 5019566
Fluid volume : 2400 G
Fluid type : Mineral Oil
Preservation :
Cooling : ONS
Core & coil wt. : 13636
Impedance :

		Sample Date :	5/13/2008	4/21/2008	4/3/2008	3/10/2008	3/15/2007
		Laboratory No. :	5019566	5019253	5019136	5018976	5014266
		Container No. :	10542	10062	10038	10049	7521
		Temperature :	30	18.6	43	10	45
H2	Hydrogen	(ppm) :	374	285	248	262	24
CH4	Methane	(ppm) :	761	539	463	451	29
C2H6	Ethane	(ppm) :	258	213	165	171	32
C2H4	Ethylene	(ppm) :	1376	1176	943	900	144
C2H2	Acetylene	(ppm) :	9	6	13	7	2
CO	Carbon monoxide	(ppm) :	678	632	596	670	604
CO2	Carbon dioxide	(ppm) :	9364	8216	8373	9843	7228
N2	Nitrogen	(ppm) :	86952	91327	85100	91198	76942
O2	Oxygen	(ppm) :	29076	27138	25585	17394	14323
		Total (ppm) :	128848	129532	121486	120896	99328
		TDCG (ppm) :	3456	2851	2428	2461	835
		SHL (%) :	5.34	5.55	5.67	5.78	9.97
		ETCG (% in blanket) :	1.33	1.06	1.02	1.07	0.58
Particles		5 to 15 um :	247225	433610	550960	1331300	201740
Particles		15 to 25 um :	17180	30420	98345	126650	30530
Particles		25 to 50 um :	1385	1825	23405	10050	9660
Particles		50 to 100 um :	60	45	1670	0	310
Particles		> 100 um :	0	0	25	0	5
D1533	Moisture	(ppm) :	26	33	26	26	29
D1816	Dielectric BV	(kV) :	24	20	25	18	31
D974	Acid Number	(mg KOH/g) :	0.084	0.076	0.075	0.083	0.068
D971	Interfacial Tension	(dynes/cm) :	24.8	24.8	22.1	22.1	20.1
D1500	Color Number	:	<1.5	<1.5	<1.5	<1.0	<1.5
D924	Power Factor	:	0.026	0.026	0.043	0.032	0.029
D2668	Oxidation Inhibitor	(%) :	0.060	0.061	0.021	<0.010	0.086
5 HMF	5 hydroxymethyl-2-furaldehyde	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
2 FAL	2 furaldehyde	(ppm) :	0.606	0.759	0.558	0.635	0.123
2 ACF	2 acetylfuran	(ppm) :	<0.010	0.074	<0.010	0.049	0.070
5 MEF	5 methyl-2-furaldehyde	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
2 FOL	2 furfurol	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
	Estimated DP	:	494	454-466	504	479-488	636-692

Transformer Condition Assessment Diagnostic Evaluation

TCA Assessment : Potential 4* ID: 200165 Sampler: W. England
Sampling Interval : Retest immediately to establish condition.
Operating Procedure : Consider treatment to remove oxidation products. Paper is reduced to 40% tensile strength.
Comments : Heating at higher temperatures and arcing are indicated. Cellulose may be involved.
Field Comments : Fluid oxidation is advancing. Dielectric is reduced.

TJH2B Analytical Services , Inc. Bay #1, 2835 - 19 Street N.E. Calgary, AB T2E 7A2 Canada Phone: (403) 282-8542
Sacramento, CA (916) 361-7177 / Jefferson, LA (504) 734-9722 / Sun Prarie, WI (608) 825-2022 / Kennett Square, PA (610) 925-0688
Glen Waverly, Australia +61 3 9574 9467 / Chester, United Kindom +44 0 151 339 5100

TJ H2b ANALYTICAL SERVICES INCORPORATED

Dissolved Gas Analysis

Date: 5/23/2008
Report Number: 5019616
P.O. Number:

Glenn Samms
Newfoundland Power
P.O. Box 8910
55 Kenmount Road
St. John's, NF A1B 3P6

Location :	HorseChops	Year of Mfg. :	1951
Bank & Phase :	HCP-T1	kV Rating :	66
Serial Number :	TP 1050	Breathing :	
Manufacturer :	Reliance	Cooling :	ONS
Equipment Type :	Transformer	Fluid type :	Mineral Oil
Model :		Fluid Volume :	2400 G

Sample Date :	5/22/2008	5/13/2008	4/21/2008	4/3/2008	3/10/2008	3/15/2007
Laboratory No. :	5019616	5019566	5019253	5019136	5018976	5014266
Container No. :	10071	10542	10062	10038	10049	7521
Temperature :	24	30	18.6	43	10	45
Hydrogen (ppm) :	390	374	285	248	262	24
Methane (ppm) :	805	761	539	463	451	29
Ethane (ppm) :	276	258	213	165	171	32
Ethylene (ppm) :	1439	1376	1176	943	900	144
Acetylene (ppm) :	7	9	6	13	7	2
Carbon monoxide (ppm) :	730	678	632	596	670	604
Carbon dioxide (ppm) :	9051	9364	8216	8373	9843	7228
Nitrogen (ppm) :	84628	86952	91327	85100	91198	76942
Oxygen (ppm) :	24160	29076	27138	25585	17394	14323
Total (ppm) :	121486	128848	129532	121486	120896	99328
TDCG (ppm) :	3647	3456	2852	2428	2460	835
TDCG Rate (ppm/day) :	21.3	27.5	23.5	-1.3	4.5	-0.3
TDCG (gallons) :						
TDHHG (ppm) :	2520	2395	1929	1571	1522	205
ETCG (% in blanket) :	1.48	1.33	1.06	1.02	1.07	0.58
CH4 / H2 :	2.06	2.03	1.89	1.87	1.72	1.20
C2H2 / C2H4 :	0.01	0.01	0.01	0.01	0.01	0.01
C2H2 / CH4 :	0.01	0.01	0.01	0.03	0.01	0.07
C2H6 / C2H2 :	37.28	29.12	35.45	12.56	25.77	16.53
C2H4 / C2H6 :	5.21	5.33	5.51	5.71	5.26	4.54
CO2 / CO :	12.39	13.81	13.01	14.05	14.70	11.97

Dissolved Gas Diagnostics

Key Gas Method : Possible sparking, Overheating, Arcing,
Doernenburg Ratios : Thermal decomposition
Rodgers Ratios (3) : Not in table
Rodgers Ratios (4) : Core and Tank Circulating Currents Overheated Joints
CO2 / CO :
Heat Index : 0.25

IEEE Std. C57.104 -1991 Condition : 3 TDCG Level (ppm) : 3647 TDCG Rate (ppm/day) : 21.3
Sampling Interval : Weekly
Operating Procedure : Exercise Extreme caution. Analyze for individual gases. Plan outage. Advise manufacturer.
Comments :

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Appendix C

Transformer Consultant's Recommendation

van Kooy
Transformer Consulting Services Inc.

Ph. 905 308-9888 Fax 308-9638
E Mail john@vankooy.com
web site www.vanKooy.com

May 28, 2008

To: Glenn Samms, Newfoundland Power

Subject: Transformer 200165, Commonwealth S# TP 1050, built in 1951
8000/fut. 10666 kVA, ONS/fut. ONP, 55 °C Rise
HV 66//33 kV w DTC, Wye Connected, LV 6.9 kV, Delta Connected

This transformer has a long history of elevated levels of dissolved gases in oil. A recent bump in levels of Hydrogen, Methane, Ethane, Ethylene and Carbon Dioxide initiated a de-energization and internal inspection. The dissolved gas levels are now sitting at an elevated caution level.

The limited internal inspection through the top manhole inspection cover did not reveal the source of the gassing.

This transformer is near the end of life and at 57 years old certainly has provided service beyond expectations. I do not believe this transformer will fail in the immediate future, but I recommend replacement at the earliest convenient opportunity.

The time frame for replacement versus rewind is about the same in the present market.

Consider operating at a reduced load. Monitor the dissolved gases on a two week cycle to follow the dissolve gas trending.

Regards,

van Kooy Transformer Consulting Services Inc.

____

per: Sjoerd (John) van Kooy

Appendix D

Photographs

Photo 1

Lack of clearance between transformer and plant building

Photo 2

Future site of substation, about 20 metres from existing substation

Photo 3

Existing substation adjacent to plant

Transmission Line Rebuild

June 2008

Prepared by:

Trina L. Troke, P.Eng.

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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 is proactive in ensuring that transmission lines are maintained so as to avoid significant 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 failure.

The *Transmission Line Rebuild Strategy* is reviewed and revised on an ongoing basis to ensure that it accurately reflects the latest reliability data, inspection information, condition assessments, as well as the capital requirements within other asset classes. The strategy will continue to change with time to ensure targeted spending on the highest priority transmission lines based on physical condition, risk of failure, potential impact upon customers in the event of a failure, and alignment with corporate goals and objectives.

Appendix A contains the updated Transmission Line Rebuild Strategy Schedule. The cost estimates in this revision have been adjusted to reflect the inflationary increases that have affected both labour and non-labour costs since the original strategy was prepared in 2005. As well, the costs presented in the table now utilize escalation factors to more accurately indicate the estimated cost of the project in the year in which it will take place.

2.0 Transmission Line Rebuild Projects Planned for 2009

In 2009, the Company plans to rebuild a section of transmission line 110L and to rebuild the final section of transmission line 111L. These two transmission lines were exposed to severe ice loading during the December 2007 sleet storm on the Bonavista Peninsula. Customers relying on these lines for electricity experienced power outages that extended for as much as 4 days, before the lines could be reconstructed and electricity supply restored.

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

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 more than 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.

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

2.1 Transmission Line 110L

110L is a 66 kV transmission line built in 1958. The line runs between Clarenville Substation and Lockston Substation on the Bonavista Peninsula. The line has a total length of 79 km and is of single wood pole construction.

110L serves approximately 4,000 customers of the Bonavista Peninsula between Milton and Lockston. This line also connects the Company's Lockston hydro plant to the Island interconnected electrical system.

The conductor is damaged in many places and has been subjected to ice loading since its original installation. The steel core shows evidence of rust and the aluminum strands are corroded which reduces the physical strength and the current carrying capacity of the conductor. This conductor has deteriorated to the point that the line has been de-rated to about one-half of its original current carrying capacity out of concern that it 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, April 2004, and December 2007 when ice build-up on overhead conductors caused the line to fail resulting in outages to customers.

In 1966, 17 km of the line was upgraded and between 1972 and 1974, an additional 18 km was upgraded. In 2006 and 2007, the 21 km section of the line that extends between the Company's Lockston substation and Summerville substation was rebuilt. The remaining 22 km of the existing line is still original 1958 construction and is 50 years old.

Based on the condition of this line, it is recommended that another 4.9 km of 110L be rebuilt in 2009 at an estimated cost of $627,000.

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.

2.2 Transmission Line 111L

111L is a 66 kV transmission line built in 1956. The line runs between Lockston Substation and Catalina Substation, via Port Union Substation, on the Bonavista Peninsula. The line is 31 kilometres in length and is of single wood pole construction. The line serves approximately 1,058 customers on the Bonavista Peninsula. This line also connects the Company's Port Union hydroelectric and diesel plants to the Island interconnected electrical system.

Many of the poles on this line are deteriorated and some are severely decayed. The guy wires are generally corroded and are nearing the point of failure.

The non-standard conductor on this line is damaged in many places and its strands are broken in some locations. Over the years, many inline splices (sleeves) have been installed along the length of the conductor. These inline splices are evidence of repairs made after the conductor failed during various sleet storms in the area, most recently, during a severe ice storm in December 2007.

A 13 kilometre section of this line was approved for reconstruction in the 2008 Capital Budget Application. Based on the overall deteriorated condition of the line, it is recommended that the remaining 17.7 km of the line be rebuilt in 2009. The estimated cost of this work is $2,285,000.

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 111L, as recommended in this report, is the most cost-effective alternative to ensure the continued provision of safe, reliable electrical service.

Appendix A

Transmission Line Rebuild Strategy Schedule

Transmission Line Rebuilds
2009-2013
($000)

Line	Year	2009	2010	2011	2012	2013
012L KBR-MUN	1950		436			
014L SLA-MUN	1950				147	
015L SLA-MOL	1958				95	
016L PEP-KBR	1950		840			
018L GOU-GDL	1951					689
021L 20L-HCP	1952		705			
023L MOB-PBK	1942		732			
024L MOB-BIG	1964				1,111	
025L GOU-SJM	1954			1,283		
030L RRD-KBR	1959		584			
032L OXP-RRD	1959					458
035L OXP-KEN	1963					809
041L CAR-HCT	1958			2,612		
049L HWD-CHA	1966			377		
057L BRB-HGR	1958				2,556	
068L HGR-CAR	1951					768
069L KEN-SLA	1951				394	
110L CLV-LOK	1958	627	2,396	1,276		
111L LOK-CAT	1956	2,285				
124L CLV-GAM	1964				1,528	3,280
	Total	**$2,912**	**$5,693**	**$5,548**	**$5,831**	**$6,004**

Transmission Line Rebuilds 2014-2020 ($000)								
Line	**Year**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
013L SJM-SLA	1962				318			
100L SUN-CLV	1964		3.047	2,163				
101L GFS-RBK	1957			1,331	2,071	1702		
102L GAN-RBK	1958				4,488	3,403	2,975	
105L GFS-SBK	1963							2,442
124L CLV-GAM	1964	3,556	1,823					
146L GAN-GAM	1964	2,474	962	3,161				
301L SPO-GRH	1959	170						
302L SPO-LAU	1959					1,970	2,882	
400L BBK-WHE	1967						1,487	2,702
403L TAP-ROB	1960		643					
	Total	**$6,200**	**$6,475**	**$6,655**	**$6,877**	**$7,075**	**$7,344**	**$5,144**

Appendix B

Topographic Maps of Transmission Lines 110L and 111L

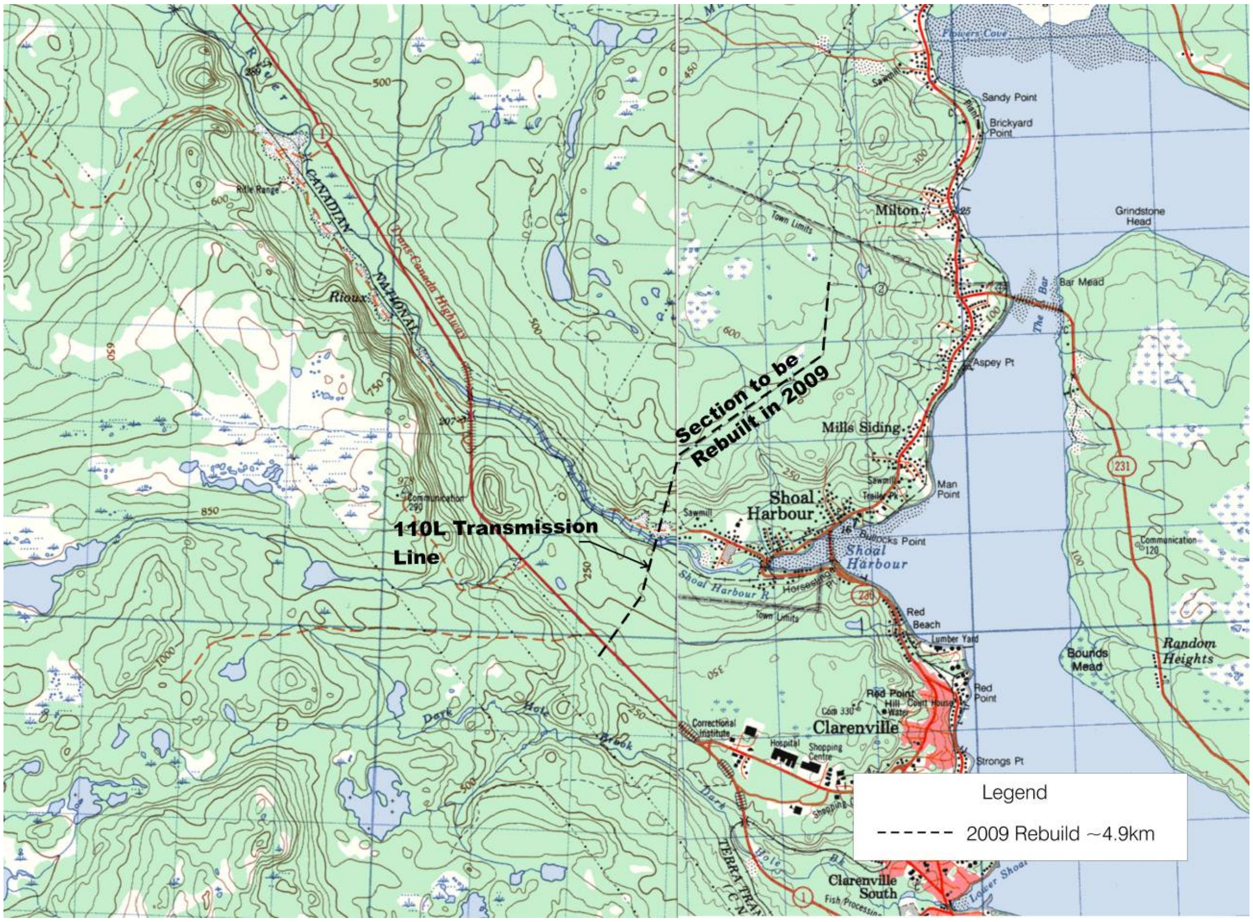

Figure 1 – Topographic Map 110L

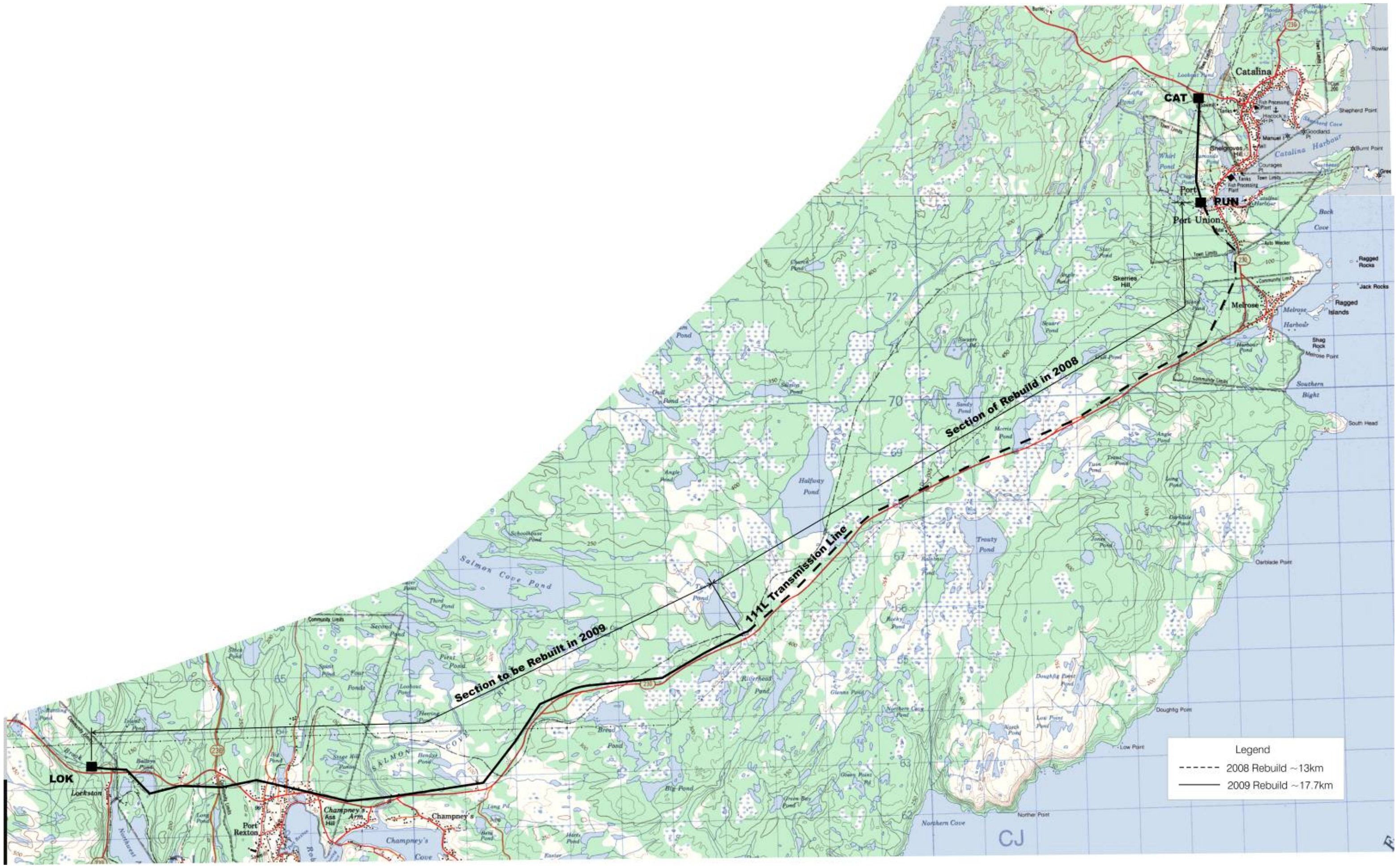

Figure 2 – Topographic Map 111L

Appendix C

Photographs of
Transmission Lines 110L and 111L

<u>Transmission Line 110L</u>

Figure 1 - 110L Ice Storm Damage December 2003

Figure 2 - 110L Broken conductor - ice build up December, 2003


Figure 3 - Deteriorated pole 110L


Figure 4 - Deteriorated pole 110L

Transmission Line 111L

Figure 5 - Deteriorated Pole 111L

Figure 6 - Deteriorated Pole 111L

Figure 7 – Deteriorated Pole (Top Split) 111L

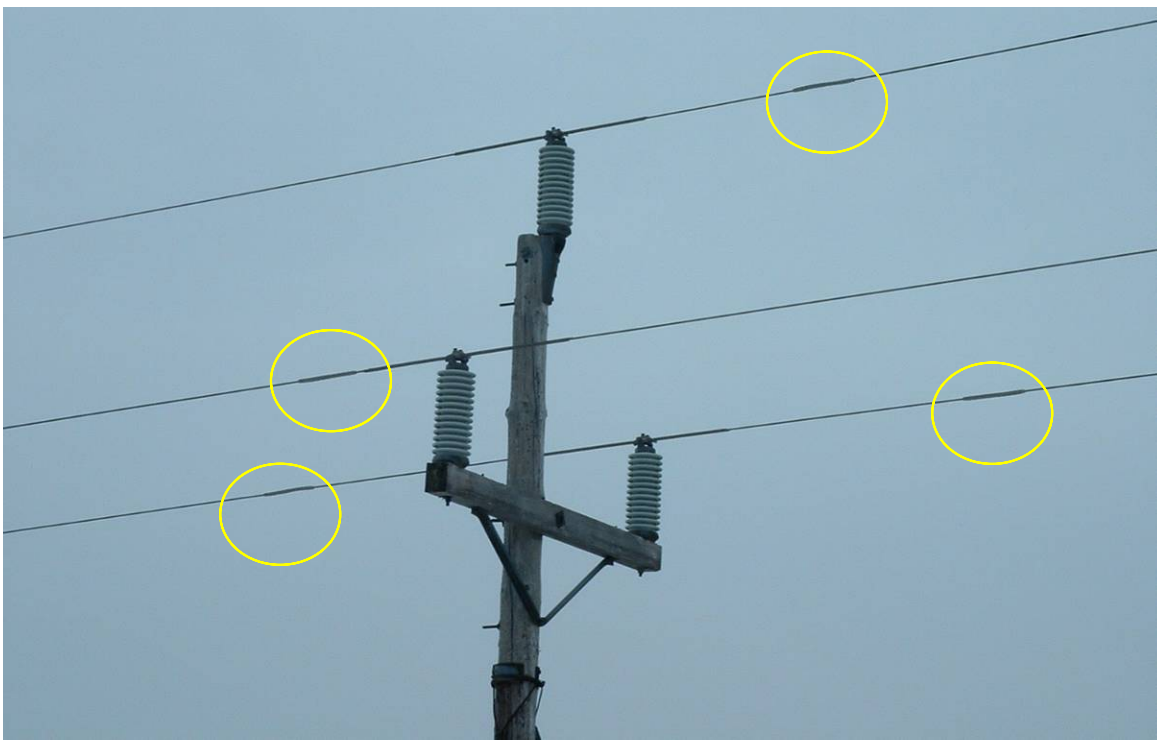

Figure 8 – Inline Splices Installed to Repair Conductor 111L

Figure 9 – Failed Guy Wire and Ice Loading on 111L


Figure 10 - 111L Ice Storm Damage December 2007

Distribution Reliability Initiative

June 2008

Prepared by:

Ralph Mugford P. Eng.

REGISTERED PROFESSIONAL ENGINEER
RALPH W. MUGFORD
SIGNATURE
July 2/2008
DATE
NEWFOUNDLAND & LABRADOR

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1.0 Distribution Reliability Initiative

The Distribution Reliability Initiative is a capital project that focuses on the reconstruction of the worst performing distribution feeders. Customers on these feeders experience more frequent and longer duration outages than the majority of customers.

Newfoundland Power manages system reliability through capital investment, maintenance practices and operational deployment. Newfoundland Power examines its actual distribution reliability performance to assess whether targeted capital investment is warranted to improve service reliability. Through this process the Company identifies the worst performing feeders in the power system based upon reliability measures. Engineering assessments are completed for each of the worst performing feeders and, where appropriate, the Company makes capital investment to improve the reliability of these feeders.

Appendix A contains the five-year average distribution reliability data of the 15 worst performing feeders.

Appendix B contains a summary of the assessment carried out on each of the feeders listed in Appendix A.

2.0 Distribution Reliability Initiative Projects: 2006-2007

The 2006 Capital Budget Application proposed Reliability Rebuild Projects for BOT-01, GLV-02 and LEW-02 feeders. The BOT-01 and GLV-02 rebuilds proposed work over three years to be completed in 2006, 2007 and 2008 while the LEW-02 rebuild proposed work over two years to be completed in 2006 and 2007.

The 2007 Capital Budget Application included significant expenditure for the Rattling Brook Refurbishment project. As a result the Distribution Reliability Initiative was suspended for 2007.

3.0 Distribution Reliability Initiative Projects: 2008

In the 2008 Capital Budget Application, the Company resumed the Distribution Reliability Initiative project with the work initially planned for 2007 on BOT-01, GLV-02 and LEW-02 feeders to be completed. However recent reliability issues in the Salvage area on the Eastport Peninsula requires additional work to be carried out on the GLV-02 feeder in 2008 and work scheduled for LEW-02 be deferred until 2009. Table 1 shows the revised forecast for the Distribution Reliability Initiative project for 2008.

Table 1

Distribution Reliability Initiative
2008 (Revised)
($000s)

Feeder	2008
BOT–01	789
GLV–02	497
Total	**1,286**[1]

4.0 Distribution Reliability Initiative Projects: 2009

In 2009, the Company plans to continue the Distribution Reliability Initiative. It is planned to complete work on the GLV-02 and LEW-02 feeders as proposed in the 2006 Capital Budget Application and detailed in the *GLV-02 and LEW-02 Feeder Studies* filed with the 2006 Capital Budget Application. Work is also being proposed for the NWB-02 feeder. A detailed analysis is provided in the *NWB-02 Feeder Study* filed with the 2009 Capital Budget Application. Appendix B contains maps of the feeder sections that are proposed to be rebuilt in 2009.

Table 2

Distribution Reliability Initiative
2009
($000s)

Feeder	2009
LEW-02	313
GLV–02	457
NWB–02	496
Total	**1,266**

4.1 LEW-02

The LEW-02 feeder is located in the Grand Falls-Windsor operating area of the Western Region. The 25 kV feeder originates at the Lewisporte Substation located in the community of Lewisporte and serves approximately 1,390 customers.

[1] The 2008 estimates for GLV-02 and BOT-01 have been revised from original estimates due to upgrades which have or will be carried out on the feeders to accommodate third party attachments and due to a review of recent reliability data.

The report *LEW-02 Feeder Study* filed with the 2006 Capital Budget Application recommended work be carried out over a 2-year period. The report recommended upgrades to the following sections of line that will now be completed in 2009:

- End of three phase line to Baytona Tap
- Baytona Tap to Birchy Bay Tap
- Birchy Bay Tap

Table 3 is a summary of the current outage statistics for the LEW-02 feeder.

Table 3

Unscheduled Distribution Related Outages [1]

	Customer Interruptions	Customer Minutes of Interruption	Distribution SAIFI	Distribution SAIDI
LEW-02	4,712	713,417	3.39	8.55
Company Average	1,207	92,119	1.68	2.13

[1] Outages are the five-year averages from 2003 through 2007.

4.2 GLV-02

The GLV-02 feeder is located in the Gander operating area of the Western Region. The 25kV feeder originates at the Glovertown Substation in the community of Glovertown and serves approximately 1,259 customers.

The report *GLV-02 Feeder Study* filed with the 2006 Capital Budget Application recommended work be carried out over a 3-year period. The report recommended upgrades to the following sections of line that will now be completed in 2009:

- Tap to Happy Adventure
- Sandy Cove
- Tap to Burnside
- End of three phase line to St. Chad's
- St. Chad's
- Tap St. Chad's to Burnside
- Tap to Trans Canada Highway

Table 4 is a summary of the current outage statistics for the GLV-02 feeder.

Table 4

Unscheduled Distribution Related Outages[1]

	Customer Interruptions	Customer Minutes of Interruption	Distribution SAIFI	Distribution SAIDI
GLV-02	4,855	685,055	3.85	9.07
Company Average	1,207	92,119	1.68	2.13

[1] Outages are the five-year averages from 2003 through 2007.

4.3 NWB-02

The NWB-02 feeder is located in the Bonavista operating area of the Eastern Region. The 25 kV originates at the Northwest Brook Substation west of the community of Goobies and serves approximately 1,050 customers.

The report *NWB-02 Feeder Study* recommends work be carried out in 2009 on the following sections of line:

- Northwest Brook substation along the TCH to boat basin in Long Beach
- Boat basin in Long Beach to end of Hodge’s Cove
- Northwest Brook to the TCH near Ivany’s Cove
- Community of Hillview
- Community of St. Jones Within

Table 5 is a summary of the current outage statistics for the NWB-02 feeder.

Table 5

Unscheduled Distribution Related Outages[1]

	Customer Interruptions	Customer Minutes of Interruption	Distribution SAIFI	Distribution SAIDI
NWB-02	3,155	414,821	3.04	6.58
Company Average	1,207	92,119	1.68	2.13

[1] Outages are the five-year averages from 2003 through 2007.

Appendix A

Distribution Reliability Data

Unscheduled Distribution Related Outages Five-Year Average 2003-2007 Sorted By Customer Minutes of Interruption				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
LEW - 02	4,712	713,417	3.39	8.55
GLV – 02	4,855	685,055	3.85	9.07
BOT - 01	4,858	646,003	2.99	6.59
BCV – 02	3,932	460,113	2.58	5.04
ROB - 01	3,671	458,645	3.42	7.12
PUL - 01	3,511	441,638	2.10	4.42
DUN - 01	3,046	431,874	3.23	7.62
NWB - 02	3,155	414,821	3.04	6.58
DOY - 01	4,248	404,597	2.75	4.34
GFS - 06	2,409	357,363	1.48	3.60
MIL - 02	4,190	335,103	3.07	4.11
CHA-01	5,818	324,566	2.79	2.57
MOB-01	3,749	323,911	3.35	4.83
PUL-02	3,371	323,352	2.46	3.94
HWD-02	2,665	289,735	1.95	3.54
Company Average	**1,207**	**92,119**	**1.68**	**2.13**

Unscheduled Distribution Related Outages

Five-Year Average
2003-2007
Sorted By Distribution SAIFI

Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
GLV-02	4,855	685,055	3.85	9.07
FER-01	2,258	108,213	3.57	2.88
ROB-01	3,671	458,645	3.42	7.12
LEW-02	4,712	713,417	3.39	8.55
MOB-01	3,749	323,911	3.35	4.83
DUN-01	3,046	431,874	3.23	7.62
GBS-02	1,403	103,714	3.18	3.87
CAB-01	3,658	247,645	3.13	3.50
NWB-02	3,155	414,821	3.04	6.58
BOT-01	4,858	646,003	2.99	6.59
GRH-02	2,366	190,942	2.99	4.03
LOK-01	2,933	179,753	2.87	2.93
CHA-01	5,818	324,566	2.79	2.57
KEL-02	2,817	161,108	2.77	2.55
DOY-01	4,248	404,597	2.75	4.34
Company Average	**1,207**	**92,119**	**1.68**	**2.13**

Unscheduled Distribution Related Outages Five-Year Average 2003-2007 Sorted By Distribution SAIDI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
GPD-01	379	157,275	1.61	11.25
GLV-02	4,855	685,055	3.85	9.07
LEW-02	4,712	713,417	3.39	8.55
DUN-01	3,046	431,874	3.23	7.62
ROB-01	3,671	458,645	3.42	7.12
BOT-01	4,858	646,003	2.99	6.59
NWB-02	3,155	414,821	3.04	6.58
WES-02	1,939	238,818	2.59	5.31
BCV-02	3,932	460,113	2.58	5.04
MOB-01	3,749	323,911	3.35	4.83
SUM-02	943	168,605	1.59	4.73
SMV-01	1,755	287,522	1.70	4.66
PUL-01	3,511	441,638	2.10	4.42
GBY-03	1,259	202,585	1.65	4.42
DOY-01	4,248	404,597	2.75	4.34
Company Average	**1,207**	**92,119**	**1.68**	**2.13**

Appendix B

Worst Performing Feeders
Summary of Data Analysis

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
GPD-01	Reliability statistics were poor in 2003 & 2004. Work was carried out under the Rebuild Distribution Lines program in 2005 and there have been no reliability issues since that time. No work is required at this time.
GLV-02	Work is in progress on this feeder under a project initiated in 2006.
LEW-02	Work is in progress on this feeder under a project initiated in 2006.
DUN-01	Reliability statistics were poor in both 2006 and 2007 however the statistics were driven by a sleet storm in 2006 and a broken recloser bushing in 2007. No work is required at this time.
ROB-01	The ROB-01 feeder has displayed consistently poor reliability however the issues have been primarily related to trees and lightning. Trees have been cut under the vegetation management program and lightning arrestors have been installed on distribution equipment. No work is required at this time.
BOT-01	Work is in progress on this feeder under a project initiated in 2006.
NWB-02	The NWB-02 feeder has displayed consistently poor reliability over the past five years. The issues experienced have been due to a variety of issues related to the age and condition of the line. This feeder should be considered for work under the Distribution Reliability Initiative.
WES-02	Reliability statistics were poor in 2003 & 2004. Work was carried out under the Rebuild Distribution Lines program in 2005 and there have been no reliability issues since 2005. No work is required at this time.
BCV-02	Problems in 2003, 2004 & 2005. This feeder was rebuilt under the Distribution Reliability Initiative in 2006. There have been no reliability issues since 2006. No work is required at this time.
MOB-01	Reliability statistics were poor in 2003 & 2004. Work was carried out under the Rebuild Distribution Lines program in 2005 and there have been no reliability issues since 2005. No work is required at this time.

FER-01	Reliability statistics were poor in 2003 & 2005. Work was carried out under the Rebuild Distribution Lines program in 2005 and there have been no reliability issues since 2005. No work is required at this time.
GBS-02	Reliability statistics were poor in 2004. Work was carried out under the Rebuild Distribution Lines program in 2004 and there have been no reliability issues since 2005. No work is required at this time.
CAB-01	Reliability statistics were poor in 2003 & 2004. Work was carried out under the Rebuild Distribution Lines program in 2005 and there have been no reliability issues since 2005. No work is required at this time.
PUL-01	Reliability statistics were poor in 2003 & 2004. Work was carried out under the Rebuild Distribution Lines program in 2006 and there have been no reliability issues since 2006. No work is required at this time.
DOY-01	Overall reliability statistics on this feeder have been good. The poor average statistics are driven by a single weather related issue in 2006. No work is required at this time.
GFS-06	Reliability statistics were poor in 2005. Work was carried out under the Rebuild Distribution Lines program in 2006 and there have been no reliability issues since 2006. No work is required at this time.
MIL-02	The MIL-02 feeder has displayed consistently poor reliability from 2002 to 2006. Significant work was carried out under the Rebuild Distribution Lines program in 2006 and there were no reliability issues in 2007. No work is required at this time.
CHA-01	Reliability statistics were poor in 2004 & 2005. Work was carried out under the Rebuild Distribution Lines program in 2005 and there have been no reliability issues since 2005. No work is required at this time.
PUL-02	Reliability statistics were poor in 2003, 2004 & 2005. Work was carried out under the Rebuild Distribution Lines program in 2006 and there have been no reliability issues since 2005. No work is required at this time.
HWD-02	Overall reliability statistics on this feeder have been good. The poor average statistics are driven by a single weather related issue in 2004. No work is required at this time.
GRH-02	Reliability statistics were poor in 2004 & 2005. Work was carried out under the Rebuild Distribution Lines program in 2005 and there have been no reliability issues since 2005. No work is required at this time.

LOK-01	Reliability statistics were poor in 2004. Work was carried out under the Rebuild Distribution Lines program in 2006 and there have been no reliability issues since 2006. No work is required at this time.
KEL-02	Overall reliability statistics on this feeder have been good. The poor average statistics are driven by a single weather related issue in 2003. No work is required at this time.
SUM-02	Reliability statistics were poor in 2003, 2004 and 2005. Work was carried out under the Rebuild Distribution Lines program in 2005 and there have been no reliability issues since 2005. No work is required at this time.
SMV-01	Reliability statistics were poor in 2003 & 2004. Work was carried out under the Rebuild Distribution Lines program in 2004 and there have been no reliability issues since 2004. No work is required at this time.
GBY-03	Reliability statistics were poor in 2003 & 2004. Work was carried out under the Rebuild Distribution Lines program in 2004 and there have been no reliability issues since that time. No work is required at this time.

Northwest Brook NWB-02 Feeder Study

June 2008

Prepared by:

Roger Conway

Approved by:

Peter Upshall, P.Eng.

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NEWFOUNDLAND POWER
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1.0 Executive Summary

The purpose of this report is to provide a plan to improve the reliability of the Northwest Brook (NWB-02) feeder. Outages have been of extended duration because of the inaccessibility of numerous segments of the feeder. This feeder was examined in sections with a review of the cause and duration of the outages. This was combined with field knowledge of the feeder from local personnel to address known reliability problems.

NWB-02 feeder originates from the Northwest Brook substation located just west of the Goobies intersection on the TCH and extends down both sides of Southwest Arm. The feeder has been prone to failure due to the condition of its primary conductor (#2 Aluminum Conductor Steel Reinforced "ACSR"), crossarms and insulator failures. Many sections of the feeder are located remote from the road making it difficult to locate the cause of outages and then to complete repairs.

Weather conditions along this section of the north east coast of the province expose the feeder to high winds, snow and ice loading. Significant upgrading of the feeder is recommended to improve performance in these weather conditions.

To improve the performance of this feeder, it is recommended to:

- Relocate the existing main trunk of the feeder to the existing road right-of-way ("ROW") at a number of locations;
- Replace insulators and crossarms on existing sections of the main trunk feeder near the road ROW employing severe weather construction design; and
- Remove all danger trees along the entire feeder.

2.0 NWB-02 Feeder

Located in the Bonavista operating area of Eastern Region, NWB-02 is a 25 kV distribution line that was originally constructed in the early 1960s servicing approximately 1,050 customers. The feeder extends from the substation located on the TCH west of Goobies to the community of Northwest Brook where it divides and extends down both sides of Southwest Arm. The first 3 km section running along the TCH to the community of Northwest Brook was constructed in 1992 and is in good condition. From Northwest Brook the feeder extends 28 km on the south side of the Southwest Arm to the community of Southport and 20 km along the north side of Southwest Arm to the community of St. Jones Within (refer to map in Appendix A).

The section extending 28 km down the southern side of Southwest Arm to the community of Southport is 3 phase construction as far as the community of Queen's Cove and continues as a 2 phase line to the end of Little Heart's Ease. The remaining 6 km of line along Route 204 consists of single phase construction with #2 ACSR conductor.

The second 20 km section of line extends down the north side of Southwest Arm to the community of St. Jones Within. The feeder through the community of Northwest Brook is 3 phase construction and then reduces to 2 phases to the community of Hillview. A single phase line extends from Hillview to the community of St. Jones Within.

3.0 Outage History for Feeder

The feeder has a history of extended outages. Most feeder sections between communities are located remote from the road ROW and are not visible from the road during adverse weather conditions. The lack of visibility makes locating the cause of outages difficult and extends the time necessary to complete repairs. The radial nature of this feeder provides no alternative means of supplying power to customers. Most sections of line to be relocated to the road ROW have had minimal upgrades since the initial feeder construction in the early 1960s.

Much of the single-phase sections are conductored with the original #2 ACSR. This conductor has been noted to have poor operating characteristics in a salt spray environment. Over time, the outer aluminum strands break, leaving the steel core to carry the load. Eventually the steel core breaks causing an outage to customers. Sections of the two-phase main trunk feeder have one phase with #2 ACSR and the second phase has 4/0 Aluminum Alloy Stranded Conductor (“AASC”).

Two piece pin type insulators are also prevalent on this feeder. This type of insulator has been prone to separation and failure. Any remaining two piece insulators on the main trunk part of NWB-02 feeder should be replaced with 34 kV Clamp Top insulators and V brace crossarms as required.

3.1 NWB-02 Feeder by Component that Failed

Table 1 below shows a summary of the 190 interruption reports for the period from 2002 to 2006. The sleet storm in December 2007 caused outages on this feeder which lasted for several days. The study period from 2002-2006 was selected to eliminate the overwhelming impact of these December 2007 outages. The period 2003-2007 had accumulated customer minutes of 5,604,493 including the December sleet storm, compared to the 2002-2006 period with 2,151,561 accumulated customer minutes.

The interruption reports are sorted using the “Component that Failed” as its base. In some occurrences, such as in sleet and windstorms, there were no particular components that failed.

Table 1
Interruption Summary by Component
2002 – 2006

Component that Failed	Number of Outages	Customer Minutes
Conductor	5	411,169
Fuses [1]	68	414,840
Insulators	20	410,041
Control Equipment at Sub [2]	4	178,805
Transformers	32	56,570
Service Wires	19	744
Cutout / Switch	25	85,943
Pole Hardware	3	83,180
None	11	451,105
Other	3	59,164
Total	**190**	**2,151,561**

[1] Fuses operated as a result of sleet, wind, and lightning.
[2] Includes equipment operated due to wind, trees in line etc.

3.2 NWB-02 Feeder by Cause

Table 2 below summarizes the 190 interruption reports for the period from 2002 to 2006. Problems are sorted using the "Cause" as its base.

Table 2
Interruption Summary by Cause
2002 – 2006

Cause	Number of Outages	Customer Minutes
Snow	2	70,642
Wind	14	606,355
Lightning	43	69,013
Broken/Defective Equipment [1]	105	936,661
Damage Outside Party	3	680
Trees	3	204,628
Animals	6	45,595
Sleet	8	97,263
Unexplained	6	120,724
Total	**190**	**2,151,561**

[1] Broken and Defective equipment include items such as insulators, conductor and hardware. In a windstorm, outages can occur due to trees on line, damage to conductor, etc.

4.0 Recommendations

The NWB-02 feeder was reviewed for location characteristics (i.e. subject to salt spray conditions and ice loading). Each section of the feeder was then analyzed to see if specific causes could be determined and appropriate solutions recommended. The recommendations to improve this feeder are listed in geographic order, beginning at the substation and proceeding along the south side of Southwest Arm, then along the north side of Southwest Arm.

4.1 All Sections of NWB-02 Feeder

1. All new construction will be built to heavy loading standards using the 34 kV clamp top insulators. Structures to be re-insulated will also have the crossarms replaced.

2. Feeder coordination will be reviewed and all taps protected by a fused cutout.

3. The replacement of porcelain cutouts and installation of lightning arrestors. The work is planned for 2009 & 2010 and estimated at $68,000.

4. The feeder design will be remodeled to optimize the location of existing voltage regulators taking into account the relocated sections of feeder.

4.2 NWB Substation along TCH to Northwest Brook and Long Beach (Work planned for 2009)

This 13.2 km section of the main trunk is in good condition with the ROW clear of brush and clamp top insulators on most of the line. It is necessary to replace insulators on the last section of line and also install mid span poles to reduce span lengths. Total estimated cost for this work is approximately $21,000.

4.3 Long Beach to Hodge's Cove (Work planned for 2009)

This 7.2 km two phase section consists of poles installed in the early 1960's except for 2 km through the community of Hodge's Cove. The conductor consists of one phase of #2 ACSR and the second phase 4/0 AASC. It is recommended to relocate the first 5.3 km of this line to the road ROW and replace insulators on the section through the community of Hodge's Cove to the voltage regulator structure *(NWB-02-VR3)*. The estimate for planned work in this section is approximately $367,000.

4.4 Northwest Brook to the TCH near Ivany's Cove (Work planned for 2009)

This 2.6 km section of feeder is in good condition with some structures already re-insulated. The remaining structures consist of 2-piece pin type insulators. It is recommended that the 2-piece pin type insulators be replaced on the remaining structures and six deteriorated poles be replaced. The estimate for planned work in this section is approximately $42,000.

4.5 Hodge's Cove Little Heart's Ease (Work planned for 2010)

This 4.9 km section of feeder consists of one phase of #2 ACSR conductor and the other phase being 4/0 AASC constructed in the early 1960s. Recommendations include the relocation of a 1.6 km section of line to the road ROW in the community of Little Heart's Ease and replacing insulators on the remaining structures. The estimate for planned work in this section is approximately $114,000.

4.6 Little Heart's Ease to Southport (Work planned for 2010)

Insulators have been replaced on some structures on this section of feeder through the communities of Gooseberry Cove and Southport. The first 3.1 km consist of #2 ACSR conductors on original poles located remote from the road. Recommendations include the relocation of this 3.1 km to the road ROW and installing 10 new structures to replace deteriorated poles and long spans at the beginning of Southport. The total estimate for planned work in this section is approximately $175,000.

4.7 TCH to Hillview (Work planned for 2010)

This 2 phase section of feeder consists of 1.9 km of line located remote from the road with no upgrades since the initial construction. Recommendations include the relocation of this 1.9 km of line to the road ROW. The total estimate for planned work in this section is approximately $114,000.

4.8 The community of Hillview (Work planned for 2009)

This 1.5 km section of feeder is in good condition with insulators replaced on some structures. The remaining structures consist of 2-piece and smaller pin type insulators. Recommendations include replacing insulators on the remaining structures and the replacement of 6 deteriorated poles. The estimate for planned work in this section is approximately $23,000.

4.9 Hillview to the Hatchet Cove Tap (Work planned for 2011)

This 8.9 km section of single phase line consists of poles installed in the early 1960's with #2 ACSR conductor. The line is remote from the road ROW with long spans. Recommendations include relocation of 7 km of single phase line to the road ROW. The estimate for planned work in this section is approximately $350,000.

4.10 Hatchet's Cove Tap to St. Jones Within (Work planned for 2011)

This 3.4 km section of single phase line consists of poles installed in the early 1960's with #2 ACSR conductor. The line is remote from the road ROW and includes long span lengths. There have been no upgrades on this section of line since the initial construction. Recommendations include relocation of the 3.4 km of single phase line to the road ROW. The estimate for planned work in this section is approximately $170,000.

4.11 Community of St. Jones Within (Work planned for 2009)

This 1.9 km section of the single phase line is visible from the road with some structures already re-insulated. Recommendations include the re-insulation of the remaining structures and replacement of 6 deteriorated poles. The estimate for planned work in this section is approximately $19,000.

5.0 Conclusion

Customers served by NWB-02 have experienced extended outages during the study period. The work outlined in this report will reduce the number and duration of customer outages.

Outage data indicates that 57% of all outages were related to conductor, insulators, or the operation of fuses. The planned upgrades involve replacing insulators and conductor along critical sections of the feeder.

Large sections of NWB-02 feeder are located remote from the road. Relocating these sections of the feeder to the road ROW will reduce the time required to identify damage and affect repairs.

It is recommended that NWB-02 be rebuilt and relocated as per sections 4.1 to 4.11. The total estimate for planned work on this feeder is approximately $1,463,000 over a 3 year period.

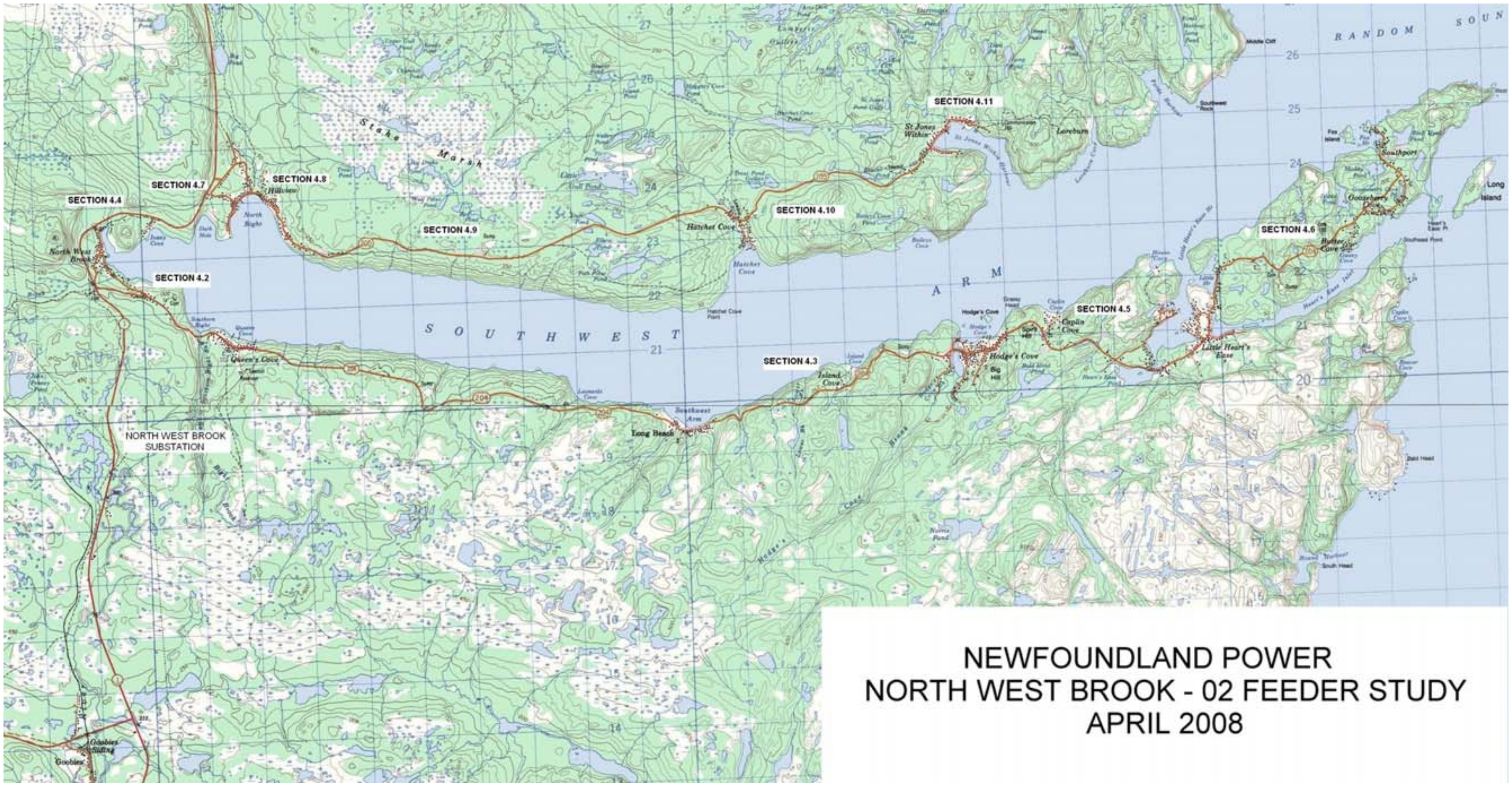
- 2009 – Complete work in sections 4.1, 4.2, 4.3, 4.4, 4.8, and 4.11 ($496,000)[1].
- 2010 – Complete work in sections 4.1, 4.5, 4.6, and 4.7 ($447,000).
- 2011 – Complete work in sections 4.9 and 4.10 ($520,000).

The recommended work is required in order to ensure the continued provision of safe, reliable electrical service.

[1] As per section 4.1, the total cost for installing lightning arrestors and replacing porcelain cut-outs is $68,000, with $24,000 to be spent in 2009 and $44,000 to be spent in 2010.

Appendix A

Map Showing
Areas Serviced by NWB-02


SECTION 4.4
SECTION 4.7
SECTION 4.8
SECTION 4.2
SECTION 4.9
SECTION 4.10
SECTION 4.11
SECTION 4.3
SECTION 4.5
SECTION 4.6
NORTH WEST BROOK
SUBSTATION
S O U T H W E S T
A R M
R A N D O M
NEWFOUNDLAND POWER
NORTH WEST BROOK - 02 FEEDER STUDY
APRIL 2008

ENERGY EFFICIENT STREETLIGHTS

Convert Mercury Vapour Streetlights
To High Pressure Sodium

June 2008

Prepared by:

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PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
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1.0 Introduction

Newfoundland Power ("the Company") maintains approximately 56,000 streetlights providing street and area lighting throughout its service territory, including approximately 7,000 Mercury Vapour (MV) streetlights. These MV streetlights are not as energy efficient as the High Pressure Sodium (HPS) streetlights that have replaced the MV units as the Company standard. Through normal attrition approximately 538 MV streetlights are replaced each year. At the current replacement rate it will take approximately 13 years to remove all of the remaining 7,000 MV streetlights from the distribution system. This study examines the feasibility of converting the remaining MV streetlights to HPS at an accelerated rate.

In 1982 Newfoundland Power's street lighting standard was changed from MV to HPS streetlights. The change was justified on the improved efficiency of the HPS lamps, with the HPS lamp providing higher light output at lower wattages and associated energy savings.

There has been no MV streetlight fixtures purchased since the standard was changed in 1982. Replacement lamps and some components have been purchased, and limited repairs have been completed on existing fixtures. Therefore all remaining MV streetlight fixtures were purchased prior to the 1982 change in standard. At an age in excess of 26 years, these fixtures have an in service life greater than what would normally be expected.

2.0 Energy Savings

Energy efficient streetlights provide the same quality of area lighting while consuming less electricity. For example, 175 watt MV lamps may be replaced by more efficient 100 watt HPS lamps to realize energy savings of more than 35% while providing the same light output. Table 1 identifies the energy and demand savings achieved from replacing a MV streetlight with the appropriate HPS streetlight.

Table 1
Energy Savings

		Mercury Vapour Lamps	
Lamp Size	**175 Watts**	**250 Watts**	**400 Watts**
Loading Watts	200	283	445
KWH per Year	840	1,189	1,869
		High Pressure Sodium Lamps	
Lamp Size	**100 Watts**	**150 Watts**	**250 Watts**
Loading Watts	130	191	303
KWH per Year	545	802	1,273
		Savings	
Energy savings[1] (KWH)	294	386	596
Demand Savings (Watts)	70	92	142

[1] Calculated based upon 4,200 hours of operation per year.

3.0 System Savings

There are approximately 7,000 MV street lights remaining in service. Collectively, they have the potential to reduce the energy consumption attributable to street lighting by 2,184 MWh on an annual basis. During time of system peak, replacing these 7,000 street lights with the more energy efficient HPS lamp, would remove approximately 0.5 MW from the system peak. Table 2 identifies the estimated energy and demand savings associated with replacing the MV streetlights with HPS streetlights.

Table 2
Estimated Energy and Demand Savings

MV Lamp Size	Quantity	Energy Savings (MWh)	Demand Savings (kWs)
175 watts	5,900	1,734	413
250 watts	980	378	90
400 watts	120	72	17
Total	**7,000**	**2,184**	**520**

4.0 Economic Analysis

In order to estimate the financial benefit associated with a more energy efficient form of street lighting, an incremental cost of electricity must be selected. Recent marginal cost studies suggest that energy costs at the Holyrood Thermal Generating Station is a good proxy for the marginal cost of electricity on the system. Based upon most recent fuel pricing projections, an estimate of the 25 year levelized cost of energy[2] from the Holyrood facility is 12.84¢/KWh.[3] More recently Newfoundland and Labrador Hydro has entered into power purchase agreements with two wind energy proponents. Under these agreements wind energy will be purchased for approximately 6.7¢/KWh[4].

To evaluate the economic impact of the proposed streetlight replacement, a comparison of the cumulative present worth revenue requirement for two alternatives was considered.

Option 1 is the "status quo" alternative where the remaining 7,000 MV streetlights are replaced through normal attrition at the rate of 538 per year. This rate reflects the average annual replacements over the period 2001 to 2007. At the rate of 538 streetlights per year, it will take approximately 13 years to remove all MV streetlights from the system.

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2 Incremental energy from the Holyrood thermal generating station is estimated at 10.63 cents per kWh for 2009 (based upon $67.00 per barrel of No. 6 fuel from Hydro's fuel price projection dated March 31, 2008), with associated levelized cost of 12.84 cents per kWh over 25 years and 13.90 cents per kWh over 50 years.

3 The 25 year levelized cost was selected for comparison purposes because it more closely approximates the anticipated life expectancy of a street light.

4 Response to Request for Information PUB 1.0 NLH, Newfoundland Power's application for approval of capital expenditures supplemental to its 2008 Capital Budget to connect two 27 MW wind farms to the Island Interconnected System.

Option 2 is the planned replacement of all 7,000 MV streetlights over a 3 year period commencing in 2009. The decision to complete the work over 3 years was based upon managing the Company's workforce and contractors effectively, in concert with the other distribution work included in the 5 year capital plan.

Appendix A includes the present worth analysis for the two alternatives. Option 1 has a cumulative present worth cost of $1,522,000 over the period from 2009 to 2030[5]. Option 2 has a cumulative present worth cost of $896,000 over the same period. Selecting Option 2 over Option 1 provides a net present worth ***benefit*** of approximately $626,000.

The present worth analysis shows that the project is economic when compared to the alternative of replacing MV streetlights through normal attrition.

Using the present worth benefit analysis provided in Appendix A, and taking into account the net energy savings over the period from 2009 to 2030, the levelized cost of energy saved through this project is 5.65¢/KWh. This levelized cost of energy compares favourably with the 25-year levelized cost of energy from the Holyrood Thermal Generating Station and the power purchase price for the proposed wind energy projects.

Table 3 shows the cost breakdown for the 3-year project.

Table 3
Project Costs 2009-2011
(000s)

Year	Budget
2009	$806
2010	$581
2011	$581
Total	**$1,968**

5.0 Concluding

Converting the remaining 7,000 mercury vapour streetlights with high pressure sodium streetlights is technically and economically feasible. Replacing mercury vapour streetlights with the more energy efficient high pressure sodium streetlights is consistent with improved energy efficiency.

The economic analysis indicates that the project as proposed provides a net cost benefit of approximately $626,000 over the life of the equipment when compared to the current process of replacing streetlights through normal attrition. Also, the levelized cost of energy saved compares favourably with other sources of energy on the Island Interconnected System.

5 The period 2009 to 2030 was selected to represent the reasonable life expectancy of the street lights.

Appendix A

Present Worth Analysis

Present Worth Analysis

Option 1
Replace 7,000 MV Streetlights Through Attrition
(538 units per year)

Weighted Average Incremental Cost of Capital	**7.27%**
Present Worth Year	**2008**
Depreciation Rate	**20years @ 8% CCA**

Year	Capital Cost	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
2009	134,500	14,657	121,333	21,569	-114,421	-106,667	-106,667
2010	136,652	31,630	114,469	43,139	-102,960	-89,477	-196,144
2011	138,702	48,565	107,249	64,708	-91,105	-73,809	-269,953
2012	140,782	65,401	99,786	86,278	-78,910	-59,596	-329,549
2013	143,176	82,207	92,257	107,847	-66,616	-46,902	-376,451
2014	145,610	98,963	84,443	129,417	-53,989	-35,435	-411,886
2015	148,085	115,648	76,336	150,986	-40,998	-25,085	-436,971
2016	150,602	132,242	135,859	172,556	-95,545	-54,498	-491,469
2017	153,313	148,741	128,426	194,125	-83,041	-44,156	-535,625
2018	156,073	165,130	120,681	215,695	-70,116	-34,756	-570,381
2019	158,882	181,392	112,615	237,264	-56,743	-26,221	-596,602
2020	161,742	197,512	104,220	258,834	-42,899	-18,480	-615,082
2021	164,653	213,475	95,487	280,403	-28,558	-11,469	-626,551
2022		210,999	86,405		-297,404	-111,340	-737,891
2023		205,416	153,930		-359,346	-125,412	-863,303
2024		199,618	156,701		-356,319	-115,928	-979,230
2025		193,667	159,522		-353,189	-107,121	-1,086,352
2026		187,503	162,393		-349,897	-98,931	-1,185,282
2027		181,143	165,316		-346,460	-91,320	-1,276,602
2028		173,491	168,292		-341,783	-83,982	-1,360,584
2029		158,160	171,321		-329,481	-75,472	-1,436,056
2030		143,071	261,607		-404,678	-86,415	**-1,522,471**

Present Worth Analysis

Option 2
Replace 7,000 MV Streetlights in 3 Years
(2009, 2010 and 2011)

Weighted Average Incremental Cost of Capital	**7.27%**
Present Worth Year	**2008**
Depreciation Rate	**20years @ 8% CCA**

Year	**Capital Cost**	**Capital Revenue Requirement**	**Operating Costs**	**Operating Benefits**	**Net Benefit**	**Present Worth Benefit**	**Cumulative Present Worth Benefit**
2009	581,000	63,316	86,667	93,548	-56,434	-52,610	-52,610
2010	590,296	136,631	44,027	187,096	6,438	5,595	-47,015
2011	599,150	209,786	0	280,644	70,858	57,405	10,390
2012		216,241	0	280,644	64,403	48,640	59,030
2013		212,030	0	280,644	68,614	48,309	107,339
2014		207,628	0	280,644	73,016	47,924	155,262
2015		203,208	0	280,644	77,436	47,380	202,642
2016		198,510	339,649	280,644	-257,515	-146,884	55,758
2017		193,557	345,762	280,644	-258,675	-137,547	-81,789
2018		188,369	351,986	280,644	-259,711	-128,738	-210,527
2019		182,965	0	280,644	97,679	45,138	-165,389
2020		177,361	0	280,644	103,283	44,493	-120,897
2021		171,575	0	280,644	109,069	43,801	-77,096
2022		165,621	0	0	-165,621	-62,004	-139,100
2023		159,511	384,826	0	-544,337	-189,974	-329,073
2024		153,259	391,753	0	-545,012	-177,318	-506,392
2025		146,876	398,804	0	-545,680	-165,504	-671,895
2026		140,372	0	0	-140,372	-39,689	-711,584
2027		133,758	0	0	-133,758	-35,256	-746,840
2028		122,236	0	0	-122,236	-30,035	-776,876
2029		78,171	0	0	-78,171	-17,906	-794,782
2030		35,719	436,012	0	-471,731	-100,733	**-895,515**

Notes:

Capital Cost

The capital cost of both alternatives is calculated using $238 per streetlight, inflated by the appropriate number of years, then multiplied by the quantity of streetlights to be replaced in the given year.

Capital Revenue Requirement

The capital revenue requirement includes depreciation cost, return on rate base and taxes.

Operating Costs

Costs associated with maintaining the 7,000 streetlights. The estimate is based upon the cost to replace lamps on a 7 year cycle. It includes both Mercury Vapour ("MV") lamps and High Pressure Sodium ("HPS") lamps.

Operating Benefits

Energy savings associated with the difference in energy consumption between MV and HPS streetlights, estimated at 12.84¢/KWh.

Net Benefits

The net benefit is calculated as the operating benefit less the operating cost and the capital revenue requirement.

Present Worth Benefit

The calculated present worth of the net benefit in 2008 dollars.

Cumulative Present Worth Benefit

The cumulative present worth benefit for the particular year is the sum of the present worth benefit for the year and the preceding years in 2008 dollars.

2009 Application Enhancements

June 2008

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1.0 Introduction

The Company operates and supports over 50 computer applications including software packages such as the Great Plains financial system, 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.

The Company's computer application enhancements can be considered in four broad categories: Customer Service 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 routinely encountered during the course of the year.

Enhancing these applications either through vendor supplied functionality or internal software development enables the Company to meet its obligation to provide service to its customers at least cost.

The following sections describe the items budgeted for 2009.

2.0 Customer Service Systems Enhancements

Customer Service System Enhancements include application enhancements necessary to support customer service delivery, along with the various forms of communications necessary to allow customers to receive service from the Company. For 2009, enhancements are proposed for Customer Contact**,** Customer Billing and Credit Management.

Table 1 summarizes the cost associated with these items.

Table 1
Customer Service System Enhancements
Project Expenditures
($000s)

Cost Category	2009 Estimate
Material	100
Labour – Internal	331
Labour – Contract	-
Engineering	-
Other	30
Total	**461**

2.1 Customer Contact Enhancements ($278,000)

Description

This item involves improving the Company's response to the various methods of customer communication received at the Contact Centre. The methods of communication include agent assisted phone calls, Interactive Voice Response ("IVR"), email, fax and posted mail.

The original CSS went into service in 1991 and was designed to provide effective service to customers through the public telephone system with the assistance of a Contact Centre agent. Today, customers request service from the Company through the IVR, email, fax and posted mail, in addition to the traditional method of agent assisted phone calls. The CSS and other systems used by the Contact Center do not currently support efficient handling of customer contacts not made with Call Centre agents.

This item will involve enhancing the current applications to allow other forms of electronic communications associated with customer contact to be effectively recorded and made immediately available to Contact Centre agents. Making comprehensive customer contact data available will permit Call Centre agents to respond to customers' needs in a more timely way.

Operating Experience

The Contact Centre handles various forms of customer communication. Approximately 520,000 customer phone calls (handled via the IVR and agent assisted calls), 18,000 emails, 2,000 pieces of posted mail and 3,000 faxes are handled annually. The types of customer interactions that are processed via these methods vary considerably and include requests for new service, outage reporting, billing inquiries and requests for energy efficiency information.

The customer communication to the Contact Centre via means such as IVR, email and fax has reached a point where staff are often unaware of previous contacts by customers by the different means. This situation can also result in Call Centre agents having an incomplete picture of customer contact, potentially leading to ineffective customer response.

Justification

This item is justified primarily on improved customer service.

Providing Contact Centre agents with an improved means of dealing with all occurrences and forms of communications will ensure agents are able to more effectively handle customer inquires.

2.2 Customer Billing Enhancements ($85,000)

Description

The purpose of this item is to improve the accuracy of customer bills by reducing the number of meter reading estimates and by enhancing the automated bill verification process. The item involves changes to CSS to reduce the number of bills requiring follow up, and the use of automated telephone technology to reduce the number of meter reading estimates.

Meter reading estimates can be reduced through the use of automated telephone communications with customers encouraging them to improve access to their meter, and to submit their own meter reading using either the Contact Centre, the Internet or the IVR.

Improving the accuracy of the customer bills, through a reduction in meter reading estimates, and more advanced edit checks in the automated bill verification process will improve efficiency and reduce operating costs.

Operating Experience

The Company processes approximately 2.7 million customer bills annually. The bill processing functionality is inherently complex in order to ensure accurate bills are produced. When customer bills fall outside the defined reasonableness checks, the bill is delayed and follow-up is required by Contact Centre staff.

In 2007 the Company estimated approximately 215,000 customer meter readings largely due to inaccessible meters during the winter season. These meter reading estimates resulted in approximately 20,000 manual follow-ups. When estimates are required in consecutive billing periods, the likelihood of an inaccurate estimate increases. This situation increases the frequency and complexity of customer high bill inquiries.

Justification

This item is justified on improved customer service and operating efficiency.

Introducing call automation to customers regarding meter accessibility is expected to reduce the number of billing estimates. Reducing the number of situations where consecutive estimates occur will result in improved customer service and a reduction in customer calls to the Contact Centre associated with high bill inquiries.

A financial analysis of the costs and benefits associated with this item indicates a positive net present value of $29,118 over the next 5 years. The financial analysis is included in Appendix A.

2.3 Credit Management Enhancements ($98,000)

Description

The purpose of this item is to improve the method by which the Company identifies customer accounts which require collection action. Currently various collection notices are issued and telephone contacts are made according to automated rules that may be unnecessary for many customers.

The Company intends to develop the necessary software tools to permit greater automation in the analysis of customer credit data. This, in turn, will improve the Company's ability to ensure collection activities are only performed on those customer accounts that require collection action.

Operating Experience

The Company performs various types of customer contact with regards to credit and collection matters. The types of contact include automated and agent initiated printed notices and telephone calls as well as field visits. In 2007, there were over 235,000 automated and manually issued collection notices, over 45,000 automated phone calls, over 140,000 agent handled credit calls and over 10,500 in-person field visits to customers.

Currently, there is no systematic means of identifying customers in arrears that do not require any type of collection contact. Customers with extenuating circumstances are currently contacted in the same manner as other credit customers. Altering the type and content of automated collection activities to better reflect a customer's situation would improve the overall customer service experience and reduce the requirement for field visits.

Justification

This item is justified on improved operating efficiency and customer service.

Avoiding unnecessary collection activities and improving the method of automated customer contact will reduce collection costs, including the reduction of unnecessary and expensive field visits. As well, avoiding unnecessary customer contacts that by their nature are potentially sensitive will improve overall customer service.

A financial analysis of the costs and benefits associated with this item indicates a positive net present value of $3,840 over the next 5 years. The financial analysis is included in Appendix A.

3.0 Operations and Engineering Systems Enhancements

Operations and Engineering Systems Enhancements includes application enhancements necessary to support the Company's engineering and operations function. The information technology in this category includes the Asset Management System (Avantis), the Outage Management System and various other applications used to engineer and maintain Company assets and manage work in a safe and environmentally responsible manner.

For 2009, enhancements are proposed for the Asset Management System, Outage Management System, and Safety and Environment Systems.

Table 2 summarizes the cost associated with these items.

Table 2
Operations and Engineering Enhancements
Project Expenditures
($000s)

Cost Category	2009 Estimate
Material	50
Labour – Internal	321
Labour – Contract	-
Engineering	34
Other	150
Total	**555**

3.1 Asset Management System Enhancements ($240,000)

Description

This item includes enhancements to the Company's asset management application to improve processes related to distribution and transmission construction and maintenance activities. This includes expanding the Technical Work Request ("TWR") Mobile application to Western Region technicians, improving streetlight management processes and improving the ability to provide up-to-date distribution and transmission system information (distribution system diagrams, distribution and transmission design, and maintenance standards) to the Company's mobile workforce.

Operating Experience

In 2007, the Company implemented the TWR Mobile application for technicians in the St. John's area. This application has improved employee productivity and customer service by allowing technicians real-time access to customer driven work requests when away from the office. Providing technicians with the ability to update the status of the work request while in the field allows the Contact Centre immediate access to this information to respond to customer inquiries. In turn, technicians are able to view updates to customer requests once recorded by Contact Centre staff.

The Company has approximately 56,000 streetlights installed throughout its service territory. The process for ensuring that streetlights installed in the field are properly recorded in the street light application is largely manual, making the resulting database records subject to errors and omissions. The physical tags used to uniquely identify poles and streetlights are susceptible to damage or misplacement due to storm damage, vehicle accidents, vandalism and normal weathering over time.

The Company manages approximately 8,500 kilometres of distribution lines throughout its service territory. An integral part of ensuring the safe and effective management of the distribution system is ensuring that distribution system drawings (or single-line diagrams) are current and available to technical staff. Daily construction, maintenance and electrical system management activities require ongoing updates to the single-line diagrams in order to reflect new customer connections, distribution feeder customer load transfers or overall system configuration changes to ensure effective customer service and electricity supply. As well distribution and transmission line design and maintenance standards are required for safe and effective field operations.

Justification

Expanding the use of the mobile capabilities of the TWR application will improve customer service by shortening the time between information being captured in the field and information being available for Contact Centre agents to provide customers with the effective and timely updates regarding their work requests.

Expanding the current distribution asset management system to support streetlight installation and maintenance will increase efficiency and improve data quality. Uniquely identifying installed poles and attached lights with a geographic location will improve the data quality of the streetlight database, reducing the amount of time reconciling field installations to application databases.

Ensuring that the most current versions of the distribution system diagrams are available to technical field staff ensures that the field work is performed in a safe and effective manner.

A financial analysis of the costs and benefits associated with this item results in a positive net present value of $21,466 over the next 5 years. The financial analysis is included in Appendix A.

3.2 Outage Management System Enhancements ($147,000)

Description

This item includes enhancements to outage management systems to improve the accuracy of outage reporting to customers. This item will consolidate the various outage data sources to a common application ensuring the most current outage information is always available.

Operating Experience

The Company uses three different applications to track and manage outages. The SCADA system monitors all activity on the power system in real-time. The Outage Notification System creates voice messages for any outages on the power system. The Outage Management System tracks customer outages for dispatch and follow up. Each of these applications has its own database, and the time when each database is updated for an individual outage is not synchronized. As a result, information flow between the System Control Centre, the Contact Centre and customers can get confused and customers may not be provided with the most up to date information.

During the December 2007 storm that affected the Bonavista and Avalon Penninsulas it became evident that inconsistent communication occurred as the result of multiple data sources being updated at different times. This situation caused confusion for customers as well as Company employees who were responsible for keeping customers informed of the outages.

Justification

This item is justified primarily on customer service improvements.

Enhancing the outage management systems will improve customer service by providing consistent outage information for customers. In addition, it will reduce the amount of time spent recording outage information in separate systems. Improving application and data management processes in this way will improve the Company's ability to communicate consistent and realistic restoration times to customers.

3.3 Safety and Environment System Enhancements ($168,000)

Description

The purpose of this item is to make available to field employees the Company's Health and Safety Management System ("HSMS") and Environment Management System ("EMS") documentation. This will involve providing field employees access to the online manuals using mobile computers in vehicles.

Operating Experience

The safety of the general public, employees and contractors as well as operating in an environmentally responsible manner are priorities for the Company. As part of the established processes related to the HSMS and EMS, the Company continually evaluates the effectiveness of related policies, procedures and systems with a focus on continual improvement. Ensuring that all employees have access to current documents, procedures and other information related to the HSMS and EMS is the next step in the improvement process.

The HSMS is based on the *Occupation Health and Safety Assessment Series* (OSHAS 18001) for health and safety management systems. The EMS system is based on the *International Organization for Standardization* (ISO 14001) for implementing an effective environment management system. [1]

Currently there are approximately 120 paper copies of manuals regarding HSMS and EMS policy and procedures' distributed throughout the Company's area offices. The process for ensuring that these manuals are updated promptly and the process of removing outdated manuals from the field are labour intensive. Employees who work in the field rely on the manuals to reference safety, environment and other related work procedures. Occasionally, there have been instances where field manuals are not updated in a timely manner.

Justification

This item is justified on operating efficiencies.

Ensuring that employees have access to the most current policies and procedures related to the HSMS and EMS is central to effective safety and environment initiatives. Providing the HSMS and EMS information electronically through mobile computers in Company vehicles will ensure field staff have access to current information, increase employee awareness, and reduce the risk of safety or environment incidents.

A financial analysis of the costs and benefits associated with this item indicates a positive net present value of $59,087 over the next 5 years. The financial analysis is included in Appendix A.

4.0 Customer Service Internet Enhancements ($197,000)

Description

This item includes enhancements to the Company's website including expanded customer self-service functionality and improvements to site navigation. For 2009, additional self-service functionality includes improved energy efficiency support capabilities, expanded contractor self-

[1] ISO 14001 was first implemented at Newfoundland Power within the Generation group in 1999 with the Generation group becoming registered ISO compliant in 2001. The remainder of the Company became consistent with the ISO 14001 Standard in 2001.

service and improved bill payment support. Improvements to ensure effective security of customer information are also included.

Operating Experience

In 2007, the Company's Internet website received more than 393,000 visits. This is a 725% increase since 2000 and an average annual increase of 134% over the 2000 to 2007 period. Currently, over 39,000 customers have created login accounts on the Company's website and approximately 20,000 customer accounts are sent bills electronically as part of the Company's *eBills* offering.

The Company invests in improvements to its website to meet evolving customer expectations. Continuing to expand self-service options allows customers to do business with the Company at their convenience and reduces the overall number of calls to the Contact Centre.

Internet security is an issue that most companies must manage on a continual basis. The nature and frequency of potential internet threats such as viruses, identity theft and internet fraud are evolving. Newfoundland Power continually assesses and implements security and threat detection systems that protect and respect the privacy and sensitivity of customer and Company information.

Justification

This item is justified on improved customer service by enhancing the Company's Internet website in response to increasing usage by customers.

5.0 Business Support Systems Enhancements ($75,000)

Description

The purpose of this item is to improve the process of managing the Company's capital and operating budgets. Budget data currently tracked and analysed outside of the Great Plains financial system will be functionally integrated into the financial management application.

Operating Experience

Current management of annual capital and operating budgets by departments is labour intensive due, in part, to the need for manual adjustments. This process involves employees with budget coordination responsibilities in all departments and regions and is performed using spreadsheets not integrated with the Company's financial management application, Great Plains.

In addition, Great Plains currently does not provide the ability to track changes. Many Company initiatives involve cross-functional groups that require ongoing monitoring to ensure departmental budgets and forecasts are maintained during the execution of these cross-functional projects. The lack of audit trail capabilities often results in extensive follow-up analysis between budget coordinators and Finance staff in order to effectively understand the reasons for the changes.

Justification

This item is justified on operational efficiency and process auditing improvements.

Effectively managing budgets and related forecasts is a core component of least cost management. Providing a means for budget coordinators to more effectively manage budgets and forecasts will reduce the time spent rekeying information and tracking cost variances.

A financial analysis of the costs and benefits associated with this item indicates a positive net present value of $4,362 over the next 5 years. The financial analysis is included in Appendix A.

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 or employee identified enhancements designed to improve customer service or employee productivity.

Operating Experience

Examples of previous work completed under this budget item include implementing an employee self-service kiosk at the St. John's area office to allow field personnel quick access to the Operations Manual, Standard Work Methods and Standard Protection Code as well as implementing a mobile version of applications used by operational employees involved with system peak load management and outage management activities.

Justification

Work completed as part of Various Minor Enhancements is justified on the basis of improved customer service, operating efficiencies or regulatory and legislative requirements.

Appendix A

Net Present Value Analysis

CUSTOMER BILLING IMPROVEMENTS

Net Present Value Analysis

		Capital Impacts		**Operating Cost Impacts**								
		Additions	**Tax Deductions**	**Cost Increases**		**Cost Benefits**						
	Year	**New Software (A)**	**Software (B)**	**Labour (C)**	**Non Labour (C)**	**Labour (D)**	**Non Labour (D)**	**Net Operating Savings (E)**	**Income Tax (F)**	**After Tax Cash Flow (G)**	**After Tax Discounted Cash Flow (H)**	**Cumulative Discounted Cash Flow (I)**
0	**2009-**	($85,000)	$42,500			$0	$0	$0	$14,025	($70,975)	($70,975)	($70,975)
1	**2010**		$42,500			$34,711	$0	$34,711	$2,492	$37,203	$35,036	($35,939)
2	**2011**					$35,752	$0	$35,752	($10,904)	$24,848	$22,037	($13,902)
3	**2012**					$36,825	$0	$36,825	($10,679)	$26,146	$21,837	$7,936
4	**2013**					$37,930	$0	$37,930	($11,000)	$26,930	$21,182	$29,118
								Present Value at 6.19% (see Note J)			**$29,118**	

Notes:

A Is the sum of the software additions by year

B Is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.

C Is any software maintenance fees and internal support costs associated with the project. The cost estimate are escalated using the GDP Deflator

D Is the reduced operating costs. The cost estimate are escalated using the GDP Deflator

E Is the sum of columns C and D

F Is the impact on taxes from the CCA and operating cost expenditures. It is equal to column B less column E times the tax rate.

G Is the after tax cash flow which is the sum of the capital expenditure (column A) plus operating expenditures (column E) plus income tax (column F).

H Is the after tax cash flow discounted to the first year of the cash flow analysis using a discount rate equal to NP's weighted average incremental cost of capital

I Is the cumulative value of the discounted cash flow in column H

J Is the present value of the after tax cash flows and equal to the sum of column I

CREDIT MANAGEMENT IMPROVEMENTS

Net Present Value Analysis

		Capital Impacts		Operating Cost Impacts								
		Additions	**Tax Deductions**	**Cost Increases**		**Cost Benefits**						
	Year	**New Software**	**Software**	**Labour**	**Non Labour**	**Labour**	**Non Labour**	**Net Operating Savings**	**Income Tax**	**After Tax Cash Flow**	**After Tax Discounted Cash Flow**	**Cumulative Discounted Cash Flow**
		(A)	**(B)**	**(C)**		**(D)**		**(E)**	**(F)**	**(G)**	**(H)**	**(I)**
0	**2009-**	($98,000)	$49,000			$0	$0	$0	$16,170	($81,830)	($81,830)	($81,830)
1	**2010**		$49,000			$28,196	$0	$28,196	$6,657	$34,853	$32,823	($49,007)
2	**2011**					$29,042	$0	$29,042	($8,858)	$20,184	$17,901	($31,106)
3	**2012**					$29,913	$0	$29,913	($8,675)	$21,239	$17,739	($13,367)
4	**2013**					$30,811	$0	$30,811	($8,935)	$21,876	$17,207	$3,840
								Present Value at 6.19% (see Note J)			**$3,840**	

Notes:

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ASSET MANAGEMENT SYSTEM ENHANCEMENTS

Net Present Value Analysis

		Capital Impacts		Operating Cost Impacts								
		Additions	**Tax Deductions**	**Cost Increases**		**Cost Benefits**						
	Year	**New Software**	**Software**	**Labour**	**Non Labour**	**Labour**	**Non Labour**	**Net Operating Savings**	**Income Tax**	**After Tax Cash Flow**	**After Tax Discounted Cash Flow**	**Cumulative Discounted Cash Flow**
		(A)	**(B)**	**(C)**		**(D)**		**(E)**	**(F)**	**(G)**	**(H)**	**(I)**
0	**2009-**	($240,000)	$120,000			$16,500	$0	$16,500	$34,155	($189,345)	($189,345)	($189,345)
1	**2010**		$120,000			$69,453	$0	$69,453	$16,175	$85,628	$80,640	($108,705)
2	**2011**					$71,536	$0	$71,536	($21,819)	$49,718	$44,094	($64,611)
3	**2012**					$73,683	$0	$73,683	($21,368)	$52,315	$43,694	($20,917)
4	**2013**					$75,893	$0	$75,893	($22,009)	$53,884	$42,383	$21,466
								Present Value at 6.19% (see Note J)			**$21,466**	

Notes:

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SAFETY AND ENVIRONMENT

Net Present Value Analysis

		Capital Impacts		**Operating Cost Impacts**								
		Additions	**Tax Deductions**	**Cost Increases**		**Cost Benefits**						
	Year	**New Software (A)**	**Software (B)**	**Labour (C)**	**Non Labour**	**Labour (D)**	**Non Labour**	**Net Operating Savings (E)**	**Income Tax (F)**	**After Tax Cash Flow (G)**	**After Tax Discounted Cash Flow (H)**	**Cumulative Discounted Cash Flow (I)**
0	**2009-**	($168,000)	$84,000			$0	$0	$0	$27,720	($140,280)	($140,280)	($140,280)
1	**2010**		$84,000			$69,216	$0	$69,216	$4,731	$73,947	$69,639	($70,641)
2	**2011**					$71,292	$0	$71,292	($21,744)	$49,548	$43,944	($26,697)
3	**2012**					$73,431	$0	$73,431	($21,295)	$52,136	$43,545	$16,848
4	**2013**					$75,634	$0	$75,634	($21,934)	$53,700	$42,239	$59,087
								Present Value at 6.19% (see Note J)			**$59,087**	

Notes:

A Is the sum of the software additions by year
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BUDGETING AND FORECASTING IMPROVEMENTS

Net Present Value Analysis

		Capital Impacts		**Operating Cost Impacts**								
		Additions	**Tax Deductions**	**Cost Increases**		**Cost Benefits**						
	Year	**New Software (A)**	**Software (B)**	**Labour (C)**	**Non Labour (C)**	**Labour (D)**	**Non Labour (D)**	**Net Operating Savings (E)**	**Income Tax (F)**	**After Tax Cash Flow (G)**	**After Tax Discounted Cash Flow (H)**	**Cumulative Discounted Cash Flow (I)**
0	**2009-**	($75,000)	$37,500			$0	$0	$0	$12,375	($62,625)	($62,625)	($62,625)
1	**2010**		$37,500			$22,145	$0	$22,145	$4,914	$27,059	$25,482	($37,143)
2	**2011**					$22,809	$0	$22,809	($6,957)	$15,852	$14,059	($23,083)
3	**2012**					$23,494	$0	$23,494	($6,813)	$16,680	$13,932	($9,151)
4	**2013**					$24,198	$0	$24,198	($7,018)	$17,181	$13,514	$4,362
								Present Value at 6.19% (see Note J)			**$4,362**	

Notes:

A Is the sum of the software additions by year
B Is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
C Is any software maintenance fees and internal support costs associated with the project. The cost estimate are escalated using the GDP Deflator
D Is the reduced operating costs. The cost estimate are escalated using the GDP Deflator
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2009 System Upgrades

June 2008

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

The Company depends on the effective implementation and on-going operation of its business applications in order to continue to provide least cost service to customers. Over time, these applications need to be upgraded to address functional or vendor obsolescence, to ensure continued vendor support, to improve software compatibility, or to take advantage of newly developed functionality.

This project consists of Business Application Upgrades, Information Technology Management Upgrades and continuation of the Microsoft Enterprise Agreement.

2.0 Business Application Upgrades ($387,000)

Business Application Upgrades involve third party software that support the Company's business applications. For 2009 upgrades are proposed for *Avantis Asset Management System***,** *Database Software*, and *Hand Held Meter Reading Software.*

Table 1 summarizes the cost associated with these items.

Table 1
Business Applications Upgrades
Project Expenditures
($000s)

Cost Category	2009 Estimate
Material	-
Labour – Internal	224
Labour – Contract	-
Engineering	13
Other	150
Total	**387**

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, the Company's software applications are reviewed to determine if upgrades are required.

For 2009, upgrades include:

1) Database Software - $190,000

   This item involves an upgrade to the Company's database software used to operate several Company applications such as the Customer Service System ("CSS"), Customer Service Internet, Outage Management System and Intranet to the most current version supported by the vendors (Oracle and Microsoft).

2) Hand Held Meter Reading Software - $143,000

   This item involves an upgrade to the Company's Hand Held Meter Reading software to the most current version supported by the vendor, Itron.

3) Asset Management System - $54,000

   This item involves an upgrade to the Company's Avantis Asset Management System.

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 upgrade. System upgrades are also required for compatibility with upgrades in hardware platforms that occur when shared servers are upgraded.

As well, upgrades are often completed in order to take advantage of functional or technical enhancements provided by the vendor in new versions of the software application.

Justification

Investments in Business Application Upgrades are necessary to replace outdated technology that is no longer supported by vendors and to take advantage of newly developed capabilities provided in the most recent release of the applications. Unstable and unsupported software applications can negatively impact operating efficiencies and customer service.

3.0 Information Technology Management Upgrades ($92,000)

Information Technology ("IT") management upgrades involve the upgrades necessary to maintain IT controls that ensure the integrity and availability of customer and corporate data.

Table 2 summarizes the cost associated with these items.

Table 2
IT Management Upgrades
Project Expenditures
($000s)

Cost Category	**2009 Estimate**
Material	10
Labour – Internal	42
Labour – Contract	-
Engineering	-
Other	40
Total	**92**

Description

Managing the IT used to operate and support the Company's business applications utilizes a variety of interrelated technologies and processes. These technologies are used by the Company to develop, configure, test, implement, monitor and maintain applications throughout their life. For 2009, this item includes improvements to the software and interrelated processes used to monitor and report changes made to Company applications and databases to ensure that unauthorized changes are detected promptly and corrective action is initiated immediately.

Operating Experience

The Company depends on the stable operation of its over 50 business applications such as CSS, Great Plains and Avantis to sustain an effective level of customer service and employee productivity. Change is an inherent part of business activity and the ability to monitor and control the changes to corporate applications and data is an integral part of overall IT control.

In 2007, for example, the Company implemented approximately 300 individual changes to CSS. Examples of these changes include application code modifications and database changes to support new or enhanced functionality. Managing and monitoring these changes is critical to ensuring that application reliability and data integrity is maintained.

Justification

This item ensures that the integrity of the Company's applications and data are maintained and that IT controls operate effectively. Effective IT controls are necessary for reliable, least cost service delivery to customers.

4.0 The Microsoft Enterprise Agreement ($200,000)

Description

This Agreement covers the purchase of Microsoft software and provides access to the latest versions of each software product purchased under this agreement.

Through the Microsoft Enterprise Agreement, Newfoundland Power achieves an overall cost savings. This is a fixed, annual price agreement based on the number of eligible desktops. Under this agreement, the Company distributes its purchasing costs for these licenses over three years, as outlined in Schedule D.

Operating Experience

In 2008, the Company investigated three options for the purchase of the following Microsoft licenses: Windows Professional, Office Professional and Client Access Licenses for Exchange Server, SQL Server, Windows Server, and System Management Server. The three options identified by the Company were:

- Do nothing now, and pay for new licenses to upgrade in the future. The expected cost per personal computer is $1,131.77 over three years.

- Purchase a Microsoft Select Agreement for each installation of the software. This provides the Company with ownership of the latest releases of the identified software. These licenses have to be purchased individually as needed. The annual cost per personal computer is $317.00 or $951.00 over three years.

- Renew the existing Microsoft Enterprise Agreement. This provides the Company with ownership of the latest releases of the identified software. These licenses are paid for annually following a count of the personal computers within the Company. Costs are spread out over the three-year period. The annual cost per personal computer is $274.75 or $824.25 over three years.

Justification

The Microsoft Enterprise Agreement is the least cost option to ensuring access to current Microsoft software products.

2009 Shared Server Infrastructure

June 2008

Introduction

The Company's Shared Server Infrastructure consists of over 100 shared servers that are used for production, testing, and disaster recovery of 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. The assessment also determines new computing requirements for corporate applications and identifies security management equipment necessary for the protection of customer and corporate data.

Description

This project includes the addition, upgrade and replacement of computer hardware components and related technology associated with the Company's shared server infrastructure.

Table 1 summarizes the cost associated with these items.

Table 1
Shared Server Infrastructure Upgrades
Project Expenditures
($000s)

Cost Category	2009 Estimate
Material	387
Labour – Internal	233
Labour – Contract	-
Engineering	-
Other	80
Total	**700**

For 2009, this project includes:

1. The replacement of the existing customer contact servers that have reached the end of useful life. The budget for this item is $71,000.

2. The purchase of servers responsible for housing the database for Hand Held Meter Reading system that has reached the end of its useful life. This project is related to the *System Upgrades* project for the *Hand Held Meter Reading Software* upgrade. The budget for this item is $37,000.

3. The replacement of the Avantis Asset Management system servers that have reached the end of useful life. This project is related to the *System Upgrades* project for the *Avantis Asset Management System* upgrade. The budget for this item is $134,000.

4. The replacement of the area office servers located throughout the province that have reached the end of their useful life. These servers provide reliable and effective file and printing services in all area office locations. The budget for this item is $111,000.

5. The purchase of database servers and additional disk storage for the System Control Centre. This will ensure customer and corporate data is replicated for disaster recovery purposes. The budget for this item is $57,000.

6. Infrastructure improvements necessary to manage and support wireless data security including the integrity of customer and corporate data stored on mobile devices. The budget for this item is $239,000.

7. Infrastructure improvements for security of the Company's facilities. This item involves the addition, upgrade and replacement of hardware components and related technology including cameras, intruder detection, and security monitoring at 4 locations.[1] The budget for this item is $51,000.

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.

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[2] has indicated that computer servers have a useful life of approximately 5 years. By making appropriate investments in its shared server infrastructure, Newfoundland Power's experience is that the useful life of its corporate servers exceeds 7 years.

[1] The four locations are Duffy Place, Kenmount Road, Topsail Road and Carbonear.
[2] Gartner Inc. is the leading provider of research and analysis on the global Information Technology industry.

In order to ensure high availability of applications and to minimize the vulnerability of its computer systems to external interference, the Company invests in system availability and proactive security monitoring and protection tools. These tools allow the Company to monitor and respond to problems that could impede the normal operation of applications or damage Company information.

Justification

The shared server infrastructure is essential to maintaining the provision of least cost 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.

The average age of servers to be replaced in 2009 is expected to be 7.5 years.

Investments in the shared server infrastructure are made by evaluating the alternatives of modernizing or replacing technology components and selecting the least cost alternative.

Deferred Charges and Rate Base

June 2008

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1.0 Introduction

In Order No. P.U. 19 (2003), the Board of Commissioners of Public Utilities (the "Board") ordered Newfoundland Power (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, 2007 reported in the Company's 2008 Capital Budget Application, the actual deferred charges reported at December 31, 2007 and forecast deferred charges at December 31, 2008 and 2009.

Table 1
Deferred Charges: 2007-2009F
($000s)

	2007F	Actual 2007	2008F	2009F
Deferred Pension Cost	96,656	96,654	100,196	103,400
Weather Normalization Account	10,683	10,516	9,150	7,784
Unamortized Debt Discount & Issue Expense	3,433	3,111	2,934[1]	3,355[1]
Unamortized Capital Stock Issue Expense	137	137	75	37
Deferred Credit Facility Issue Costs	58	59	69	44
Deferred Depreciation Expense	11,586	11,586	7,724	3,862
Deferred Replacement Energy Cost	1,147	1,147	764	381
Deferred General Rate Application Costs	-	1,250	398	199
Total Deferred Charges	123,700	124,460	121,310	119,062

Actual deferred charges at December 31, 2007 were approximately $0.8 million higher than that forecast in the Company's 2008 Capital Budget Application. This was due to the addition of deferred costs related to the Company's 2007 General Rate Application ("GRA") offset by lower than anticipated bond issue costs.

[1] In accordance with the adoption of the Asset Rate Base Method, approved by Order No. P.U. 32 (2007), effective 2008 Unamortized Debt Discount and Issue Expense will be excluded from the calculation of Average Rate Base and included in the calculation of the Weighted Average Cost of Capital.

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 in accordance with Order No. P.U. 17 (1987).

Table 2 sets out (i) forecast December 31, 2007 deferred pension cost per the Company's 2008 Capital Budget Application, (ii) actual deferred pension costs at December 31, 2007, and (iii) forecast deferred pension cost at December 31, 2008 and 2009.

Table 2
Deferred Pension Costs: 2007-2009F
($000s)

	2007F	**Actual 2007**	**2008F**	**2009F**
Deferred Pension Costs, January 1st	90,122	90,122	96,654	100,196
Pension Plan Funding				
- Current Service Funding	3,598	3,597	3,847	4,000
- Special Funding	7,308	7,307	1,578	298
Total Pension Plan Funding	10,906	10,904	5,425	4,298
Pension Plan Expense	(4,372)	(4,372)	(1,883)	(1,094)
Increase in Deferred Pension Costs	6,534	6,532	3,542	3,204
Deferred Pension Costs, December 31st	96,656	96,654	100,196	103,400

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 last valuation was completed as of December 31, 2005. Therefore, the next valuation is required to be completed as of December 31, 2008, at the latest.

The Company calculates annual pension expense in accordance with recommendations of the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3461 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 2009 is subject to change based upon the following factors:

1. The final pension expense for 2009 cannot be determined until early in 2009 once actual pension plan asset balances for 2008 are known. This determination is made based on the December 31, 2008 market-related 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 2009 pension expense is the actual market interest rate at December 31, 2008. This rate is based on high-quality debt instruments with duration similar to the pension obligation. Pension expense for 2009, in Table 2 above, is calculated assuming a 5.50% discount rate at December 31, 2008. If a change in discount rate is required based on December 31, 2008 market interest rates, 2009 pension expense will vary from the amount forecast for 2009 in Table 2.

While pension plan expense for 2009 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: 2007-2009F
($000s)

	2007F	Actual 2007	2008F	2009F
Hydro Production Equalization Reserve	3,856	3,868	3,868	3,868
Degree Day Normalization Reserve	6,827	6,648	5,282	3,916
Total	10,683	10,516	9,150	7,784

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. The 2007 forecast for the Weather Normalization assumed normal stream-flows and weather patterns for 2007.

Table 4
Hydro Production Equalization Reserve: 2007-2009F
($000s)

	2007F	Actual 2007	2008F	2009F
Balance, January 1st	4,982	4,982	3,868	3,868
Amortization during the year	(1,126)	(1,126)	-	-
Normal operation of the reserve	-	12	-	-
Balance, December 31st	3,856	3,868	3,868	3,868

In Order No. P.U. 19 (2003), the Board approved 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 final annual reduction in the Hydro Production Equalization Reserve of $1.126 million was in 2007. The 2008 and 2009 forecasts assume normal stream-flows from January 2008 through December 2009.

Table 5
Degree Day Normalization Reserve: 2007-2009F
($000s)

	2007F	Actual 2007	2008F	2009F
Balance, January 1st	6,827	6,827	6,648	5,282
Normal operation of the reserve	-	(179)	-	-
Amortization during the year	-	-	(1,366)	(1,366)
Balance, December 31st	6,827	6,648	5,282	3,916

In Order No. P.U. 32 (2007), the Board approved the Company's proposal to amortize the $6.8 million non-reversing balance in the Degree Day Normalization Reserve over 5 years beginning in 2008. The 2008 and 2009 forecasts assume normal weather conditions from January 2008 through December 2009.

In Order No. P.U. 7 (2008), the Board approved the balance in the Weather Normalization Accounts as at December 31, 2007.

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: 2007-2009F
($000s)

	2007F	Actual 2007	2008F	2009F
Balance, January 1st	3,035	3,035	3,111	2,934
Costs incurred during the year	600	273	-	600
Amortization during the year	(202)	(197)	(177)	(179)
Balance, December 31st	3,433	3,111	2,934	3,355

The Company anticipated the issue of Series AL First Mortgage Sinking Fund Bonds in August of 2007 to be 1 percent of the face value of the bonds or $600,000. Actual issue costs for the private placement of Series AL First Mortgage Sinking Fund Bonds were $273,000. The amortization recorded includes the normal amortization of these costs over 360 months beginning August 1, 2007. The Company is anticipating an additional issue of a First Sinking Fund Bond in December 2009. The issue expenses are estimated to be 1 percent of the face value of the bonds or $600,000.

2.5 Unamortized Capital Stock Issue Expense

Change in Unamortized Capital Stock Issue Expense is set out in Table 7.

Table 7
Unamortized Capital Stock Issue Expense: 2007-2009F
($000s)

	2007F	Actual 2007	2008F	2009F
Balance, January 1st	199	199	137	75
Amortization during the year	(62)	(62)	(62)	(38)
Balance, December 31st	137	137	75	37

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: 2007-2009F
($000s)

	2007F	Actual 2007	2008F	2009F
Balance, January 1st	133	133	-	-
Cost incurred during the year	-	-	-	-
Amortization during the year	(133)	(133)	-	-
Balance, December 31st	-	-	-	-

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 and the final amortization in 2007.

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: 2007-2009F
($000s)

	2007F	Actual 2007	2008F	2009F
Balance, January 1st	118	118	59	69
Cost incurred during the year	-	-	75	-
Amortization during the year	(60)	(59)	(65)	(25)
Balance, December 31st	58	59	69	44

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). The Company is anticipating an additional $75,000 in credit facility issue costs in 2008 relating to the expected fall 2008 credit facility renewal.

2.8 Deferred Depreciation True-up

The details of the changes are set out in Table 10.

Table 10
Deferred Depreciation Expense: 2007-2009F
($000s)

	2007F	Actual 2007	2008F	2009F
Balance, January 1st	5,793	5,793	11,586	7,724
Cost deferred during the year	5,793	5,793	-	-
Amortization during the year	-	-	(3,862)	(3,862)
Balance, December 31st	11,586	11,586	7,724	3,862

In Order No. P.U. 40 (2005) and P.U. 39 (2006), the Board ordered the Company to defer the recovery of an increase in depreciation expense of $5,793,000 in each of 2006 and 2007 related to the amortization of depreciation true-up in 2005. In Order No. P.U. 32 (2007), the Board ordered that the resultant deferral be amortized equally over three years beginning in 2008.

2.9 Deferred Replacement Energy Costs

The details of the deferred replacement energy costs, on an after-tax basis, are set out in Table 11.

Table 11
Deferred Replacement Energy Costs: 2007-2009F
($000s)

	2007F	Actual 2007	2008F	2009F
Balance, January 1st	-	-	1,147	764
Cost deferred during the year	1,147	1,147	-	-
Amortization during the year	-	-	(383)	(383)
Balance, December 31st	1,147	1,147	764	381

In P.U. 39 (2006), the Board ordered the Company to defer recovery in 2007 of an after-tax amount of $1,147,000 related to the replacement of energy costs associated with the Rattling Brook Project. In Order No. P.U. 32 (2007), the Board ordered the deferral be amortized equally over three years beginning in 2008.

2.10 Deferred General Rate Application Costs

The details of the changes are set out in Table 12.

Table 12
Deferred General Rate Application Costs: 2007-2009F
($000s)

	2007F	Actual 2007	2008F	2009F
Balance, January 1st	-	-	1,250	398
Cost deferred during the year	-	1,250	-	-
Adjusted for actual application costs	-	-	(653)	-
Amortization during the year	-	-	(199)	(199)
Balance, December 31st	-	1,250	398	199

In Order No. P.U. 32 (2007), the Board approved that the estimated $1.3 million of external costs related to the Company's 2007 GRA be deferred and amortized equally over three years beginning in 2008. In 2008 this estimate of $1.3 million was reduced by $0.7 million as a result of lower than anticipated costs.