NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

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St. John's, Newfoundland
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DELIVERED BY HAND

June 19, 2009

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 2010 Capital Budget Application

A. 2010 Capital Budget Application

Enclosed are the original and 10 copies of Newfoundland Power Inc.'s (the "Company") 2010 Capital Budget Application and supporting materials (the "Filing").

The Filing outlines proposed 2010 capital expenditures totaling $64,679,000. In addition, it seeks approval of a 2008 rate base in the amount of $820,876,000.

B. Compliance Matters

B.1 Board Orders

In Order No. P.U. 27 (2008) (the "2009 Capital Order"), the Board required a progress report on 2009 capital expenditures to be provided with the Filing. In Order No. P.U. 35 (2003) (the "2004 Capital Order"), the Board required a 5-year capital plan to be provided with the Filing. 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 capital budget applications.

These requirements are specifically addressed in the Filing in the following:

1. *2009 Capital Expenditure Status Report*: this meets the requirements of the 2008 Capital Order;

2. *2010 Capital Budget Plan*: this meets the requirements of the 2004 Capital Order; and

3. *Rate Base: Additions, Deductions & Allowances*: this meets the requirements of the 2003 Rate Order.

B.2 The Guidelines

In the October 2007 Capital Budget Application Guidelines (the "Guidelines"), the Board provided certain directions on how to 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 2 of the *2010 Capital Budget Plan* provides a breakdown of the overall 2010 Capital Budget by definition, classification, and materiality segmentation as described in the Guidelines. Pages ii through viii of Schedule B to the formal application provides details by project of these categorizations.

C. Filing Details and Circulation

The Filing will be posted on the Company's website (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.
2010 Capital Budget Application
Filing Contents

Application

Application

Supporting Materials

Generation

Substations

Transmission

Distribution

General Property

Newfoundland Power Inc.
2010 Capital Budget Application
Filing Contents

Supporting Materials

Information Systems

6.1 2010 Application Enhancements
6.2 2010 System Upgrades
6.3 2010 Shared Server Infrastructure

Deferred Charges

7.1 Rate Base: Additions, Deductions & Allowances

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 2010 Capital Budget of $64,679,000; and
(b) fixing and determining its 2008 rate base at $820,876,000

2010 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 2010 Capital Budget of $64,679,000; and
(b) fixing and determining its 2008 rate base at $820,876,000

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 2010 Capital Budget in the amount of $64,679,000 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 2010. All contributions to be recovered from customers shall be calculated in a manner approved by the Board.

3. Schedule C to this Application is an estimate of future required expenditures on improvements or additions to the property of Newfoundland Power that are included in the 2010 Capital Budget but will not be completed in 2010.

4. The proposed expenditures as set out in Schedules A and B 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.

5. Schedule C to this Application shows Newfoundland Power's actual average rate base for 2008 of $820,876,000.

6. 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.

7. 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 2010 of the improvements and additions to its property in the amount of $64,679,000 as set out in Schedules A and B to the Application;

   (b) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2008 in the amount of $820,876,000 as set out in Schedule E to the Application.

DATED at St. John's, Newfoundland and Labrador, this 19th day of June, 2009.

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 2010 Capital Budget of $64,679,000; and
(b) fixing and determining its 2008 rate base at $820,876,000

AFFIDAVIT

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

1. That I am Vice President, Regulatory Affairs 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 19th day of June, 2009, before me:

Barrister

Peter Alteen

2010 CAPITAL BUDGET SUMMARY

Asset Class	**Budget (000s)**
1. Generation - Hydro	$ 5,279
2. Generation - Thermal	150
3. Substations	10,218
4. Transmission	5,915
5. Distribution	31,965
6. General Property	1,381
7. Transportation	2,352
8. Telecommunications	379
9. Information Systems	3,490
10. Unforeseen Allowance	750
11. General Expenses Capitalized	2,800
Total	**$ 64,679**

2010 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
1. Generation – Hydro		
Facility Rehabilitation	$1,340	2
Lookout Brook Hydro Plant Refurbishment	2,155	4
Petty Harbour Surge Tank and Unit No. 1Main Valve	632	6
Raise Sandy Lake Spillway to Increase Production	612	8
Seal Cove Hydro Plant Runner Replacement	540	10
Total Generation – Hydro	**$ 5,279**	
2. Generation – Thermal		
Facility Rehabilitation Thermal	$ 150	13
Total Generation – Thermal	**$ 150**	
3. Substations		
Substations Refurbishment and Modernization	$ 4,043	16
Replacements Due to In-Service Failures	2,052	18
Additions Due to Load Growth	3,650	20
Convert 23L to 66 KV	286	22
Lookout Brook Substation Upgrades	187	24
Total Substations	**$10,218**	
4. Transmission		
Transmission Line Rebuild	$ 5,915	27
Total Transmission	**$ 5,915**	

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

2010 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
5. Distribution		
Extensions	$ 8,856	30
Meters	1,239	32
Services	2,447	35
Street Lighting	1,783	38
Replace Mercury Vapour Street Lights	681	41
Transformers	7,668	43
Reconstruction	3,359	45
Rebuild Distribution Lines	3,632	47
Relocate/Replace Distribution Lines for Third Parties	685	50
Distribution Reliability Initiative	447	52
St. John's Underground Distribution	550	55
Feeder Additions for Growth	465	57
Allowance for Funds Used During Construction	153	59
Total Distribution	**$ 31,965**	
6. General Property		
Tools and Equipment	$ 389	62
Additions to Real Property	225	65
Kenmount Road Building Roof and HVAC	542	67
System Control Centre UPS	225	69
Total General Property	**$ 1,381**	
7. Transportation		
Purchase Vehicles and Aerial Devices	$ 2,352	72
Total Transportation	**$ 2,352**	

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

2010 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
8. Telecommunications		
Replace/Upgrade Communications Equipment	$ 135	75
Fibre Optic Circuit Replacement	244	77
Total Telecommunications	**$ 379**	
9. Information Systems		
Application Enhancements	$ 937	80
System Upgrades[2]	1,038	82
Personal Computer Infrastructure	430	84
Shared Server Infrastructure	660	87
Network Infrastructure	153	89
Vehicle Mobile Computing Infrastructure	272	91
Total Information Systems	**$ 3,490**	
10. Unforeseen Allowance		
Allowance for Unforeseen Items	$ 750	94
Total Unforeseen Allowance	**$ 750**	
11. General Expenses Capitalized		
General Expenses Capitalized	$ 2,800	96
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 C of this application.

2010 CAPITAL PROJECTS: MULTI-YEAR
(000s)

Capital Project	Approved	2009	2010	2011
Microsoft Enterprise Agreement[3]	Order No. PU 27 (2008)	$200	$200	$200

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

2010 CAPITAL PROJECT SUMMARY

2010 Capital Project Summary

On October 29, 2007, the Board issued Capital Budget Application Guidelines (the "Guidelines") to provide direction for utility capital budget applications filed pursuant to section 41 of the *Public Utilities Act.*

The Guidelines provide that utilities present their annual capital budget with sufficient detail for the Board and interested parties to understand the nature, scope and justification for individual expenditures and the capital budget overall.

Specifically, the Guidelines require each expenditure to be defined, classified, and segmented in the following manner:

1. *Definition of the Capital Expenditure*

   Capital Expenditures are to be defined as clustered, pooled or other.

   Clustered expenditures are those which would logically be undertaken together. Pooled expenditures are a series of expenditures which are neither inter-dependant nor related but which nonetheless are logically grouped together. Other expenditures are those which do not fit the definition of clustered or pooled.

2. *Classification of the Capital Expenditure*

   Capital Expenditures are to be classified as mandatory, normal capital or justifiable.

   Mandatory capital expenditures are those a utility is obliged to carry out as the result of legislation, Board Order, safety issues or risk to the environment. Normal capital expenditures are those that are required based upon identified need or on a historical pattern of repair and replacement. Justifiable capital expenditures are those which are justified upon the positive impact the project will have on the utility's operations.

3. *Segmentation of the Capital Expenditure by Materiality*

   Capital expenditures are to be segmented by their materiality as follows:
   - Expenditures under $200,000
   - Expenditures between $200,000 and $500,000
   - Expenditures over $500,000

This 2010 Capital Project Summary provides a summary of the planned capital expenditures contained in Newfoundland Power's 2010 Capital Budget Application by definition (pages iii to iv), classification (pages v to vi), and segmentation by materiality (pages vii to viii) as required by the Guidelines. In addition, each of the project descriptions in Schedule B indicate the definitions, classifications and forecast costs as provided for in the Guidelines.

**Summary of
2010 Capital Projects by Definition
(000's)**

Clustered	**$2,342**	**Page**
Generation-Hydro	**2,155**	
Lookout Brook Plant Refurbishment	2,155	4
Substations	**187**	
Lookout Brook Substation Upgrades	187	24

Pooled	**$55,627**	**Page**
Distribution	**30,968**	
Extensions	8,856	30
Meters	1,239	32
Services	2,447	35
Street Lighting	1,783	38
Replace Mercury Vapour Street Lights	681	41
Transformers	7,668	43
Reconstruction	3,359	45
Rebuild Distribution Lines	3,632	47
Relocate/Replace Distribution Lines for Third Parties	685	50
Feeder Additions for Growth	465	57
Allowance for Funds Used During Construction	153	59
General Property	**614**	
Tools and Equipment	389	62
Additions to Real Property	225	65
Generation-Hydro	**1,972**	
Facility Rehabilitation	1,340	2
Petty Harbour Surge Tank and Main Valve	632	6
Generation-Thermal	**150**	
Facility Rehabilitation Thermal	150	13
Information Services	**3,490**	
Application Enhancements	937	80
System Upgrades	1,038	82
Personal Computer Infrastructure	430	84
Shared Server Infrastructure	660	87
Network Infrastructure	153	89
Vehicle Mobile Computing Infrastructure	272	91
Substations	**10,031**	
Substations Refurbishment & Modernization	4,043	16
Replacements Due to In-Service Failures	2,052	18
Additions Due to Load Growth	3,650	20
Convert 23L to 66 KV	286	22
Telecommunications	**135**	
Replace/Upgrade Communications Equipment	135	75

Transmission	**5,915**	
Transmission Line Rebuild	5,915	27
Transportation	**2,352**	
Purchase Vehicles and Aerial Devices	2,352	72

Other	**$6,710**	**Page**
Allowance for Unforeseen	**750**	
Allowance for Unforeseen Items	750	94
Distribution	**997**	
Distribution Reliability Initiative	447	52
St. John's Underground Distribution	550	55
General Expenses Capitalized	**2,800**	
General Expenses Capitalized	2,800	96
General Property	**767**	
Kenmount Road Building Roof and HVAC	542	67
System Control Centre UPS	225	69
Generation-Hydro	**1,152**	
Raise Sandy Lake Spillway to Increase Production	612	8
Seal Cove Hydro Plant Runner Replacement	540	10
Telecommunications	**244**	
Fibre Optic Circuit Replacement	244	77

Summary of
2010 Capital Projects by Classification
(000's)

Normal Capital	**$61,647**	**Page**
Allowance for Unforeseen	**750**	
Allowance for Unforeseen Items	750	94
Distribution	**31,284**	
Extensions	8,856	30
Meters	1,239	32
Services	2,447	35
Street Lighting	1,783	38
Transformers	7,668	43
Reconstruction	3,359	45
Rebuild Distribution Lines	3,632	47
Relocate/Replace Distribution Lines for Third Parties	685	50
Distribution Reliability Initiative	447	52
St. John's Underground Distribution	550	55
Feeder Additions for Growth	465	57
Allowance for Funds Used During Construction	153	59
General Expenses Capitalized	**2,800**	
General Expenses Capitalized	2,800	96
General Property	**1,381**	
Tools and Equipment	389	62
Additions to Real Property	225	65
Kenmount Road Building Roof and HVAC	542	67
System Control Centre UPS	225	69
Generation-Hydro	**4,667**	
Facility Rehabilitation	1,340	2
Lookout Brook Plant Refurbishment	2,155	4
Petty Harbour Surge Tank and Main Valve	632	6
Seal Cove Hydro Plant Runner Replacement	540	10
Generation-Thermal	**150**	
Facility Rehabilitation Thermal	150	13
Information Services	**2,281**	
System Upgrades	1,038	82
Personal Computer Infrastructure	430	84
Shared Server Infrastructure	660	87
Network Infrastructure	153	89
Substations	**9,932**	
Substations Refurbishment & Modernization	4,043	16
Replacements Due to In-Service Failures	2,052	18
Additions Due to Load Growth	3,650	20
Lookout Brook Substation Upgrades	187	24

Telecommunications	**135**	
Replace/Upgrade Communications Equipment	135	75
Transmission	**5,915**	
Transmission Line Rebuild	5,915	27
Transportation	**2,352**	
Purchase Vehicles and Aerial Devices	2,352	72

Justifiable	**$3,032**	**Page**
Distribution	**681**	
Replace Mercury Vapour Street Lights	681	41
Generation-Hydro	**612**	
Raise Sandy Lake Spillway to Increase Production	612	8
Information Services	**1,209**	
Application Enhancements	937	80
Vehicle Mobile Computing Infrastructure	272	91
Substations	**286**	
Convert 23L to 66 KV	286	22
Telecommunications	**244**	
Fibre Optic Circuit Replacement	244	77

Summary of
2010 Capital Projects by Materiality
(000's)

Large – Greater than $500	**$60,918**	**Page**
Allowance for Unforeseen	**750**	
Allowance for Unforeseen Items	750	94
Distribution	**30,900**	
Extensions	8,856	30
Meters	1,239	32
Services	2,447	35
Street Lighting	1,783	38
Replace Mercury Vapour Street Lights	681	41
Transformers	7,668	43
Reconstruction	3,359	45
Rebuild Distribution Lines	3,632	47
Relocate/Replace Distribution Lines for Third Parties	685	50
St. John's Underground Distribution	550	55
General Expenses Capitalized	**2,800**	
General Expenses Capitalized	2,800	96
General Property	**542**	
Kenmount Road Building Roof & HVAC	542	67
Generation-Hydro	**5,279**	
Facility Rehabilitation	1,340	2
Lookout Brook Plant Refurbishment	2,155	4
Petty Harbour Surge Tank and Main Valve	632	6
Raise Sandy Lake Spillway to Increase Production	612	8
Seal Cove Hydro Plant Runner Replacement	540	10
Information Services	**2,635**	
Application Enhancements	937	80
System Upgrades	1,038	82
Shared Server Infrastructure	660	87
Substations	**9,745**	
Substations Refurbishment & Modernization	4,043	16
Replacements Due to In-Service Failures	2,052	18
Additions Due to Load Growth	3,650	20
Transmission	**5,915**	
Transmission Line Rebuild	5,915	27
Transportation	**2,352**	
Purchase Vehicles and Aerial Devices	2,352	72

Medium - Between $200 and $500	**$2,983**	**Page**
Distribution	**912**	
Distribution Reliability Initiative	447	52
Feeder Additions for Growth	465	57

General Property	**839**	
Tools and Equipment	389	62
Additions to Real Property	225	65
System Control Centre UPS	225	69
Information Services	**702**	
Personal Computer Infrastructure	430	84
Vehicle Mobile Computing Infrastructure	272	91
Substations	**286**	
Convert 23L to 66 kV	286	22
Telecommunications	**244**	
Fibre Optic Circuit Replacement	244	77

Small – Under $200	**$778**	**Page**
Distribution	**153**	
Allowance for Funds Used During Construction	153	59
Generation-Thermal	**150**	
Facilities Rehabilitation Thermal	150	13
Information Services	**153**	
Network Infrastructure	153	89
Substations	**187**	
Lookout Brook Substation Upgrades	187	24
Telecommunications	**135**	
Replace/Upgrade Communications Equipment	135	75

GENERATION - HYDRO

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

Project Cost: **$1,340,000**

Project Description

This generation hydro project is necessary to improve the efficiency and reliability of various hydro plants or to replace plant due to in-service failures. This project involves the replacement or rehabilitation of deteriorated plant components that have been identified through routine inspections, operating experience and engineering studies. The project includes the following items:

- Refurbishment of 3 hydro dams and spillways;
- Refurbishment of 4 intake structures; and
- Equipment replacements due to in-service failures.

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.

Details on 2010 proposed expenditures are included in ***1.1** 2010 Facility Rehabilitation*.

Justification

The Company's 23 hydroelectric plants range in age from 10 to 109 years old. These facilities provide relatively inexpensive energy to the Island interconnected system. Maintaining these generating facilities reduces the need for additional, more expensive, 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 alternative to maintaining these generation facilities would be to retire them. The Company's hydro generation facilities produce a combined normal annual production of 427.9 GWh. 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 $75.95 per barrel, this translates into approximately $51 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 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures (000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$982	-	-	-
Labour – Internal	52	-	-	-
Labour – Contract	52	-	-	-
Engineering	192	-	-	-
Other	62	-	-	-
Total	**$1,340**	**$1,110**	**$3,494**	**$5,944**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2005	2006	2007	2008	2009F
Total	**$2,283**	**$1,234**	**$780**	**$3,551**[1]	**$2,076**

[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: **Lookout Brook Hydro Plant Refurbishment (Clustered)**

Project Cost: **$2,155,000**

Project Description

This generation hydro project involves a major refurbishment of the electrical and mechanical systems at the Lookout Brook Plant. This project requires major upgrades to the civil, electrical and mechanical systems of the plant in 2010. The components requiring replacement or refurbishment include the plant controls, governor controls, electrical protection, power cables and switchgear. The project also includes the implementation of a water management algorithm in the plant control system.

This plant refurbishment involves a combination of inter-dependent and related components. The refurbishment will be clustered with the Lookout Brook substation refurbishment to minimize plant downtime and maximize overall construction efficiency. It will be completed in 2010.

Details on the proposed expenditures are included in ***1.2** Lookout Brook Hydro Plant Refurbishment*.

Justification

The Lookout Brook Plant was commissioned in 1946 and consists mainly of original equipment. The plant's normal annual production is approximately 30.1 GWh of energy, or about 7% 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 electrical engineering assessment has identified that some key components have deteriorated and are in need of replacement.

A present worth feasibility analysis of projected capital and operating expenditures for the Lookout Brook Plant has determined the levelized cost of energy from the plant over the next 50 years to be 2.68¢ per kWh, which is significantly less than the cost of replacement energy at Holyrood.[1]

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[1] The cost of electricity from the Holyrood thermal generating station is estimated at 12.06¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $75.95 per barrel as of March 31, 2009.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2010 to 2014.

Table 1
Projected Expenditures
(000s)

Cost Category	**2010**	**2011**	**2012 - 2014**	**Total**
Material	$1,730	-	-	-
Labour – Internal	170	-	-	-
Labour – Contract		-	-	-
Engineering	130	-	-	-
Other	125	-	-	-
Total	**$2,155**	**-**	-	**$2,155**

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: **Petty Harbour Surge Tank and Unit No. 1 Main Valve (Pooled)**

Project Cost: **$632,000**

Project Description

This generation hydro project involves the refurbishment of the surge tank and the replacement of the main valve for Unit No. 1 at Petty Harbour Plant.

Details on the proposed expenditures are included in ***1.3*** *Petty Harbour Hydro Plant Refurbishment*.

Justification

The Petty Harbour Plant was first commissioned in 1900 and has undergone a number of changes and upgrades since that time. The normal annual plant production is approximately 15.9 GWh of energy, or about 4% of Newfoundland Power's total hydroelectric generation.

This project is necessary at this time due to the age and physical condition of the plant assets. The surge tank is approximately 83 years old, is in poor condition and requires refurbishment. The main valve on Unit No. 1 is 99 years old and requires replacement.

A present worth feasibility analysis of projected capital and operating expenditures for the Petty Harbour Plant has determined the levelized cost of energy from the plant over the next 50 years to be 2.37¢ per kWh, which is significantly less than the cost of replacement energy at Holyrood.[2]

[2] The cost of electricity from the Holyrood thermal generating station is estimated at 12.06¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $75.95 per barrel as of March 31, 2009.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2010 to 2014.

Table 1
Projected Expenditures
(000s)

Cost Category	**2010**	**2011**	**2012 - 2014**	**Total**
Material	$526	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	77	-	-	-
Other	29	-	-	-
Total	**$632**	**-**	-	**$632**

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: **Raise Sandy Lake Spillway to Increase Production (Other)**

Project Cost: **$612,000**

Project Description

This generation hydro project involves raising the spillway height at Sandy Lake to enable increased hydroelectric production at the Sandy Brook Plant.

The Sandy Brook Plant is located in the central region of the Island of Newfoundland, near the town of Grand Falls-Windsor. The plant was placed into service in 1963. The normal annual production at Sandy Brook is approximately 25.7 GWh or about 6% of Newfoundland Power's total hydroelectric generation.

In 2008, Newfoundland Power conducted a study into alternative ways to improve the efficiency and energy production of existing hydroelectric plants.

As part of the 2008 study, options to increase energy production at Sandy Brook Plant were assessed. Average annual water spill at Sandy Brook is estimated to be 5.65 GWh. Increasing the amount of storage at Sandy Lake will reduce the amount of spilled water at this location and result in increased energy production.

Details on the proposed expenditures are included in ***1.4*** *Raise Sandy Lake Spillway to Increase Production*.

Justification

Increased energy production at Newfoundland Power's existing hydroelectric plants would displace energy produced at Hydro's Holyrood thermal generating plant.

The estimated levelized cost of the additional energy resulting from raising the spillway at Sandy Lake by 1.0 metre is 6.64¢ per kWh, which is significantly less than the cost of replacement energy at Holyrood[3].

[3] The cost of electricity from the Holyrood thermal generating station is estimated at 12.06¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $75.95 per barrel as of March 31, 2009.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures (000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$535	-	-	-
Labour – Internal		-	-	-
Labour – Contract		-	-	-
Engineering	37	-	-	-
Other	40	-	-	-
Total	**$612**	-	-	**$612**

Costing Methodology

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

Future Commitments

This is not a multi-year project.

Project Title: **Seal Cove Hydro Plant Runner Replacement (Other)**

Project Cost: **$540,000**

Project Description

This generation hydro project involves the replacement of the turbine runner on Unit No.1 at Seal Cove Plant.

Newfoundland Power has conducted various inspections of the major components of the Unit No. 1 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 is such that the runner is no longer able to operate efficiently, and is at increased risk of an in-service failure.

Details on the proposed expenditures are included in ***1.5** Seal Cove Hydro Plant G1 Runner Replacement.*

Justification

Newfoundland Power's Seal Cove Plant was commissioned in 1924 and has a capacity of 3.5 MW. The normal annual production is approximately 8.76 GWh or about 2% of Newfoundland Power's total hydroelectric generation.

Engineering assessments of the Unit No. 1 turbine runner have revealed a number of deficiencies.

A present worth feasibility analysis of projected capital and operating expenditures for the Seal Cove Plant has determined the levelized cost of energy from the plant over the next 50 years to be 2.83¢ per kWh, which is significantly less than the cost of replacement energy at Holyrood.[4]

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[4] The cost of electricity from the Holyrood thermal generating station is estimated at 12.06¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $75.95 per barrel as of March 31, 2009.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2010 to 2014.

Table 1
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$324	-	-	-
Labour – Internal	154	-	-	-
Labour – Contract	-	-	-	-
Engineering	22	-	-	-
Other	40	-	-	-
Total	**$540**	**-**	-	**$540**

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.

GENERATION - THERMAL

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

Project Cost: **$150,000**

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 Island 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 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$ 90	-	-	-
Labour – Internal	30	-	-	-
Labour – Contract	-	-	-	-
Engineering	22	-	-	-
Other	8	-	-	-
Total	**$ 150**	**$153**	**$1,902**	**$2,205**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2005	2006	2007	2008	2009F
Total	$135	-	$37	$301	$250

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: **$4,043,000**

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** 2010 Substation Refurbishment and Modernization*.

The Company has 130 substations varying in age from 7 years to greater than 100 years. 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. Infrastructure to be replaced was identified as a result of inspections, engineering assessments and operating experience.

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 2010 and a projection of expenditures through 2014.

Table 1
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 – 2014	Total
Material	$2,263	-	-	-
Labour – Internal	719	-	-	-
Labour – Contract	-	-	-	-
Engineering	815	-	-	-
Other	246	-	-	-
Total	**$4,043**	**$4,063**	**$14,707**	**$22,813**

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	**2005**	**2006**	**2007**	**2008**	**2009F**
Total	**$2,072**	**$2,107**	**$2,364**	**$2,508**	**$4,393**

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: **$2,052,000**

Project Description

This substation project is necessary to replace substation equipment that has been 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 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures (000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$1,432	-	-	-
Labour – Internal	432	-	-	-
Labour – Contract	-	-	-	-
Engineering	101	-	-	-
Other	87	-	-	-
Total	**$2,052**	**$2,094**	**$6,538**	**$10,684**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	**2005**	**2006**	**2007**	**2008**	**2009F**
Total	**$1,194**	**$1,273**	**$2,134**	**$2,357**	**$2,243**

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, 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.

Project Title: **Additions Due To Load Growth (Pooled)**

Project Cost: **$3,650,000**

Project Description

This substations project includes:

1. The installation of a new 66/12.5 kV 25 MVA substation transformer at Deer Lake substation to replace the existing 66/12.5 kV 17 MVA transformer. The existing transformer loading has exceeded 100% capacity in the 2006, 2007 and 2008 winter seasons. ($2,213,000)

2. The relocation of the existing 17 MVA Deer Lake substation transformer to Mobile substation to replace the existing 7 MVA transformer. The existing transformer loading has exceeded 100% capacity in the 2008 winter season. ($1,257,000)

3. The termination of a new feeder at Kenmount Substation in St. John's. ($180,000)

The individual requirements for additions to substations due to load growth that are included in this project are not inter-dependent. However, they are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Details on 2010 proposed expenditures are included in ***2.2** 2010 Additions Due to Load Growth*.

Justification

Load forecasts for the Deer Lake and Mobile substations indicate that future loading will exceed the capacity of the substation transformers. The addition of a larger transformer at Deer Lake and relocation of the former Deer Lake transformer to Mobile substation will accommodate this increased load. These changes represent the least cost solution to meeting the forecast load requirements for both substations.

The termination of the new feeder at Kenmount Substation will allow the Company to service the new residential developments in the Kenmount Road west area.

The project is justified on the basis of accommodating customer load growth. The proper sizing of equipment is necessary to avoid overloading equipment and to maintain safe, reliable electrical service.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2010 and a projection of expenditures through 2014.

Table 1
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$2,946	-	-	-
Labour – Internal	282	-	-	-
Labour – Contract	-	-	-	-
Engineering	326	-	-	-
Other	96	-	-	-
Total	**$3,650**	**$0**	**$0**	**$3,650**

Costing Methodology

The budget estimate for this project is comprised of engineering estimates of 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: **Convert 23L to 66 kV (Pooled)**

Project Cost: **$286,000**

Project Description

This substation project is proposed to improve the energy efficiency of transmission line 23L between Pierre's Brook plant and Mobile substation. Increasing the transmission line voltage from 33 kV volts to 66 kV volts will reduce line losses, thereby making more of the energy produced at the Pierre's Brook Plant available to the Island interconnected system.

Details on the proposed expenditures are included in ***2.3*** *Convert 23L to 66kV to Reduce Losses*.

Justification

The project is justified on the energy savings as shown in the economic analysis included with the report ***2.3*** *Convert 23L to 66kV to Reduce Losses*. The project will provide an additional 251,096 kWh of energy to the system annually at a levelized unit cost of 0.77¢/kWh.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2010 and a projection of expenditures through 2014.

Table 1
Projected Cost
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$197	-	-	-
Labour – Internal	30	-	-	-
Labour – Contract		-	-	-
Engineering	44	-	-	-
Other	15	-	-	-
Total	**$286**	-	-	**$286**

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.

Project Title: **Lookout Brook Substation Upgrades (Clustered)**

Project Cost: **$187,000**

Project Description

This substation project is proposed in conjunction with the major refurbishment of the Company's Lookout Brook Plant. This substation upgrade project will involve improvements to the low voltage bus, the addition of a three phase station service transformer and termination of new power cables between the low voltage bus and the generator switchgear cubicle.

Details on 2010 proposed expenditures are included in ***1.2*** *Lookout Brook Hydro Plant Refurbishment*.

Justification

The existing 2.4 kV low voltage bus structure has non-standard clearances, materials and hardware. The existing low voltage bus does not have adequate space to accommodate the addition of the three phase station service transformer or to terminate new power cables from the generator switchgear. For these reasons the existing substation must be upgraded to current standards.

A feasibility analysis of projected capital and operating expenditure requirements for the complete Lookout Brook Plant has determined the levelized cost of energy from the plant over the next 50 years to be 2.71¢ per kWh, which is significantly less than the cost of replacement energy.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2010. There are no expenditures expected after 2010.

Table 1
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$126	-	-	-
Labour – Internal	23	-	-	-
Labour – Contract	-	-	-	-
Engineering	33	-	-	-
Other	5	-	-	-
Total	**$187**	**-**	**-**	**$187**

Costing Methodology

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

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

Future Commitments

This is not a multi-year project.

TRANSMISSION

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

Project Cost: **$5,915,000**

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.

   Proposed 2010 transmission line rebuilding work will take place on sections of 110L, 23L and 24L. Transmission line 110L is located on the Bonavista Peninsula and experienced damage during the December 2007 storm resulting in extended outages for customers. Work on this transmission line commenced in 2009. Transmission line 23L is a 33 kV transmission line connecting Pierre's Brook plant to the Island interconnected system at Mobile Substation. Transmission line 24L is a radial transmission line connecting hydro and wind generation and customers on the Southern Shore of the Avalon Peninsula to the Island interconnected system at Goulds substation.

   Details on the 2010 rebuilds are included in ***3.1** Transmission Line Rebuild* ($4,165,000).

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 ($1,750,000).

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 percent 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 2010 and a projection of expenditures through 2014. Appendix A of ***3.1** Transmission Line Rebuild* details the transmission line rebuilds planned for each year.

Table 1
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$2,055	-	-	-
Labour – Internal	291	-	-	-
Labour – Contract	3,046	-	-	-
Engineering	241	-	-	-
Other	282	-	-	-
Total	**$5,915**	**$5,599**	**$17,002**	**$28,516**

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	2005	2006	2007	2008	2009F
Total	**$2,651**	**$4,456**	**$4,440**	**$5,236**	**$4,487**

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: **$8,856,000**

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 2010 and a projection of expenditures through 2014.

Table 1
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$2,857	-	-	-
Labour – Internal	2,118	-	-	-
Labour – Contract	2,741	-	-	-
Engineering	908	-	-	-
Other	232	-	-	-
Total	**$8,856**	**$8,885**	**$29,259**	**$47,000**

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 2010.

Table 2
Expenditure History and Unit Cost Projection

Year	2005	2006	2007	2008	2009F	2010B
Total (000s)	**$ 7,962**	**$11,136**	**$ 9,285**	**$10,592**	**$ 9,724**	**$ 8,856**
Adjusted Cost (000s)[1]	$ 9,086	$ 8,882[2]	$ 8,787[2]	$10,899	$ -	$ -
New Customers	4,029	3,952	4,038	4,625	4,396	3,864
Unit Cost ($/customer)[1]	$ 2,255	$ 2,247	$ 2,176	$ 2,357	$ 2,212	$ 2,292

1 2009 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. 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.

Project Title: **Meters (Pooled)**

Project Cost: **$1,239,000**

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 meter requirement for 2010.

Table 1
2010 Proposed Meter Acquisition

Program	Number of Meters
Energy Only Domestic Meters	13,871
Other Energy Only and Demand Meters	3,103

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 2010 and a projection of expenditures through 2014.

Table 2 **Projected Expenditures** **(000s)**				
Cost Category	**2010**	**2011**	**2012 - 2014**	**Total**
Material	$1,090	-	-	-
Labour – Internal	124	-	-	-
Labour – Contract	25	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$1,239**	**$1,266**	**$3,965**	**$6,470**

Costing Methodology

Table 3 shows the annual expenditures for the most recent five-year period, as well as a projection for 2010.

Table 3 **Expenditure History and Unit Cost Projection**							
Year	**2005**	**2006**	**2007**	**2008**	**2009F**	**Avg**	**2010B**
Meter Requirements							
New Connections	4,149	3,952	3,941	4,625	4,396	4,213	3,864
GROs/CSOs	12,399	13,371	3,546	13,691	13,200	11,241	11,241
Other	2,175	1,677	1,667	2,156	1,672	1,869	1,869
Total	18,723	19,000	9,154	20,472	19,268	17,323	16,974
Meter Costs							
Actual (000s)	$ 1,342	$ 1,463	$ 1,154	$ 1,474	$ 1,413	$ 1,369	$ 1,239
Adjusted[1] (000s)	$ 924[2]	$ 1,026[2]	$ 1,194	$ 1,514	$ 1,413	$ 1,214	$ 1,239
Unit Cost[1]	$ 83[2]	$ 89[2]	$ 130	$ 74	$ 73	$ 90	$ 73

[1] 2009 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 growth in the number of customers the Company serves. 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: **$2,447,000**

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 2010 and a projection of expenditures through 2014.

Table 1
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$736	-	-	-
Labour – Internal	1,357	-	-	-
Labour – Contract	119	-	-	-
Engineering	205	-	-	-
Other	30	-	-	-
Total	**$2,447**	**$2,471**	**$8,101**	**$13,019**

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 2010.

Table 2

Expenditure History and Unit Cost Projection
New Services

Year	2005	2006	2007	2008	2009F	2010B
Total (000s)	**$ 1,894**	**$ 1,863**	**$ 1,949**	**$ 2,111**	**$ 2,150**	**$ 2,000**
Adjusted Cost (000s)[1]	$ 2,155	$ 2,065	$ 2,075	$ 2,172	$ 2,150	$ 2,000
New Customers	4,029	3,952	4,038	4,625	4,396	3,864
Unit Cost ($/customer)[1]	$ 535	$ 523	$ 514	$ 470	$ 489	$ 518

[1] 2009 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 for *replacement* services for the most recent five-year period, as well as a projected cost for 2010.

Table 3

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

Year	2005	2006	2007	2008	2009F	2010B
Total	**$339**	**$399**	**$472**	**$427**	**$422**	**$447**
Adjusted Cost[1]	$386	$442	$503	$439	$422	$447

[1] 2009 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: **$1,783,000**

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 2010 and a projection of expenditures through 2014.

Table 1
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$966	-	-	-
Labour – Internal	635	-	-	-
Labour – Contract	137	-	-	-
Engineering	27	-	-	-
Other	18	-	-	-
Total	**$1,783**	**$1,801**	**$5,819**	**$9,403**

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 2010.

Table 2

Expenditure History and Unit Cost Projection
New Street Lights

Year	2005	2006	2007	2008	2009F	2010B
Total (000s)	**$ 1,363**	**$ 1,131**	**$ 977**	**$ 1,315**	**$ 1,134**	**$ 1,106**
Exclusions[1] (000s)	$ 380	-	-	-	-	-
Adjusted Cost (000s)[2]	$ 1,567	$ 844	$ 1,043	$ 1,352	$1,134	$ 1,106
New Customers	4,029	3,952	4,038	4,625	4,396	3,864
Unit Cost ($/cust.)[2]	$ 389	$ 214	$ 258	$ 292	$ 258	$ 286

[1] Exclusions in 2005 reflect the unusually high quantity of new Street Lights installed for the City of St. John's.
[2] 2009 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 2010.

Table 3

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

Year	**2005**	**2006**	**2007**	**2008**	**2009F**	**2010B**
Total	**$489**	**$ 451**	**$ 1,112**	**$ 692**	**$ 601**	**$ 677**
Exclusions[1]	70	-	140	-	-	
Adjusted Cost[2]	$482	$ 507	$ 1,038	$ 712	$ 601	$ 677

[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] 2009 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: $681,000

Project Description

This Distribution project is the second year of a 3 year project to replace existing Mercury Vapour ("MV") street light fixtures with the more energy efficient High Pressure Sodium ("HPS") fixtures. At the beginning of 2009 there were 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 were included in the 2009 Capital Budget Application in report ***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* included with the 2009 Capital Budget Application 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¢ per kWh.[1]

[1] In the 2009 Capital Budget the cost of electricity from the Holyrood thermal generating station is estimated at 10.63¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $67.00 per barrel as of March 31, 2008.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures (000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$325	-	-	-
Labour – Internal	325	-	-	-
Labour – Contract		-	-	-
Engineering	16	-	-	-
Other	15	-	-	-
Total	**$681**	**$681**	**-**	**$1,362**

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: $7,668,000

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 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures (000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$7,668	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$7,668**	**$7,821**	**$24,399**	**$39,888**

Costing Methodology

Table 2 shows the annual expenditures for the most recent five-year period, as well as an estimate for 2010.

Table 2
Expenditure History and Budget Estimate
(000s)

Year	2005	2006	2007	2008	2009F	2010B
Total	**$4,976**	**$5,643**	**$6,992**	**$8,545**	**$6,671**	**$7,668**
Adjusted Cost[1]	$5,801	$6,456	$7,504	$8,776	$6,671	$7,668

[1] 2009 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 adjusting it using the GDP Deflator for 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: **Reconstruction (Pooled)**

Project Cost: **$3,359,000**

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 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 or the selective replacement of various line components based on preventive maintenance inspections or engineering reviews.

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 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures (000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$795	-	-	-
Labour – Internal	1,377	-	-	-
Labour – Contract	758	-	-	-
Engineering	315	-	-	-
Other	114	-	-	-
Total	**$3,359**	**$3,473**	**$11,065**	**$17,897**

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 2010.

Table 2
Expenditure History and Budget Estimate
(000s)

Year	**2005**	**2006**	**2007**	**2008**	**2009F**	**2010B**
Total	**$2,898**	**$2,989**	**$3,563**	**$3,193**	**$2,929**	**$3,359**
Adjusted Cost[1]	$3,296	$3,309	$3,260	$3,285	$2,929	$3,359

[1] 2009 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 adjusting it using the GDP Deflator for 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: **Rebuild Distribution Lines (Pooled)**

Project Cost: **$3,632,000**

Project Description

This Distribution project involves the replacement of deteriorated distribution structures and electrical equipment that have been previously identified through the ongoing preventative maintenance program or engineering reviews.

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

The work for 2010 includes 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 the need to replace defective or deteriorated electrical equipment in order to maintain a safe, reliable electrical system.

The Company has over 8,700 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 2010 and a projection of expenditures through 2014.

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2010**	**2011**	**2012 - 2014**	**Total**
Material	$1,753	-	-	-
Labour – Internal	1,216	-	-	-
Labour – Contract	208	-	-	-
Engineering	283	-	-	-
Other	172	-	-	-
Total	**$3,632**	**$3,740**	**$11,839**	**$19,211**

Costing Methodology

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

Table 2 **Expenditure History** **(000s)**					
Year	**2005**	**2006**	**2007**	**2008**	**2009F**
Total	**$3,545**	**$2,811**	**$3,249**	**$3,566**	**$3,241**

Distribution feeders are inspected in accordance with Newfoundland Power's distribution inspection standards to identify deficiencies that are a risk to public or employee safety, or that are likely to result in imminent failure of a structure or hardware. This includes primary components such as poles, crossarms and conductor and specific items such as the following:

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]

[1] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment B for further details on lightning arrestor requirements.
[2] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment C for further details on problem insulators.

d) Locations where current limiting fuses are required in accordance with the internal memo dated January 11, 2000;[3] and

e) Hardware for which a high risk of failure has been identified, such as automatic sleeves and porcelain cutouts.[4]

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

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

Future Commitments

This is not a multi-year project.

[3] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment D for further detail on current limiting fuse requirements.

[4] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment E and Attachment F for further detail on automatic sleeves and porcelain cutouts.

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

Project Cost: **$685,000**

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 2010 and a projection of expenditures through 2014.

Table 1
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$240	-	-	-
Labour – Internal	219	-	-	-
Labour – Contract	144	-	-	-
Engineering	70	-	-	-
Other	12	-	-	-
Total	**$685**	**$709**	**$2,259**	**$3,653**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	**2005**	**2006**	**2007**	**2008**	**2009F**	**2010B**
Total	**$630**	**$1,801**	**$1,604**	**$1,585**	**$1,122**	**$685**
Adjusted Cost[1]	$716	$888[2]	$607[3]	$608[4]	$522[5]	$685

1 2009 dollars.
2 Excludes $999,000 for Eastlink cross island project.
3 Excludes $1,034,000 for Eastlink cross island project.
4 Excludes $994,000 for Eastlink cross island project.
5 Excludes $600,000 for Eastlink 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 adjusting it using the GDP Deflator for Canada.

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

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 (Other)

Project Cost: $447,000

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 2010 project involves continuation of work on feeder NWB-02 included in the Distribution Reliability Initiative ("DRI") from 2009.

Table 1 shows, for this feeder, the number of customers affected and the average unscheduled distribution interruption statistics for the five-year period ending December 31, 2008. These SAIFI[1] and SAIDI[2] statistics exclude planned power interruptions and interruptions due to all causes other than distribution system failure. An analysis of this feeder is contained in report ***4.1*** *Distribution Reliability Initiative*.

Table 1

Distribution Interruption Statistics
5-Years to December 31, 2008

Feeder	Number of Customers	Distribution SAIFI	Distribution SAIDI
North West Brook (NWB-02)	1,041	3.43	8.02
Company Average	**-**	**1.25**	**1.74**

[1] 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.

[2] 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.

Justification

This project is justified on the basis of the obligation to provide reliable electrical service. Customers supplied by this feeder 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 2010 and a projection of expenditures through 2014.

Table 2

Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$216	-	-	-
Labour – Internal	181	-	-	-
Labour – Contract	26	-	-	-
Engineering	3	-	-	-
Other	21	-	-	-
Total	**$447**	**$520**	**$1,644**	**$2,611**

Costing Methodology

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

Table 3

Expenditure History
(000s)

Year	2005	2006	2007[1]	2008	2009F	2010B
Total	$1,065	$3,365	-	$1,411	$541	$447

[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: **St. John's Underground Distribution (Other)**

Project Cost: **$550,000**

Project Description

This Distribution project consists of the relocation of a section of St. John's feeder SJM-03 to the new civil infrastructure completed along Water Street and Harbour Drive, and the installation of a new padmount switch at Beck's Cove. The civil infrastructure to permit this relocation is expected to be completed in 2009.[3]

The underground distribution trunk serving the St. John's downtown core consists of three 12.5 kV underground feeders that originate at St. John's Main substation on Southside Road, and run eastward beneath Water Street. With the exception of some sections that have been upgraded in recent years, the feeder cables, and the duct banks that contain them, were installed in the mid-1960s.

Details on the proposed expenditures are included in ***4.2*** *St. John's Underground Distribution*.

Justification

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

Relocation of a section of SJM-03 feeder between Hutchings Street and Beck's Cove, and installation of a new switch will reduce risks associated with the current underground trunk. It will also allow the Company to fully serve the St. John's downtown core in the event of a single cable failure on the underground trunk.

[3] Approved in Board Order P.U. 19 (2008).

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$465[1]	-	-	-
Labour – Internal	35	-	-	-
Engineering	25	-	-	-
Other	25	-	-	-
Total	**$550**	**-**	**-**	**$550**

1 Material includes the cost of purchase and installation of the new cable and purchase of the new switch.

Costing Methodology

The budget estimate is based on detailed 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.

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

Project Cost: **$465,000**

Project Description

This Distribution project consists of load transfers from one substation to an adjacent substation, and upgrading conductor on sections of 4 feeders that have become overloaded.[4] Customer growth on the Northeast Avalon Peninsula has caused some substation transformers and sections of trunk feeders to become overloaded. Transferring customer load to an adjacent substation that has available transformer capacity is the least cost alternative as it defers the purchase of an additional transformer to a future date. Replacing overloaded conductor on an existing feeder reduces the risk of conductor failure thereby improving employee and public safety, while reducing unscheduled customer outages.

Details on the proposed expenditures are included in ***4.3*** *Feeder Additions for Load Growth*.

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.

[4] Load transfer in 2010 will involve the Hardwoods and Kenmount substations. Conductor upgrades will include sections of BCV-03, HWD-07, OXP-01 and SLA-11.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures (000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$109	-	-	-
Labour – Internal	186	-	-	-
Labour – Contract	106	-	-	-
Engineering	48	-	-	-
Other	16	-	-	-
Total	**$465**	**$725**	**$1,700**	**$2,890**

Costing 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: **$153,000**

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 in a manner consistent with Order No. P.U. 32 (2007). This method of calculating the AFUDC is the mainstream practice of regulated Canadian utilities.

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 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	-	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering		-	-	-
Other	153	-	-	-
Total	**$153**	**$156**	**$486**	**$795**

Costing Methodology

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

Table 2
Expenditure History and Budget Estimate
(000s)

Year	2005	2006	2007	2008	2009F	2010B
Total	$85	$78	$77	$176	$132	$153

The increase in AFUDC since 2008 reflects methodological changes resulting from adoption of the asset rate base method for calculating rate base. This methodology was accepted 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: **$389,000**

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 ($100,000)*: 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 ($178,000)*: 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 office furniture utilized by the Company's employees deteriorates through normal use and must be replaced.

4. *Collator ($45,000):* This project is the replacement of a collator in the Print Shop that has reached the end of its useful life. A collator is a device that assembles pages in order. The current unit is approximately 20 years old and replacement parts are no longer available.

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 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures
(000s)

Cost Category	2010	2011	2012 – 2014	Total
Material	$389	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$389**	**$350**	**$1,093**	**$1,832**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2005	2006	2007	2008	2009F
Total	$693	$659	$617	$673	$379

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. Historical expenditures in recent years have included items such as thermo scan cameras and arc flash equipment. A recent review of tool and equipment inventories indicates that future expenditures will be less than 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: **Additions to Real Property (Pooled)**

Project Cost: **$225,000**

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 replacement 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 2010 and a projection of expenditures through 2014.

Table 1
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$180	-	-	-
Labour – Internal	11	-	-	-
Labour – Contract	11	-	-	-
Engineering	12	-	-	-
Other	11	-	-	-
Total	**$225**	**$229**	**$715**	**$1,169**

Costing Methodology

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

Table 2 Expenditure History (000s)					
Year	**2005**	**2006**	**2007**	**2008**	**2009F**
Total	**$334**	**$150**	**$165**	**$244**	**$250**

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.

Project Title: **Kenmount Road Building Roof and HVAC (Other)**

Project Cost: **$542,000**

Project Description

The Kenmount Road office building was built in 1968 as a two storey structure. The original building consisted of what are now the basement and first floor of the existing building. In 1979 two additional floors were added to the building with each floor having its own air-handling system.

This General Property project includes:

1. The replacement of the 30 year old roof on the Kenmount Road office building. The roof is original to the 1979 expansion. The roof design is a four-ply built-up asphalt and gravel roof. The gravel protective surfacing has eroded with wind scouring on all corners of the building. A number of leaks have occurred over recent years, resulting in interior damage. The life expectancy of a four-ply built-up roof is 20 years. This roof is 30 years old and its longevity can be attributed to the positive drainage design of the roof. ($192,000)

2. The replacement of the 3rd floor heating, ventilating and air conditioning ("HVAC") equipment. The HVAC system servicing the top two floors was installed during the 1979 construction and is 30 years old. ($350,000)

Details on the proposed expenditures are included in ***5.1** Kenmount Road Building Renovations*.

Justification

The project is justified on the age and the deterioration of the existing roof and HVAC equipment.

The condition of the roof and HVAC equipment is such that repairs will not extend the life of the systems any further.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2010 and a projection of expenditures through 2014.

Table 1

**Projected Expenditures
(000s)**

Cost Category	2010	2011	2012 - 2014	Total
Material	$475	-	-	-
Labour – Internal	20	-	-	-
Labour – Contract	-	-	-	-
Engineering	47	-	-	-
Other	-	-	-	-
Total	**$542**	**-**	**-**	**$542**

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.

Project Title: **System Control Centre UPS (Other)**

Project Cost: **$225,000**

Project Description

This General Property project consists of the replacement of the 21 year old Uninterruptible Power Supply ("UPS") equipment at the System Control Centre ("SCC").

Details on proposed expenditures are included in ***5.2*** *System Control Centre UPS Replacement*.

Justification

The Company's SCADA system and associated communications equipment are integral to the provision of least cost reliable customer service. The reliability of the Company's SCC based SCADA system, Information System servers and critical communications equipment is dependent on a reliable UPS.

The existing UPS is 21 years old, is at the end of its service life, is operating at maximum capacity and is no longer capable of providing the redundancy or standby capability provided for in the initial design.

The associated battery technology had a service life of 20 years. These batteries have now exceeded the original life expectancy.

The critical role of the System Control Centre in providing least cost reliable service necessitates that the UPS equipment operate reliably 24 hours a day, 365 days of the year.

This project, for which there is no feasible alternative, is required to ensure the continued provision of reliable standby power for the SCC and SCADA system.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$195	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	25	-	-	-
Other	5	-	-	-
Total	**$225**	**-**	**-**	**$225**

Costing Methodology

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

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

Future Commitments

This is not a multi-year project.

TRANSPORTATION

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

Project Cost: **$2,352,000**

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 2010.

Table 1
2010 Proposed Vehicle Replacements

Category	No. of Units
Heavy fleet vehicles[1]	6
Passenger vehicles[2]	17
Off-road vehicles[3]	6
Total	**29**

[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 2010 and a projection of expenditures through 2014.

Table 2 **Projected Expenditures** **(000s)**				
Cost Category	**2010**	**2011**	**2012 - 2014**	**Total**
Material	$2,352	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$2,352**	**$2,401**	**$7,498**	**$12,251**

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

Table 3 **Expenditure History** **(000s)**					
Year	**2005**	**2006**	**2007**	**2008**	**2009F**
Total	**$2,838**	**$2,751**	**$2,231**	**$2,384**	**$2,255**

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 2010 and a projection of expenditures through 2014.

Table 1
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$87	-	-	-
Labour – Internal	3	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	45	-	-	-
Total	**$135**	**$ 137**	**$ 426**	**$ 698**

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
(000s)

Year	**2005**	**2006**	**2007**	**2008**	**2009F**
Total	**$102**	**$173**	**$110**	**$96**	**$135**
Adjusted Cost[1]	$119	$198	$118	$99	$135

[1] 2009 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: **$244,000**

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 2010 and a projection of expenditures through 2014.

Table 1
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	$220	-	-	-
Labour – Internal	24	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$244**	**$ 278**	**-**	**$ 522**

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: **$937,000**

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 2010, 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 2010 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 ***6.1*** *2010 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 ***6.1*** *2010 Application Enhancements*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2010 and a projection of expenditures through 2014.

Table 1
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 - 2014	Total
Material	-	-	-	-
Labour – Internal	720	-	-	-
Labour – Contract	-	-	-	-
Engineering	12	-	-	-
Other	205	-	-	-
Total	**$937**	**$1,200**	**$3,985**	**$6,122**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2005	2006	2007	2008	2009F
Total	**$1,185**	**$1,540**	**$1,353**	**$1,485**	**$1,427**

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: **$1,038,000**

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 2010, the project includes upgrades to the development tools used to operate corporate applications including the Customer Service System, Contact Centre technology, reporting software, substation maintenance (mobile) application, engineering design software and customer correspondence software.

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 proposed expenditures are included in ***6.2** 2010 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 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures (000s)

Cost Category	2010	2011	2012 – 2014	Total
Material	$267	-	-	-
Labour – Internal	586	-	-	-
Labour – Contract	-	-	-	-
Engineering	15	-	-	-
Other	170	-	-	-
Total	**$1,038**	**$1,000**	**$3,125**	**$5,163**

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	2005	2006	2007	2008	2009F
Total	**$779**	**$1,017**	**$679**	**$668**	**$679**

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 project includes provision for the Microsoft Enterprise Agreement for 2009 through 2011 inclusive, which was approved as part of the 2009 Capital Budget application.

This is not otherwise a multi-year project.

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

Project Cost: **$430,000**

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 2010, a total of 163 PCs will be purchased, consisting of 102 desktop computers and 61 laptop computers. Thirty-five of these laptops are required for the Vehicle Mobile Computing Infrastructure project in 2010, and their cost is included in that project. This project also includes the purchase of peripheral equipment such as monitors, mobile devices, and printers to replace existing units that have reached the end of their 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 an approximate 5 year life cycle for its PCs before they require replacement.

Table 1 outlines the PC additions and retirements for 2008 and 2009, as well as the proposed additions and retirements for 2010.

Table 1

PC Additions and Retirements
2008 – 2010

	2008			**2009F**			**2010B**		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	77	75	471	96	96	471	102	102	471
Laptop	49	38	167	57[1]	35	189	61[1]	26	224
Total	**126**	**113**	**638**	**153**	**131**	**660**	**163**	**128**	**695**

[1] In 2009, 25 ruggedized laptop computers are being added related to the Vehicle Mobile Computing Infrastructure project. In 2010, an additional 35 ruggedized laptop computers are forecast for that project.

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 2010 and a projection of expenditures through 2014.

Table 2
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 – 2014	Total
Material	$235	-	-	-
Labour – Internal	87	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	108	-	-	-
Total	**$430**	**$425**	**$1,380**	**$2,235**

Costing Methodology

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

Table 3
Expenditure History
(000s)

Year	2005	2006	2007	2008	2009F
Total	**$412**	**$380**	**$409**	**$415**	**$409**

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: **$660,000**

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 2010, the project includes the replacement of servers required for the Systems Upgrade Project, including those for Contact Centre technology, reporting software, and customer correspondence software. This project also includes the replacement of servers that are at end of their useful lives, including those for data backup and recovery, user authentication and firewall security, and System Control Centre voice communications technology.

This project also includes the purchase of additional disk storage for corporate data; software to identify and remediate security issues, and additional components used in the physical security of computing assets.

The shared server infrastructure requirements for 2010 are not inter-dependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Details on proposed expenditures are included in ***6.3*** *2010 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 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures
(000s)

Cost Category	2010	2011	2012 – 2014	Total
Material	$388	-	-	-
Labour – Internal	187	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	85	-	-	-
Total	**$660**	**$800**	**$2,450**	**$3,910**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2005	2006	2007	2008	2009F
Total	$593	$493	$883	$903	$700

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: **$153,000**

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 2010, this project includes the purchase and implementation of network equipment to provide network redundancy, guard against hardware failures and the expansion of wireless network equipment to the Company's area offices.

The individual network infrastructure requirements for 2010 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 2010 and a projection of expenditures through 2014.

Table 1

Projected Expenditures (000s)

Cost Category	2010	2011	2012 – 2014	Total
Material	$80	-	-	-
Labour – Internal	35	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	38	-	-	-
Total	**$153**	**$250**	**$545**	**$948**

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	2005	2006	2007	2008	2009
Total	**$286**	**-**	**-**	**$162**	**$149**

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: **$272,000**

Project Description

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

In 2010, 35 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 effectiveness. 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 1 provides a breakdown of the proposed expenditures for 2010 and a projection of expenditures through 2014.

Table 1
Projected Expenditures
(000s)

Cost Category	2010	2011	2012 – 2014	Total
Material	$187	-	-	-
Labour – Internal	65	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	20	-	-	-
Total	**$272**	**$178**	-	**$450**

Costing Methodology

In 2009, forecast expenditures related to Vehicle Mobile Computing Infrastructure are $350,000.

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.
2010 Capital Budget
Future Required Expenditures

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

[1] This is a multi-year project approved in Order No. P.U. 27(2008)

Newfoundland Power Inc.
Computation of Average Rate Base
For The Year Ended December 31, 2008
($000's)

	2008	2007[1]
Net Plant Investment		
Plant Investment	1,286,039	1,239,186
Accumulated Amortization	(539,654)	(516,478)
Contributions in Aid of Construction	(25,884)	(24,217)
	720,501	698,491
Additions to Rate Base		
Deferred Charges	100,723	96,850
Weather Normalization Reserve	5,910	10,516
Deferred Energy Replacement Costs	766	1,147
Cost Recovery Deferral-Depreciation	7,724	11,586
Customer Finance Programs	1,776	1,811
	116,899	121,910
Deductions from Rate Base		
2005 Unbilled Revenue	9,236	16,446
Accrued Pension Liabilities	3,142	2,943
Municipal Tax Liability	2,727	4,089
Future Income Taxes	1,184	-
Purchased Power Unit Cost Variance Reserve	895	1,650
Demand Management Incentive Account	426	-
Customer Security Deposits	785	612
	18,395	25,740
Year End Rate Base	819,005	794,661
Average Rate Base Before Allowances	806,833	777,494
Rate Base Allowances		
Materials and Supplies Allowance	4,327	4,393
Cash Working Capital Allowance	9,716	6,669
Average Rate Base at Year End	820,876	788,556

[1] To calculate the 2008 average rate base, the computation of the 2007 rate base has been restated to reflect the methodology approved in Order No. P.U. 32 (2007).

2010 Capital Plan

June 2009

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

Newfoundland Power's 2010 Capital Plan provides an overview of the Company's 2010 Capital Budget together with an outlook for capital expenditure through 2014.

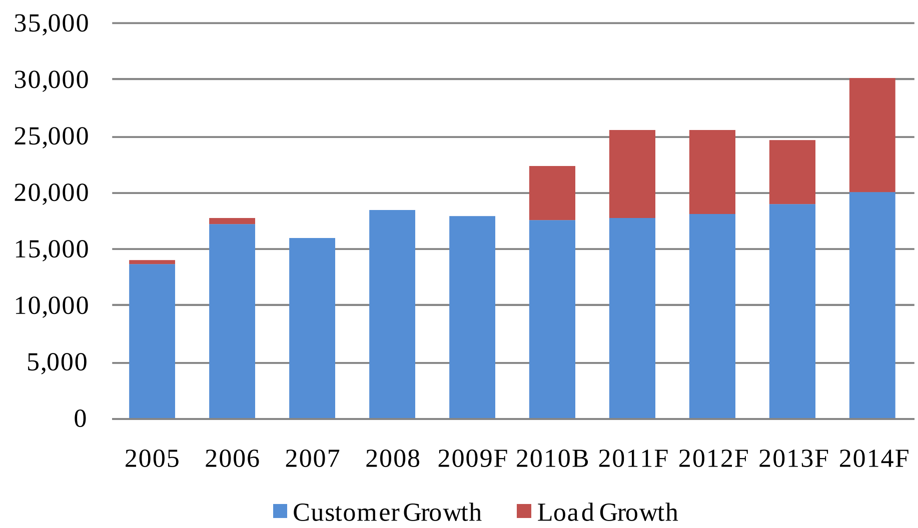
Newfoundland Power's 2010 Capital Budget totals $64,679,000.

Over the next five years, the Company plans to invest approximately $357 million in plant and equipment. The impact of inflation on utility construction projects and the need for greater system capacity over the next 5 years will increase planned expenditures through 2014.

Approximately 52% of planned expenditures through 2014 focus on the replacement of deteriorated, defective or obsolete generation, transmission, substation and distribution electrical equipment. Capital expenditures related to customer and sales growth ("Customer Growth Capital") are forecast to comprise approximately 36% of capital expenditures through 2014, compared to an average of 28% in the previous 5 years.

Chart 1 shows Newfoundland Power's Customer Growth Capital[1] for the years 2005 to 2014F.

Chart 1
Customer Growth Capital
2005 to 2014F
($000)



1 Customer Growth Capital is the portion of Newfoundland Power's annual capital investment related to customer and sales growth. The level of Customer Growth Capital reflects a number of factors. One is an increase in the number of customers that Newfoundland Power serves. Another is an increase in the amount of electricity delivered by Newfoundland Power to its customers.

Over the next 5 years, Customer Growth Capital is forecast to include significant investment to increase system capacity to serve increasing customer electricity requirements.

2.0 2010 Capital Budget

Newfoundland Power's 2010 capital budget is $64,679,000.

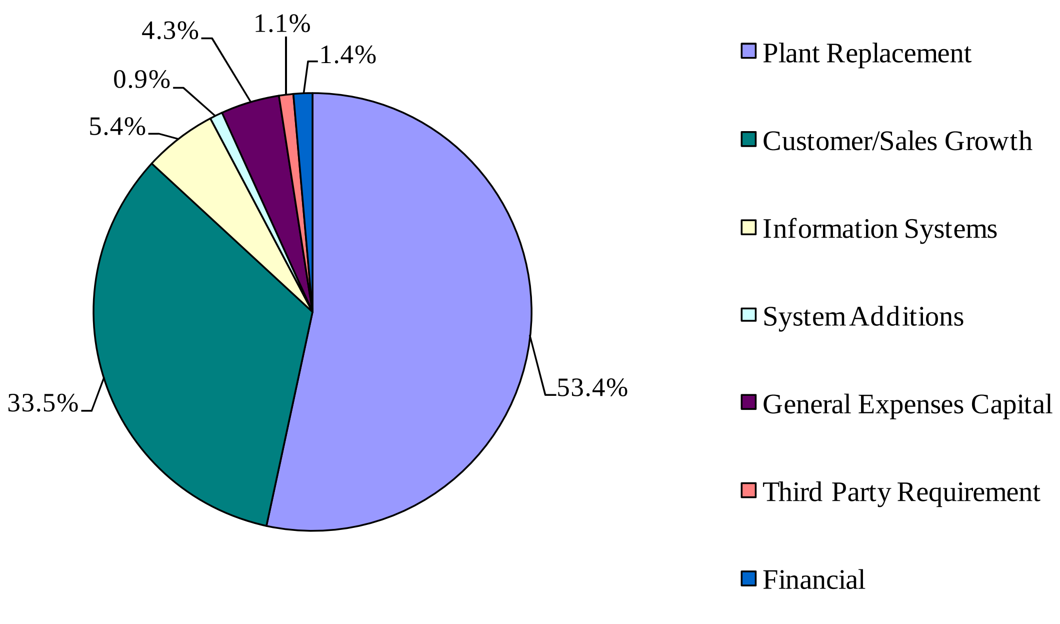
This section of the 2010 Capital Plan provides an overview of the 2010 capital budget by origin (root cause) and asset class. In addition, this section summarizes 2010 capital projects by the various categories set out in the Board's October 2007 Capital Budget Application Guidelines.

2.1 2010 Capital Budget Overview

Newfoundland Power's 2010 capital budget contains 40 projects totalling $64.7 million. From 2005 to 2009, the Company's annual capital program averaged $61.7 million in a range of $53.0 million to $68.5 million.

Chart 2 shows the 2010 capital budget by origin, or root cause.

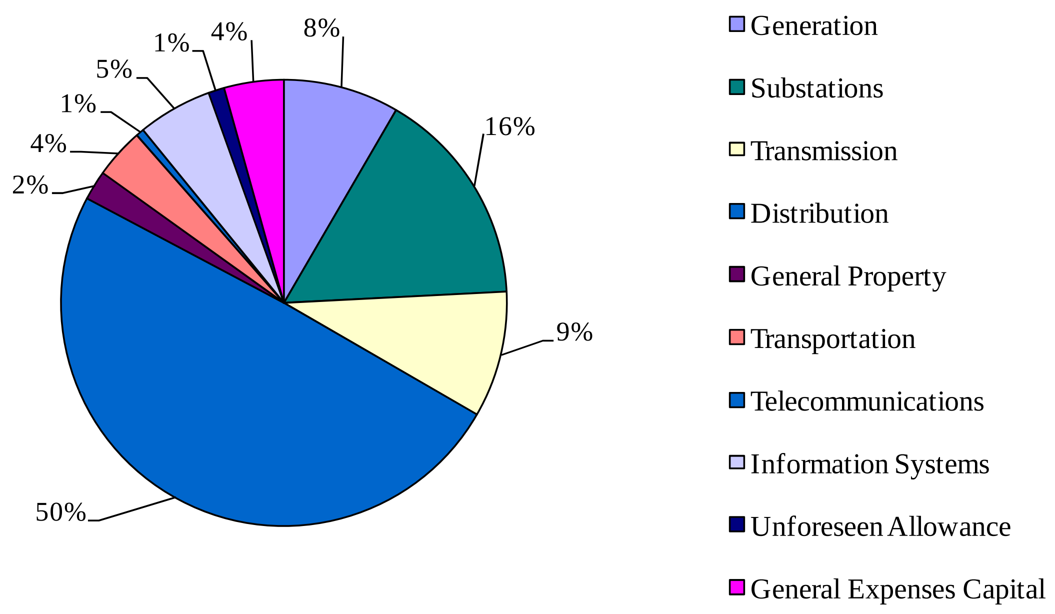
Chart 2
2010 Capital Expenditures
by Origin



Approximately 53% of proposed 2010 capital expenditure is related to the replacement of plant. A further 34% of proposed 2010 capital expenditure is required to meet the Company's obligation to provide service to new customers and meet the requirement for increased system capacity. The remaining 13% of forecast capital expenditures for 2010 relate to information systems, system additions, capitalized general expenses, third party requirements and financial carrying costs (allowance for funds used during construction). 2010 capital expenditures are broadly consistent with the allocation of the capital budget in the past five years.

Chart 3 shows the 2010 capital budget by asset class.

Chart 3
2010 Capital Expenditures
by Asset Class



As in past years, Distribution capital expenditure accounts for the greatest percentage of overall expenditure at $32.0 million, or 50% of the 2010 capital budget. Substations capital expenditure accounts for $10.2 million, or 16% of the 2010 capital budget. Transmission capital expenditure accounts for $5.9 million, or 9% of the 2010 capital budget. Generation capital expenditure accounts for $5.4 million, or 8% of the 2010 capital budget. Together, expenditure for these four asset classes comprises 83% of the Company's 2010 capital budget.

Distribution capital expenditure is primarily driven by customer requests for new connections to the electrical system. Expenditures in 2010 are expected to be consistent with recent years. This reflects a slight decline in the forecast number of new customer connections, offset by inflationary increases.

In 2010, the Company plans to replace the substation power transformer at Deer Lake to address load growth in this area. The displaced Deer Lake substation power transformer will be relocated to the Mobile substation also to address load growth.

Two Southern Shore transmission lines, 23L and 24L, and one Bonavista Peninsula transmission line, 110L, are proposed for rebuild in 2010. Rebuilding transmission line 23L from Pierre's Brook hydro plant to Mobile Substation will include upgrading the transmission line voltage to 66,000 volts. This will facilitate the removal of some older equipment at Mobile substation and reduce the energy losses associated with this transmission line by 251 MWh annually.

In 2010, the Company plans to upgrade the surge tank and replace the main valve on Unit 1 at the Petty Harbour hydroelectric plant. Upgrades are also proposed for the governors, switchgear, protection and control systems at the Lookout Brook hydroelectric plant

In 2008, Newfoundland Power completed a study to identify opportunities to increase production at existing hydroelectric plants. In 2010, the Company plans to complete the second project identified through this study. The *Sandy Lake Spillway* project involves raising the spillway dam elevation to increase the storage capacity of the watershed. The increased capacity will translate into 860 MWh of additional energy on an annual basis.

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 2010 Capital Budget Application complies with the CBA Guidelines.

The 2010 Capital Budget Application includes 40 projects, as detailed in *Schedule B. Schedule A* includes summaries of these projects organized by definition, classification, and segmentation by materiality.

The following section provides a summary of each of these views of the 2010 Capital Budget.

2010 Capital Projects by Definition

Table 1 summarizes Newfoundland Power's proposed 2010 capital projects by definition as set out in the CBA Guidelines.

Table 1
2010 Capital Projects
By Definition

Definition	**Number of Projects**	**Budget ($000s)**
Pooled	29	55,627
Clustered	2	2,342
Other	9	6,710
Total	**40**	**64,679**

There are a total of 31 *pooled* or *clustered* projects accounting for 90% of total expenditures.

2010 Capital Projects by Classification

Table 2 summarizes Newfoundland Power's proposed 2010 capital projects by classification as set out in the CBA Guidelines.

Table 2
2010 Capital Projects
By Classification

Classification	**Number of Projects**	**Budget ($000s)**
Mandatory	0	0
Normal	34	61,647
Justifiable	6	3,032
Total	**40**	**64,679**

There are 34 *normal* projects accounting for 95% of total expenditures.

2010 Capital Projects Costing

Table 3 summarizes Newfoundland Power's proposed 2010 capital projects by costing method (i.e., identified need vs. historical pattern) as set out in the CBA Guidelines.

Table 3
2010 Capital Projects
By Costing Method

Method	**Number of Projects**	**Budget ($000s)**
Identified Need	16	28,356
Historical Pattern	24	36,323
Total	**40**	**64,679**

Projects with costing method based on *identified need* account for 44% of total expenditures, while those based on *historical pattern* account for 56%.

2010 Capital Projects Materiality

Table 4 segments Newfoundland Power's proposed 2010 capital projects by materiality as set out in the CBA Guidelines.

Table 4
2010 Capital Projects
Segmentation by Materiality

Segment	Number of Projects	Budget ($000s)
Under $200,000	5	778
$200,000 - $500,000	9	2,983
Over $500,000	26	60,918
Total	**40**	**64,679**

There are 26 projects budgeted at over $500,000 accounting for 94% of total expenditures.

3.0 5-Year Outlook

Newfoundland Power's 5-year capital outlook for 2010 through 2014 includes forecast average annual capital expenditure of $71.4 million. Over the five year period 2005 through 2009, the average annual capital expenditure is expected to be $61.7 million.

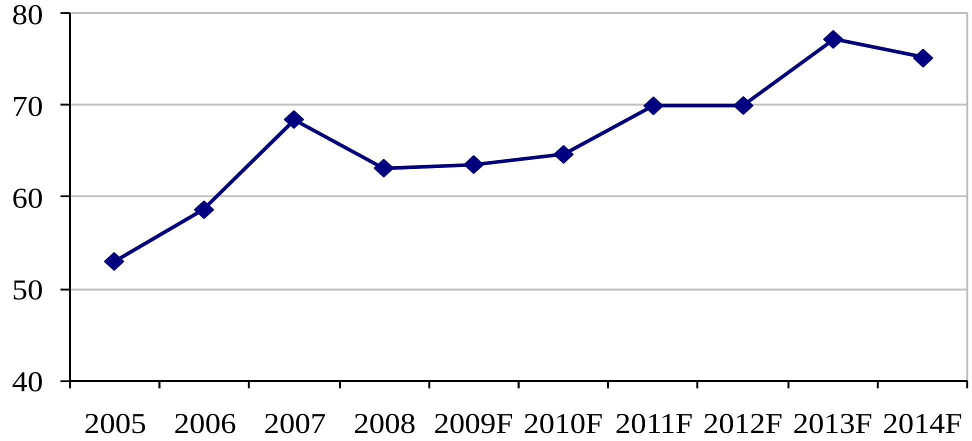
The increase in forecast annual capital expenditure reflects inflation for utility equipment and requirements for specific projects, such as additional power transformers for load growth, the replacement of Pierre's Brook penstock, mobile generation and portable substations.

3.1 Capital Expenditures: 2005 - 2014

The Company plans to invest $357 million in plant and equipment during the 2010 through 2014 period. On an annual basis, capital expenditures are expected to average approximately $71.4 million and range from a low of $64.7 million in 2010 to a high of $77.2 million in 2013.

Chart 4 shows actual capital expenditures for the period 2005 through 2008 and forecast capital expenditures for the period 2009 through 2014.

Chart 4
Capital Expenditures
2005 to 2014F
($000,000)



Overall planned capital expenditures for the 5-year period from 2010 through 2014 are expected to be greater than those in the 5-year period from 2005 through 2009. This is principally the result of inflation in utility infrastructure construction costs, and forecast requirements for additional power transformers due to load growth, the replacement penstock for Pierre's Brook plant, and a portable substation and mobile generation.

The replacement of plant has been, and will continue to be, the dominant driver of Newfoundland Power's capital budget, accounting for approximately 53% of total expenditure for the 10-year period from 2005 through 2014.

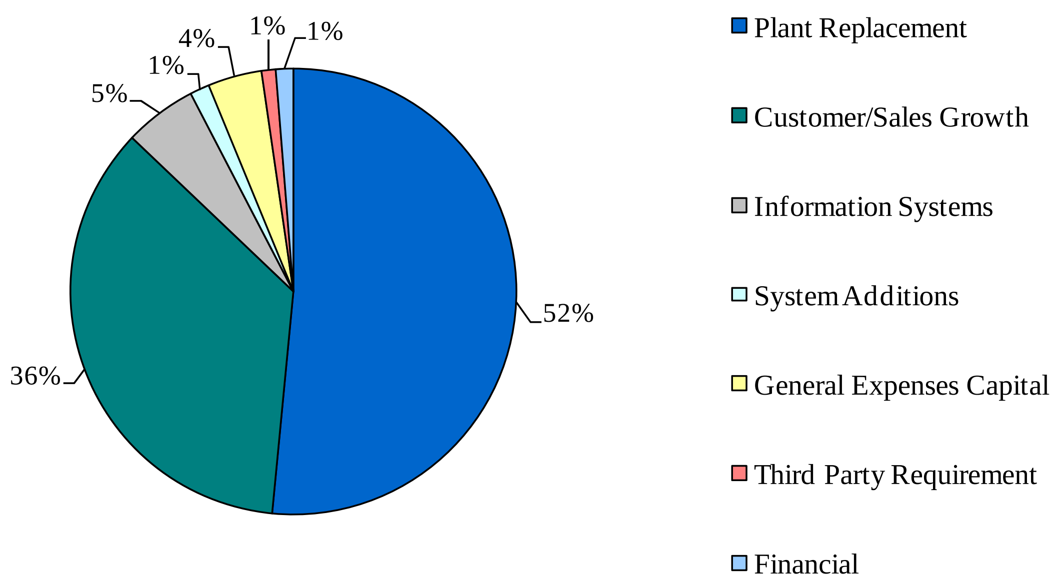
Capital expenditures to meet increases in customer connections and electricity sales over the same 10-year period account for approximately 32% of the total expenditure.

3.2 2010 – 2014 Capital Expenditures

3.2.1 Overview

Chart 5 shows aggregate forecast capital expenditures by origin for the period 2010 through 2014.

Chart 5
Capital Expenditures
by Origin
2010 - 2014

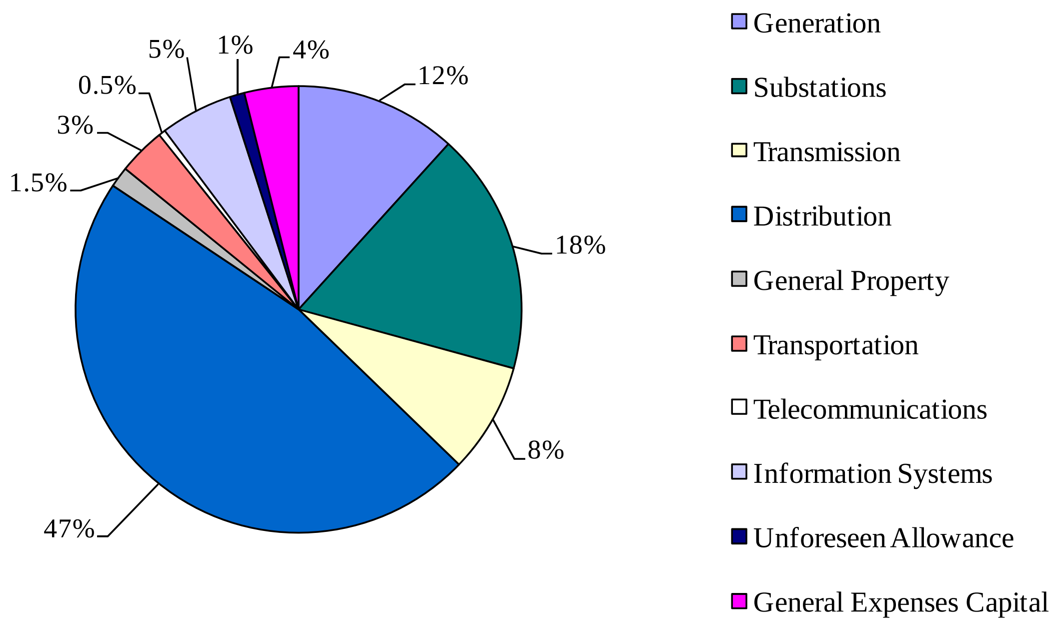


Plant replacement accounts for 52% of all planned expenditures over the 5-year period from 2010 through 2014. Capital expenditure related to customer and sales growth accounts for 36% of planned expenditures for this period. This is an increase from the average of 28% in the previous 5-year period from 2005 through 2009.

The remaining 12% of total capital expenditures for the 2010 through 2014 period relate to a variety of origins including information systems, system additions, third party requirements and financial costs.

Chart 6 shows aggregate forecast capital expenditures for the period 2010 through 2014 by asset class.

Chart 6
Capital Expenditures
by Asset Class
2010 - 2014



The Distribution asset class accounts for 47% of all planned expenditures over the next five years, followed by Substations (18%), Generation (12%) and Transmission (8%). The remaining six asset classes account for 15% of total capital expenditures for the 2010 through 2014 period.

Overall, planned expenditures for the period 2010 through 2014 are expected to remain relatively stable in all asset classes with the exception of generation and substations which vary annually due to refurbishment and system load growth requirements.

A summary of planned capital expenditures by asset class and by project is provided in Appendix A.

3.2.2 Generation

Generation capital expenditures will average approximately $8.4 million per year from 2010 through 2014, which is comparable to the annual average of $8.0 million from 2005 through 2009.

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 a 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 projects are planned:

- In 2010 the Company plans to upgrade the governors, switchgear, protection and control systems at the Lookout Brook hydroelectric plant at an estimated cost of $2.2 million as described in *1.2 Lookout Brook Hydro Plant Refurbishment*.

- In 2010, the Company plans to upgrade the surge tank and replace the main valve on Unit 1 at the Petty Harbour hydroelectric plant at an estimated cost of $0.6 million as described in *1.3 Petty Harbour Hydro Plant Refurbishment*.

- In 2011, 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 2011, a refurbishment of the Victoria hydroelectric plant is planned at an estimated cost of $2.5 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, the Company plans to replace the Pierre's Brook hydroelectric plant penstock at an estimated cost of $11.0 million.

- In 2014 and 2015, 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.

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 economic analyses of their feasibility.

3.2.3 Transmission

Transmission capital expenditures are expected to average $5.7 million annually from 2010 through 2014. This is greater than the average $4.3 million annual expenditure from 2005 through 2009 primarily 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 a maintenance program in place for its transmission assets. The level of expenditure for capital maintenance, both breakdown and preventative, is expected to be relatively stable over the forecast period.

In its 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 that are deteriorated. 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. An update of the strategic plan is included in report *3.1 Transmission Line Rebuild Strategy*.

3.2.4 Substations

Substations capital expenditures are expected to average $12.5 million annually from 2010 through 2014, a material increase from the average of $5.7 million annually from 2005 through 2009. The increase in expenditure is largely attributable to the requirement for additional system capacity to serve increased customer load, as well as the effects of inflation on utility construction.

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

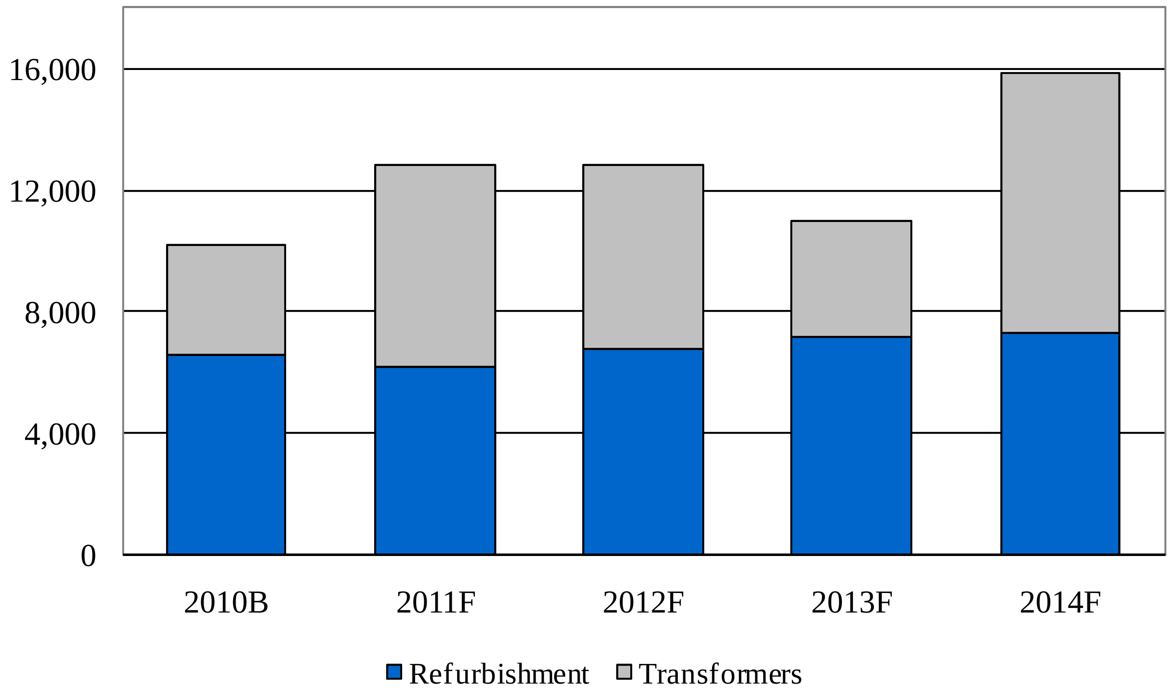
- breakdown capital maintenance;
- substation preventive capital maintenance program; and
- system load growth.

The company has a preventative capital maintenance program in place for its substation assets. Preventive maintenance is expected to counter the continuous aging of substation assets such that the level of failures and overall reliability of substation assets remains stable. The level of expenditure for breakdown capital maintenance is expected to remain constant over the forecast period.

The Company forecasts a number of significant substations projects will be required due to system load growth over the planning period. Capital expenditures will be required to increase system capacity, particular power transformation capacity.

Chart 7 shows the impact of the required new transformers on the substations capital plan for the 2010 to 2014 period.

Chart 7
Substations Capital Plan
($000s)



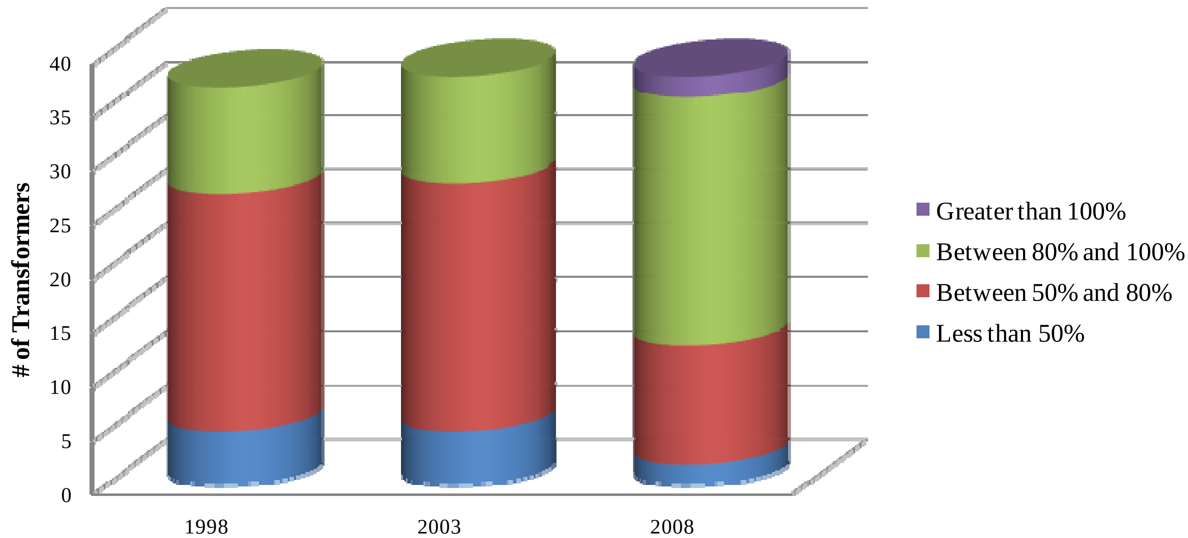
In each year of the 2010 to 2014 forecast period there is a requirement to purchase at least one large power transformer to accommodate load growth.[2] In 2010, the power transformer at Deer Lake substation is being replaced as it operating beyond its load capacity on peak. The displaced Deer Lake transformer will be relocated to the Mobile substation to replace another transformer that is also operating beyond its load capacity on peak.

Commencing in 2011 and continuing through 2014 new substation transformers are required for the Mount Pearl, Torbay, Paradise, Kelligrews and Gander areas. In recent years, at some of these locations, customer load growth has been addressed through load transfers between adjacent substations. Eventually, as customer load continues to grow, additional transformer capacity will inevitably be required.

[2] By comparison, in the period 2005 through 2009, Newfoundland Power has installed no additional power transformers to serve increased customer load. The purchase of transformers to serve customer load growth is in addition to the requirement to replace aged or deteriorated equipment. The new substation transformers for 2014 includes the addition of a portable substation.

Chart 8 shows power transformer capacity utilization on peak for power transformers located in the St. John's metropolitan area for each of 1998, 2003 and 2008.[3]

Chart 8
Power Transformer Capacity Utilization
St. John's Metropolitan Area
1998, 2003 and 2008



In 1998, approximately 27% of power transformers in the St. John's metropolitan area had capacity utilization on peak of 80% or greater. By 2008, the proportion of power transformers in the St. John's metropolitan area with capacity utilization on peak of 80% or greater had grown to approximately 66%[4]. This reflects the impact of customer load growth on power transformer capacity utilization.

The Company's annual Capital Budget Applications will include engineering studies detailing the requirements for additional power transformers in the years in which they are required.

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.

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3 Over the 5 years ended 2008, the amount of energy consumed by Newfoundland Power customers increased by 306 GWh. Approximately 76% of this increase, or 234 GWh, occurred in the St. John's metropolitan area.

4 Growth in capacity utilization of power transformers in the remainder of the Company's service territory has been less dramatic. In 1998, 15% of power transformers outside the St. John's metropolitan area had capacity utilization on peak of 80% or greater. By 2008, this proportion had grown to approximately 25%.

In 2014, there is an additional portable substation planned increasing the fleet from 3 units to 4 units. The additional portable substation will increase the number of units available in the event of an in-service transformer failure and will provide greater flexibility in scheduling major planned substation projects. This additional portable substation will cost approximately $5.0 million.

The Company has 197 substation power transformers in service, a large number of which were installed in the 1970s. As these transformers age, it can be expected that some will fail while in service. Predicting these failures is not possible, and advance purchase of replacement transformers is impractical. Therefore it is critical that a sufficient number of portable substations are available to provide temporary service while replacement transformers are manufactured and installed.

In its 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 of 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 2010 Substation Refurbishment and Modernization*.

3.2.5 Distribution

Distribution capital expenditures are expected to remain relatively stable at an average of approximately $33.7 million annually from 2010 through 2014, compared to an average of $32.6 million annually from 2005 through 2009.

The Company operates approximately 8,700 km of distribution lines serving over 236,000 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 gradually increase over the planning period. This is primarily due to 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 forecast number of new customer connections and the total capital expenditures associated with those connections over the next five years.

Table 5
New Customer Connections

	2010	2011	2012	2013	2014
New Customer Connections	3,864	3,754	3,732	3,863	4,060
Average Cost/Connection	$4,101	$4,236	$4,374	$4,488	$4,606
Capital Expenditure (000s)	$15,848	$15,901	$16,324	$17,336	$18,701

Over the period 2010 to 2014, the number of new customer connections is forecast to be relatively stable. The impact of inflation over the same period increases the average cost per customer connection by 12%. These combined effects result in an increase total capital expenditures to connect new customers over the period.

Distribution capital expenditures are required to relocate or replace distribution lines to meet third party requests from governments, telecommunications companies and individual customers. Over the next five years, these expenditures are forecast to remain stable and approximate the historical average.

The Company has a preventative capital 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 its 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 *Rebuild Distribution Lines* project. 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.

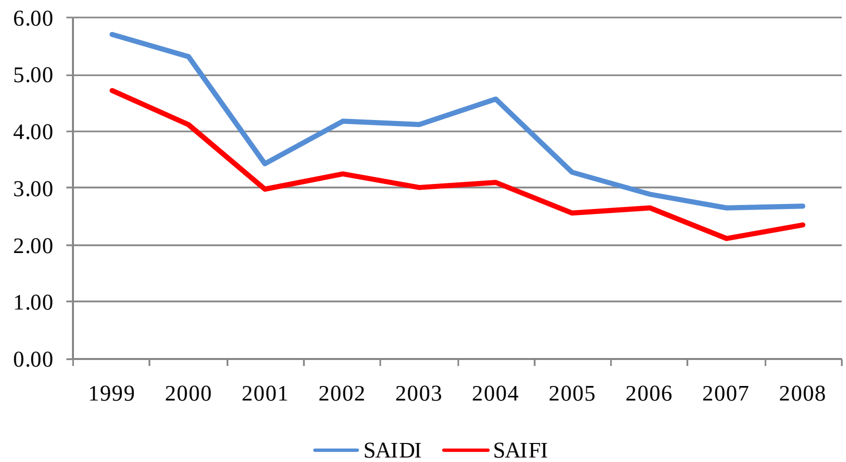
Annual capital expenditures related to *St. John's Underground Distribution* are expected to average approximately $800,000 over the next five years. These expenditures will be driven by the need to replace deteriorated existing infrastructure and reduce the risk of prolonged outage in the downtown commercial core.

Distribution capital expenditure related to system load growth primarily reflects growth in customer electricity requirements. The majority of this growth continues to be located in the St. John's metropolitan area. This requires the transfer of customer load or the upgrade of feeders to increase capacity. Expenditure for feeder modifications and additions due to system load growth from 2010 through 2014 is expected to remain relatively constant though increased in comparison to the previous five years.

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 project planned for 2010 involves the completion of reliability upgrades to a feeder in the Northwest Brook area, which were started in 2009.

Chart 9 shows SAIDI, or system average interruption duration index, and SAIFI, or system average interruption frequency index, for the years 1999 through 2008. Chart 9 has been adjusted to remove the effects of severe weather events.[5]

Chart 9
SAIDI and SAIFI
1999 to 2008



Newfoundland Power considers current levels of service reliability to be satisfactory. This reflects the current condition of Newfoundland Power's distribution system assets. As a result, capital expenditures in the *Distribution Reliability Initiative* project will be reduced compared to previous years.

[5] Adjustments exclude 1999 Burin and 2007 Bonavista severe weather events. If these were included, 1999 SAIDI and SAIFI would be 9.37 and 5.28, respectively; and 2007 SAIDI and SAIFI would be 5.94 and 2.46, respectively.

3.2.6 General Property

The General Property asset class includes capital expenditures for:

- the addition or replacement of tools and equipment utilized by line and engineering staff;
- the replacement or addition of office furniture and equipment;
- additions to real property necessary to maintain buildings and facilities; and
- backup electricity generation and demand/load control equipment at Company buildings.

The 2010 capital budget includes replacement of the roof and HVAC system at the Company's Kenmount Road office building, and replacement of the 21 year old uninterruptible power supply ("UPS") for the System Control Centre.

General Property capital expenditures are expected to average $1.0 million annually from 2010 through 2014 which is less than the average of $1.5 million annually from 2005 through 2009.

3.2.7 Transportation

The Transportation asset class includes the heavy truck 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 stable at an average of approximately $2.5 million annually from 2010 through 2014 which is the same as the annual average from 2005 through 2009.

3.2.8 Telecommunications

Capital expenditure in 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 vehicles, plants and offices.

Telecommunications capital expenditures are expected to remain relatively stable at an average of approximately $0.2 million annually from 2010 through 2014 which is the same as the annual average from 2005 through 2009.

3.2.9 Information Systems

The Information Systems asset class capital expenditure includes:

- the replacement of shared server and network infrastructure, 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 software product improvements.

Information Systems capital expenditures are expected to remain relatively stable at an average of approximately $3.8 million annually from 2010 through 2014 compared to an average of $3.6 million annually from 2005 through 2009.

3.2.10 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 approval of the Board.

The Unforeseen Allowance constitutes $0.8 million in each year's capital budget from 2010 through 2014

3.2.11 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 2010 through 2014.

3.3 5-Year Plan: Risks

While the Company accepts the Board's view of the desirable effects of year to year capital expenditure stability, the nature of the utility's obligation to serve will not, in some circumstances, necessarily facilitate such stability. The Company has identified some risks to such stability in the period 2010 through 2014.

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 sales growth vary from forecast, the capital expenditure for the required transformers (each in the order of $2-3 million) may also vary from 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 Kenmount, Horsechops, Pierre's Brook and Salt Pond power transformers, will necessitate capital expenditures.[6]

The Company has taken steps to reduce the uncertainty regarding replacement of its Customer Service System ("CSS"), which has been in service since 1991. These steps included upgrades of hardware and software components and removal of technology components that posed the

[6] Replacement of the Horsechops power transformer was approved as part of the 2009 Capital Budget Application in Board Order No. P.U. 27 (2008). Replacement of the Pierre's Brook power transformer was approved in Board Order No. P.U. 3 (2008). Replacement of the Salt Pond power transformer was approved in Board Order No. P.U. 15 (2002-2003). Kenmount power transformer failed in-service in March 2009.

highest risk. Technology vendors are currently expected to sustain CSS related product support well into the next decade. The Company has continued to make modest enhancements to CSS where investments could be justified. However, significant business changes such as rate design changes, or the introduction of advanced metering infrastructure (smart meters) would have an impact on CSS. The scale and complexity of these factors or changing technology and vendor support could require the Company to consider a full replacement of CSS. The cost of this replacement could exceed $10 million.

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

2010 – 2014 Capital Plan

Newfoundland Power Inc.
2010-2014 Capital Plan
(000s)

Asset Class	2010	2011	2012	2013	2014
Generation	$5,429	$6,986	$7,704	$14,968	$6,865
Substations	10,218	12,823	12,802	11,014	15,870
Transmission	5,915	5,599	5,533	5,701	5,768
Distribution	31,965	33,091	33,050	34,757	35,786
General Property	1,381	1,264	1,006	777	790
Transportation	2,352	2,401	2,451	2,498	2,549
Telecommunications	379	415	139	142	145
Information Systems	3,490	3,853	3,780	3,835	3,870
Unforeseen Allowance	750	750	750	750	750
General Expenses Capitalized	2,800	2,800	2,800	2,800	2,800
Total	**$64,679**	**$69,982**	**$70,015**	**$77,242**	**$75,193**

Newfoundland Power Inc.
2010-2014 Capital Plan
(000s)

GENERATION

Project	2010	2011	2012	2013	2014
Facility Rehabilitation – Hydro	$1,340	$1,110	$1,146	$1,156	$1,192
Facility Rehabilitation - Thermal	150	153	431	159	312
Raise Sandy Lake Elevation	612	-	-	-	-
Seal Cove Plant Runner Replacement	540	-	-	-	-
Petty Harbour Surge Tank & Valve	632	-	-	-	-
Lookout Brook Hydro Plant Refurbishment	2,155	-	-	-	-
Hydro Plant Production Increase	-	625	1,465	300	1,500
Rattling Brook Plant – Dam Refurbishment	-	2,600	-	-	-
Victoria Hydro Plant Refurbishment	-	2,498	-	-	-
New Chelsea Turbine Overhaul & Rewind	-	-	10	600	-
Mobile Plant Generator Rewind	-	-	535	-	-
Morris Automation, P&C	-	-	480	-	-
Hearts Content Penstock	-	-	3,637	-	-
Mobile Governor, Protection and Control	-	-	-	1,500	-
Pitman's Pond Runner Replacement	-	-	-	10	470
Pierre's Brook Penstock	-	-	-	11,000	-
Lockston Plant Refurbishment	-	-	-	243	1,550
Purchase Portable Generation	-	-	-	-	1,000
Tors Cove Runners and Wicket Gates	-	-	-	-	16
Sandy Brook Governors P&C	-	-	-	-	825
Total - Generation	**$5,429**	**$6,986**	**$7,704**	**$14,968**	**$6,865**

Newfoundland Power Inc.
2010-2014 Capital Plan
(000s)

SUBSTATIONS

Project	2010	2011	2012	2013	2014
Substations Refurbishment & Modernization	$4,043	$4,063	$4,617	$4,982	$5,108
Replacements Due to In-Service Failure	2,052	2,094	2,136	2,178	2,224
Lookout Brook Substation Modifications	187	-	-	-	-
Additions Due to Load Growth	3,650	6,666	6,049	3,854	3,538
Purchase portable Substation P5	-	-	-	-	5,000
Convert 23L to 66 KV	286	-	-	-	-
Total – Substations	**$10,218**	**$12,823**	**$12,802**	**$11,014**	**$15,870**

Newfoundland Power Inc.
2010-2014 Capital Plan
(000s)

TRANSMISSION

Project	2010	2011	2012	2013	2014
Rebuild Transmission Lines	$4,165	$3,585	$3,519	$3,687	$3,754
Transmission Line Reconstruction	1,750	2,014	2,014	2,014	2,014
Total – Transmission	**$5,915**	**$5,599**	**$5,533**	**$5,701**	**$5,768**

Newfoundland Power Inc.
2010-2014 Capital Plan
(000s)

DISTRIBUTION

Project	2010	2011	2012	2013	2014
Extensions	$8,856	$8,885	$9,122	$9,687	$10,450
Meters	1,239	1,266	1,295	1,321	1,349
Services	2,447	2,471	2,543	2,685	2,873
Street Lighting	2,464	2,482	1,847	1,931	2,041
Transformers	7,668	7,821	7,978	8,129	8,292
Reconstruction	3,359	3,473	3,591	3,687	3,787
Rebuild Distribution Lines	3,632	3,740	3,851	3,945	4,043
Relocations For Third Parties	685	709	733	753	773
Distribution Reliability Initiative	447	520	535	548	561
Feeder Additions for Load Growth	465	725	500	700	500
St. John's Underground Distribution	550	480	896	1,209	952
Trunk Feeders	-	363	-	-	-
Allowance for Funds Used During Construction	153	156	159	162	165
Total – Distribution	**$31,965**	**$33,091**	**$33,050**	**$34,757**	**$35,786**

Newfoundland Power Inc.
2010-2014 Capital Plan
(000s)

GENERAL PROPERTY

Project	2010	2011	2012	2013	2014
Tools and Equipment	$389	$350	$357	$364	$372
Additions to Real Property	225	229	234	238	243
Renovations Company Buildings	542	335	240	-	-
System Control Centre UPS	225	-	-	-	-
Bill Inserter	-	350	-	-	-
Stand-By Diesel Generators – Company Buildings	-	-	175	175	175
Total – General Property	**$1,381**	**$1,264**	**$1,006**	**$777**	**$790**

Newfoundland Power Inc.
2010-2014 Capital Plan
(000s)

TRANSPORTATION

Project	2010	2011	2012	2013	2014
Purchase Vehicles and Aerial Devices	$2,352	$2,401	$2,451	$2,498	$2,549
Total – Transportation	**$2,352**	**$2,401**	**$2,451**	**$2,498**	**$2,549**

Newfoundland Power Inc.
2010-2014 Capital Plan
(000s)

TELECOMMUNICATIONS

Project	2010	2011	2012	2013	2014
Replace/Upgrade Communications Equipment	$135	$137	$139	$142	$145
Fibre Optic Cable	244	278	-	-	-
Total – Telecommunications	**$379**	**$415**	**$139**	**$142**	**$145**

Newfoundland Power Inc.
2010-2014 Capital Plan
(000s)

INFORMATION SYSTEMS

Project	2010	2011	2012	2013	2014
Application Enhancements	$937	$1,200	$1,250	$1,275	$1,460
System Upgrades	1,038	1,000	1,125	1,025	975
Personal Computer Infrastructure	430	425	430	450	500
Shared Server Infrastructure	660	800	800	900	750
Vehicle Mobile Computing	272	178	-	-	-
Network Infrastructure	153	250	175	185	185
Total – Information Systems	**$3,490**	**$3,853**	**$3,780**	**$3,835**	**$3,870**

Newfoundland Power Inc.
2010-2014 Capital Plan
(000s)

UNFORESEEN ALLOWANCE

Project	2010	2011	2012	2013	2014
Allowance for Unforeseen	$750	$750	$750	$750	$750
Total – Unforeseen Allowance	**$750**	**$750**	**$750**	**$750**	**$750**

Newfoundland Power Inc.
2010-2014 Capital Plan
(000s)

GENERAL EXPENSES CAPITALIZED

Project	2010	2011	2012	2013	2014
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**

2009 Capital Expenditure Status Report

June 2009

Newfoundland Power Inc.

2009 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 6 of Order No. P.U. 27 (2008).

Page 1 of the 2009 Capital Expenditure Status Report outlines the forecast variances from budget of the capital expenditures approved by the Board in Order Nos. P.U. 27 (2008). The detailed tables on pages 2 to 13 provide additional detail on capital expenditures in 2009, and also include information on those capital projects approved for 2008 that were not completed prior to 2009.

Variances of more than 10% of approved expenditure and of $100,000 or greater are explained in the Notes contained in Appendix A.

Newfoundland Power Inc.

Forecast 2009 Capital Budget Variances
(000s)

Asset Class	Approved by Order No. P.U. 27 (2008)	Forecast	Variance
Generation - Hydro	$8,899	$7,899	($ 1,000)
Generation - Thermal	100	250	150
Substations	7,172	7,629	457
Transmission	4,507	4,487	(20)
Distribution	30,178	31,182	1,004
General Property	835	629	(206)
Transportation	2,255	2,255	0
Telecommunications	350	350	0
Information Systems	3,725	3,714	(11)
Unforeseen Items	750	750	0
General Expenses Capitalized	2,800	2,800	0
Total	$61,571	$61,945	$374
Projects carried forward from 2008		$1,619	

2009 Capital Expenditure Status Report
(000s)

Category: All Asset Classes

	Capital Budget			Actual Expenditures			Forecast			
	2008	2009	Total	2008	2009	Total To Date	Remainder 2009	Total 2009	Overall Total	Variance
	A	B	C	D	E	F	G	H	I	J
2009 Projects	$ -	$ 61,571	$ 61,571	$ -	$ 24,319	$ 24,319	$ 37,626	$ 61,945	$ 61,945	$ 374
2008 Projects	2,858	-	2,858	1,272	95	1,367	1,524	1,619	2,891	33
Grand Total	**$ 2,858**	**$ 61,571**	**$ 64,429**	**$ 1,272**	**$ 24,414**	**$ 25,686**	**$ 39,150**	**$ 63,564**	**$ 64,836**	**$ 407**

Column A	Approved Capital Budget for 2008
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Column H	Total of Columns E and G
Column I	Total of Columns D and H
Column J	Column I less Column C

2009 Capital Expenditure Status Report
(000s)

Category: Generation - Hydro

	Capital Budget		Actual Expenditures		Forecast				
	2009	Total	2009	Total To Date	Remainder 2009	Total 2009	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2009 Projects									
Hydro Plants - Facility Rehabilitation	$ 1,917	$ 1,917	$ 853	$ 853	$ 1,223	$ 2,076	$ 2,076	$ 159	
Rocky Pond Plant Refurbishment	6,517	6,517	839	839	4,521	5,360	5,360	(1,157)	1
Raise Rose Blanche Spillway to Increase Production	465	465	29	29	434	463	463	(2)	
Total - Generation Hydro	**$ 8,899**	**$ 8,899**	**$ 1,721**	**$ 1,721**	**$ 6,178**	**$ 7,899**	**$ 7,899**	**$ (1,000)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2009
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2009
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Column E	Forecast for Remainder of 2009
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2009 Capital Expenditure Status Report
(000s)

Category: Generation - Thermal

	Capital Budget		Actual Expenditures		Forecast				
	2009	**Total**	**2009**	**Total To Date**	**Remainder 2009**	**Total 2009**	**Overall Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2009 Projects									
Thermal Plants - Facility Rehabilitation	$ 100	$ 100	$ 37	$ 37	$ 213	$ 250	$ 250	$ 150	2
Total - Generation Thermal	**$ 100**	**$ 100**	**$ 37**	**$ 37**	**$ 213**	**$ 250**	**$ 250**	**$ 150**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2009
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Column H	Column G less Column B

2009 Capital Expenditure Status Report
(000s)

Category: Substations

	Capital Budget			Actual Expenditures			Forecast				
	2008	**2009**	**Total**	**2008**	**2009**	**Total To Date**	**Remainder 2009**	**Total 2009**	**Overall Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	
2009 Projects											
Substation Refurbishment and Modernization	$ -	$ 4,102	$ 4,102	$ -	$ 1,105	$ 1,105	$ 3,288	$ 4,393	$ 4,393	$ 291	
Replacement Due to In-Service Failures	-	1,729	1,729	-	948	948	1,295	2,243	2,243	514	3
Horse Chops Transformer Replacement	-	1,341	1,341	-	202	202	791	993	993	(348)	4
Total 2009 Substations	-	7,172	7,172	-	2,255	2,255	5,374	7,629	7,629	457	
2008 Projects											
Interconnection Wind Turbine - Fermuese Substation	$ 928	$ -	$ 928	$ 910	$ 51	$ 961	$ -	$ 51	$ 961	$ 33	
Total - Substations	**$ 928**	**$ 7,172**	**$ 8,100**	**$ 910**	**$ 2,306**	**$ 3,216**	**$ 5,374**	**$ 7,680**	**$ 8,590**	**$ 490**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2008
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Column H	Total of Columns E and G
Column I	Total of Columns D and H
Column J	Column I less Column C

2009 Capital Expenditure Status Report
(000s)

Category: Transmission

	Capital Budget		Actual Expenditures		Forecast				
	2009	Total	2009	Total To Date	Remainder 2009	Total 2009	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2009 Projects									
Transmission Line Rebuild	$ 4,507	$ 4,507	$ 875	$ 875	$ 3,612	$ 4,487	$ 4,487	$ (20)	
Total - Transmission	**$ 4,507**	**$ 4,507**	**$ 875**	**$ 875**	**$ 3,612**	**$ 4,487**	**$ 4,487**	**$ (20)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2009
Column B	Total of Column A
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Column E	Forecast for Remainder of 2009
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2009 Capital Expenditure Status Report
(000s)

Category: Distribution

	Capital Budget			Actual Expenditures			Forecast				
	2008	2009	Total	2008	2009	Total To Date	Remainder 2009	Total 2009	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2009 Projects											
Extensions	$ -	$ 8,786	$ 8,786	$ -	$ 3,812	$ 3,812	$ 5,912	$ 9,724	$ 9,724	$ 938	5
Meters	-	1,127	1,127	-	890	890	575	1,465	1,465	338	6
Services	-	2,373	2,373	-	1,377	1,377	1,195	2,572	2,572	199	
Street Lighting	-	1,646	1,646	-	885	885	850	1,735	1,735	89	
Transformers	-	6,406	6,406	-	3,742	3,742	2,929	6,671	6,671	265	
Reconstruction	-	3,229	3,229	-	1,506	1,506	1,423	2,929	2,929	(300)	
Rebuild Distribution Lines	-	3,541	3,541	-	1,198	1,198	2,043	3,241	3,241	(300)	
Relocate/Replace Distribution Lines For 3rd Parties	-	622	622	-	699	699	423	1,122	1,122	500	7
Distribution Reliability Initiative	-	1,266	1,266	-	44	44	497	541	541	(725)	8
Feeder additions for Growth	-	244	244	-	108	108	136	244	244	-	
Replace Mercury Vapour Street Lights	-	806	806	-	55	55	751	806	806	-	
AFUDC	-	132	132	-	58	58	74	132	132	-	
Total 2009 Distribution	-	30,178	30,178	-	14,374	14,374	16,808	31,182	31,182	1,004	
2008 Projects											
Water Street Underground Civil Infrastructure	$ 1,930	$ -	$ 1,930	$ 362	$ 44	$ 406	$ 1,524	$ 1,568	$ 1,930	$ -	
Total - Distribution	**$ 1,930**	**$ 30,178**	**$ 32,108**	**$ 362**	**$ 14,418**	**$ 14,780**	**$ 18,332**	**$ 32,750**	**$ 33,112**	**$ 1,004**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2008
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Column H	Total of Columns E and G
Column I	Total of Columns D and H
Column J	Column I less Column C

2009 Capital Expenditure Status Report
(000s)

Category: General Property

	Capital Budget		Actual Expenditures		Forecast				
	2009	Total	2009	Total To Date	Remainder 2009	Total 2009	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2009 Projects									
Tools and Equipment	$ 691	$ 691	$ 166	$ 166	$ 213	$ 379	$ 379	$ (312)	9
Additions to Real Property	144	144	57	57	193	250	250	106	10
Total - General Property	**$ 835**	**$ 835**	**$ 223**	**$ 223**	**$ 406**	**$ 629**	**$ 629**	**$ (206)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2009
Column B	Total of Column A
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Column D	Total of Column C
Column E	Forecast for Remainder of 2009
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2009 Capital Expenditure Status Report
(000s)

Category: Transportation

	Capital Budget		Actual Expenditures		Forecast				
	2009	Total	2009	Total To Date	Remainder 2009	Total 2009	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2009 Projects									
Purchase Vehicles and Aerial Devices	$ 2,255	$ 2,255	$ 1,733	$ 1,733	$ 522	$ 2,255	$ 2,255	$ -	
Total - Transportation	**$ 2,255**	**$ 2,255**	**$ 1,733**	**$ 1,733**	**$ 522**	**$ 2,255**	**$ 2,255**	**$ -**	

* See Appendix A for notes containing variance explanations.

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Column H	Column G less Column B

2009 Capital Expenditure Status Report
(000s)

Category: Telecommunications

	Capital Budget		Actual Expenditures		Forecast				
	2009	Total	2009	Total To Date	Remainder 2009	Total 2009	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2009 Projects									
Replace/Upgrade Communications Equipment	$ 135	$ 135	$ 61	$ 61	$ 74	$ 135	$ 135	$ -	
Fibre Optic Circuit Replacement	215	215	87	87	128	215	215	-	
Total - Telecommunications	**$ 350**	**$ 350**	**$ 148**	**$ 148**	**$ 202**	**$ 350**	**$ 350**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2009
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2009 Capital Expenditure Status Report
(000s)

Category: Information Systems

	Capital Budget		Actual Expenditures		Forecast				
	2009	Total	2009	Total To Date	Remainder 2009	Total 2009	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2009 Projects									
Application Enhancements	$ 1,438	$ 1,438	$ 578	$ 578	$ 849	$ 1,427	$ 1,427	$ (11)	
System Upgrades	679	679	226	226	453	679	679	-	
Personal Computer Infrastructure	409	409	335	335	74	409	409	-	
Shared Server Infrastructure	700	700	344	344	356	700	700	-	
Network Infrastructure	149	149	56	56	93	149	149	-	
Vehicle Mobile Computing Infrastructure	350	350	70	70	280	350	350	-	
Total - Information Systems	**$ 3,725**	**$ 3,725**	**$ 1,609**	**$ 1,609**	**$ 2,105**	**$ 3,714**	**$ 3,714**	**$ (11)**	

* See Appendix A for notes containing variance explanations.

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2009 Capital Expenditure Status Report
(000s)

Category: Unforeseen Items

	Capital Budget		Actual Expenditures		Forecast				
	2009	Total	2009	Total To Date	Remainder 2009	Total 2009	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2009 Projects									
Allowance for Unforeseen Items	$ 750	$ 750	$ -	$ -	$ 750	$ 750	$ 750	$ -	
Total - Unforeseen Items	**$ 750**	**$ 750**	**$ -**	**$ -**	**$ 750**	**$ 750**	**$ 750**	**$ -**	

* See Appendix A for notes containing variance explanations.

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2009 Capital Expenditure Status Report
(000s)

Category: General Expenses Capitalized

	Capital Budget		Actual Expenditures		Forecast				
	2009	**Total**	**2009**	**Total To Date**	**Remainder 2009**	**Total 2009**	**Overall Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2009 Projects									
Allowance for General Expenses Capitalized	$ 2,800	$ 2,800	$ 1,344	$ 1,344	$ 1,456	$ 2,800	$ 2,800	$ -	
Total - General Expenses Capitalized	**$ 2,800**	**$ 2,800**	**$ 1,344**	**$ 1,344**	**$ 1,456**	**$ 2,800**	**$ 2,800**	**$ -**	

* See Appendix A for notes containing variance explanations.

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Column A	Approved Capital Budget for 2009
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Generation - Hydro

1. *Rocky Pond Plant Refurbishment:*
   Budget: $6,517,000 Forecast: $5,360,000 Variance: ($1,157,000)

   Expenditure associated with Rocky Pond Plant Refurbishment is expected to be less than originally budgeted due to the purchase cost of the penstock being lower than anticipated. This is principally because of lower steel prices.

Generation - Thermal

2. *Thermal Plants – Facility Rehabilitation:*
Budget: $100,000 Forecast: $250,000 Variance: $150,000

The original budget was based on average historical expenditure. However expenditure has tended to fluctuate substantially from year to year. Over the past 5 years expenditure has ranged from a low of $0 to a high of $301,000. The 2009 requirements include general upgrades to the generating units at Greenhill, Wesleyville, Port Aux Basques as well as the Mobile Gas Turbine.

Substations

3. *Replacement Due to In-Service Failures:*
   Budget: $1,729,000 Forecast: $2,243,000 Variance: $514,000

   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 $750,000 based on historical averages. Committed expenditure to date is approximately $575,000 and the remaining $175,000 is expected to be spent.

   The cost of refurbishing equipment was budgeted at $460,000 based on historical averages. Expenditure to date is approximately $260,000 and the remaining $200,000 is expected to be spent.

   The direct cost associated with emergency in-service failures was budgeted at $519,000 based on historical averages. The cost of emergency work completed or in progress to the end of May was $446,000. Major in–service failures to date include radiator replacements on the power transformers at Webber's Cove ($170,000) and Stamp's Lane ($54,000) and breaker/recloser replacements ($140,000). Based on these higher than expected expenditures year to date, it is now estimated that the annual expenditure for in-service failures will be $1,033,000, an increase of $514,000.

4. *Horse Chops Transformer Replacement :*
   Budget: $1,341,000 Forecast: $993,000 Variance: ($348,000)

   Expenditure associated with Horse Chops Transformer Replacement is expected to be less than originally budgeted due to the purchase cost of the transformer being lower than anticipated.

Distribution

5. *Extensions :*
Budget: $8,786,000 Forecast: $9,724,000 Variance: $938,000

The original budget estimate for extensions was based on 3,962 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 4,396. The additional $938,000 is forecast to be required to build the infrastructure required to connect the additional customers.

6. *Meters :*
Budget: $1,127,000 Forecast: $1,465,000 Variance: $338,000

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 2009, Newfoundland Power is required to replace an additional 13,000 meters due to the failure of two groups of meters that were purchased and installed in 1974 and 1996. 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.

7. *Relocate/Replace Distribution Lines for Third Parties :*
Budget: $622,000 Forecast: $1,122,000 Variance: $500,000

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 2009 is driven by continued higher than normal activity associated with system upgrades by the various telecommunications companies. The total cost is now estimated to be $1,122,000. Contributions in Aid of Construction are expected to recover approximately 45% of the total capital cost of this project.

Distribution

8. *Distribution Reliability Initiative :*
Budget: $1,266,000 Forecast: $541,000 Variance: ($725,000)

Under the Distribution Reliability Initiative the 15 worst performing feeders based on SAIDI, SAIFI and customer minutes are assessed on an annual basis to determine if and where targeted capital investment is warranted to improve service reliability. In 2009, based on five year data covering 2003-2007 it was planned to carry out work on three feeders LEW-02, GLV-02 and NWB-02. These feeders were re-assessed in 2009 based on data covering 2004 – 2008. The 2008 SAIDI and SAIFI for LEW-02 and GLV-02, excluding events beyond the Company's control, were below the company average. Based on 2008 data and the improving trend over time it was decided to cancel the proposed work on LEW-02 and GLV-02. Details are included in 4.1 *Distribution Reliability Initiative* filed with the 2010 Capital Budget Application.

General Property

9. *Tools and Equipment :*
Budget: $691,000 Forecast: $379,000 Variance: ($312,000)

The original budget was based on average historical expenditure which in recent history included substantial expenditure for thermoscan equipment and substation grounds. The latest review of tool and equipment requirements indicates that additional expenditure for such items will not be required in 2009.

10. *Additions to Real Property :*
Budget: $144,000 Forecast: $250,000 Variance: $106,000

The original budget was based on average historical expenditure. The expenditure consists of miscellaneous small expenditures required to maintain the various company properties and buildings. Year to date actual expenditures and committed costs total approximately $140,000. This includes renovations to accommodate customer energy conservation employees at Duffy Place and renovations to Human Resources and Safety employees' office space. Based on the year to date variance from average historical expenditures, the current forecast has been increased to $250,000.

2010 Facility Rehabilitation

June 2009

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NEWFOUNDLAND POWER
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1.0 Introduction

The 2010 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 427.9 GWh[1]. The alternative to maintaining these facilities would be to retire them.

The 2010 Facility Rehabilitation project totalling $1,340,000 is comprised of Hydro Dam Rehabilitation and Generation Equipment Replacements Due to In-Service Failures.

2.0 Hydro Dam Rehabilitation

Cost: $820,000

Newfoundland Power has over 150 dam structures throughout its 23 hydroelectric facilities. Based on the 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, intake rehabilitation at several plants, and spillway and outlet structure repairs.

[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 8.3 GWh as a result of the capacity increase at Rattling Brook to make the revised base normal hydroelectric production to be 427.9 GWh.

Table 1 shows the expenditures for Hydro Dam Rehabilitation since 2005.

Table 1
Expenditures for Hydro Dam Rehabilitation
(000s)

Year	**2005**	**2006**	**2007**	**2008**	**2009F**
Total	$757	$551	$305	$1,046	$890

Specific work to be completed in 2010 includes:

1. Hearts Content Plant: Long Pond Outlet Refurbishment ($110,000)
   This item involves the replacement of the outlet structure at Long Pond dam. Inspections have shown that the outlet structure is in poor condition. The timber abutments are significantly deteriorated and the gate and gate guides are in poor condition and require replacement. It is recommended that the outlet structure be replaced.

2. Pierre's Brook Plant: Gull Pond Dam ($120,000)
   This item involves improvements to the upstream riprap zone, improvement to the dam slopes and drainage along the toe of the dam. Inspections have indicated that additional riprap is required on the upstream slope of Gull Pond Dam as it is sparse in several areas along the length of the dam. In addition the slopes on the upstream and downstream slope of dam are steep and will be re-sloped. The drainage along the toe of the dam will also be improved to promote good drainage.

3. Intake Rehabilitation at West Brook, Lawn, Seal Cove and Port Union Plant ($380,000)

   This item involves the rehabilitation of the intake structures at West Brook, Lawn, Seal Cove and Port Union Plants.

   West Brook Plant: Intake Structure and Spillway Rehabilitation

   The concrete foundation for the intake structure at West Brook Canal and the concrete overflow spillway require rehabilitation. The concrete overflow spillway is severely weathered with a significant amount of exposed rebar and aggregate. The concrete foundation of the intake structure is also deteriorating. In particular, significant concrete cracks are evident on the downstream side of the intake foundation. The concrete foundation is also showing signs of deterioration along the waterline of the intake structure. It is recommended that the concrete overflow spillway and concrete foundation for the intake at West Brook Canal be rehabilitated.

Lawn Plant: Intake Structure Rehabilitation

The concrete deck of the forebay dam and the concrete support structure for the intake gate at Lawn Plant require rehabilitation. Inspections have indicated that the concrete deck of the dam is deteriorating. In particular, weathered concrete, exposed aggregate and rebar are evident throughout. The concrete support structure for the intake gate is also deteriorating. Excessive flows currently migrate through the concrete that is installed on the top and sides of the gate when the gate is in the closed position. It is recommended that the concrete deck of the forebay dam and the concrete support structure for the intake gate at Lawn Plant be rehabilitated.

Seal Cove Plant: Intake Structure Rehabilitation

The concrete intake foundation at Seal Cove Plant requires rehabilitation. The foundation has several horizontal cracks and is severely weathered with a significant amount of exposed aggregate. In March 2009, a piece of concrete that appears to have come from the intake structure jammed open the wicket gates on one of the generator units, resulting in damage to the unit. During the summer of 2009, repairs will be made to the section of the intake structure where the concrete appears to have come from. The damage to the generator units will be subject of a separate 2009 application for capital expenditure approval.

In addition the wooden gate house is in poor condition and requires replacement. It is recommended that the concrete intake foundation be rehabilitated and the intake gate house be replaced at Seal Cove Plant.

Port Union Plant: Intake Structure Rehabilitation

This item involves the rehabilitation of the concrete foundation and replacement of the wooden gate house for the Port Union intake structure. The concrete intake foundation has several vertical cracks in the north and south walls of the structure. There are significant horizontal cracks with exposed and crumbling aggregate along the length of the north and south walls at the waterline. Seepage is evident downstream and along the south foundation wall. The existing wooden gate guides, are no longer in service and are split and rotted. The wooden gate house and roof is deteriorated with several rotted sections. Rehabilitation is recommended for the intake concrete foundation and the wooden gatehouse.

4. Rocky Pond Plant: Butlers Spillway Rehabilitation ($210,000)
   This item involves the rehabilitation of Butlers Spillway and clearing of the outlet channel at the Rocky Pond development. Inspections indicate that the existing timber section of the spillway is significantly deteriorated and requires replacement. In addition there is a significant amount of vegetation along the outlet channel that is obstructing flow. To enhance dam safety performance of the structure under flood conditions the spillway will be rehabilitated and the outlet channel cleared.

3.0 Generation Equipment Replacements Due to In-Service Failures

Cost: $520,000

This item involves the refurbishment or replacement of structures and equipment due to damage, deterioration, corrosion 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 2 shows the expenditures for replacements due to in-service failures since 2005.

Table 2
Expenditures Due to In-Service Failures
(000s)

Year	2005	2006	2007	2008	2009F
Total	$570[1]	$591[1]	$409	$679	$425

[1] Excludes Rocky Pond rebuild.

Based upon recent historical information $520,000 is estimated to be required in 2010 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.

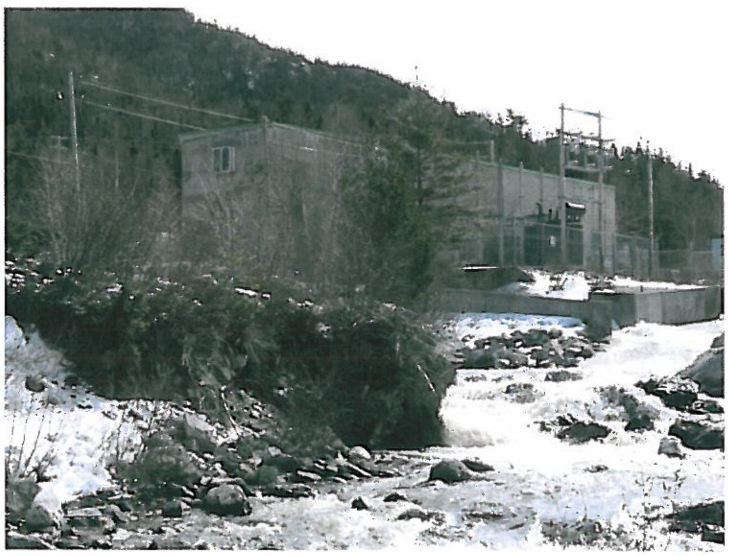
4.0 Recommendations

This project, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable plant operations. A 2010 budget of $1,340,000 for Facility Rehabilitation is recommended as follows:

- $820,000 for Hydro Dam Rehabilitation; and
- $520,000 for Generation Equipment Replacements Due to In-Service Failures.

Lookout Brook Hydro Plant Refurbishment

June 2009



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NEWFOUNDLAND POWER
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1.0 Introduction

The Lookout Brook hydroelectric plant (the "Plant") is located in Western Newfoundland near the community of St. George's. The two original generating units ("G1 and G2") were commissioned in 1946 with a third unit ("G3") added in 1958. The two original units were replaced by a single larger generator ("G4") in 1984, resulting in the current unit designations of G3 and G4. The present capacity of the Plant is 6.2 MW under a net head of 154.6 metres. The normal annual production from the plant is 30.1 GWH or approximately 7.0% of Newfoundland Power's annual hydroelectric production.

The Plant contains two horizontal Francis turbines, one connected to a General Electric generator and the other connected to an Ideal Electric generator. The Plant is connected to the Island interconnected system at Stephenville Gas Turbine substation via Newfoundland Power's transmission lines 403L and 407L.

The Plant is located approximately fourteen kilometres from the Trans Canada Highway at the end of a private road. Snow is not cleared from the road restricting access to the Plant during the winter and spring months. Thus responding to operational issues during this period of time is difficult.

Newfoundland Power ("the Company") has determined that the switchgear requires replacement, the existing protection and control schemes, including the governor, generator protection, voltage regulation and the plant control systems are in need of modernization. The Plant AC and DC systems do not have sufficient capacity to supply the heating requirements and to accommodate the existing protection and control systems. Replacement of the forebay cable and upgrades to the communication equipment will be completed.

Replacement of the switchgear will provide adequate arc flash clearances for employees working near energized equipment. Upgrading the PLC and communication system will enhance plant operations and permit remote operation of devices that would normally require a site visit. This will reduce the need for maintenance personnel to travel to this remote plant, which for a portion of the year is only accessible by snowmobile. Improvements to the protective relaying systems will enhance the protection of the plant electrical equipment.

In addition to the above upgrades a Water Management System will also be implemented, ensuring the efficient operation of the plant and efficient utilization of available water resources.

Results of the feasibility analysis conclude that the continued operation of Lookout Brook plant, including the planned 2010 refurbishment, 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 Governors

2.1 Unit No. 3 - G3

The Gilkes governor was installed in 1958 as part of the installation of G3. The original control mechanism and pumping unit were replaced in 1980. The main actuator, hand wheel control, Giljet[1] impulse turbine and dashpot are original to the 1958 installation.

On unit start up there are excessive operations of the impulse turbine controls. The surfaces of the cover and bottom casing have been eroded by frequent exposure to high pressure water spray. Dashpot operating mechanisms for the Giljet impulse turbine require modification to integrate with the new governor controls.

The existing mechanical controls will be replaced with digital controls interfaced to a new proportional valve. This will improve the generator speed control to minimize the number of operations of the impulse turbine during start up. A reduction in the number of impulse turbine operations will extend the life of the unit. To implement this new arrangement the unit will require additional instrumentation to monitor operating conditions. In addition, the flexible hydraulic lines are deteriorated on the governor and will be replaced to ensure continued reliable operation.

2.2 Unit No. 4 - G4

The governor for G4 was installed in 1984 and is currently 25 years old. G4 governor consists of two sections, a Voist-Alpine electronic control unit and high pressure pumping unit (“HPU”).

The governor control unit is unable to effectively control unit speed. In addition, the supply of spare parts has been exhausted.[2] The unavailability of replacement parts from the original manufacturer has necessitated some governor control functionality being transferred to a programmable logic controller (“PLC”). This has resulted in control limitations with the governor system. The electronic controls for the governor will be replaced with a PLC governor controller and interfaced to the existing HPU.

The HPU, which supplies high pressure oil to the main valve and gate actuator, is in good condition and will not be replaced. The hydraulic control valves on the HPU are not functioning properly. In addition they are not compatible with the new controls that will be implemented for the governor. They will be replaced with valves compatible with the new governor controls.

The new governor control makes possible the implementation of a water management algorithm in the plant control system to optimize energy production from the water available.

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1 A hydraulic impulse brake system using a water jet directed towards a pelton wheel to retard the generator rotation. The name was given to this governing system by Gilbert Gilkes & Gordon Ltd. This is one of three such systems that are in use at Newfoundland Power.

2 A flood in 1992 damaged the electronics resulting in the installation of some spare components that were included with the initial purchase of the equipment. The remaining spares have been used to address in service failures since 1992.

3.0 Generators

The generator windings are original to both units. There is no evidence that the windings require any upgrading at this time. Temperature signals from the existing resistance temperature detectors (RTDs) installed in the stator windings will be monitored by the new control system.

The neutral points on both generators are solidly bonded to ground. This method of grounding does not provide optimum protection of the generator windings as it permits large currents to flow through the generator windings under fault conditions. To minimize the magnitude of fault currents, a high impedance grounding system will be installed to connect the generator neutral to ground. Neutral grounding transformers with secondary resistors will be installed to provide this protection.

To monitor the insulation integrity of the generator windings a MegAlert® continuous stator insulation testing system[3] will be installed. The original lighting arresters and surge capacitors on both units will be replaced to provide protection for the generator windings from electric surges.

The installation of new switchgear will necessitate the reconfiguration of power cables to both generators. This reconfiguration requires replacement of the cables and terminations from the switchgear to the generator and substation.

4.0 Voltage Regulators

4.1 Unit No. 3 - G3

G3 has a Brown Boveri voltage regulator (Figure 1) with a mechanical operating mechanism. The mechanical operating mechanism is worn from 50 years of operation affecting responsiveness of the regulator. The voltage regulator is manufacturer discontinued and cannot be integrated into the upgraded control system. The existing voltage regulator will become redundant[4] with the installation of a modern PLC providing plant control.

Figure 1 - BB Voltage Regulator

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3 The MegAlert® continuous stator insulation testing system has been installed at other Newfoundland Power hydroelectric plants. This provides protection from inadvertent starting of generators contaminated with moisture.

4 The ControlLogix PLC incorporates the digital voltage regulator functionality into the Combination Generator Control Module ("CGCM"). The CGCM is specifically designed to monitor and control a three phase alternating current generator through PLC logic.

4.2 Unit No. 4 - G4

Unit G4 has a Basler MVC108 solid state voltage regulator original to the unit which is manufacturer discontinued. Similar to the voltage regulator on unit G3, integration of this device into the upgraded plant control system is not possible. This voltage regulator will also be replaced with a digital voltage regulator incorporated in the plant control PLC.

5.0 Switchgear

The existing switchgear is a combination of the original G3 switchgear that was installed in 1958 and the switchgear installed as part of the installation of G4 in 1984. When the G4 switchgear was installed field modifications were made to the bus to connect the different switchgear cabinets. Protective devices and control switches for each unit are presently mounted in the front door of the switchgear cabinet.

The G3 generator breaker cannot be removed from the switchgear to provide electrical isolation from the generator when performing maintenance. This introduces an arc flash hazard for employees operating and performing maintenance on the equipment. The G4 generator breaker is original to the 1984 installation and spare parts for maintaining this breaker are not available.[5] The replacement of the switchgear will address the arc flash hazard and maintenance issues.

The replacement switchgear will be arc flash rated with breakers that require minimum maintenance. The new switchgear design will permit isolation of one breaker while the other generator remains online. Higher accuracy instrument transformers for improved protection and metering will be supplied with the switchgear. The potential transformers will have a disconnect mechanism to permit isolation for improved employee safety during maintenance. The control switches and associated wiring will be relocated to a new unit control panel remote from the switchgear and outside the arc flash zone of influence, improving employee safety.

There is currently no emergency station service transformer to supply essential plant services while placing a generator online during a system outage. To provide this capability an emergency station service transformer and transfer switch will be included in the new switchgear.

6.0 AC Distribution

The AC service is comprised of the main service entrance panel and subpanels located throughout the Plant. Some panels are original while others have been installed during various plant modifications. The capacity of the existing AC electrical service is not sufficient to supply the amount of heat required to avoid condensation[6] and prevent freezing of cooling water piping. A new service entrance with two AC distribution panels will provide increased capacity and consolidate all AC circuits. An automatic transfer switch will be installed in conjunction with an

[5] The G4 generator breaker is similar to the breaker that failed in service at Rocky Pond Hydro Plant in 2005 which resulted in extensive fire damage to the plant.

[6] High humidity levels appear to be a contributing factor to the corrosion experienced on some electrical equipment.

emergency station service transformer to supply AC power to critical plant loads from either generator during a system outage.

7.0 DC Distribution

The existing 12 circuit DC distribution panel is original to the plant construction in 1958 and does not have enough capacity to accommodate the existing protection and control equipment. As a result control circuits for different functions have been paralleled on the same circuit breaker. Thus, when one piece of equipment requires maintenance several pieces of equipment have to be taken out of service to complete the maintenance work. A new 60-circuit panel will be installed to provide adequate capacity, improved circuit isolation and ensure the availability of replacement circuit breakers.

8.0 Battery Bank

The C&D Technologies lead-antimony battery bank was installed in 1996. This type of battery bank produces hydrogen gas during charging and is currently located in the main generator hall. The generator hall is not properly ventilated to dispose of hydrogen gas that is produced when the batteries are charging. To eliminate the requirement to construct a separate battery room the battery bank will be replaced with gel cell technology.

9.0 Main and By-Pass Valves

9.1 Unit No. 3 - G3

Both the main valve and actuator for G3 were replaced in 1998 and are in good condition. The electrical contactors in the valve control cabinet are worn and will be replaced

9.2 Unit No. 4 - G4

Both the main valve and actuator for G4 are original to the 1984 installation and are in good condition. The bypass valve leaks and will be replaced. The flexible high pressure hydraulic hoses that run from the pumping unit to the hydraulic cylinder are deteriorated and will be replaced.

10.0 Protective Relaying

Protective relaying systems provide protection for equipment and personnel during abnormal loading and fault conditions. Protective relaying elements are critical to protecting generators and other electrical equipment against hazardous conditions that occur on the power system. The evaluation of the protective relays considers age of the relay, its reliability and the extent to which the protection provided meets current protection standards.

The following protective relaying elements are currently in service at Lookout Brook Plant:

40	Loss of Field
49	Thermal Protection
50/51N	Overcurrent
51V	Backup Protection – Voltage Controlled Overcurrent
59	Overvoltage
64	Voltage Relay for Rotor Ground Fault
87	Differential

The existing protective relays at Lookout Brook plant lack seven elements[7] of the minimum protection set. In addition to not meeting the minimum recommended protection level, the existing electromechanical relays are no longer satisfactory and are corroded.

The existing generator protective relays will be replaced with modern digital relays to provide the minimum protection set. Improved generator protection reduces stresses due to electrical faults and in turn extends the life of the generator.

In addition to the enhanced generator protection, bus differential and arc flash protection will be added with the new switchgear to provide improved equipment protection and reduce the arc flash hazard to employees working in the vicinity of the switchgear.

11.0 Plant Control

Currently, the generators at the Plant are controlled through various electromagnetic relays and switches which were installed in 1958. This equipment controls the generator exciters, the main unit valves, and the generators' mechanical protection. It shows signs of corrosion and deterioration.

An existing PLC installed in 1994 is an Allan-Bradley SLC 5/03 which is interfaced to G4. It was initially installed to control unit speed as a result of the problems experienced with the original governor controls. However, since that time annunciation of some unit alarms have been moved to the PLC due to the failure of the original alarm annunciation equipment. This PLC is at its capacity limitations and is not capable of more fully controlling the generators.

Plant control will provided by an Allan-Bradley ControlLogix PLC. The new PLC will provide automated local and remote control of both generators and plant functions. Modern industrial human-machine interfaces will be installed in the unit control panels to provide improved alarm annunciation and control functionality.

Although the Plant is remotely controlled and monitored from SCADA, remote control functions are limited to basic unit start and stop capability. At present, there is no automation with respect to water management and the setting of machine loads to optimize the use of the available water.

[7] The existing generator protection does not include Volts/Hz 24, Reverse Power 32, Stator Unbalance 46, Voltage Balance 60, Loss of Synchronization 78, Frequency 81 and sensitive Ground Fault 87GN elements which are recommended by the IEEE for these generators.

The new plant control PLC will greatly improve the local and remote monitoring and control functionality. It will facilitate the implementation of a variety of control modes to ensure the efficient operation of the plant and efficient utilization of available water resources.

A new gateway data concentrator will be installed to enhance the communications to the SCADA system and facilitate remote administration[8] of the PLC and protection relays provided with the controls upgrade.

Control switches, protection relays and associated wiring will be removed from the switchgear. These devices will need to be relocated to separate protection and control panels which will be located outside the switchgear arc flash zone of influence. This will minimize the arc flash hazard to employees in the plant during switching operations.

12.0 Synchronizing

The existing Basler Electric PRS170 synchronizer[9] will be taken out of service and kept as a spare for other in-service units.[10] A synchrocheck relay will be installed to supervise both automatic and manual synchronizing.

13.0 Instrumentation

The existing instrumentation is original to the generator installations in 1958 and 1984. The instrumentation is worn from many years of service and the interface cables are frayed.

Upgrading the plant control to PLC technology provides the ability to continuously monitor various mechanical subsystems. The operating condition of the bearings, cooling water, windings and other mechanical equipment can be recorded and trends identified before any damage occurs. To provide this capability the existing instrumentation devices must be replaced with modern devices that provide a scaled analog quantity in addition to a trip contact.

The following instrumentation will be added or replaced on each unit:

- Cooling water temperature sensing
- Cooling water solenoids
- Cooling water flow meters
- Brushgear infrared detection
- Bearing thermocouples
- Bearing oil level
- Governor oil level
- Governor oil pressure
- Governor oil temperature

8 Remote administration of intelligent devices will reduce the need to travel to site to diagnose events that happen through the normal course of operation.

9 A synchronizer monitors the power system and the generator coming on line to ensure that unit speed and voltage are within acceptable limits before breaker closure is permitted.

10 The synchronizer is redundant with a modern ControlLogix PLC equipped with a CGCM module.

- Scroll case pressure
- Speed sensing tooth gear

14.0 Heating and Ventilation

There are infrared heaters installed over each generator with both blower type and convection heat in the valve and generator pits. There are three exhaust fans (Figure 2) located in the building. The outside louvers have no operating mechanism, making it difficult to control plant heating and ventilation.

The amount of installed plant heat is inadequate due to the size of the electrical service and distribution panels.

The heating and ventilation controls will be consolidated into a common heating control panel and integrated with the plant control PLC. Additional heat will be installed to prevent condensation on the generators and freezing of the cooling water pipes in the winter when the units are not operating. Louvers will be replaced and controls added to better manage plant heating and cooling cycles.

15.0 Cooling Water

The existing cooling water system is antiquated with deteriorated piping to the individual bearings requiring replacement.

A header system will be installed on both units to ensure adequate flows to the individual bearings are maintained. This header arrangement will permit the installation of monitoring and control devices for the cooling water system that will be integrated with the plant control PLC.

16.0 Forebay Water Level Monitoring and Control

The existing water level signal from the forebay is transmitted to the plant on a communications cable with copper wire conductors. The existing forebay communications cable has been damaged resulting in the loss of signal quality. The current damage makes the forebay cable susceptible to further damage from water ingress, lightning strikes and ground potential rise.

The existing water level probe is corroded and requires replacement.

The forebay water level system is critical to the implementation of the Water Management System in the plant control PLC. The plant control PLC will use the water level signals to control the Water Management System. High level and low level alarms will also be initiated when specified water levels are reached. The Water Management System will optimize the efficiency of the plant by controlling the load on the unit based upon water level, inflow, wicket gate position and control mode set points.

The communications cable will be upgraded to a fibre optic cable between the plant and the forebay to ensure reliability of the water level signal.

17.0 Control Room Extension

The existing powerhouse does not have adequate space to install the new switchgear and control panels while maintaining a lay down area to perform maintenance on generator G4 turbine and valve. In addition, the installation of protection and control panels in any of the existing floor space would prevent removal of major components of the G4 generator from the building.

A 26 m^2 extension to the powerhouse will be required to provide the additional space required for this equipment.

18.0 Project Cost

The total project cost is estimated at $2,342,000. Table 1 below provides the cost breakdown by major components.

Table 1
Lookout Brook Hydro Plant Refurbishment
Estimated Cost

Civil	
Control Room Extension	$ 166,900
Mechanical	
Cooling Water and Governor Upgrade	$ 27,900
Electrical	
Engineering (All disciplines) & Supervision	$ 243,000
Generator Upgrades	$ 59,400
Governor Upgrades	$ 210,200
Plant Control	$ 530,100
Protective Relaying & Communications	$ 91,100
Instrumentation	$ 81,000
AC & DC Systems	$ 110,100
Commissioning	$ 112,400
Heating and Ventilation	$ 19,100
Switchgear	$ 417,300
Forebay Cable	$ 86,500
Plant Subtotal	**$ 2,155,000**
Substation	$ 187,000
Total Project Cost	**$ 2,342,000**

19.0 Recommendations

The following major systems are recommended to be replaced or modified during the 2010 refurbishment project:

1. Upgrade the governor control;
2. Install high impedance grounding system on both generators;
3. Replace voltage regulators on both generators;
4. Replace the switchgear and generator power cables;
5. Replace the AC and DC distribution panel;
6. Replace the battery bank;
7. Upgrade protective relays for both generators and switchgear;
8. Replace the existing programmable logic controller;
9. Upgrade and or replace instrumentation on both units;
10. Upgrade the heating and ventilation equipment and controls;
11. Upgrade the cooling water system;
12. Replace forebay communication cable;
13. Install a new water management system; and
14. Build an extension on the plant.

20.0 Economic Feasibility

Appendix A provides an economic feasibility analysis for the continued operation of Lookout Brook hydroelectric development. The results of the analysis show that the continued operation of Lookout Brook hydroelectric development is economical over the long term. Investing in the life extension of Lookout Brook ensures the continued availability of 30.1 GWh of annual energy to the Island interconnected system.

The estimated levelized cost of energy from the Lookout Brook over the next 50 years associated with future capital and operating expenditures as outlined in Appendix A is 2.68 ¢/kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation[11].

[11] The cost of electricity from the Holyrood thermal generating plant is estimated at 12.06 ¢/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil forecast from Hydro of $75.95/barrel dated March 31, 2009.

Appendix A
Feasibility Analysis

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1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Lookout Brook hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2010.

With investment required in 2010 to permit the continued reliable operation of the 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 Plant over the next 25 years have been identified. The capital expenditures required to maintain the safe and reliable operation of the facilities are summarized in Table 1.

Table 1
Lookout Brook
Hydroelectric Plant
Capital Expenditures

Year	**(000s)**
2010	$2,342
2015	1,400
2018	760
2019	100
2020	750
2021	400
2025	5,033
2030	52
2034	1,165
2035	540
Total	**$12,542**

The total capital expenditure for the Plant until 2035 is $12,542,000 in 2010 dollars. A more comprehensive breakdown of capital costs is provided in Attachment A.

3.0 Operating Costs

Operating costs for the Plant are estimated to be approximately $118,052[1] per year. This estimate is based primarily upon recent historical operating experience. The operating cost represents both direct charges for operations and maintenance at the 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.

4.0 Benefits

The maximum output from the Plant is 5.9 MW. The Plant normally operates at an efficient load of 5.3 MW to maximize the energy from the water.

The estimated long-term normal production at the Plant under present operating conditions is 30.1 GWh per year. This estimate is based on the results of the Water Management Study completed by SGE Acres in 2005.

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 Plant over the next 50 years is 2.68 ¢/kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Lookout Brook can be produced at a significantly lower price than the cost of electricity currently supplied from Newfoundland and Labrador Hydro's Holyrood thermal generating station at 12.06 ¢/kWh[2].

The future capacity benefits of the continued availability of the 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 Plant is economically viable. Investing in the current upgrades of the facilities at Lookout Brook ensures the availability of low cost energy to the Province. Otherwise, the annual production of 30.1 GWh would be replaced by more expensive energy sources from the Holyrood thermal generating station. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

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1 2009 dollars

2 Based on 630 kWh/barrel conversion efficiency of Holyrood and oil forecast from Hydro of $75.95/barrel dated March 19, 2009

Attachment A
Summary of Capital Costs

Lookout Brook Feasibility Analysis
Summary of Capital Costs
($000s)

Description	2010	2015	2018	2019	2020	2021	2025	2030	2034	2035
Civil										
Dam, Spillways and Control Structures		1,400			750					
Penstock							5,000			
Powerhouse	202		100						50	
Plant Access				100						
Mechanical										
Mechanical Refurbishment									515	
Turbine Upgrades										
Governor			55							
Upgrades	256									
Electrical										
Controls Upgrade	1,064						33	52		540
Generator Rewind			565						570	
Exciter			40						30	
Switchgear	520									
Forebay Cable	90									
Substation	210					400				
Annual Totals	**2,342**	**1,400**	**760**	**100**	**750**	**400**	**5,033**	**52**	**1,165**	**540**

Attachment B
Summary of Operating Costs

Lookout Brook Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs

Year	**Amount**
2004	$180,347
2005	134,639
2006	82,942
2007	86,523
2008	105,808
Average	**$118,052**

5 -Year Average Operating Cost	$118,052[1]
Total Forecast Annual Operating Cost	$118,052

[1] 2009 dollars

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital 8.58%
PW Year 2009

Year	Generation Hydro 64.4yrs 8% CCA	Substation 46.2 yrs 8% CCA	Building 53.6 yrs 4% CCA	Capital Revenue Rqmt	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2010	1,988,000	187,000	167,000	244,609	118,052	0	-362,661	-334,004	-334,004	1.20	2.68
2011	0	0	0	235,111	120,185	0	-355,296	-301,363	-635,367	1.18	2.68
2012	0	0	0	236,402	122,290	0	-358,692	-280,203	-915,570	1.19	2.68
2013	0	0	0	236,790	124,731	0	-361,521	-260,096	-1,175,666	1.20	2.68
2014	0	0	0	236,772	127,153	0	-363,925	-241,136	-1,416,802	1.21	2.68
2015	1,533,746	0	0	395,064	129,330	0	-524,394	-320,006	-1,736,809	1.74	2.68
2016	0	0	0	386,911	131,608	0	-518,519	-291,418	-2,028,226	1.72	2.68
2017	0	0	0	387,126	133,888	0	-521,013	-269,681	-2,297,907	1.73	2.68
2018	876,933	0	0	477,022	136,215	0	-613,238	-292,335	-2,590,242	2.04	2.68
2019	117,447	0	0	483,549	138,648	0	-622,198	-273,168	-2,863,410	2.07	2.68
2020	896,852	0	0	574,604	141,167	0	-715,771	-289,418	-3,152,828	2.38	2.68
2021	487,278	0	0	618,712	143,810	0	-762,523	-283,958	-3,436,786	2.53	2.68
2022	0	0	0	614,478	146,415	0	-760,894	-260,961	-3,697,748	2.53	2.68
2023	0	0	0	611,996	149,116	0	-761,112	-240,409	-3,938,157	2.53	2.68
2024	0	0	0	608,587	151,929	0	-760,516	-221,239	-4,159,395	2.53	2.68
2025	6,599,120	0	0	1,287,207	154,786	0	-1,441,993	-386,337	-4,545,732	4.79	2.68
2026	0	0	0	1,250,495	157,566	0	-1,408,061	-347,435	-4,893,167	4.68	2.68
2027	0	0	0	1,250,537	160,423	0	-1,410,961	-320,640	-5,213,807	4.69	2.68
2028	0	0	0	1,246,768	163,292	0	-1,410,060	-295,115	-5,508,922	4.68	2.68
2029	0	0	0	1,241,263	166,268	0	-1,407,531	-271,307	-5,780,229	4.68	2.68
2030	74,588	0	0	1,241,877	169,332	0	-1,411,209	-250,521	-6,030,750	4.69	2.68
2031	0	0	0	1,232,944	172,380	0	-1,405,323	-229,763	-6,260,513	4.67	2.68
2032	0	0	0	1,223,080	175,482	0	-1,398,562	-210,589	-6,471,102	4.65	2.68
2033	0	0	0	1,211,936	178,641	0	-1,390,577	-192,841	-6,663,943	4.62	2.68
2034	1,794,658	0	0	1,385,310	181,857	0	-1,567,167	-200,156	-6,864,099	5.21	2.68
2035	846,832	0	0	1,450,875	185,130	0	-1,636,005	-192,437	-7,056,536	5.44	2.68
2036	0	0	0	1,433,912	225,053	0	-1,658,965	-179,718	-7,236,254	5.51	2.68
2037	0	0	0	1,419,958	229,104	0	-1,649,061	-164,529	-7,400,783	5.48	2.68
2038	0	0	0	1,404,425	233,227	0	-1,637,652	-150,479	-7,551,262	5.44	2.68
2039	0	0	0	1,387,667	237,426	0	-1,625,092	-137,525	-7,688,787	5.40	2.68
2040	73,724	0	0	1,377,409	241,699	0	-1,619,108	-126,192	-7,814,979	5.38	2.68
2041	0	0	0	1,358,130	246,050	0	-1,604,180	-115,148	-7,930,128	5.33	2.68
2042	0	0	0	1,338,314	250,479	0	-1,588,793	-105,032	-8,035,160	5.28	2.68
2043	0	0	0	1,317,584	254,987	0	-1,572,571	-95,745	-8,130,905	5.22	2.68
2044	0	0	0	1,296,033	259,577	0	-1,555,610	-87,228	-8,218,133	5.17	2.68
2045	0	0	0	1,273,726	264,249	0	-1,537,975	-79,425	-8,297,558	5.11	2.68
2046	0	0	0	1,250,723	269,006	0	-1,519,729	-72,281	-8,369,838	5.05	2.68
2047	0	0	0	1,227,081	273,848	0	-1,500,929	-65,746	-8,435,584	4.99	2.68
2048	0	0	0	1,202,851	278,777	0	-1,481,628	-59,772	-8,495,355	4.92	2.68
2049	1,610,506	0	0	1,344,703	283,795	0	-1,628,498	-60,505	-8,555,861	5.41	2.68
2050	12,915,124	0	0	2,647,854	288,904	0	-2,936,758	-100,490	-8,656,351	9.76	2.68
2051	0	0	0	2,560,990	294,104	0	-2,855,094	-89,976	-8,746,327	9.49	2.68
2052	0	0	0	2,546,041	299,398	0	-2,845,438	-82,586	-8,828,913	9.45	2.68
2053	0	0	0	2,524,046	304,787	0	-2,828,833	-75,616	-8,904,529	9.40	2.68
2054	0	0	0	2,499,035	310,273	0	-2,809,308	-69,160	-8,973,690	9.33	2.68
2055	73,939	0	0	2,478,899	315,858	0	-2,794,757	-63,365	-9,037,055	9.28	2.68
2056	0	0	0	2,442,619	321,543	0	-2,764,162	-57,719	-9,094,774	9.18	2.68
2057	0	0	0	2,411,792	327,331	0	-2,739,123	-52,677	-9,147,451	9.10	2.68
2058	0	0	0	2,377,430	333,223	0	-2,710,654	-48,010	-9,195,461	9.01	2.68
2059	0	0	0	2,341,068	339,221	0	-2,680,289	-43,721	-9,239,182	8.90	2.68
2060	1,322,793	0	0	2,439,722	345,327	0	-2,785,049	-41,840	-9,281,022	9.25	2.68

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 32%.

Operating Costs: Operating costs were assumed to be in 2009 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	6.60%	3.63%
Common Equity	45.00%	11.0%	4.95%
Total	**100.00%**		**8.58%**

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.

Escalation Factors: Conference Board of Canada GDP deflator, January 29, 2009.

Petty Harbour Surge Tank Refurbishment and Unit No. 1 Main Valve Replacement

June 2009

Prepared by:

Trina Cormier, P.Eng.

Shaun Marshall, P.Eng.

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NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

Newfoundland Power's Petty Harbour plant is located on the east coast of the Avalon Peninsula. The powerhouse is situated in the community of Petty Harbour Maddox Cove. The original development was constructed in 1900 and various changes and upgrades to the system have been implemented since that time.

There are three horizontal Francis turbines and generators in the plant. The first unit was commissioned in 1900 and the other units were commissioned in 1908 and 1926. The total installed capacity of the three units is about 5,300 kW under a net head of 57.9 metres. The normal annual production at Petty Harbour plant is approximately 15.87 GWH per year.

Newfoundland Power has determined that the surge tank requires refurbishment (See Appendix A for pictures of the surge tank) and the main valve for Unit No. 1 requires replacement.

This project is necessary at this time due to the physical condition of the plant assets. The surge tank is in poor condition and requires refurbishment. It is approximately 83 years old. The main valve requires replacement and is 99 years old.

Results of the feasibility analysis conclude that the continued operation of Petty Harbour plant, including the refurbishment of the surge tank and replacement of the main valve, 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

Since 1900, there have been various upgrades to the original plant and equipment. The major upgrades that have occurred in the past 25 years are:

- In 1984 Unit No. 2 turbine and generator were replaced and Unit No.3 turbine was upgraded;
- In 1992 dam improvements were made to Second Pond Dam (Forebay);
- In 1996, Cochrane Pond Spillway was rebuilt and various upgrades were made to Bay Bulls Big Pond Dam;
- In 1999, the lower section of woodstave penstock was replaced with a new steel penstock;
- In 2006, the plant AC and DC systems were upgraded, the unit control programmable logic controllers ("PLC") were replaced on Unit No.2 and Unit No. 3 and the voltage regulator replaced on Unit No.1. The generator protection and controls were upgraded and the governor controls replaced on Unit No.2 and Unit No.3.

3.0 Surge Tank

The surge tank at Petty Harbour is in fair to poor condition and requires extensive refurbishment to extend the life of the structure.

The surge tank consists of two main parts:

- 12.2 metres high, 5 metre internal diameter, surge tank with a rounded dish bottom, treated wooden frost casing and a conical wood roof. The tank bottom rests on a poured concrete foundation over exposed bedrock.
- 88 metres high, 2.3 metre internal diameter, riser pipe which is supported by concrete cradles.

An inspection of the surge tank and riser was completed by Hatch[1] on April 22 and 23, 2009. The report is included in Appendix B. The inspection has determined that significant rehabilitation of the surge tank and the riser is required.

Issues that will be addressed as part of the refurbishment plan include:

- Refurbish the interior of the surge tank and riser;
- Refurbish the exterior of the external riser;
- Install a new metal cladding system;
- Upgrade lap joints, floor lap joints, and the riser inlet connections;
- Replace the ladder on the interior of the tank;
- Replace the ladder on the exterior of the tank;
- Install a new fall arrest system; and
- Refurbish the existing concrete foundation.

Upgrades to the surge tank will extend the life of the structure and avoid costly replacement of the entire structure in the near future.

4.0 Unit No. 1 Main Inlet Valve

The main inlet valve at Petty Harbour is a 48 inch diameter water actuated butterfly valve which was manufactured by Voith in 1910. An internal inspection of the main valve was not possible due to the amount of leakage around the valve disc. When the unit is shutdown there is a constant flow of high pressure water around the valve disc indicating that the disc is not seating properly. This leakage prevents our employees from obtaining safe access to the scroll case and necessitates dewatering of the penstock each time work is required on the turbine. This situation limits the Company's ability to maintain and service other equipment in the plant.

Typically the main valve arrangement would include a bypass valve. However, the main valve arrangement on Unit No. 1 at Petty Harbour does not include a bypass valve. The primary function of the bypass valve is to direct water past the main valve prior to opening thereby equalizing the pressure on both sides of the main valve to reduce the strain associated with

[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.

opening the valve disc. 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 through the valve.

Also the existing arrangement does not incorporate a dismantling joint. A dismantling joint allows for easy installation and removal of the valve for maintenance purposes.

Based upon its condition and age the main valve and associated equipment will be replaced. In addition, a bypass valve and dismantling joint will be incorporated into the redesign of the main valve arrangement.

The existing butterfly valve is water actuated. This arrangement will be decommissioned and the valve actuator replaced with a 125V DC electric actuator.

5.0 Project Execution

The refurbishment of the surge tank and the replacement of the main inlet valve for Unit No.1 are necessary in 2010. The surge tank requires extensive refurbishment to extend the life of the structure and the main valve requires replacement due to its condition and age and to ensure safe and reliable plant operation.

It is estimated that the plant will be out of service for 12 weeks from June to August 2010. Due to the long lead times required to manufacture custom designed valves such as the main valve on Unit No. 1, the process to order the main valve will commence in late 2009, including engineering work in preparation of the tenders.

6.0 Project Cost

The total project cost for the surge tank refurbishment and the main valve replacement is estimated at $632,000.

7.0 Feasibility Analysis

Appendix C provides a feasibility analysis for the continued operation of the Petty Harbour 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 Petty Harbour hydroelectric development ensures the continued availability of 15.87 GWh of energy annually to the Island Interconnected System.

The estimated levelized cost of energy from Petty Harbour over the next 25 years, including the proposed capital expenditures, is 2.37¢ per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation.[2]

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[2] The cost of electricity from the Holyrood thermal generating station is estimated at 12.06¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil forecast from Hydro of $75.95 per barrel dated March 31, 2009.

Appendix A

Pictures of Petty Harbour Surge Tank

Picture 1

Petty Harbour Surge Tank and Riser
(Note corrosion on exterior of riser)

Picture 2

Leak between the tank shell
and riser connection

Picture 3

Erosion and surface spalling
of the surge tank concrete foundation

Appendix B

Petty Harbour Surge Tank and Riser Inspection

Suite E200, Bally Rou Place, 280 Torbay Rd.
St. John's, Newfoundland, Canada A1A 3W8
Tel. (709) 754 6933 • Fax: (709) 754 2717 • www.hatch.ca

June 1, 2009

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

Dear Ms. Cormier:

Subject: Petty Harbour Surge Tank and Riser Inspection - April 2009

Purpose

Hatch was engaged by Newfoundland Power (NP) to undertake a condition assessment of the surge tank and riser at Petty Harbour Generating Station. The inspection was completed in two phases. Civil structural inspection of the concrete foundations was completed on April 22, 2009 by Mr. Walter Smith, P.Eng., of Hatch, and the inspection of the steel riser pipe and the interior of the surge tank was completed on April 23, 2009. The inspections carried out on April 23 were supervised by Mr. Gregory Saunders, P.Eng., of Hatch and completed by two rope access technicians supplied by Remote Access Technology (RAT) and a UT technician from Acuren.

Introduction

The riser pipe was reconstructed in 1953 along the same route of the previous riveted steel pipe penstock. The pipe is about 2.29 m (90 inches) in diameter welded steel pipe and 88.4 m (290 feet) long and is supported on reinforced concrete saddles founded on bedrock. It traverses a steep slope down to the powerhouse where it connects to a steel pipe manifold distributor to split flows to each of the three turbine generator units. A reducer and 90 degree triple mitered section is located at the riser/surge tank interface and an increaser is located at the powerhouse manifold distributor. The riser steel is noted to be ASTM A283 Grade C plate.

Significant elevations along the riser, based on local datum are as follows:

- Lowest point of 9.5 mm (3/8") section is 38.1 m (125 feet).
- Lowest point of 8 mm (5/16") section 48.46 m (159 feet).
- Bottom of surge tank 84.42 m (277 feet).

The surge tank is the original riveted steel tank which was installed about 1926 and is supported on a reinforced concrete slab founded on bedrock. The tank is 12.19 metres (40 feet) in height and 5 metre

(16.5 feet) in diameter. The tank is enclosed by a wooden hoarding structure (frost casing). The roof of the tank is of wooden construction with steel supports.

There was one steel hold down anchor near the tank bottom on the east side and one high level tie back on the northwest side.

A copy of a report titled "Inspection-Petty Harbour Surge Tank and Riser" by Varcon Inc. and carried out in January 1999 was supplied to Newfoundland Power for information purposes.

Condition Assessment

Civil

Several of the concrete riser saddle supports were constructed on original penstock concrete saddles. Some saddles were newly (1953 vintage) constructed between the existing ones and some of the original saddles were abandoned in place and not re-used.

The course rock material around and under the riser pipe is contacting the pipe itself in some cases. This presents two problems: one being the physical loads and potential damage from sliding and movement of the rocks and the second being the reduction of ventilation which increases the progress of corrosion.

The rockfill is prone to moving down the slope under the influence of normal runoff and spill discharges overflowing the surge tanks, and as well from the associated forces of ice jacking and snow melt during winter.

The wooden enclosure around the surge tank is exhibiting some defects such as opening up at the corners, leaching out of the creosote treatment and some rotting and general decay.

The surge tank concrete foundation is suffering some erosion and surface spalling and there is water flowing at the concrete/foundation interface which is likely discharging from the bottom of the tank. This flow would tend to create continuing damage to the foundation from ice jacking.

Steel Structures

Thickness readings of the shell of the surge tank and the riser pipe were taken for each accessible shell course and riser section. The section of shell between the underside of the riser inlet and the surge tank floor was inaccessible as the water could not be drained from this area.

The upper-most courses of the tank shell were not corroded as the coating system was in good condition. The lower sections of the tank were heavily pitted with little of the coating system remaining. On the exterior there is evidence of a small leak around the connection between the tank shell and the riser connection.

The interior ladder has been damaged and the exterior ladder is in poor condition and does not have a fall arrest system.

The steel truss that supports the wooden roof is in good condition but shows signs of surface corrosion.

The exterior of the surge tank is covered by a wooden frost casing which prevents any inspection of the exterior shell.

The exterior of the riser pipe is in good condition with some pitting corrosion occurring where the coating system has failed.

A review of the thickness readings is presented in Appendix A and a copy of the reports supplied by Acuran area included in Appendix B.

Thickness measurements taken on the surge tank shell and the riser were compared with the readings taken in 1999. Differences were noted between the two reports which called into question the calibration of the equipment during the recent inspection. To verify the equipment calibration, Acuren made a second visit to site on May 13, 2009 and checked the shell thickness of the surge tank at the upper shell course. The readings were found to be the same as those recorded during the April 23 inspection, thus are considered satisfactory. A copy of these thickness readings is included.

Conclusions and Recommendations

In our opinion, the existing surge tank and riser do not require replacement, provided steps are taken to coat the interior surface of the surge tank and exterior surface of the riser to prevent further corrosion. The following is a list of recommendations required to upgrade and maintain the surge tanks.

Civil

1. Continue regular maintenance to repair minor concrete damage and promote good drainage to slow deterioration, particularly at the surge tank foundation.
2. Remove rock fill which encroaches on the riser pipe to reduce susceptibility to corrosion.

Steel Structures

1. Inspect the bottom section of shell and the floor of the surge tank.
2. In an attempt to stop the existing leaking, weld the riveted lap joints of the first meter of the bottom shell course, the floor lap joints, the riser inlet connection and seal weld around the rivet heads in these areas.
3. Remove the interior ladder and, if required for maintenance, replace it with rungs welded to the shell.
4. Replace the exterior ladder and cage and install a fall arrest system.
5. Inspect the exterior of the shell where it bears on the concrete by opening some windows in the wooden cladding.
6. Repair existing wooden frost casing and install a metal cladding around the tank shell.
7. Grit blast and coat with an epoxy paint system the interior surface of the surge tank and riser and the exterior surface of the riser. Note that some of the lower section of the riser is partially buried.

8. An effective means of preventing an ice cover forming over the surge tank's water surface is needed. We recommend you checking the effectiveness of the emersion heater system recently installed at the Rattling Brook surge tank. If this solution is working satisfactorily, then a similar system should be designed and installed in the Petty Harbour surge tank.

Yours faithfully,

Gregory D. Saunders, P.Eng.
Hatch St. John's, General Manager

GS:nl
Ref.: H332313-CO-CA01-10001.doc
Attachments: Appendix A
Appendix B
Appendix C

cc: W. Smith

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
PROFESSIONAL ENGINEERS AND GEOSCIENTISTS
GREG SAUNDERS
SIGNATURE
June 1/09
DATE
NEWFOUNDLAND & LABRADOR

PROVINCE OF NEWFOUNDLAND
PEG Newfoundland and Labrador
PERMIT HOLDER
CLASS "A"
This Permit Allows
HATCH LTD.
To practice Professional Engineering
in Newfoundland and Labrador
Permit No. as issued by PEG-NL N0130
which is valid for the year 2009

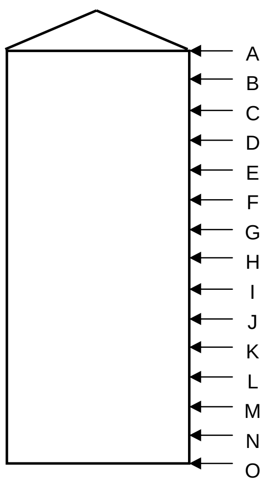
Appendix A

Review of Surge Tank and Riser Thickness Readings

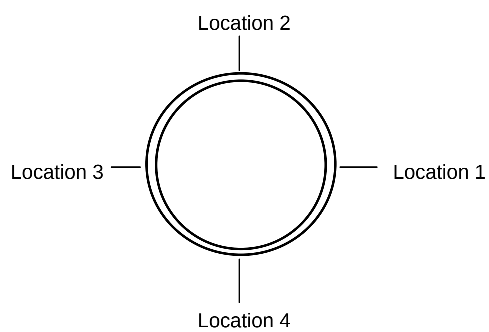
READING	LOCATION 1			LOCATION 2			LOCATION 3			LOCATION 4		
	mm	inches	% Loss	mm	inches	% Loss	mm	inches	% Loss	mm	inches	% Loss
A	8.6	0.339	8.3	8.1	0.319	2.0	8.3	0.327	4.6	8.1	0.319	2.0
B	8.4	0.331	5.8	8.1	0.319	2.0	8.9	0.350	12.1	8.9	0.350	12.1
C	8.3	0.327	4.6	9.0	0.354	13.4	8.5	0.335	7.1	8.6	0.339	8.3
D	9.1	0.358	14.6	8.3	0.327	4.6	8.3	0.327	4.6	8.4	0.331	5.8
E	8.7	0.343	9.6	8.6	0.339	8.3	7.9	0.311	-0.5	8.3	0.327	4.6
F	8.5	0.335	7.1	8.4	0.331	5.8	8.6	0.339	8.3	9.2	0.362	15.9
G	8.6	0.339	8.3	8.0	0.315	0.8	8.0	0.315	0.8	8.8	0.346	10.9
H	8.6	0.339	8.3	8.4	0.331	5.8	8.8	0.346	10.9	8.1	0.319	2.0
I	8.8	0.346	10.9	8.6	0.339	8.3	8.6	0.339	8.3	8.3	0.327	4.6
J	9.1	0.358	14.6	8.8	0.346	10.9	8.8	0.346	10.9	8.7	0.343	9.6
K	8.3	0.327	4.6	7.8	0.307	-1.7	9.1	0.358	14.6	8.1	0.319	2.0
L	8.7	0.343	9.6	8.8	0.346	10.9	9.0	0.354	13.4	8.6	0.339	8.3
M	8.2	0.323	3.3	8.3	0.327	4.6	9.2	0.362	15.9	8.5	0.335	7.1
N	9.0	0.354	13.4	8.7	0.343	9.6	8.7	0.343	9.6	7.9	0.311	-0.5
O	8.5	0.335	7.1	8.6	0.339	8.3	8.5	0.335	7.1	8.3	0.327	4.6

SHELL UT READINGS

Note: Original Plate thickness is 5/16" (0.3125"), 7.9375mm



ELEVATION



PLAN

AWWA D100 Standard Calculation for Wall Thickness (Eq 3-40)

$$t = \frac{2.6 h_p DG}{sE}$$

where:

- t = Required Design Shell-Plate Thickness (inches)
- h_p = Head to Bottom of Shell Course (feet) = 40'
- D = Nominal Tank Diameter (feet) = 16.5'
- G = Specific Gravity = 1.0 for Water
- s = Allowable Design Stress (psi) = 15,000psi
- E = Joint Efficiency = 0.85 (Chosen from Table 15 in AWWA D100 Standard)

t = 0.134588 inches

AWWA D100 Standard for Minimum Wall Thickness (Sec. 3.10)

t= 0.1875 inches

Additional Readings on the top of the tank shell, (May 13, 2009)

READING	LOCATION 1			LOCATION 2			LOCATION 3			LOCATION 4		
	mm	inches	% Loss	mm	inches	% Loss	mm	inches	% Loss	mm	inches	% Loss
A	7.9	0.311	-0.5	8.1	0.319	2.0	7.8	0.307	-1.7	8.2	0.323	3.3

ACUREN 2 Hunt's Lane, St. John's, Nfld. A1B 2L3 Tel: (709) 753-2100 / Fax: (709) 753-7011	TITLE **HATCH (332313)** **SHELL READINGS AND LOCATION**				
	DATE	SCALE	JOB No.	REV. NO.	DWG. NO.
	09.04.28 YY.MM.DD	N.T.S.	5385-11	A	SK4

Acuren UT Results - Petty Harbour Surge Tank Riser (H332313)

	Riser Information		Location A Original Information			Location A UT Results			Location B Original Information			Location B UT Results			Location C Original Information			Location C UT Results		
		UT Riser	Head	Required t	Min. t	Acuren			Head	Required t	Min. t	Acuren			Head	Required t	Min. t	Acuren		
	Course	Location	(Ft)	Cal. (inches)	Code (inches)	mm	inches	Loss %	(Ft)	Cal. (inches)	Code (inches)	mm	inches	Loss %	(Ft)	Cal. (inches)	Code (inches)	mm	inches	Loss %
Original Stated Pipe Wall Thickness - 5/16"	1	1	37.75	0.058	0.250	7.3	0.287	-8.0	34.00	0.052	0.250	6.8	0.268	-14.3	37.75	0.058	0.250	7.9	0.311	-0.5
		2	40.75	0.062	0.250	8.3	0.327	4.6	37.00	0.057	0.250	7.0	0.276	-11.8	40.75	0.062	0.250	6.9	0.272	-13.1
		3	43.75	0.067	0.250	7.5	0.295	-5.5	40.00	0.061	0.250	6.9	0.272	-13.1	43.75	0.067	0.250	6.8	0.268	-14.3
	2	4	43.75	0.067	0.250	7.5	0.295	-5.5	40.00	0.061	0.250	8.8	0.346	10.9	43.75	0.067	0.250	7.6	0.299	-4.3
		5	46.75	0.072	0.250	8.1	0.319	2.0	43.00	0.066	0.250	8.6	0.339	8.3	46.75	0.072	0.250	8.8	0.346	10.9
		6	49.65	0.076	0.250	7.1	0.280	-10.6	45.90	0.070	0.250	8.4	0.331	5.8	49.65	0.076	0.250	6.7	0.264	-15.6
	3	7	49.65	0.076	0.250	7.8	0.307	-1.7	45.90	0.070	0.250	8.0	0.315	0.8	49.65	0.076	0.250	8.6	0.339	8.3
		8	52.55	0.080	0.250	6.4	0.252	-19.4	48.80	0.075	0.250	6.9	0.272	-13.1	52.55	0.080	0.250	7.3	0.287	-8.0
		9	55.55	0.085	0.250	6.2	0.244	-21.9	51.80	0.079	0.250	5.7	0.224	-28.2	55.55	0.085	0.250	5.8	0.228	-26.9
	4	10	55.55	0.085	0.250	6.8	0.268	-14.3	51.80	0.079	0.250	6.9	0.272	-13.1	55.55	0.085	0.250	6.8	0.268	-14.3
		11	58.45	0.089	0.250	9.1	0.358	14.6	54.70	0.084	0.250	7.7	0.303	-3.0	58.45	0.089	0.250	7.9	0.311	-0.5
		12	61.45	0.094	0.250	6.0	0.236	-24.4	57.70	0.088	0.250	7.8	0.307	-1.7	61.45	0.094	0.250	6.5	0.256	-18.1
	5	13	61.45	0.094	0.250	8.9	0.350	12.1	57.70	0.088	0.250	6.1	0.240	-23.1	61.45	0.094	0.250	6.3	0.248	-20.6
		14	64.35	0.098	0.250	7.0	0.276	-11.8	60.60	0.093	0.250	7.6	0.299	-4.3	64.35	0.098	0.250	6.0	0.236	-24.4
		15	67.35	0.103	0.250	6.1	0.240	-23.1	63.60	0.097	0.250	5.8	0.228	-26.9	67.35	0.103	0.250	8.4	0.331	5.8
	6	16	67.35	0.103	0.250	7.7	0.303	-3.0	63.60	0.097	0.250	8.7	0.343	9.6	67.35	0.103	0.250	8.3	0.327	4.6
		17	70.25	0.107	0.250	7.7	0.303	-3.0	66.50	0.102	0.250	7.9	0.311	-0.5	70.25	0.107	0.250	8.7	0.343	9.6
		18	73.25	0.112	0.250	8.2	0.323	3.3	69.50	0.106	0.250	7.6	0.299	-4.3	73.25	0.112	0.250	7.1	0.280	-10.6
	7	19	73.25	0.112	0.250	7.8	0.307	-1.7	69.50	0.106	0.250	7.6	0.299	-4.3	73.25	0.112	0.250	7.3	0.287	-8.0
		20	76.15	0.116	0.250	7.4	0.291	-6.8	72.40	0.111	0.250	7.5	0.295	-5.5	76.15	0.116	0.250	7.5	0.295	-5.5
		21	79.15	0.121	0.250	7.0	0.276	-11.8	75.40	0.115	0.250	7.3	0.287	-8.0	79.15	0.121	0.250	6.3	0.248	-20.6
	8	22	79.15	0.121	0.250	6.6	0.260	-16.9	75.40	0.115	0.250	6.3	0.248	-20.6	79.15	0.121	0.250	6.8	0.268	-14.3
		23	82.05	0.125	0.250	6.3	0.248	-20.6	78.30	0.120	0.250	6.0	0.236	-24.4	82.05	0.125	0.250	6.8	0.268	-14.3
		24	85.05	0.130	0.250	6.5	0.256	-18.1	81.30	0.124	0.250	6.2	0.244	-21.9	85.05	0.130	0.250	6.5	0.256	-18.1
	9	25	85.05	0.130	0.250	6.9	0.272	-13.1	81.30	0.124	0.250	6.1	0.240	-23.1	85.05	0.130	0.250	6.2	0.244	-21.9
		26	87.95	0.135	0.250	7.1	0.280	-10.6	84.20	0.129	0.250	6.7	0.264	-15.6	87.95	0.135	0.250	6.3	0.248	-20.6
		27	90.95	0.139	0.250	6.0	0.236	-24.4	87.20	0.133	0.250	6.3	0.248	-20.6	90.95	0.139	0.250	6.4	0.252	-19.4
	10	28	90.95	0.139	0.250	6.7	0.264	-15.6	87.20	0.133	0.250	6.8	0.268	-14.3	90.95	0.139	0.250	6.3	0.248	-20.6
		29	93.85	0.144	0.250	6.6	0.260	-16.9	90.10	0.138	0.250	6.5	0.256	-18.1	93.85	0.144	0.250	7.2	0.283	-9.3
		30	96.85	0.148	0.250	7.7	0.303	-3.0	93.10	0.142	0.250	7.4	0.291	-6.8	96.85	0.148	0.250	6.7	0.264	-15.6
	11	31	96.85	0.148	0.250	7.3	0.287	-8.0	93.10	0.142	0.250	7.5	0.295	-5.5	96.85	0.148	0.250	7.1	0.280	-10.6
		32	99.85	0.153	0.250	6.5	0.256	-18.1	96.10	0.147	0.250	7.0	0.276	-11.8	99.85	0.153	0.250	7.2	0.283	-9.3
		33	102.75	0.157	0.250	6.5	0.256	-18.1	99.00	0.151	0.250	7.1	0.280	-10.6	102.75	0.157	0.250	6.8	0.268	-14.3
	12	34	102.75	0.157	0.250	6.4	0.252	-19.4	99.00	0.151	0.250	6.1	0.240	-23.1	102.75	0.157	0.250	7.1	0.280	-10.6
		35	105.65	0.162	0.250	7.6	0.299	-4.3	101.90	0.156	0.250	6.7	0.264	-15.6	105.65	0.162	0.250	6.3	0.248	-20.6
		36	108.65	0.166	0.250	6.0	0.236	-24.4	104.90	0.160	0.250	7.3	0.287	-8.0	108.65	0.166	0.250	7.8	0.307	-1.7
	13	37	108.65	0.166	0.250	6.2	0.244	-21.9	104.90	0.160	0.250	6.7	0.264	-15.6	108.65	0.166	0.250	7.4	0.291	-6.8
		38	111.55	0.171	0.250	7.0	0.276	-11.8	107.80	0.165	0.250	8.1	0.319	2.0	111.55	0.171	0.250	7.5	0.295	-5.5
		39	114.55	0.175	0.250	5.9	0.232	-25.7	110.80	0.169	0.250	7.1	0.280	-10.6	114.55	0.175	0.250	6.4	0.252	-19.4
	14	40	114.55	0.175	0.250	6.6	0.260	-16.9	110.80	0.169	0.250	7.4	0.291	-6.8	114.55	0.175	0.250	7.1	0.280	-10.6
		41	117.45	0.180	0.250	7.8	0.307	-1.7	113.70	0.174	0.250	7.9	0.311	-0.5	117.45	0.180	0.250	6.7	0.264	-15.6
		42	120.45	0.184	0.250	6.0	0.236	-24.4	116.70	0.178	0.250	6.7	0.264	-15.6	120.45	0.184	0.250	7.8	0.307	-1.7

	Riser Information		Location A Original Information			Location A UT Results			Location B Original Information			Location B UT Results			Location C Original Information			Location C UT Results		
		UT Riser	Head	Required t	Min. t	Acuren			Head	Required t	Min. t	Acuren			Head	Required t	Min. t	Acuren		
	Course	Location	(Ft)	Cal. (inches)	Code (inches)	mm	inches	Loss %	(Ft)	Cal. (inches)	Code (inches)	mm	inches	Loss %	(Ft)	Cal. (inches)	Code (inches)	mm	inches	Loss %
Original Stated Pipe Wall Thickness - 5/16"	15	43	120.45	0.184	0.250	8.1	0.319	2.0	116.70	0.178	0.250	7.4	0.291	-6.8	120.45	0.184	0.250	6.8	0.268	-14.3
		44	123.35	0.189	0.250	6.5	0.256	-18.1	119.60	0.183	0.250	7.8	0.307	-1.7	123.35	0.189	0.250	6.2	0.244	-21.9
		45	126.35	0.193	0.250	6.6	0.260	-16.9	122.60	0.188	0.250	6.5	0.256	-18.1	126.35	0.193	0.250	6.6	0.260	-16.9
	16	46	126.35	0.193	0.250	6.2	0.244	-21.9	122.60	0.188	0.250	7.4	0.291	-6.8	126.35	0.193	0.250	6.4	0.252	-19.4
		47	129.25	0.198	0.250	7.1	0.280	-10.6	125.50	0.192	0.250	7.0	0.276	-11.8	129.25	0.198	0.250	7.4	0.291	-6.8
		48	132.25	0.202	0.250	6.3	0.248	-20.6	128.50	0.197	0.250	7.3	0.287	-8.0	132.25	0.202	0.250	6.8	0.268	-14.3
	17	49	132.25	0.202	0.250	8.1	0.319	2.0	128.50	0.197	0.250	7.2	0.283	-9.3	132.25	0.202	0.250	6.2	0.244	-21.9
		50	135.15	0.207	0.250	6.8	0.268	-14.3	131.40	0.201	0.250	7.1	0.280	-10.6	135.15	0.207	0.250	7.0	0.276	-11.8
		51	138.15	0.211	0.250	6.0	0.236	-24.4	134.40	0.206	0.250	7.0	0.276	-11.8	138.15	0.211	0.250	7.8	0.307	-1.7
	18	52	138.15	0.211	0.250	6.7	0.264	-15.6	134.40	0.206	0.250	6.2	0.244	-21.9	138.15	0.211	0.250	6.5	0.256	-18.1
		53	141.05	0.216	0.250	6.4	0.252	-19.4	137.30	0.210	0.250	6.6	0.260	-16.9	141.05	0.216	0.250	6.4	0.252	-19.4
		54	144.05	0.220	0.250	6.0	0.236	-24.4	140.30	0.215	0.250	6.1	0.240	-23.1	144.05	0.220	0.250	7.4	0.291	-6.8
	19	55	144.05	0.220	0.250	5.9	0.232	-25.7	140.30	0.215	0.250	6.2	0.244	-21.9	144.05	0.220	0.250	5.9	0.232	-25.7
		56	146.95	0.225	0.250	6.8	0.268	-14.3	143.20	0.219	0.250	7.6	0.299	-4.3	146.95	0.225	0.250	7.5	0.295	-5.5
		57	149.95	0.229	0.250	7.9	0.311	-0.5	146.20	0.224	0.250	7.1	0.280	-10.6	149.95	0.229	0.250	7.2	0.283	-9.3
	20	58	149.95	0.229	0.250	7.5	0.295	-5.5	146.20	0.224	0.250	8.2	0.323	3.3	149.95	0.229	0.250	7.3	0.287	-8.0
		59	152.85	0.234	0.250	7.6	0.299	-4.3	149.10	0.228	0.250	6.4	0.252	-19.4	152.85	0.234	0.250	7.5	0.295	-5.5
		60	155.85	0.238	0.250	6.0	0.236	-24.4	152.10	0.233	0.250	7.8	0.307	-1.7	155.85	0.238	0.250	7.2	0.283	-9.3
	21	61	155.85	0.238	0.250	6.6	0.260	-16.9	152.10	0.233	0.250	7.4	0.291	-6.8	155.85	0.238	0.250	7.9	0.311	-0.5
		62	158.75	0.243	0.250	8.3	0.327	4.6	155.00	0.237	0.250	7.9	0.311	-0.5	158.75	0.243	0.250	7.5	0.295	-5.5
		63	161.75	0.247	0.250	7.7	0.303	-3.0	158.00	0.242	0.250	7.4	0.291	-6.8	161.75	0.247	0.250	7.6	0.299	-4.3
Original Stated Pipe Wall Thickness - 3/8"	22	64	161.75	0.247	0.250	8.1	0.319	-15.0	158.00	0.242	0.250	8.6	0.339	-9.7	161.75	0.247	0.250	7.8	0.307	-18.1
		65	163.75	0.250	0.250	7.7	0.303	-19.2	160.00	0.245	0.250	8.1	0.319	-15.0	163.75	0.250	0.250	8.4	0.331	-11.8
		66	165.75	0.254	0.250	7.9	0.311	-17.1	162.00	0.248	0.250	7.8	0.307	-18.1	165.75	0.254	0.250	7.3	0.287	-23.4
	23	67	165.75	0.254	0.250	7.1	0.280	-25.5	162.00	0.248	0.250	8.0	0.315	-16.0	165.75	0.254	0.250	7.8	0.307	-18.1
		68	167.75	0.257	0.250	7.5	0.295	-21.3	164.00	0.251	0.250	7.2	0.283	-24.4	167.75	0.257	0.250	7.2	0.283	-24.4
		69	169.75	0.260	0.250	7.5	0.295	-21.3	166.00	0.254	0.250	8.0	0.315	-16.0	169.75	0.260	0.250	6.9	0.272	-27.6
	24	70	169.75	0.260	0.250	7.7	0.303	-19.2	166.00	0.254	0.250	8.2	0.323	-13.9	169.75	0.260	0.250	7.9	0.311	-17.1
		71	171.75	0.263	0.250	7.5	0.295	-21.3	168.00	0.257	0.250	7.0	0.276	-26.5	171.75	0.263	0.250	7.4	0.291	-22.3
		72	173.75	0.266	0.250	6.4	0.252	-32.8	170.00	0.260	0.250	6.5	0.256	-31.8	173.75	0.266	0.250	7.8	0.307	-18.1
	25	73	173.75	0.266	0.250	7.0	0.276	-26.5	170.00	0.260	0.250	6.2	0.244	-34.9	173.75	0.266	0.250	6.8	0.268	-28.6
		74	174.75	0.267	0.250	7.4	0.291	-22.3	171.00	0.262	0.250	6.4	0.252	-32.8	174.75	0.267	0.250	6.6	0.260	-30.7
		75	175.75	0.269	0.250	7.1	0.280	-25.5	172.00	0.263	0.250	6.8	0.268	-28.6	175.75	0.269	0.250	7.8	0.307	-18.1
	26	76	175.75	0.269	0.250	6.7	0.264	-29.7	172.00	0.263	0.250	7.1	0.280	-25.5	175.75	0.269	0.250	6.9	0.272	-27.6
		77	176.75	0.270	0.250	7.5	0.295	-21.3	173.00	0.265	0.250	7.4	0.291	-22.3	176.75	0.270	0.250	8.1	0.319	-15.0
		78	178.75	0.273	0.250	6.8	0.268	-28.6	175.00	0.268	0.250	7.3	0.287	-23.4	178.75	0.273	0.250	6.6	0.260	-30.7
	27	79	178.75	0.273	0.250	8.1	0.319	-15.0	175.00	0.268	0.250	7.1	0.280	-25.5	178.75	0.273	0.250	6.7	0.264	-29.7
		80	179.75	0.275	0.250	7.2	0.283	-24.4	176.00	0.269	0.250	6.3	0.248	-33.9	179.75	0.275	0.250	6.9	0.272	-27.6
		81	180.75	0.276	0.250	6.8	0.268	-28.6	177.00	0.271	0.250	6.2	0.244	-34.9	180.75	0.276	0.250	6.5	0.256	-31.8
	28	82	182.75	0.280	0.250	6.1	0.240	-36.0	179.00	0.274	0.250	7.8	0.307	-18.1	182.75	0.280	0.250	6.3	0.248	-33.9
		83	184.25	0.282	0.250	7.5	0.295	-21.3	180.50	0.276	0.250	7.9	0.311	-17.1	184.25	0.282	0.250	7.6	0.299	-20.2
		84	185.75	0.284	0.250	8.0	0.315	-16.0	182.00	0.278	0.250	7.4	0.291	-22.3	185.75	0.284	0.250	7.7	0.303	-19.2

	Riser Information		Location A Original Information			Location A UT Results			Location B Original Information			Location B UT Results			Location C Original Information			Location C UT Results		
		UT Riser	Head	Required t	Min. t	Acuren			Head	Required t	Min. t	Acuren			Head	Required t	Min. t	Acuren		
	Course	Location	(Ft)	Cal. (inches)	Code (inches)	mm	inches	Loss %	(Ft)	Cal. (inches)	Code (inches)	mm	inches	Loss %	(Ft)	Cal. (inches)	Code (inches)	mm	inches	Loss %
Original Stated Pipe Wall Thickness - 3/8"	29	85	185.75	0.284	0.250	6.9	0.272	-27.6	182.00	0.278	0.250	7.3	0.287	-23.4	185.75	0.284	0.250	7.8	0.307	-18.1
		86	186.75	0.286	0.250	6.8	0.268	-28.6	183.00	0.280	0.250	6.2	0.244	-34.9	186.75	0.286	0.250	7.5	0.295	-21.3
		87	188.75	0.289	0.250	7.3	0.287	-23.4	185.00	0.283	0.250	6.7	0.264	-29.7	188.75	0.289	0.250	6.2	0.244	-34.9
	30	88	188.75	0.289	0.250	7.1	0.280	-25.5	185.00	0.283	0.250	7.8	0.307	-18.1	188.75	0.289	0.250	7.9	0.311	-17.1
		89	189.75	0.290	0.250	7.3	0.287	-23.4	186.00	0.284	0.250	8.0	0.315	-16.0	189.75	0.290	0.250	7.6	0.299	-20.2
		90	190.75	0.292	0.250	6.9	0.272	-27.6	187.00	0.286	0.250	6.8	0.268	-28.6	190.75	0.292	0.250	7.7	0.303	-19.2
	31	91	190.75	0.292	0.250	7.1	0.280	-25.5	187.00	0.286	0.250	6.8	0.268	-28.6	190.75	0.292	0.250	7.3	0.287	-23.4
		92	191.75	0.293	0.250	7.2	0.283	-24.4	188.00	0.288	0.250	8.0	0.315	-16.0	191.75	0.293	0.250	7.8	0.307	-18.1
		93	192.75	0.295	0.250	7.6	0.299	-20.2	189.00	0.289	0.250	7.4	0.291	-22.3	192.75	0.295	0.250	7.3	0.287	-23.4
	32	94	192.75	0.295	0.250	6.7	0.264	-29.7	189.00	0.289	0.250	6.9	0.272	-27.6	192.75	0.295	0.250	6.1	0.240	-36.0
		95	193.75	0.296	0.250	7.2	0.283	-24.4	190.00	0.291	0.250	7.8	0.307	-18.1	193.75	0.296	0.250	6.6	0.260	-30.7
		96	194.75	0.298	0.250	6.5	0.256	-31.8	191.00	0.292	0.250	6.9	0.272	-27.6	194.75	0.298	0.250	7.2	0.283	-24.4
	33	97	194.75	0.298	0.250	7.5	0.295	-21.3	191.00	0.292	0.250	7.0	0.276	-26.5	194.75	0.298	0.250	8.1	0.319	-15.0
		98	195.75	0.299	0.250	6.6	0.260	-30.7	192.00	0.294	0.250	7.3	0.287	-23.4	195.75	0.299	0.250	7.1	0.280	-25.5
		99	195.75	0.299	0.250	6.7	0.264	-29.7	192.00	0.294	0.250	7.5	0.295	-21.3	195.75	0.299	0.250	7.1	0.280	-25.5
	34	100	195.75	0.299	0.250	7.4	0.291	-22.3	192.00	0.294	0.250	7.9	0.311	-17.1	195.75	0.299	0.250	6.7	0.264	-29.7
		101	195.75	0.299	0.250	7.4	0.291	-22.3	192.00	0.294	0.250	7.8	0.307	-18.1	195.75	0.299	0.250	6.5	0.256	-31.8
		102	195.75	0.299	0.250	7.6	0.299	-20.2	192.00	0.294	0.250	7.0	0.276	-26.5	195.75	0.299	0.250	7.3	0.287	-23.4
	35	103	195.75	0.299	0.250	7.5	0.295	-21.3	192.00	0.294	0.250	7.1	0.280	-25.5	195.75	0.299	0.250	7.3	0.287	-23.4
		104	195.75	0.299	0.250	7.6	0.299	-20.2	192.00	0.294	0.250	7.3	0.287	-23.4	195.75	0.299	0.250	7.5	0.295	-21.3
		105	195.75	0.299	0.250	6.9	0.272	-27.6	192.00	0.294	0.250	7.2	0.283	-24.4	195.75	0.299	0.250	7.7	0.303	-19.2

Notes
Riser - 35 Courses, Each is 8' long, Upper 21 had 5/16" original pipe wall thickness,
Lower 14 had 3/8" original pipe wall thickness
Pipe Diameter = 7.5'
Pipe Length = 290'
Required calculated wall thickness t, based on AWWA D100, Eq 3-40
Minimum wall thickness t, based on code AWWA Sec. 3.10 is 1/4"

Average Loss for Location A (Neglecting erroneous increases) = -18.6%
Average Loss for Location B (Neglecting erroneous increases) = -17.0%
Average Loss for Location C (Neglecting erroneous increases) = -17.3%

Additional readings of the riser at the bottom section, (May 13, 2009)

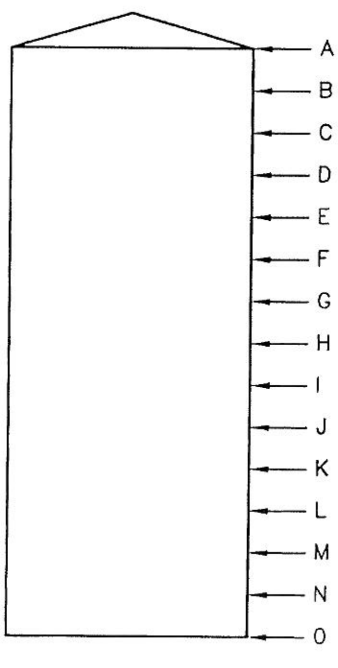
Riser Information		Location B Original Information			Location B UT Results		
	UT Riser	Head	Required t	Min. t	Acuren		
Course	Location	(Ft)	Cal. (inches)	Code (inches)	mm	inches	Loss %
34	102	192.00	0.294	0.250	7.8	0.307	-18.1
35	103	192.00	0.294	0.250	7.4	0.291	-22.3
	104	192.00	0.294	0.250	8.0	0.315	-16.0
	105	192.00	0.294	0.250	7.2	0.283	-24.4

Appendix B

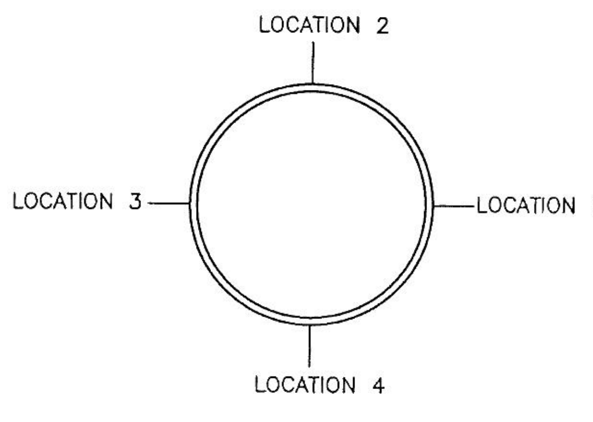
Acuren Reports

SHELL UT READINGS

READING	LOCATION 1	LOCATION 2	LOCATION 3	LOCATION 4
A	8.6	8.1	8.3	8.1
B	8.4	8.1	8.9	8.9
C	8.3	9.0	8.5	8.6
D	9.1	8.3	8.3	8.4
E	8.7	8.6	7.9	8.3
F	8.5	8.4	8.6	9.2
G	8.6	8.0	8.0	8.8
H	8.6	8.4	8.8	8.1
I	8.8	8.6	8.6	8.3
J	9.1	8.8	8.8	8.7
K	8.3	7.8	9.1	8.1
L	8.7	8.8	9.0	8.6
M	8.2	8.3	9.2	8.5
N	9.0	8.7	8.7	7.9
O	8.5	8.6	8.5	8.3



ELEVATION

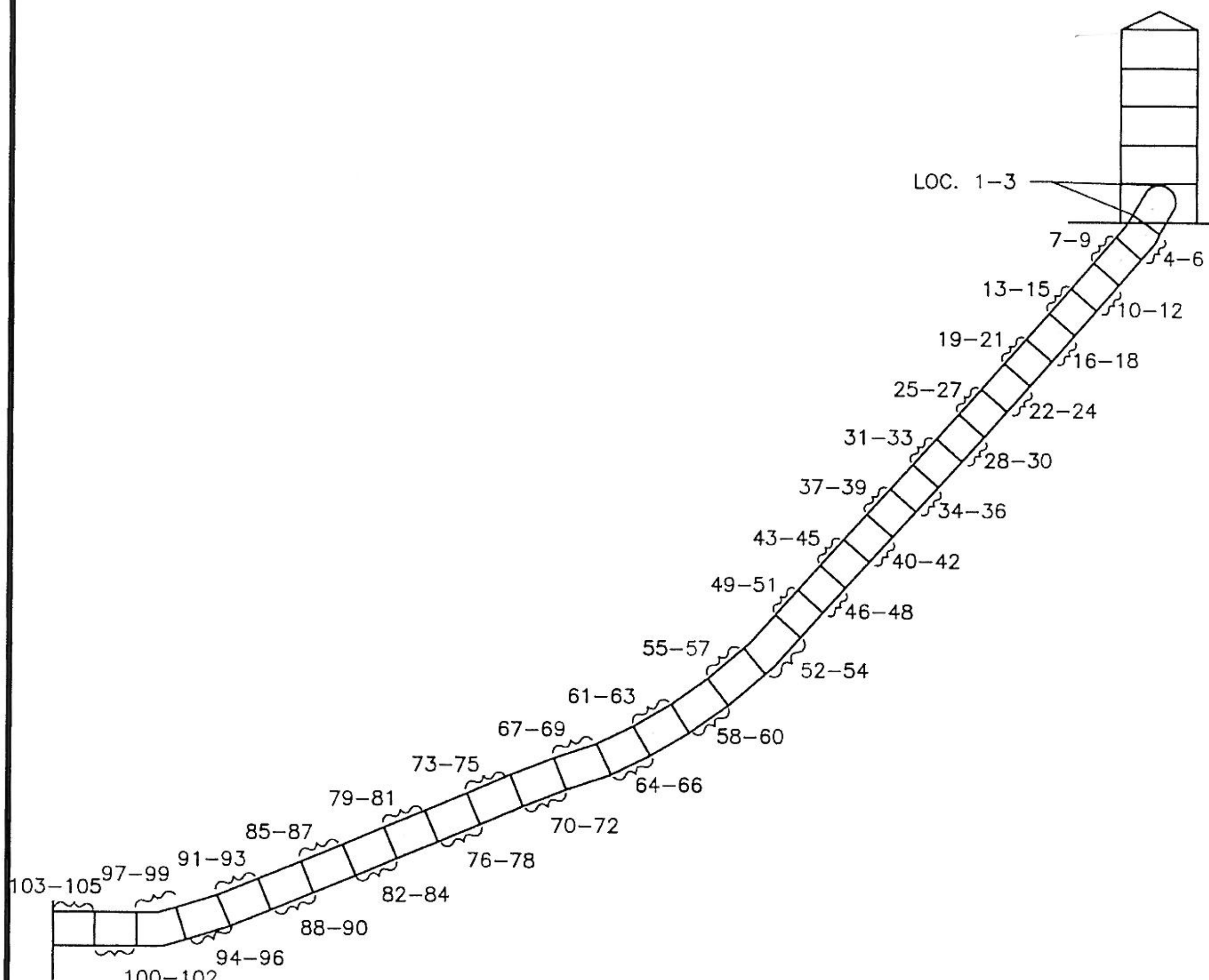


PLAN

ACUREN
2 Hunt's Lane, St. John's, Nfld. A1B 2L3
Tel: (709) 753-2100 / Fax: (709) 753-7011

TITLE
HATCH
SHEEL READINGS AND LOCATIONS

DATE	SCALE	JOB No.	REV. No.	DWG. No.
09.04.28 YY.MM.DD	N.T.S	5385-11	A	SK4



GENERAL LAYOUT

ACUREN

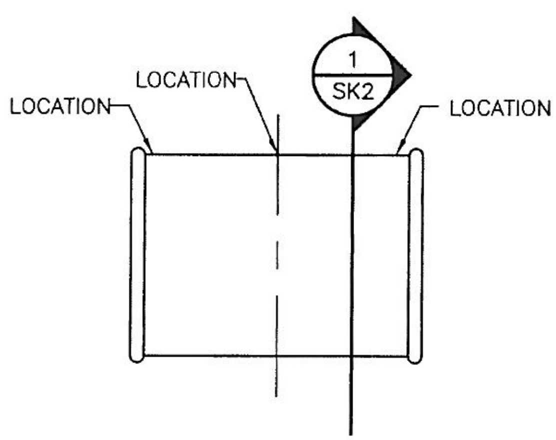
2 Hunt's Lane, St. John's, Nfld. A1B 2L3
Tel: (709) 753-2100 / Fax: (709) 753-7011

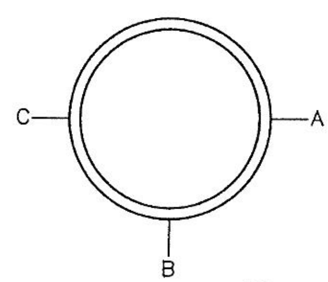
TITLE
HATCH
READING LOCATIONS

DATE	SCALE	JOB No.	REV. No.	DWG. No.
09.04.28 YY.MM.DD	N.T.S	5385-11	A	SK1

UT READINGS

LOCATION #	A	B	C	LOCATION #	A	B	C
1	7.3	6.8	7.9	27	6.0	6.3	6.4
2	8.3	7.0	6.9	28	6.7	6.8	6.3
3	7.5	6.9	6.8	29	6.6	6.5	7.2
4	7.5	8.8	7.6	30	7.7	7.4	6.7
5	8.1	8.6	8.8	31	7.3	7.5	7.1
6	7.1	8.4	6.7	32	6.5	7.0	7.2
7	7.8	8.0	8.6	33	6.5	7.1	6.8
8	6.4	6.9	7.3	34	6.4	6.1	7.1
9	6.2	5.7	5.8	35	7.6	6.7	6.3
10	6.8	6.9	6.8	36	6.0	7.3	7.8
11	9.1	7.7	7.9	37	6.2	6.7	7.4
12	6.0	7.8	6.5	38	7.0	8.1	7.5
13	8.9	6.1	6.3	39	5.9	7.1	6.4
14	7.0	7.6	6.0	40	6.6	7.4	7.1
15	6.1	5.8	8.4	41	7.8	7.9	6.7
16	7.7	8.7	8.3	42	6.0	6.7	7.8
17	7.7	7.9	8.7	43	8.1	7.4	6.8
18	8.2	7.6	7.1	44	6.5	7.8	6.2
19	7.8	7.6	7.3	45	6.6	6.5	6.6
20	7.4	7.5	7.5	46	6.2	7.4	6.4
21	7.0	7.3	6.3	47	7.1	7.0	7.4
22	6.6	6.3	6.8	48	6.3	7.3	6.8
23	6.3	6.0	6.8	49	8.1	7.2	6.2
24	6.5	6.2	6.5	50	6.8	7.1	7.0
25	6.9	6.1	6.2	51	6.0	7.0	7.8
26	7.1	6.7	6.3	52	6.7	6.2	6.5





SECTION 1/SK2
N.T.S

ACUREN

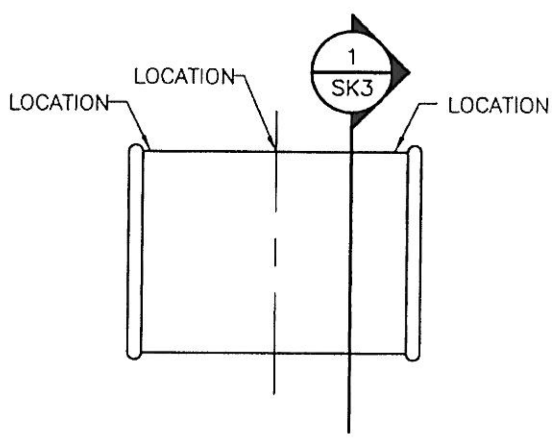
2 Hunt's Lane, St. John's, Nfld. A1B 2L3
Tel: (709) 753-2100 / Fax: (709) 753-7011

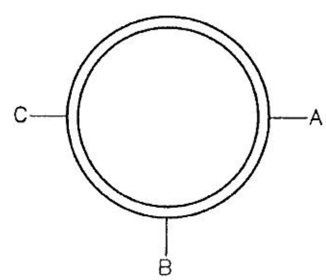
TITLE
HATCH
UT READING

DATE	SCALE	JOB No.	REV. No.	DWG. No.
09.04.28 YY.MM.DD	N.T.S	5385-11	A	SK2

UT READINGS

LOCATION 1	A	B	C	LOCATION #	A	B	C
53	6.4	6.6	6.4	80	7.2	6.3	6.9
54	6.0	6.1	7.4	81	6.8	6.2	6.5
55	5.9	6.2	5.9	82	6.1	7.8	6.3
56	6.8	7.6	7.5	83	7.5	7.9	7.6
57	7.9	7.1	7.2	84	8.0	7.4	7.7
58	7.5	8.2	7.3	85	6.9	7.3	7.8
59	7.6	6.4	7.5	86	6.8	6.2	7.5
60	6.0	7.8	7.2	87	7.3	6.7	6.2
61	6.6	7.4	7.9	88	7.1	7.8	7.9
62	8.3	7.9	7.5	89	7.3	8.0	7.6
63	7.7	7.4	7.6	90	6.9	6.8	7.7
64	8.1	8.6	7.8	91	7.1	6.8	7.3
65	7.7	8.1	8.4	92	7.2	8.0	7.8
66	7.9	7.8	7.3	93	7.6	7.4	7.3
67	7.1	8.0	7.8	94	6.7	6.9	6.1
68	7.5	7.2	7.2	95	7.2	7.8	6.6
69	7.5	8.0	6.9	96	6.5	6.9	7.2
70	7.7	8.2	7.9	97	7.5	7.0	8.1
71	7.5	7.0	7.4	98	6.6	7.3	7.1
72	6.4	6.5	7.8	99	6.7	7.5	7.1
73	7.0	6.2	6.8	100	7.4	7.9	6.7
74	7.4	6.4	6.6	101	7.4	7.8	6.5
75	7.1	6.8	7.8	102	7.6	7.0	7.3
76	6.7	7.1	6.9	103	7.5	7.1	7.3
77	7.5	7.4	8.1	104	7.6	7.3	7.5
78	6.8	7.3	6.6	105	6.9	7.2	7.7
79	8.1	7.1	6.7				





SECTION 1/SK3
N.T.S

ACUREN
2 Hunt's Lane, St. John's, Nfld. A1B 2L3
Tel: (709) 753-2100 / Fax: (709) 753-7011

TITLE
HATCH
UT READINGS

DATE	SCALE	JOB No.	REV. No.	DWG. No.
09.04.28 YY.MM.DD	N.T.S	5385-11	A	SK3

Saunders, Greg

From: Jamie Carberry [JCarberry@fgaconsulting.com]

Sent: Wednesday, May 13, 2009 1:45 PM

To: Saunders, Greg

Subject: UT readings

Hi Greg.

Here are some additional readings on the top of the tank (shell) .
1)7.9
2)8.1
3)7.8
4)8.2

I could not get any readings on the bottom area that we were talking about because of the access.I also took some readings on the riser at the bottom section.

Riser readings;
1)7.8
2)7.4
3)8.0
4)7.2

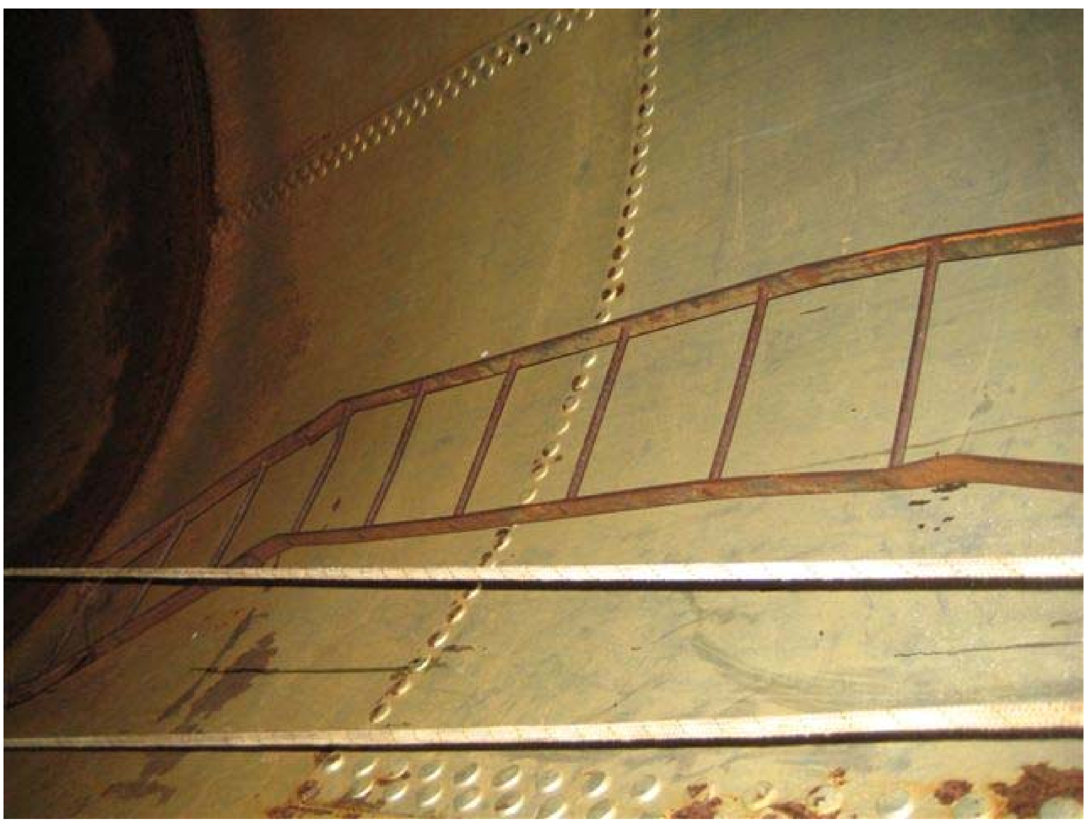
Any questions give me a call.

Thanks. Jamie

Appendix C

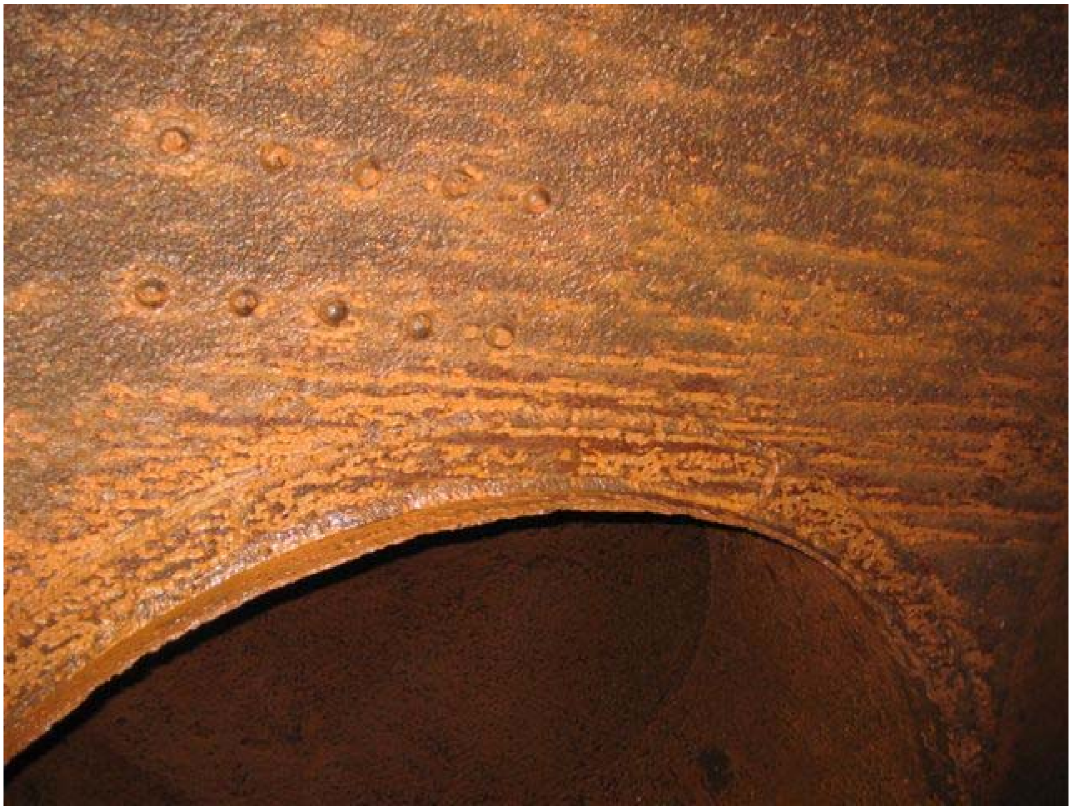
Photographs


Top Shell Course

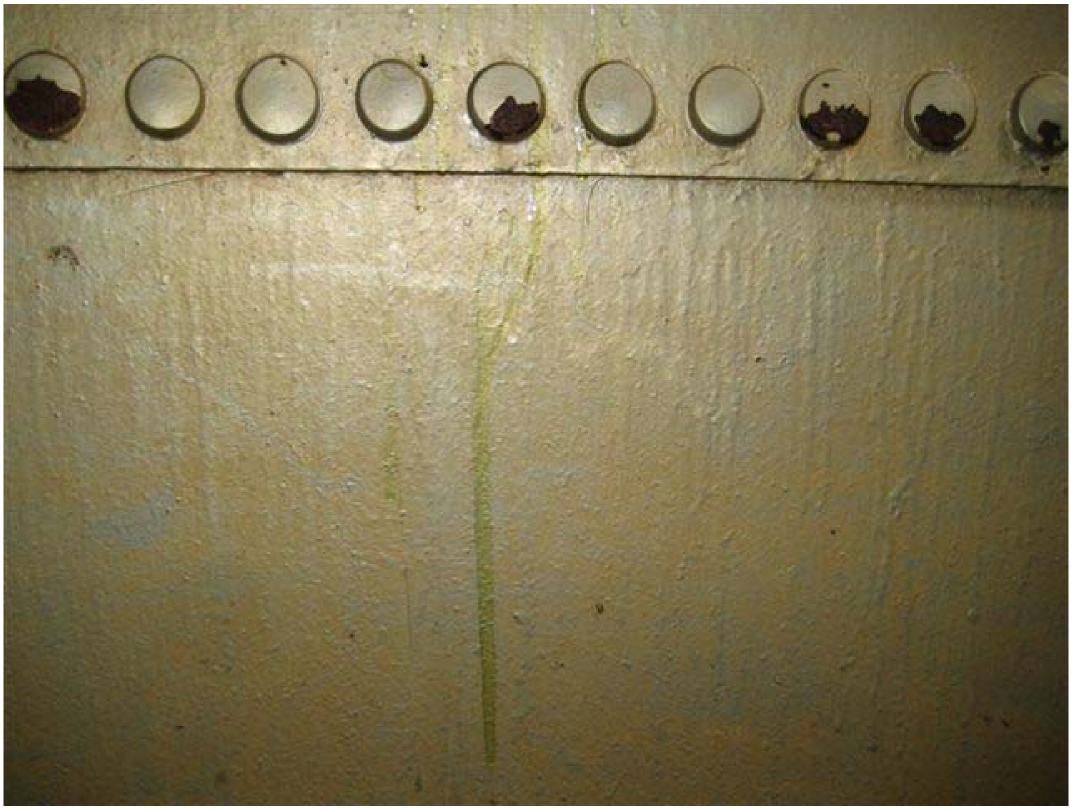

Ladder

Ladder

End of Penstock in Tank

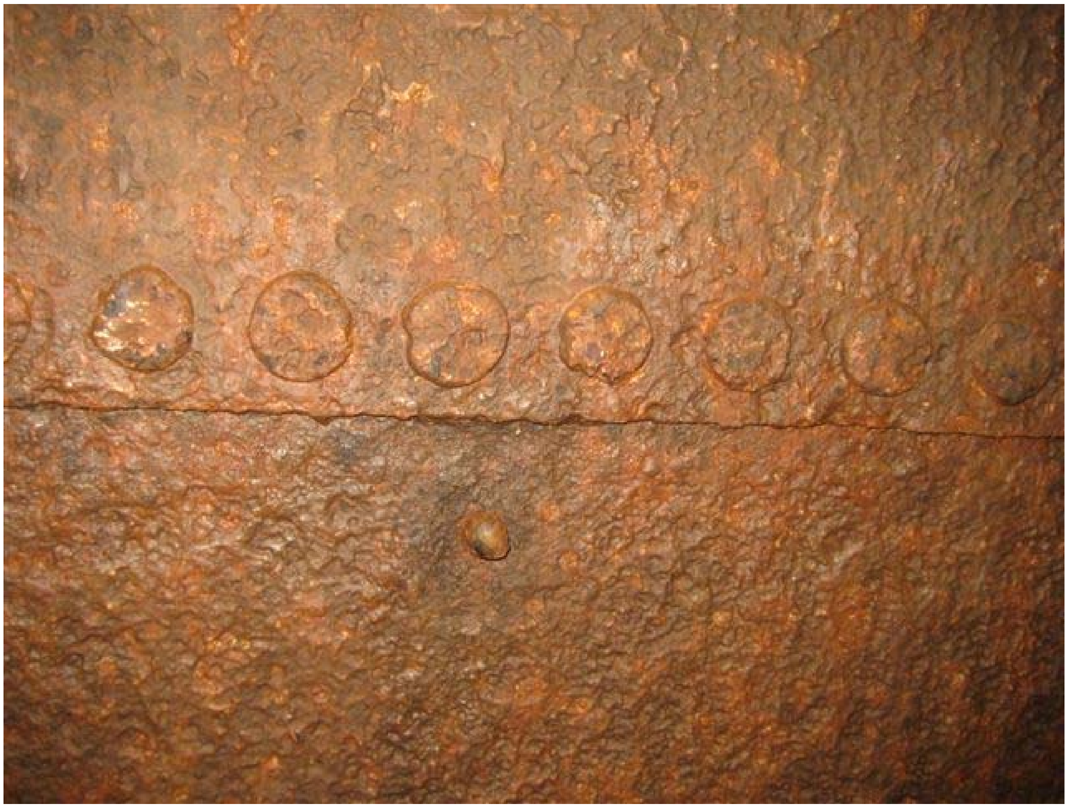

End of Penstock in Tank


Course 1


Bottom of Course 1, Top of Course 2

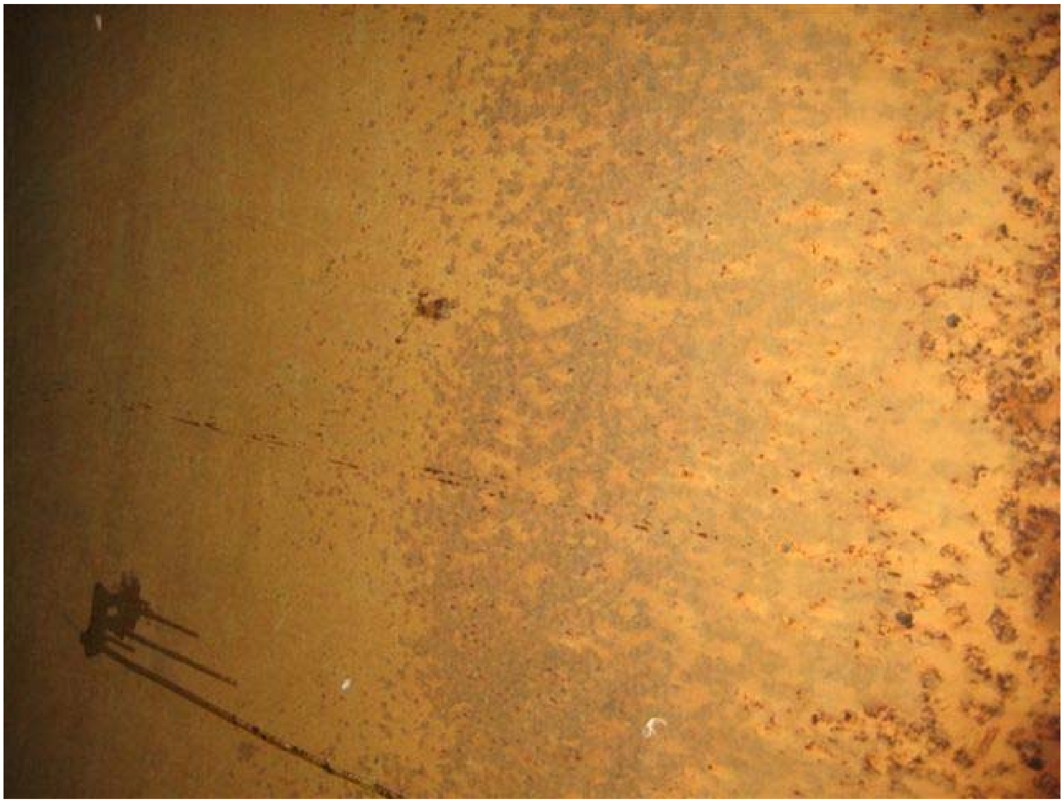

Bottom of Course 2, Top of Course 3


Bottom of Course 2, Top of Course 3


Bottom of Course 4, Top of Course 5


Bottom of Course 4, Top of Course 5


Bottom of Course 4, Top of Course 5


Course 2 Centre Reading


Course 2 Centre Reading

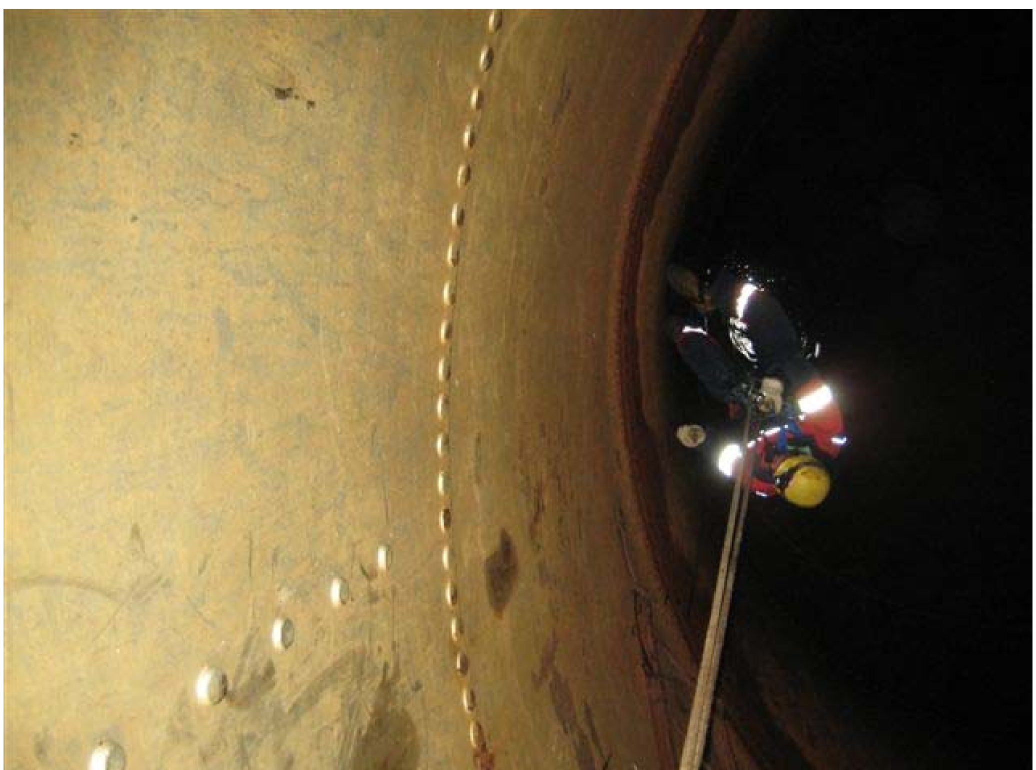

Course 4 General Pitting


Course 4 General Pitting


Roof Beams


Roof Beam Connection to Outer Ring


RAT Descending to 3rd Course


RAT Descending to 3rd Course

RAT Descending to 3rd Course

Appendix C

Feasibility Analysis

Table of Contents

Page

1.0 Introduction

This feasibility analysis examines the future viability of Newfoundland Power's Petty Harbour hydroelectric development. With 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 25 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 25 years have been identified. 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
(000s)

Year	Expenditure
2010-2014	$707
2015-2019	$2,154
2020-2024	$200
2025-2029	$450
2030-2035	$1,424
Total	**$4,935**

The total capital expenditure of all of the projects listed above is $4.935 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 $94,592 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 MWh. This fee is paid annually to the Provincial Department of Environment and Conservation (Water Resources Management Division) based on yearly hydro plant production. Such a charge is not reflected in the historical annual operating costs for the Petty Harbour development. Therefore, an adjustment is applied to account for the associated increased operating expenses on a go-forward basis.

4.0 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 Petty Harbour plant over the next 25 years is 2.37¢ per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Petty Harbour 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. [1]

5.0 Recommendation

The results of this feasibility analysis show that the continued operation of the Petty Harbour hydroelectric development is economically viable. Investing in the life extension of facilities at Petty Harbour guarantees the availability of low cost energy to the Province. Otherwise the annual production of 15.87 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

[1] The cost of electricity from the Holyrood thermal generating station is estimated at 12.06¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil forecast from Hydro of $75.95 per barrel dated March 31, 2009.

Attachment A
Summary of Capital Costs

Petty Harbour Feasibility Analysis
Summary of Capital Cost
(000s)

Description	2010	2014	2015	2017	2019	2021	2026	2030	2031	2035
Civil										
Penstock			$1,300							
Intake				$200						
Dams, Spillways, and Gates		$75	$200	$200	$100	$200				
Surge Tank	$371									
Tailrace										
Roof and Building Upgrades					$100					
Mechanical										
Main Valve	$261									
Governor Upgrades							$60			
Cooling Water										
Ventilation/Compressor										
Pressure Relief Valve										
Electrical										
Protection Upgrade							$120			
Instrumentation							$40			
PLC Upgrade							$100			
Governor Control							$130			
Batteries Bank			$32					$32		
Battery Charger			$22							$22
Rotor/Stator Rewind									$850	
Switchgear									$520	
Annual Totals ($2010)	**$632**	**$75**	**$1,554**	**$400**	**$200**	**$200**	**$450**	**$32**	**$1,370**	**$22**

Attachment B
Summary of Operating Costs

Petty Harbour Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs

Year	Amount
2004	$61,314
2005	68,511
2006	89,637
2007	108,088
2008	81,931
Average	**$81,896**

5-Year Average Operating Cost	$81,896
Water Power Rental Rate[1]	12,696
Total Forecast Annual Operating Cost	$94,592

[1] ($0.80/MWh * 15,870 MWh/yr)

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital 8.58%
PW Year 2009

Year	Generation Hydro 64.4yrs 8% CCA	Capital Revenue Rqmt	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2010	632,000	65,387	94,592	0	-159,979	-147,338	-147,338	1.01	2.37
2011	0	62,331	96,301	0	-158,632	-134,552	-281,890	1.00	2.37
2012	0	62,852	97,988	0	-160,840	-125,645	-407,535	1.01	2.37
2013	0	63,063	99,943	0	-163,007	-117,275	-524,810	1.03	2.37
2014	80,782	71,515	101,884	0	-173,399	-114,894	-639,704	1.09	2.37
2015	1,702,459	247,249	103,629	0	-350,877	-214,119	-853,824	2.21	2.37
2016	0	238,969	105,454	0	-344,423	-193,572	-1,047,396	2.17	2.37
2017	453,657	287,134	107,281	0	-394,415	-204,153	-1,251,549	2.49	2.37
2018	0	285,233	109,146	0	-394,379	-188,003	-1,439,552	2.49	2.37
2019	234,894	309,797	111,095	0	-420,893	-184,788	-1,624,339	2.65	2.37
2020	0	308,327	113,113	0	-421,441	-170,407	-1,794,747	2.66	2.37
2021	243,639	332,968	115,231	0	-448,199	-166,906	-1,961,653	2.82	2.37
2022	0	330,714	117,319	0	-448,033	-153,660	-2,115,313	2.82	2.37
2023	0	329,436	119,483	0	-448,919	-141,798	-2,257,111	2.83	2.37
2024	0	327,666	121,737	0	-449,403	-130,734	-2,387,845	2.83	2.37
2025	0	325,508	124,026	0	-449,534	-120,439	-2,508,284	2.83	2.37
2026	600,622	385,135	126,253	0	-511,388	-126,184	-2,634,467	3.22	2.37
2027	0	379,388	128,543	0	-507,931	-115,427	-2,749,894	3.20	2.37
2028	0	376,740	130,842	0	-507,582	-106,233	-2,856,127	3.20	2.37
2029	0	373,519	133,226	0	-506,745	-97,677	-2,953,804	3.19	2.37
2030	45,900	374,681	135,681	0	-510,362	-90,601	-3,044,405	3.22	2.37
2031	2,000,474	577,505	138,123	0	-715,629	-117,001	-3,161,407	4.51	2.37
2032	0	563,634	140,609	0	-704,243	-106,042	-3,267,448	4.44	2.37
2033	0	560,781	143,140	0	-703,922	-97,618	-3,365,066	4.44	2.37
2034	0	556,673	145,717	0	-702,390	-89,708	-3,454,774	4.43	2.37
2035	34,501	555,516	148,340	0	-703,856	-82,792	-3,537,566	4.44	2.37
2036	0	550,053	151,010	0	-701,063	-75,947	-3,613,513	4.42	2.37
2037	0	544,262	153,728	0	-697,990	-69,639	-3,683,152	4.40	2.37
2038	0	537,972	156,495	0	-694,467	-63,813	-3,746,965	4.38	2.37
2039	0	531,232	159,312	0	-690,544	-58,438	-3,805,403	4.35	2.37
2040	0	524,079	162,180	0	-686,259	-53,486	-3,858,889	4.32	2.37
2041	0	516,545	165,099	0	-681,644	-48,929	-3,907,818	4.30	2.37
2042	0	508,661	168,071	0	-676,732	-44,738	-3,952,555	4.26	2.37
2043	0	500,455	171,096	0	-671,551	-40,887	-3,993,442	4.23	2.37
2044	0	491,953	174,176	0	-666,129	-37,352	-4,030,794	4.20	2.37
2045	0	483,178	177,311	0	-660,489	-34,109	-4,064,904	4.16	2.37
2046	0	474,153	180,503	0	-654,655	-31,136	-4,096,040	4.13	2.37
2047	0	464,896	183,752	0	-648,648	-28,413	-4,124,453	4.09	2.37
2048	0	455,428	187,059	0	-642,487	-25,919	-4,150,372	4.05	2.37
2049	0	445,764	190,426	0	-636,190	-23,637	-4,174,009	4.01	2.37
2050	0	435,920	193,854	0	-629,774	-21,550	-4,195,559	3.97	2.37
2051	0	425,911	197,343	0	-623,254	-19,641	-4,215,200	3.93	2.37
2052	0	415,750	200,895	0	-616,646	-17,898	-4,233,098	3.89	2.37
2053	0	405,449	204,512	0	-609,961	-16,305	-4,249,402	3.84	2.37
2054	0	395,020	208,193	0	-603,212	-14,850	-4,264,252	3.80	2.37
2055	0	384,471	211,940	0	-596,412	-13,522	-4,277,775	3.76	2.37
2056	0	373,814	215,755	0	-589,570	-12,311	-4,290,086	3.71	2.37
2057	0	363,057	219,639	0	-582,696	-11,206	-4,301,292	3.67	2.37
2058	0	352,208	223,592	0	-575,800	-10,198	-4,311,490	3.63	2.37
2059	0	341,274	227,617	0	-568,890	-9,280	-4,320,770	3.58	2.37
2060	0	330,261	231,714	0	-561,975	-8,443	-4,329,212	3.54	2.37

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects an income tax rate of 32.0%.

Operating Costs: Operating Costs were assumed to be $94,592 escalated yearly using GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55%	6.60	3.63
Common Equity	45%	11.00	4.95
Total	**100%**		**8.58**

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 Sandy Lake Spillway to Increase Production

June 2009

Prepared by:

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1.0 Introduction

The Sandy Brook hydroelectric development is located in central Newfoundland near Grand Falls-Windsor. The plant was placed into service in 1963. The normal annual production at Sandy Brook is approximately 25.70 GWh or about 6.0% of Newfoundland Power's total hydroelectric production.

In December 2000, Hatch[1] completed a Water Management Study for Newfoundland Power to provide an estimate of the normal production of Newfoundland Power's hydroelectric system. As a follow up to that study, Hatch also completed a review of Newfoundland Power's larger hydroelectric developments to identify potential opportunities for increasing generation. This study was completed in 2001.

In 2008 Newfoundland Power undertook a review of its existing hydroelectric facilities to determine the potential opportunities for increasing production. For the most part the technical evaluations completed in 2000 and 2001 remain valid. However, the increased cost of electricity production at the Holyrood Generating Station has changed the economic feasibility of some projects identified previously.

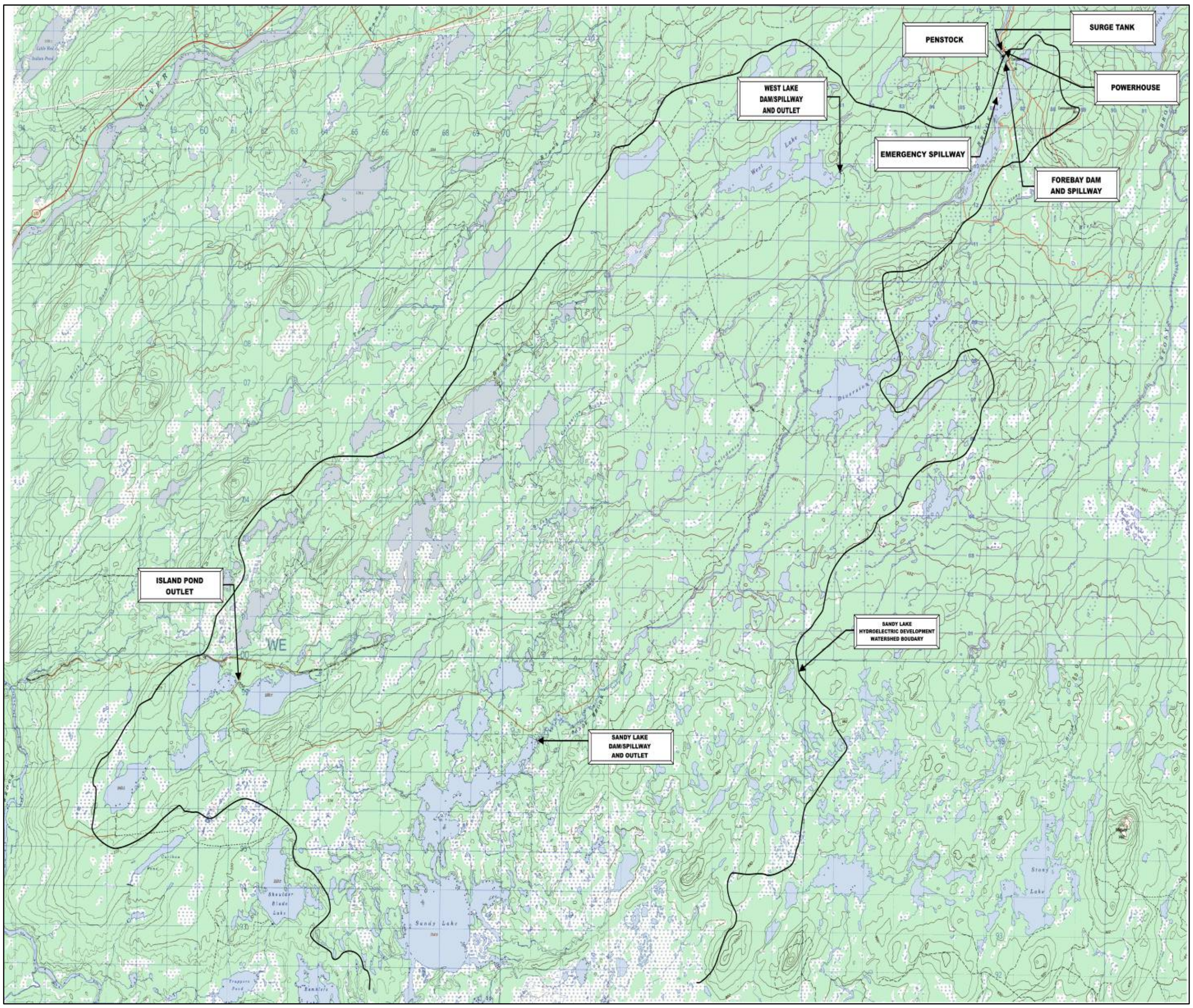
As part of the 2008 study, options to increase energy production at Sandy Brook hydroelectric development were assessed. Average annual water spill at Sandy Brook is estimated to be 5.65 GWh. Increasing the amount of storage at Sandy Lake will reduce the amount of spilled water at this location and result in increased energy production.

[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.

2.0 Background

The Sandy Brook generator has a nameplate capacity of 5.5 MW and a rated net head of 33.5 metres. The total drainage area upstream of the intake is 529 km^2. Storage is provided by structures at Island Pond, West Lake, Sandy Lake and Sandy Brook Forebay. A schematic of the Sandy Brook hydroelectric development is provided in Figure 1.

Figure 1



On the west side of the drainage basin, Island Pond drains into a series of small lakes along West Brook, and into West Lake. On the east side of the basin, Sandy Lake and other smaller lakes drain into Sandy Brook. West Lake and Sandy Lake are the main storage reservoirs for the system. Structures within Sandy Brook system include:

- an outlet structure at Island Pond;
- a gated outlet and overflow spillway at West Lake;
- a gated outlet and overflow spillway at Sandy Lake; and
- a gated spillway and overflow spillway at Sandy Brook forebay.

The Sandy Brook forebay spillways discharge out of the system, the other spillways discharge within the system.

Structures on Sandy Lake reservoir include Sandy Lake dam, spillway and outlet. The dam and spillway structure is a combination earth-fill and rock-fill overflow type constructed with a galvanized metal core. The structure is approximately 130 metres long with a maximum height of 2.7 metres. A reinforced concrete outlet structure with a 2.4 metres x 2.4 metres timber gate and a mechanically operated gate lift is located in the spillway section near the left abutment. Photos of Sandy Lake structures are included in Appendix A.

3.0 Options to Increase Energy Production

Average annual spill at Sandy Brook has been estimated to be 5.65 GWh. In 2001 Newfoundland Power engaged Hatch to complete a study to identify potential opportunities to increase generation at Newfoundland Power's larger hydroelectric developments. As part of this study options to increase energy production at Sandy Brook hydroelectric development were assessed.

Production may be increased within a hydroelectric development through either physical changes or operational changes to the system. Based on the study completed by Hatch it was determined that the present operating guidelines for Sandy Brook plant maximize system output. Therefore no changes to the operating guidelines were recommended.

It was determined however, that a physical change to the Sandy Brook system would increase energy production at least cost. That change is to raise the elevation of Sandy Lake spillway.

Raising the spillway elevation at Sandy Lake will result in additional reservoir flooding. There are a number of cabins that are located on Sandy Lake reservoir. Each cabin location was visited to determine if raising the elevation of the spillway would have any impact on the property of the cabin owners. Based on the site visits it was determined that raising the spillway elevation by 1.5 or 2.0 metres could result in flooding of these properties. Raising the spillway elevation by 1.0 metre would not impact cabin owners' property.[2]

[2] Newfoundland Power assessed the cost benefit of raising the spillway elevation by 1m, 1.5m and 2m. While the capital costs were higher for raising the elevation 1.5m or 2m, the levelized cost of incremental energy output was lower. Newfoundland Power is currently proposing to raise the spillway elevation by 1m. However, following environmental assessment and detailed engineering design it may be feasible to achieve a higher elevation. This would increase the capital costs associated with the project, but also increase the customer benefits associated with the lower cost of the incremental energy output.

The total estimated cost for increasing the height of the existing spillway by 1.0 metre is \$612,000. The incremental increase in production related to raising the spillway is estimated to be 0.86 GWh annually, resulting in a total energy output from Sandy Brook plant of 26.56 GWh annually.

Increasing the height of the spillway will be completed from July to mid August 2010 when reservoir levels are low. During this construction period the plant will remain in operation. The detailed design will be completed in-house.

4.0 Feasibility Analysis

Appendix B of this report provides a feasibility analysis for raising the height of the existing Sandy Lake spillway to increase production at Sandy Brook plant. The results of the feasibility analysis show that raising the height of the existing spillway by 1.0 metre is economical and will result in an additional 0.86 GWh of annual energy production.

The estimated levelized cost of the incremental energy output from raising the spillway at Sandy Lake is 6.64 ¢/kWh. This energy is lower in cost than energy from Holyrood thermal generation.[3]

5.0 Conclusion

Increasing the height of the spillway at Sandy Lake by 1.0 metre will result in an additional 0.86 GWh of annual energy production at Sandy Brook plant. The feasibility analysis included in Appendix B verifies the economic viability of completing this project. Based upon the considerations outlined in this report and the attached assessment, the project is recommended to proceed in 2010.

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[3] The cost of electricity from the Holyrood thermal generating station is estimated at 12.06 cents per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of \$75.95 per barrel as of March 31, 2009.

Appendix A

Photos of Sandy Lake Structures

Picture 1

Aerial Shot of Sandy Lake Spillway

Picture 2

Outlet Structure at Sandy Lake Spillway

Appendix B

Feasibility Analysis

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Page

1.0 Introduction

This feasibility analysis was completed by Newfoundland Power to determine if increasing the height of Sandy Lake spillway to reduce spill and increase the energy production at Newfoundland Power's Sandy Brook hydroelectric development is feasible.

The results of the analysis are presented in this report.

2.0 Capital Costs and Energy Benefits

The capital cost to increase the spillway elevation by 1.0 metre was estimated by Newfoundland Power and is based on previous projects of a similar scope. The energy benefit was provided by Hatch based on their research and experience in hydroelectric system modelling. The estimated capital costs and energy benefit for raising Sandy Lake spillway is summarized in Table 1.

Table 1
Capital Costs and Energy Benefits

Option	Capital Cost (000's)	Energy Benefit (GWh)
Increase spillway elevation by 1.0 metre	$612	0.86

3.0 Financial Analysis

An overall financial analysis has been completed 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 Sandy Lake.

The estimated levelized cost to raise the elevation of Sandy Lake spillway by 1.0 metre is summarized in Table 2.

Table 2
Levelized Cost

Option	Levelized Cost (¢/kWh)
Increase spillway elevation by 1.0 metre	6.64

4.0 Recommendation

The results of the feasibility analysis show that the levelized cost is lower than energy from sources such as a new hydroelectric development or additional Holyrood thermal generation.[1]

Based on these results it is recommended that Newfoundland Power increase the height of Sandy Lake spillway by 1.0 metre. The expected new annual energy output at Sandy Brook plant will be 26.56 GWh.

[1] The cost of electricity from the Holyrood thermal generating station is estimated at 12.06 cents per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $75.95 per barrel as of March 31, 2009.

Attachment A
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital 8.58%
PW Year 2009

Year	Generation Hydro 64.4yrs 8% CCA	Capital Revenue Rqmt	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2010	612,000	63,318	0	0	-63,318	-58,315	-58,315	7.36	6.64
2011	0	60,358	0	0	-60,358	-51,196	-109,511	7.02	6.64
2012	0	60,863	0	0	-60,863	-47,545	-157,056	7.08	6.64
2013	0	61,067	0	0	-61,067	-43,935	-200,991	7.10	6.64
2014	0	61,158	0	0	-61,158	-40,523	-241,514	7.11	6.64
2015	0	61,145	0	0	-61,145	-37,313	-278,828	7.11	6.64
2016	0	61,037	0	0	-61,037	-34,304	-313,131	7.10	6.64
2017	0	60,840	0	0	-60,840	-31,491	-344,623	7.07	6.64
2018	0	60,562	0	0	-60,562	-28,870	-373,493	7.04	6.64
2019	0	60,210	0	0	-60,210	-26,434	-399,928	7.00	6.64
2020	0	59,789	0	0	-59,789	-24,175	-424,103	6.95	6.64
2021	0	59,305	0	0	-59,305	-22,085	-446,188	6.90	6.64
2022	0	58,764	0	0	-58,764	-20,154	-466,342	6.83	6.64
2023	0	58,168	0	0	-58,168	-18,373	-484,715	6.76	6.64
2024	0	57,524	0	0	-57,524	-16,734	-501,449	6.69	6.64
2025	0	56,835	0	0	-56,835	-15,227	-516,676	6.61	6.64
2026	0	56,103	0	0	-56,103	-13,843	-530,520	6.52	6.64
2027	0	55,334	0	0	-55,334	-12,575	-543,094	6.43	6.64
2028	0	54,530	0	0	-54,530	-11,413	-554,507	6.34	6.64
2029	0	53,693	0	0	-53,693	-10,350	-564,856	6.24	6.64
2030	0	52,826	0	0	-52,826	-9,378	-574,234	6.14	6.64
2031	0	51,932	0	0	-51,932	-8,491	-582,725	6.04	6.64
2032	0	51,013	0	0	-51,013	-7,681	-590,406	5.93	6.64
2033	0	50,071	0	0	-50,071	-6,944	-597,350	5.82	6.64
2034	0	49,107	0	0	-49,107	-6,272	-603,622	5.71	6.64
2035	0	48,124	0	0	-48,124	-5,661	-609,283	5.60	6.64
2036	0	47,122	0	0	-47,122	-5,105	-614,387	5.48	6.64
2037	0	46,104	0	0	-46,104	-4,600	-618,987	5.36	6.64
2038	0	45,071	0	0	-45,071	-4,141	-623,129	5.24	6.64
2039	0	44,024	0	0	-44,024	-3,726	-626,854	5.12	6.64
2040	0	42,964	0	0	-42,964	-3,349	-630,203	5.00	6.64
2041	0	41,892	0	0	-41,892	-3,007	-633,210	4.87	6.64
2042	0	40,808	0	0	-40,808	-2,698	-635,908	4.75	6.64
2043	0	39,715	0	0	-39,715	-2,418	-638,326	4.62	6.64
2044	0	38,613	0	0	-38,613	-2,165	-640,491	4.49	6.64
2045	0	37,502	0	0	-37,502	-1,937	-642,427	4.36	6.64
2046	0	36,383	0	0	-36,383	-1,730	-644,158	4.23	6.64
2047	0	35,257	0	0	-35,257	-1,544	-645,702	4.10	6.64
2048	0	34,124	0	0	-34,124	-1,377	-647,079	3.97	6.64
2049	0	32,986	0	0	-32,986	-1,226	-648,304	3.84	6.64
2050	0	31,841	0	0	-31,841	-1,090	-649,394	3.70	6.64
2051	0	30,692	0	0	-30,692	-967	-650,361	3.57	6.64
2052	0	29,537	0	0	-29,537	-857	-651,219	3.43	6.64
2053	0	28,379	0	0	-28,379	-759	-651,977	3.30	6.64
2054	0	27,216	0	0	-27,216	-670	-652,647	3.16	6.64
2055	0	26,050	0	0	-26,050	-591	-653,238	3.03	6.64
2056	0	24,880	0	0	-24,880	-520	-653,757	2.89	6.64
2057	0	23,707	0	0	-23,707	-456	-654,213	2.76	6.64
2058	0	22,531	0	0	-22,531	-399	-654,612	2.62	6.64
2059	0	21,353	0	0	-21,353	-348	-654,961	2.48	6.64
2060	0	20,172	0	0	-20,172	-303	-655,264	2.35	6.64

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects an income tax rate of 32.0%.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55%	6.60	3.63
Common Equity	45%	11.00	4.95
Total	**100%**		**8.58**

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.

Seal Cove Hydro Plant
G1 Runner Replacement

June 2009

Prepared by:

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1.0 Introduction

The Seal Cove Hydro Plant is located on the southern part of Conception Bay near the Community of Seal Cove. It has a total capacity of 3.5 MW under a net head of 55.5 metres. The system was commissioned in 1924 and consists of two generating units in a concrete powerhouse supplied by a steel penstock and concrete intake. Storage is provided by structures at White Hill Pond, Fenelon's Pond and Soldiers Pond.

The normal annual production of the plant is approximately 8.76 GWh of energy, or about 2.0 % of Newfoundland Power's normal annual hydroelectric production.

Replacing the runner for Generator No. 1 will result in improved plant reliability, as well as provide increased energy production of 0.3 GWh per year.

2.0 Background

The Seal Cove generating station has a nameplate capacity of 3.5 MW across two units, Generator No. 1 ("G1") at 1.1 MW and Generator No. 2 ("G2") at 2.4 MW.

The existing G1 runner at Seal Cove is 45 years old. It replaced the original runner. The original runner lasted 40 years from 1924, until it was replaced in 1964.

Inspections have revealed severe deterioration of the turbine runner, which is constructed from mild steel. The most severe deterioration is at the lower pressure zones and the trailing edge of each runner blade. Figure 1 and 2 show the extent to which the runner has deteriorated.

Figure 1

Figure 2

The runner has now deteriorated through cavitation to the extent that there are large holes in the runner blades. The damage has escalated to the extent that G1 is de-rated, and cannot run efficiently. The turbine wicket gates are also of mild steel construction and have experienced corrosion damage such that the gates no longer operate efficiently.

Index testing was performed on G1 by Hatch in 2003[1]. At that time it was determined that peak turbine efficiency was 81% at 980 KW. Given the age and size of the unit, this performance is considered to be average; however it is reasonable to expect a 10% efficiency increase by replacing the runner. Results from the index test, plus observations made during the test, led Hatch to recommend the runner be replaced.

A replacement runner will provide in a peak capacity of 1.4 MW, with a peak efficiency of 91%. This efficiency increase will also result in the runner using 10% less water. The increase in energy production due to the runner replacement is estimated to be 0.3 GWh/yr.

3.0 G1 Runner Replacement

This project includes the replacement of the deteriorated runner with a stainless steel runner and replacement of the existing wicket gates with stainless steel wicket gates. This also includes ancillary work including the replacement of the wicket gate bushings.

Table 1 shows the cost estimate for the runner and wicket gate replacement.

Table 1
Seal Cove
Runner and Wicket Gate Replacement

Item	Amount
Material	$324,000
Internal Labour	154,000
Engineering	22,000
Other	40,000
Total	**$540,000**

This replacement will permit efficient operations at Seal Cove Hydro Plant.

4.0 Feasibility Analysis

Appendix A of this report provides a feasibility analysis for replacing the runner and wicket gates. The estimated levelized cost of energy from the Seal Cove Hydro Plant is 2.83¢ per

[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.

kWh[2]. This energy is lower in cost than energy from other sources such as a new hydroelectric development or additional Holyrood thermal generation[3].

5.0 Conclusion

The G1 runner and turbine wicket gates at Seal Cove Hydro Plant have deteriorated to the extent they must be replaced.

Replacing the G1 runner and turbine wicket gates will result in an additional 0.3 MW of capacity and 0.3 GWh of annual energy production at the Seal Cove Hydro Plant.

The feasibility analysis included in Appendix A indicates that extending the life of the Seal Cove Hydro Plant is justified n the basis of providing least cost energy to customers.

[2] Feasibility analysis is based on the total investment in Seal Cove Plant in 2010 which includes this project along with $224,000 to rebuild the gatehouse and intake structure. This project is explained under *1.1 Facilities Rehabilitation*.

[3] The cost of electricity from the Holyrood thermal generating plant is estimated at 12.06¢/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil forecast from Hydro of $75.95/barrel dated March 31, 2009.

Appendix A

Feasibility Analysis

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1.0 Introduction

This feasibility analysis examines the future viability of Newfoundland Power's Seal Cove Hydro Plant. With 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.

The results of the analysis are presented in this report.

2.0 Capital Costs

All significant capital expenditures for the hydroelectric development over the next 25 years have been identified. 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
(000s)

Year	Expenditure
2010-2014	$764
2015-2019	$867
2020-2024	$660
2025-2029	$232
2030-2035	$1,117
Total	**$3,640**

The total capital expenditure of all of the projects listed above is $3.64 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 $62,351 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 MWh. This fee is paid annually to the Provincial Department of Environment and Conservation (Water Resources Management Division) based on yearly hydro plant production. Such a charge is not reflected in the historical annual operating costs for the Seal Cove Hydro. Therefore, an adjustment is applied to account for the associated increased operating expenses on a go-forward basis.

4.0 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 Seal Cove Hydro Plant over the next 50 years is 2.83 cents per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from the Seal Cove Hydro Plant 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 12.06 cents per kWh.[4]

5.0 Recommendation

The results of this feasibility analysis show that the continued operation of the Seal Cove hydroelectric development is economically viable. Investing in the life extension of facilities at Seal Cove Hydro Plant ensures the availability of low cost energy to the Province. Otherwise the annual production of 8.76 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

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[4] The cost of electricity from the Holyrood thermal generating station is estimated at 12.06 cents per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil forecast from Hydro of $75.95 per barrel dated March 31, 2009.

Attachment A

Summary of Capital Costs

Seal Cove Feasibility Analysis
Summary of Capital Cost
(000s)

Description	2010	2015	2016	2018	2023	2025+	2030+
Civil							
Penstock				$587			
Intake	$170						
Dams, Spillways, and Gates		$100				$200	$400
Tailrace							$50
Mechanical							
Main Valve/Runner Replacment	$540						
Governor Upgrades					$270		
Electrical							
Protection Upgrade					$120		
Rotor/Stator Rewind			$180				$575
Breakers							$70
PLC Upgrade					$270		
Batteries Bank	$32					$32	
Battery Charger	$22						$22
Annual Totals ($2010)	**$764**	**$100**	**$180**	**$587**	**$660**	**$232**	**$1,117**

Attachment B

Summary of Operating Costs

Seal Cove Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs

Year	Amount
2004	$53,385
2005	33,733
2006	64,950
2007	59,439
2008	65,633
Average	**$55,428**

5-Year Average Operating Cost	$55,428
Water Power Rental Rate[1]	7,008
Total Forecast Annual Operating Cost	$62,436

1 ($0.80/MWh * 8,760 MWh/yr).

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital 8.58%
PW Year 2009

Year	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Rqmt	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2010	224,000	540,000	25,679	62,436	0	-88,115	-81,153	-81,153	1.01	2.83
2011	0	0	4,682	63,564	0	-68,246	-57,887	-139,039	0.78	2.83
2012	0	0	50,208	64,677	0	-114,886	-89,746	-228,786	1.31	2.83
2013	0	0	69,894	65,968	0	-135,862	-97,746	-326,532	1.55	2.83
2014	0	0	79,200	67,249	0	-146,449	-97,037	-423,569	1.67	2.83
2015	109,553	0	94,632	68,401	0	-163,033	-99,489	-523,058	1.86	2.83
2016	200,670	0	116,342	69,606	0	-185,947	-104,506	-627,564	2.12	2.83
2017	0	0	115,615	70,811	0	-186,427	-96,496	-724,060	2.13	2.83
2018	677,316	0	185,371	72,042	0	-257,413	-122,711	-846,771	2.94	2.83
2019	0	0	181,306	73,329	0	-254,635	-111,794	-958,565	2.91	2.83
2020	0	0	180,833	74,661	0	-255,494	-103,308	-1,061,873	2.92	2.83
2021	0	0	179,872	76,059	0	-255,931	-95,307	-1,157,180	2.92	2.83
2022	0	0	178,677	77,437	0	-256,114	-87,839	-1,245,019	2.92	2.83
2023	833,670	0	263,536	78,865	0	-342,402	-108,153	-1,353,171	3.91	2.83
2024	0	0	257,937	80,353	0	-338,291	-98,411	-1,451,582	3.86	2.83
2025	41,957	0	261,244	81,864	0	-343,108	-91,925	-1,543,507	3.92	2.83
2026	0	0	259,455	83,334	0	-342,790	-84,582	-1,628,090	3.91	2.83
2027	0	0	257,621	84,845	0	-342,467	-77,825	-1,705,915	3.91	2.83
2028	276,644	0	284,129	86,363	0	-370,492	-77,541	-1,783,456	4.23	2.83
2029	0	0	280,431	87,937	0	-368,367	-71,004	-1,854,460	4.21	2.83
2030	318,433	0	311,017	89,557	0	-400,574	-71,111	-1,925,571	4.57	2.83
2031	0	0	306,774	91,169	0	-397,943	-65,062	-1,990,633	4.54	2.83
2032	297,297	0	334,850	92,810	0	-427,660	-64,395	-2,055,028	4.88	2.83
2033	976,040	0	431,331	94,481	0	-525,812	-72,918	-2,127,946	6.00	2.83
2034	77,024	0	431,498	96,181	0	-527,679	-67,394	-2,195,340	6.02	2.83
2035	0	0	428,460	97,913	0	-526,373	-61,915	-2,257,255	6.01	2.83
2036	0	0	425,099	99,675	0	-524,774	-56,850	-2,314,105	5.99	2.83
2037	0	0	421,264	101,469	0	-522,733	-52,154	-2,366,259	5.97	2.83
2038	0	0	417,013	103,296	0	-520,309	-47,810	-2,414,068	5.94	2.83
2039	0	0	412,380	105,155	0	-517,535	-43,797	-2,457,865	5.91	2.83
2040	0	0	407,394	107,048	0	-514,442	-40,095	-2,497,960	5.87	2.83
2041	0	0	402,085	108,975	0	-511,059	-36,684	-2,534,644	5.83	2.83
2042	0	0	396,478	110,936	0	-507,414	-33,544	-2,568,189	5.79	2.83
2043	0	0	390,596	112,933	0	-503,529	-30,657	-2,598,846	5.75	2.83
2044	0	0	384,463	114,966	0	-499,429	-28,005	-2,626,850	5.70	2.83
2045	0	0	378,098	117,035	0	-495,133	-25,570	-2,652,420	5.65	2.83
2046	0	0	371,519	119,142	0	-490,661	-23,337	-2,675,757	5.60	2.83
2047	0	0	364,744	121,286	0	-486,030	-21,290	-2,697,046	5.55	2.83
2048	0	0	357,788	123,470	0	-481,257	-19,415	-2,716,461	5.49	2.83
2049	0	0	350,666	125,692	0	-476,358	-17,699	-2,734,160	5.44	2.83
2050	0	0	343,391	127,954	0	-471,346	-16,129	-2,750,288	5.38	2.83
2051	0	0	335,976	130,258	0	-466,233	-14,693	-2,764,981	5.32	2.83
2052	0	0	328,431	132,602	0	-461,033	-13,381	-2,778,362	5.26	2.83
2053	0	0	320,767	134,989	0	-455,756	-12,183	-2,790,545	5.20	2.83
2054	0	0	312,994	137,419	0	-450,413	-11,088	-2,801,633	5.14	2.83
2055	0	0	305,119	139,892	0	-445,012	-10,090	-2,811,723	5.08	2.83
2056	0	0	297,153	142,410	0	-439,563	-9,179	-2,820,902	5.02	2.83
2057	0	0	289,100	144,974	0	-434,074	-8,348	-2,829,250	4.96	2.83
2058	0	0	280,970	147,583	0	-428,553	-7,590	-2,836,840	4.89	2.83
2059	0	0	272,767	150,240	0	-423,007	-6,900	-2,843,740	4.83	2.83
2060	0	0	264,498	152,944	0	-417,442	-6,271	-2,850,011	4.77	2.83

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects an income tax rate of 32.0%.

Operating Costs: Operating Costs were assumed to be $62,436 escalated yearly using GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55%	6.60	3.63
Common Equity	45%	11.00	4.95
Total	**100%**		**8.58**

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.

2010 Substation Refurbishment and Modernization

June 2009

Prepared by:

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PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Substation Refurbishment and Modernization Strategy

Newfoundland Power's (the "Company") substations connect the high voltage transmission system to the low voltage distribution system. The Company's substation maintenance program and the Substation Refurbishment and Modernization project ensures the delivery of reliable least cost electricity to customers in a safe and environmentally responsible manner.

The Substation Refurbishment and Modernization project provides a structured approach for the overall refurbishment and modernization of substations and coordinates major equipment maintenance and replacement activities. Where practical the substation plan is coordinated with the maintenance cycle for major substation equipment. This coordination minimizes customer service interruptions and ensures optimum use of resources.

In preparation of annual capital budgets, substations are assessed with particular consideration given to the physical condition of the infrastructure and equipment and the need to upgrade and modernize protection and control systems. This assessment is used to establish the priority for substation work. The priority is then balanced against the available equipment and human resources to develop the annual budget. Much of this work requires the power transformer to be removed from service and therefore the timing of the work is restricted to the availability of the portable substation and the capacity of the portable substation to meet the load requirement. In many circumstances, this requires the work to be completed in the late spring and summer when the substation load is light.

In the *Substation Strategic Plan* filed with the Company's 2007 Capital Budget Application, it was indicated that expenditures under the Substation Refurbishment and Modernization project were expected to average approximately $4 million per year. Expenditure is currently expected to reach this level in 2009. In 2008, expenditure was materially below this level due to increases in both unplanned substation work and in-service failures. Such developments highlight the practical requirement for flexibility in execution of the Substation Refurbishment and Modernization project over time.

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

2.0 2010 Substation Refurbishment and Modernization Project

The 2010 Substation Refurbishment and Modernization Project includes planned refurbishment and modernization work on 10 substations, including one of the Company's portable substations. This work is estimated to cost a total of $3.7 million, which comprises approximately 91% of total 2010 project costs. Silicon carbide lightning arrestors are planned to be replaced in an additional 6 substations on a priority basis and minor site improvements are planned for 1 substation. These lightning arrestors and site improvements are estimated to cost a total of $193,000, which comprises approximately 5% of total 2010 project costs. Finally, system monitoring and operations technology upgrades are planned at $150,000. This comprises approximately 4% of total 2010 project costs.

Table 1 is work planned under the Substation Refurbishment and Modernization project for 2010.

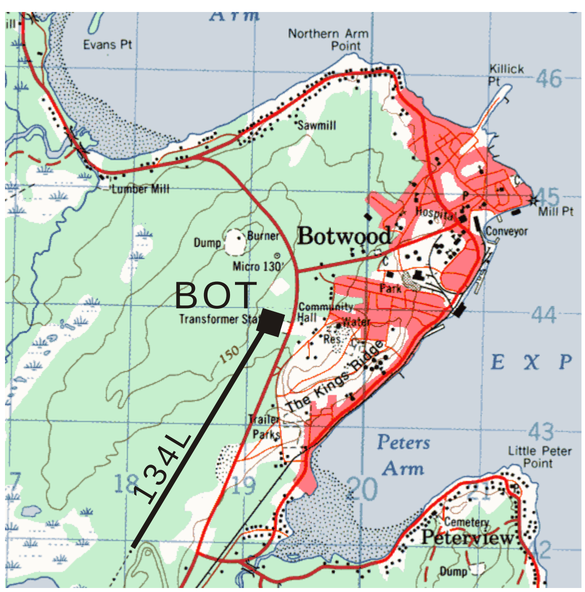
Table 1
2010 Substation Refurbishment and Modernization
(000s)

Substation	**Cost**
Botwood (BOT)	$837
Boyd's Cove (BOY)	$ 67
Clarkes Pond (CLK)	$228
Gallant Street (GAL)	$703
Gillams (GIL)	$138
Glovertown (GLV)	$199
Grand Falls (GFS)	$797
Springfield (SPF)	$138
Wesleyville (WES)	$ 53
Portable Substation 3 (P3)	$540
Items Under $50,000	$193
Substation Monitoring	$150
Total	**$4,043**

The following provides a description for this work.

2.1 Botwood Substation ($837,000)

Botwood substation was built in 1977 as a distribution substation. It contains one 138 kV to 25 kV power transformer. The power transformer is rated for 20 MVA. The 138 kV bus is energized by a radial 138 kV transmission line 134L from Bishop's Falls substation. The substation serves approximately 3,350 customers in the Botwood area through three 25 kV feeders.



Botwood Substation Location

The power transformer is in good condition with no obvious sign of deterioration. The 138 kV and 25 kV steel structures are also in good condition.

Work at this station includes installing protection for the power transformer to bring it in line with current utility practice. This requires installation of protective relaying; a potential transformer; a high speed ground switch at the transmission termination in the station; air break switching; and alarms. Metal oxide lightning arrestors will be installed on the transformer.

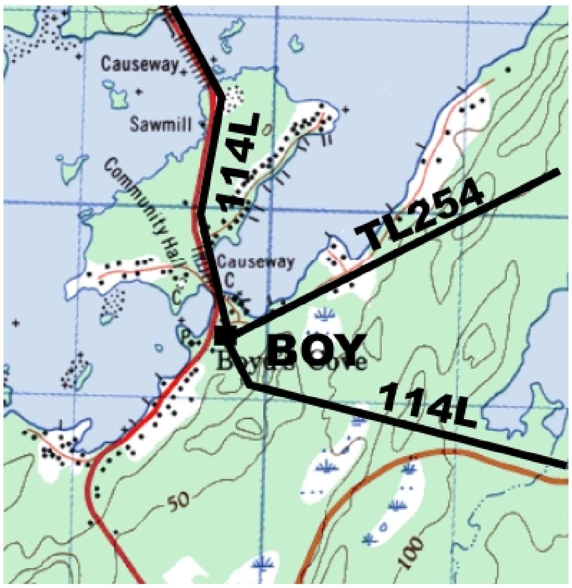
Replacement of existing hydraulic reclosers with computer-controlled reclosers and communication equipment is planned. This will permit remote monitoring of the substation and enable feeder automation, including under frequency load-shedding capability.

Ground grid improvements and a new control building; protection from small animal risks; and concrete foundation repairs also comprise part of the required work on this substation.

25 kV Structure Foundation

2.2 Boyd's Cove Substation ($67,000)

Boyd's Cove substation is a Newfoundland Power transmission substation built in 1988. There are three 66 kV transmission lines terminated in the substation, transmission lines 114L to Summerford substation, 114L to Gander Bay substation and TL254 to Newfoundland & Labrador ("Hydro") substation at Farewell Head. There are no customers served directly from Boyds Cove substation.



Boyd's Cove Substation Location

Engineering assessment indicates that the structures, bus and equipment at this substation are in good condition.

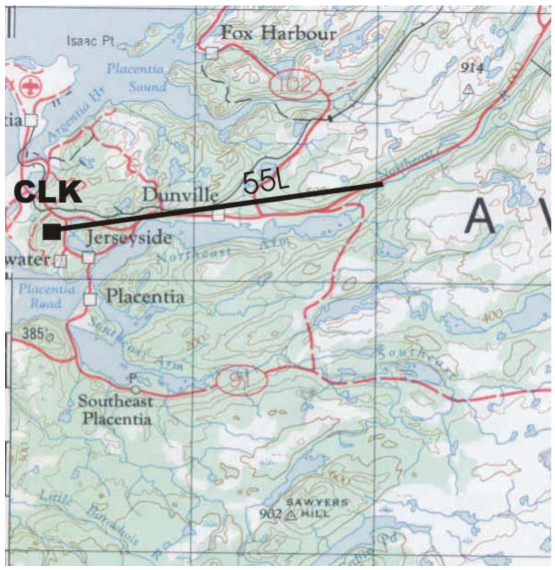
Lightning arrestors are planned to be installed for protection of the 66 kV station service transformer at this substation. Lightning arrestors will reduce the potential for future long duration outages which would result from a lightning strike at the transformer. In turn, this will improve security of supply for customers in the Notre Dame Bay area served by Newfoundland Power and Hydro.

Grounding for the substation will be extended in 2010 to improve safety for personnel working inside the substation.

Station Service Transformer Structure

2.3 Clarke's Pond Substation ($228,000)

Clarkes Pond substation was built in 1976 as a distribution substation. It contains two 66 kV to 12 kV power transformers. Each power transformer is rated for 10 MVA for a total station capacity of 20 MVA. The 66 kV bus is energized via a radial 66 kV transmission line 55L from Blaketown substation. The substation serves approximately 1,160 customers in the Placentia/Argentia areas through three 12 kV feeders.



Clarkes Pond Substation Location

The two power transformers are in good condition with no obvious signs of deterioration. The 66 kV and 12 kV steel structures are in good condition.

Tap changer controllers for both power transformers require replacement. The existing controllers are 29 and 30 years old respectively. Life expectancy of controllers is 25 years. Installing a heating unit on the transformer spill pan is also planned for 2010.[1]

Communication equipment installation is planned to permit remote monitoring of the substation and enable feeder automation, including under frequency load-shedding capability.

Concrete foundation repairs and protection from small animal risks also comprise part of the required work on this substation.

[1] Because Clarke's Pond substation is located in a watershed the transformers are equipped with oil control spill pans. To avoid transformer damage, heating of spill pans is required to prevent ice build up.

Foundation damage at Clarkes Pond Substation

2.4 Gallant Street Substation ($703,000)

Gallant Street substation was built in 1973 as a 66 kV to 12 kV distribution substation. The substation contains two power transformers with a combined capacity of 26.7 MVA. This substation directly serves approximately 3,200 customers in the Stephenville area through four 12 kV feeders. In the substation, there are three 66 kV transmission lines terminated in the high voltage bus. These are transmission lines 401L to Stephenville Gas Turbine substation, 402L to Berryhead substation and 406L to Harmon substation.

Gallant Street Substation Location

Both power transformers and the 66 kV and 12 kV steel structures and bus are in good condition.

Transmission Line Protection Relays

The original transmission line electro-mechanical relays will be replaced with new electronic digital protection relays. A 66 kV potential transformer and fuse will be installed on transmission line 401L and used to improve protection for the transmission line. Defective insulation, deteriorated structures, and deteriorated metering tanks require replacement. Remote monitoring of transformer alarms and improved transformer protection are also planned.

Communication equipment installation is planned to permit increased remote monitoring of the substation and enable under frequency load-shedding capability.

Replacement of approximately 33 meters of substation fence and the substation gate is also part of the work planned for 2010. The ground grid for the substation will be extended to improve safety for personnel inside the substation.

2.5 Gillams Substation ($138,000)

Gillams substation was built in 1977 as a distribution substation. The substation contains one 66 kV to 12 kV power transformer with a capacity of 6.7 MVA. This substation directly serves approximately 1,400 customers in the Gillams area through two 12 kV feeders. In the substation there is one 66 kV transmission line 358L from Bayview substation terminated in the high voltage bus.

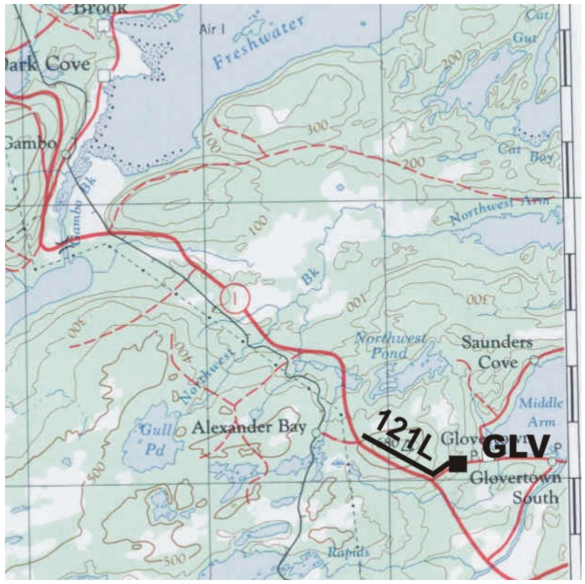
Gillams Substation Location

Inspection indicates significant rust on the transformer's radiators. These radiators will be replaced in 2010. In addition, a deteriorated AC panel at the substation requires replacement.

Gillams Transformer Radiator Deterioration

2.6 Glovertown Substation ($199,000)

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



Glovertown Substation Location

Engineering assessment indicates that the 138 kV and 25 kV steel structures and concrete foundations are in good condition. The power transformer is also in good condition.

Work on this station includes installing protection for the power transformer to bring it in line with current utility practice. This requires installation of protective relaying; a high speed ground switch at the transmission termination in the station; and alarms. The thirty year old tap changer controller will be replaced. Metal oxide lightning arrestors will be installed on the transformer.

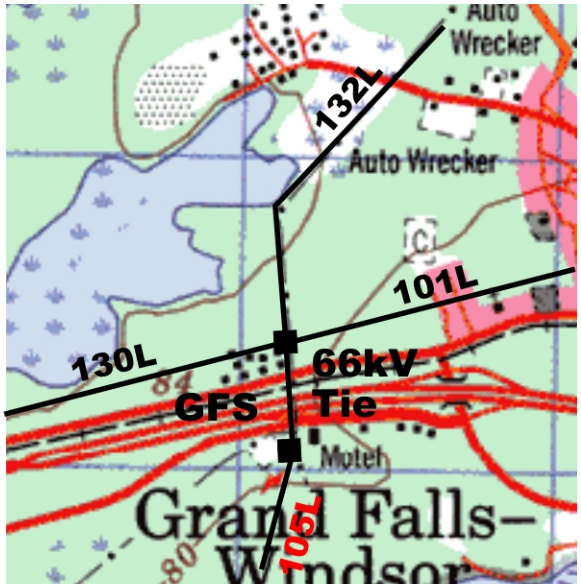
Communication equipment installation is planned to permit remote monitoring of the substation and enable feeder automation, including under frequency load-shedding capability

Protection from small animals will also be installed on the substation equipment.

2.7 Grand Falls Substation ($797,000)

Grand Falls substation was originally built in 1959 as a 66 kV to 4 kV distribution substation. Today, it is a 138 kV and 66 kV transmission substation as well as a 25 kV and 4 kV distribution substation. The substation contains three power transformers with a combined capacity of 48.4 MVA. The substation has two yards separated by the Trans-Canada highway.

Work planned for 2010 is in the southern yard. This substation yard directly serves approximately 1,400 customers in the Grand Falls area through four 4 kV metal clad switchgear feeders. In the yard there is one 66 kV transmission line terminated in the high voltage bus. This is a transmission line to Sandy Brook substation.



Grand Falls Substation Location

The power transformer is in good condition. The 4 kV switchgear building is of steel construction and is in good condition.

Metal oxide lightning arrestors will be installed on the power transformer. The original transmission line electro-mechanical relays are deteriorated and will be replaced with electronic digital protection relays.

Communication equipment installation is planned to permit remote monitoring of the substation and enable feeder automation, including under frequency load-shedding capability

The fifty year old 66 kV wood pole structures in this substation are in poor condition. The structures are leaning considerably and switches will not stay in alignment. These wood pole structures will be replaced with a steel box structure in 2010.

Grand Falls Substation 66 kV Wood Pole Structures (Leaning)

The switchgear building currently houses the 4 kV equipment for the four 4 kV feeders, the transmission line protection panel and the 125 V DC battery bank in one room. A battery room will be constructed within the switchgear building for the 125 V DC battery bank and a wall constructed to separate the protection panels from the switchgear. This will provide the required thresholds of arc flash safety for personnel working in the building.

Grand Falls - Single Room Switchgear & Control Building

2.8 Springfield Substation ($138,000)

Springfield substation was built in 1976 as a 138 kV to 12 kV distribution substation. The distribution substation contains one power transformer with a capacity of 20 MVA at 12 kV. The substation directly serves approximately 2,900 customers in the Springfield area through three 12 kV feeders. There are two 138 kV transmission lines terminated in the substation. These are transmission lines 39L to Colliers substation and 39L to Bay Roberts substation.

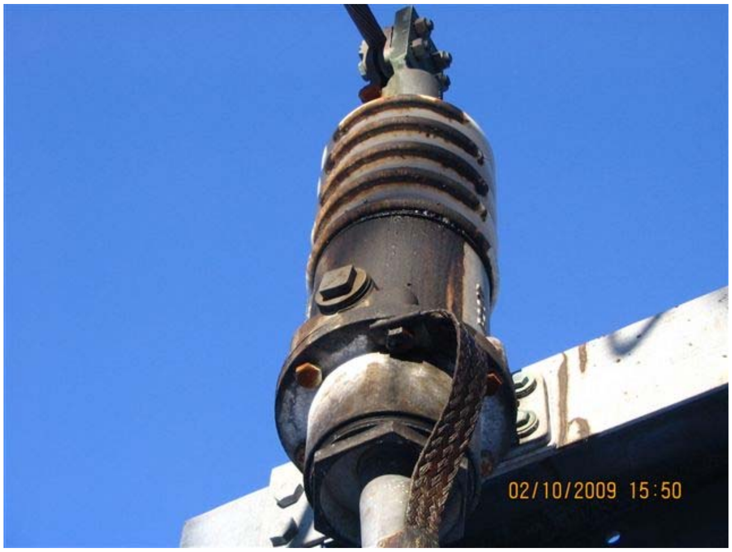
Springfield Substation Location

Inspection of the power transformer identified deteriorated radiators which were leaking insulating oil. One radiator has since been shut off and drained. New radiators will be installed in 2010.

Leaking Radiator

Deteriorated Radiator

The 12 kV power cables supplying the transformer are thirty five years old and are leaking insulating compound. These will be replaced with overhead conductor.



Leaking 12.5 kV Potheads

2.9 Wesleyville Substation ($53,000)

Wesleyville substation was built in 1974 as a 12 kV distribution substation. The distribution substation contains two power transformers. One power transformer is a 66 kV to 12 kV unit with a capacity of 13 MVA. It serves approximately 1700 customers in the New-Wes-Valley area through three 12 kV feeders. A gas turbine was relocated to the substation in 2005. The substation's second power transformer, which is a 66 kV to 13 kV unit with a capacity of 20 MVA, connects the gas turbine to the Island interconnected grid. There is one 66 kV transmission line, 116L from Trinity substation terminated in the substation.

Wesleyville Substation Location

The substation is in generally good condition and the power transformers show no signs of deterioration.

Metal oxide lightning arrestors will be installed on the 13 MVA power transformer. A 66 kV potential transformer at the termination of transmission line 116L will be relocated to permit safe work access.

WES-T1 Low Voltage Lightning Arrestors

2.10 Portable Substation P3 ($540,000)

Portable substation P3 was purchased in 1977. It is used to respond to power transformer failures and for carrying out planned transformer and substation maintenance. Of the approximate 190 power transformers in service on Newfoundland Power's system, P3 can provide backup for 68% of them.

This is the first comprehensive refurbishment of this portable substation since its purchase over thirty years ago. Purchase of a comparable new portable substation would cost approximately $4 million. Refurbishment of portable substation P3 should ensure its continued availability for the next decade.

Portable Substation P3

The manual hydraulic jacks on the unit have deteriorated and they will be replaced with a motorized system. The alarm panel has had several failures and will be replaced. The protection relays are thirty two year old electro mechanical type and will be replaced with new electronic digital protection relays.

The control wiring associated with the protection and control of the portable substation is original wiring showing signs of deterioration and will also be replaced.

A SCADA remote terminal unit will be installed on the portable substation to provide remote monitoring and control capability of the unit.

2.11 Items Under $50,000 ($193,000)

The 2010 Substation Refurbishment and Modernization project includes a number of smaller items that must be addressed in the near future, and cannot wait for a more comprehensive refurbishment of the substation. The replacement of lightning arrestors in six locations receives priority because of the risk of customer outages related to existing lightning arrestor failure. Site improvements are required at one location to ensure employee and public safety.

Lightning Arrestors
The primary function of lightning arrestors in a substation is to protect power transformers. Until the early 1980s, silicon carbide lightning arrestors were standard in the utility industry, and as a result many transformers in the Newfoundland Power fleet are protected using silicon carbide lightning arrestors.

Silicon carbide lightning arrestors are now known to fail as they age due to moisture seeping into the arrestor through failed seals. The Company has experienced high levels of failure on this type of lightning arrestor. There is no reliable way to test or monitor an arrestor to predict its failure. All remaining silicon carbide lightning arrestors in Newfoundland Power substations are being replaced on a priority basis and, where possible, coordinated with other capital work and transformer maintenance.

Table 2 shows the substations and costs associated with 2010 lighting arrestor replacement.

Table 2
2010 Lighting Arrestor Replacement
(000s)

Substation	**Cost**
Islington (ISL)	$34
Jonathan's Pond (JON)	$17
Pepperell (PEP)	$38
Placentia Junction (PJN)	$38
Seal Cove Substation (SCV)	$14
Summerville (SMV)	$24
Total	**$165**

Site Improvements
The fence at West Brook Hydro Plant has deteriorated to the point where it needs to be replaced in 2010 at an estimated cost of $28,000.

2.12 Substation Monitoring and Operations ($150,000)

Over the past decade, there has been substantial increased use of computer-based equipment in electrical system control and operations. Periodic upgrades of this equipment are necessary to ensure continued effective electrical system control and operations.

In 2010, upgrades to the communications hubs that connect multiple devices in substations to the SCADA system are planned. Effective management of increased volumes of electrical system data requires the upgrading of the hubs. This requires both hardware and software upgrades.

In 2010, the required work will incorporate manufacturers' upgrades to communications and other computer-based equipment located in Company substations. These upgrades typically increase functionality of the equipment and software and remedy known deficiencies.

Appendix A

Substation Refurbishment and Modernization Plan
Five-Year Forecast 2010 to 2014

Substation Refurbishment and Modernization Plan
Five-Year Forecast
2010 to 2014
(000s)

2010		**2011**		**2012**		**2013**		**2014**	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
BOT	837	HCT	906	BHD	218	GBS	874	ABC	632
BOY	67	NCH	866	CAR	583	HBS	213	BIG	408
CLK	228	NGF	686	FRN	755	MKS	600	BVA	911
GAL	703	PAS	20	GLN	330	NHR	591	GBY	250
GFS	797	P4	527	GBE	93	SPO	650	GPD	256
GIL	138	SCT	155	ILC	69	SCR	737	HAR	226
GLV	199	VIC	903	MAS	473	SUN	626	HUM	1099
P3	540			P1	486	VIR	393	ISL	156
SPF	138			STX	191	WAV	298	MOL	438
WES	53			STV	440			SPR	346
MISC	193			TBS	157			TCV	386
SCADA	150			TWG	210				
				WAL	612				
	$4,043		**$4,063**		**$4,617**		**$4,982**		**$5,108**

Note: SUB: Substation - Refer to the Electrical System handbook included with the 2006 Capital Budget Application for three letter substation designations. P1, P3 and P4 are the designations for the portable substations.

2010 Additions Due to Load Growth

June 2009

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1.0 Introduction

As load increases on an electrical system, individual components can become overloaded. When a substation power transformer becomes overloaded, technical alternatives are identified to remove the overload. Once these technical alternatives are fully developed, they are costed and an economic analysis is performed to identify the least cost alternative.

The actual peak loads experienced this past winter season revealed two overloaded substation power transformers as follows:

- Transformer No. 2 at Mobile ("MOB") substation ("MOB-T2") is rated at 6.7 MVA. The load on this transformer peaked at 8.2 MVA in 2008.

- Transformer No. 1 at Deer Lake ("DLK") substation ("DLK-T1") is rated at 16.7 MVA. The load on this transformer peaked at 16.8 MVA in 2008.

This report identifies two items for the Additions Due to Load Growth Project to be included in the 2010 Capital Budget. The first item is to replace MOB-T2 transformer with a 16.7 MVA unit relocated from DLK. The second item is to purchase a new 25 MVA transformer for DLK. These two items jointly provide the least cost alternative to removing the overloads at Mobile and Deer Lake substations

Both capital expenditure items will provide sufficient capacity to meet forecasted loads over the next 20 years.

2.0 MOB-T2 Loading

2.1 Description of Existing System

MOB substation is located in the community of Mobile, on the southern shore of the Avalon Peninsula. The substation has one distribution power transformer, MOB-T2.[1] This is a 6.7 MVA transformer used to convert the 66 kV transmission voltage to the 12.5 kV distribution voltage and supply customers through MOB substation.

There are two 12.5 kV feeders supplied from MOB substation. MOB-01 feeder extends north from the substation along the Southern Shore Highway and supplies approximately 1,162 customers in the communities of Mobile, Witless Bay and Bay Bulls. MOB-02 extends south from the substation and supplies approximately 586 customers from Mobile to Bauline East.

2.2 Load Forecast

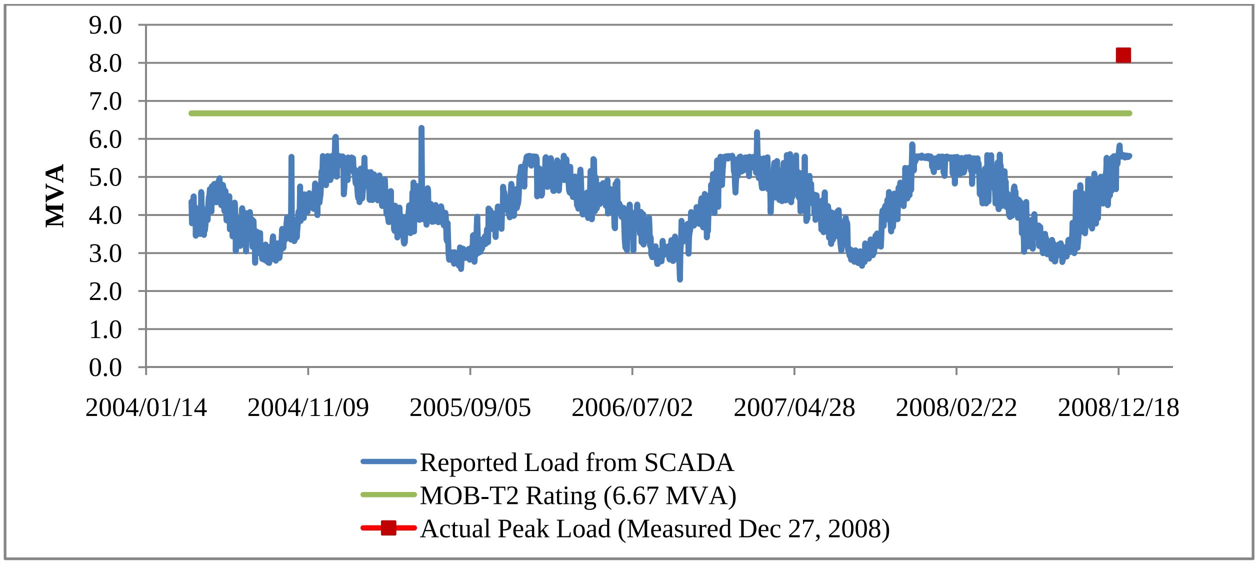
In December 2008, it was discovered that the transformer load readings reported through Newfoundland Power's SCADA system for MOB-T2 were incorrect. This was due to an insufficiently sized current transformer, which caused saturation in the metering circuit during

[1] A distribution power transformer, converts electricity from transmission voltages (typically > 60 kV) to distribution primary voltages (typically between 4kV and 34kV)

high load periods. With the saturated circuit, it appeared that the maximum load on the 6.7 MVA transformer had not exceeded 5.5 MVA. Once the metering problem was corrected, in actual fact, the peak load on MOB-T2 in 2008 had been 8.2 MVA, and the transformer had experienced a 23% overload on peak.

Graph 1 shows the reported transformer load and actual peak load measurement.

Graph 1[2]
MOB-T2 Load Readings



A load forecast has been completed on MOB-T2 based on the current load readings and projected load growth for the next 20 years. This forecast can be found in Appendix B. Load growth projections are based on Newfoundland Power's five year substation forecast, with the growth rate in year five applied over the subsequent fifteen years.

A high and low forecast has also been created for use in the sensitivity analysis. The high and low forecasts can also be found in Appendix A.

3.0 DLK-T1 Loading

3.1 Description of Existing System

DLK substation is located in the community of Deer Lake, in western Newfoundland. There is one distribution power transformer located in the substation, DLK-T1. This is a 16.7 MVA

2 Load readings reported from MOB-T2 through SCADA (blue) appeared to be within the transformer rating of 6.67MVA (green). However, the actual load has reached as high as 8.2MVA (red), 23% above the transformer rating.

transformer used to convert 66 kV transmission voltage to 12.5 kV distribution voltage and supply customers through DLK substation.

There are three 12.5 kV feeders originating from DLK substation. DLK-01 feeder supplies approximately 864 customers in the community of Deer Lake. DLK-03 feeder extends north from the substation along Route 430 and supplies approximately 1,144 customers in the communities of Reidville, Cormack and the Bonne Bay Pond area. DLK-04 feeder extends south from the substation and supplies approximately 1,362 customers in Deer Lake, Nicholsville and St. Judes.

3.2 Load Forecast

DLK-T1 is rated for 16.7 MVA, and reached 16.8 MVA under system peak conditions in 2008. A load forecast has been completed for DLK-T1 based on the current load readings and projected load growth for the next 20 years. This forecast can be found in Appendix B. Load growth projections are based on Newfoundland Power's five year substation forecast, with the growth rate in year five applied over the subsequent fifteen years.

A high and low forecast has also been created for use in the sensitivity analysis. The high and low forecasts can also be found in Appendix B.

4.0 Development of Alternatives

MOB-T2 and DLK-T1 transformers are overloaded and steps must be taken to reduce the amount of load on each transformer.

Four alternatives have been developed to eliminate the overload conditions using a set of defined technical criteria.[3]

For purposes of evaluating the alternatives for each substation, both the MOB and DLK substations are being evaluated together. This is because two of the alternatives have activities at MOB and DLK that are interdependent.

4.1 Alternative 1

Alternative 1 is to replace DLK-T1 with a new 25 MVA, 66/12.5 kV transformer and replace MOB-T2 with the 16.7 MVA, 66/12.5 kV transformer currently located at DLK substation.

[3] The following technical criteria were applied to ensure acceptable operating conditions for the MOB and DLK systems, as well as other systems affected by this study.

- The steady state power transformer loading should not exceed the nameplate rating.
- The minimum steady state feeder voltage should not fall below 116 Volts (on a 120 Volt base).
- The recloser normal peak loading should be sufficient to permit cold load pickup.
- The conductor loading should not exceed the ampacity rating established in the distribution planning guidelines.

With the transferred 16.7 MVA transformer at MOB and a new 25 MVA transformer at DLK, there is no transformer overload in either substation for the 20 year load forecast horizon.

The costs for this alternative include $2,213,000 to purchase a new transformer for DLK and complete the required substation modification. In addition, $1,257,000 is required to relocate the 16.7 MVA transformer from DLK substation to MOB substation and complete required substation upgrades at MOB substation.

4.2 Alternative 2

Alternative 2 is to replace both DLK-T1 with a new, 25 MVA, 66/12.5 kV transformer and to replace MOB-T2 with a new, 16.7 MVA, 66/12.5 kV transformer.

With a new 16.7 MVA transformer at MOB and a new 25 MVA transformer at DLK, there is no further transformer overload in the 20 year load forecast horizon.

The costs for this alternative include $2,213,000 to purchase a new transformer for DLK and complete the required substation modifications, as well as $2,082,000 to purchase a new transformer for MOB and complete the required substation modifications.

4.3 Alternative 3

Alternative 3 is to replace MOB-T2 with a new 16.7 MVA, 66/12.5 kV transformer and move the 6.7 MVA transformer to DLK to function in parallel with the 16.7 MVA, 66/12.5 kV transformer currently located at DLK substation.

With the new 16.7 MVA transformer at MOB and, the 6.7 MVA and 16.7 MVA transformers at DLK, there is no further transformer overload in the 20 year load forecast horizon.

The costs for this alternative include $2,082,000 to purchase a new transformer for MOB and complete the required substation modification. In addition, $1,980,000 is required to relocate the 6.7 MVA transformer from MOB substation to DLK substation and complete required substation upgrades at DLK. These modifications include addition of new substation and distribution bus terminations.

4.4 Alternative 4

Alternative 4 would be to reduce the amount of load on each transformer by transferring load to an adjacent substation. Due to the unavailability of connection points to adjacent feeders and capacity limitations on the adjacent substations, this option was not further considered as a reasonable alternative.

For DLK-T1, this option would involve the transfer a section of load to Pasadena (“PAS”) substation. However, there is currently no connection point between DLK and PAS substations. To create a connection point would require a 12 km section of DLK-04 and PAS-02 feeders to be upgraded from 1-phase to 3-phase, and construction of 2 km of new distribution line. The estimated cost to complete the upgrades and load transfer is $400,000. This load transfer would create an overload condition on PAS-T1 transformer in 2011, with no available option to transfer load to another adjacent substation.

For MOB-T2, a load transfer could be done by transferring a section of load to Big Pond substation ("BIG"). However, this would require a 6 km section of BIG-02 feeder to be upgraded from 2-phase to 3-phase, and a 5 km section to be upgraded from 1-phase to 3-phase. The estimated cost to complete this upgrade and load transfer is $300,000. The resulting increased load on BIG-02 feeder would immediately cause an overload on BIG-T1 transformer. A section of load would then need to be transferred from BIG substation to Goulds substation ("GOU"), creating an overload condition on GOU-03 feeder, with no available option to transfer load from GOU-03 to another feeder.

5.0 Evaluation of Alternatives

5.1 Cost of Alternatives

Table 1 shows the total 2010 capital costs for alternatives 1, 2 and 3.

Table 1
Total 2010 Capital Costs

Alternative 1

Year	Item	Cost
2010	Purchase new 25 MVA transformer for DLK substation and complete substation modifications.	$2,213,000
2010	Transport existing 16.7 MVA transformer from DLK substation to MOB substation and complete substation modifications.	$1,257,000
	Total	**$3,470,000**

Alternative 2

Year	Item	Cost
2010	Purchase new 25 MVA transformer for DLK substation and complete substation modifications.	$2,213,000
2010	Purchase new 16.7 MVA transformer for MOB substation and complete substation modifications.	$2,082,000
	Total	**$4,295,000**

Alternative 3

Year	Item	Cost
2010	Purchase new 16.7 MVA transformer for MOB substation and complete substation modifications.	$2,082,000
2010	Transport existing 6.7 MVA transformer from MOB substation to DLK substation and complete substation modifications.	$1,980,000
	Total	**$4,062,000**

Based on the load forecast, there are no future overload conditions and no additional capital expenditures required in the 20 year forecast period.

5.2 Economic Analysis

No net present value analysis is required to make the least cost decision as all costs are capital costs in 2010 and are therefore directly comparable for purposes of choosing the least cost alternative. Alternative 1is the least cost alternative based upon capital costs.

Implementation of either Alternative 1 or 2 will result in Newfoundland Power placing a transformer or transformers into its inventory of spare equipment. For Alternative 1, it would be the 6.7 MVA MOB-T2. For Alternative 2, it would be the 6.7 MVA MOB-T2 and the 16.7 MVA DLK-T1. In assessing alternatives, it is reasonable to place some value on this spare equipment.

Table 2 shows the capital cost of each alternative; and estimated credit to be deducted from capital cost to reflect the value of spare transformers in Alternative 1 and 2[4]; and the net capital cost of each alternative following crediting of the value of spare transformers.

Table 2
Alternative Costs

Alternative	Capital Cost	Spare Credit	Net Capital Cost
1	$3,470,000	$117,000	$3.353,000
2	$4,295,000	$156,000+$117,000	$4,022,000
3	$4,062,000	$0	$4,062,000

Alternative 1 is the least cost alternative after crediting the reasonable value of spare transformers, as appropriate to the alternatives.[5]

5.3 Sensitivity Analysis

To judge the sensitivity to load forecast error of Alternative 1 being the least cost alternative, high and low forecasts were developed. With exception of the first year forecast, the sensitivities were based on increasing the load growth by a factor of 50% for the high forecast and decreasing by a factor of 50% for the low forecast.

Both the high and low load forecasts did not yield any future overload conditions for Alternatives 1 and 2. For Alternative 3 with the high load forecast there is an overload at DLK in 2027, the 3rd last year of the load forecast horizon. Given Alternative 3 is already the highest cost of the three alternatives, no further economic analysis was required to judge the sensitivity of the recommendation to high and low forecasts.

As a result the recommendation to select Alternative 1 doesn't change with the sensitivity analysis.

4 Both transformers were purchased in 1974. Using the Iowa 46R2 depreciation curve, a probable remaining life of 18 years is projected for each. Also using the Iowa 46R2 depreciation curve, the probable life of a new transformer is 46 years. The remaining value can be reasonably estimated by multiplying the current new price for each transformer by a ratio of 18/46.

5 The 6.7 MVA MOB-T2 will provide a transformer spare for 12 units currently in service for which the only existing back-up is a portable substation.

6.0 Conclusion and Recommendation

Both DLK-T1 and MOB-T2 transformers are currently overloaded during peak load conditions. There are no reasonable options to transfer load to adjacent substations, and as a result, it is necessary to increase transformer capacity at both Deer Lake and Mobile substations.

Three alternatives have been developed that will increase capacity at both substations. A 20 year system load forecast was created to determine if additional capital expenditures would be required within that period, and high and low load forecasts were created to determine the effect of load growth on required capital expenditures. The load forecast results show that both alternatives will provide sufficient capacity and no additional capital expenditures for load growth will be required within the 20 year period.

It is recommended that Alternative 1, which is the least cost alternative, be completed as part of Newfoundland Power's 2010 Capital Budget. This alternative includes purchase and installation of a new 25 MVA transformer at Deer Lake substation to replace DLK-T1, and relocating the existing 16.7 MVA transformer from Deer Lake substation to Mobile substation to replace MOB-T2.

Appendix A

MOB-T2 20 Year Load Forecast

MOB-T2 20 Year Load Forecast

	Forecast		Sensitivity - High		Sensitivity - Low	
Year	**Demand (kVA)**	**% increase**	**Demand (kVA)**	**% increase**	**Demand (kVA)**	**% increase**
2009	8,786		8,879		8,694	
2010	8,984	2.25%	9,178	3.38%	8,792	1.13%
2011	9,182	2.20%	9,481	3.30%	8,889	1.10%
2012	9,411	2.50%	9,837	3.75%	9,000	1.25%
2013	9,597	1.97%	10,127	2.96%	9,088	0.99%
2014	9,782	1.93%	10,420	2.90%	9,176	0.97%
2015	9,971	1.93%	10,722	2.90%	9,265	0.97%
2016	10,163	1.93%	11,033	2.90%	9,354	0.97%
2017	10,359	1.93%	11,352	2.90%	9,444	0.97%
2018	10,559	1.93%	11,681	2.90%	9,535	0.97%
2019	10,763	1.93%	12,019	2.90%	9,627	0.97%
2020	10,971	1.93%	12,367	2.90%	9,720	0.97%
2021	11,182	1.93%	12,725	2.90%	9,814	0.97%
2022	11,398	1.93%	13,093	2.90%	9,909	0.97%
2023	11,618	1.93%	13,472	2.90%	10,004	0.97%
2024	11,842	1.93%	13,862	2.90%	10,101	0.97%
2025	12,071	1.93%	14,263	2.90%	10,198	0.97%
2026	12,304	1.93%	14,676	2.90%	10,297	0.97%
2027	12,541	1.93%	15,101	2.90%	10,396	0.97%
2028	12,783	1.93%	15,538	2.90%	10,497	0.97%
2029	13,030	1.93%	15,988	2.90%	10,598	0.97%

Appendix B

DLK-T1 20 Year Load Forecast

DLK-T1 20 Year Load Forecast

	Forecast		Sensitivity - High		Sensitivity - Low	
Year	Demand (kVA)	% increase	Demand (kVA)	% increase	Demand (kVA)	% increase
2009	18,018		18,152		17,885	
2010	18,305	1.59%	18,585	2.39%	18,027	0.80%
2011	18,486	0.99%	18,861	1.49%	18,116	0.50%
2012	18,667	0.98%	19,138	1.47%	18,205	0.49%
2013	18,848	0.97%	19,416	1.46%	18,293	0.49%
2014	19,029	0.96%	19,696	1.44%	18,381	0.48%
2015	19,212	0.96%	19,979	1.44%	18,469	0.48%
2016	19,396	0.96%	20,267	1.44%	18,558	0.48%
2017	19,582	0.96%	20,559	1.44%	18,647	0.48%
2018	19,770	0.96%	20,855	1.44%	18,737	0.48%
2019	19,960	0.96%	21,155	1.44%	18,826	0.48%
2020	20,152	0.96%	21,460	1.44%	18,917	0.48%
2021	20,345	0.96%	21,769	1.44%	19,008	0.48%
2022	20,541	0.96%	22,083	1.44%	19,099	0.48%
2023	20,738	0.96%	22,401	1.44%	19,191	0.48%
2024	20,937	0.96%	22,723	1.44%	19,283	0.48%
2025	21,138	0.96%	23,050	1.44%	19,375	0.48%
2026	21,341	0.96%	23,382	1.44%	19,468	0.48%
2027	21,546	0.96%	23,719	1.44%	19,562	0.48%
2028	21,753	0.96%	24,060	1.44%	19,656	0.48%
2029	21,961	0.96%	24,407	1.44%	19,750	0.48%

Convert 23L to 66kV to Reduce Losses

June 2009

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1.0 Introduction

The efficiency of transmitting energy between Pierre's Brook plant and Mobile substation can be improved by increasing the operating transmission line voltage of 23L from 33,000 volts (33 kV) to 66,000 volts (66 kV). Operating at the higher voltage will reduce energy losses, thereby making more of the energy produced at Pierre's Brook plant available to the Island interconnected system. This study examines the feasibility of operating transmission line 23L at 66 kV rather than 33 kV.

Newfoundland Power is proposing to rebuild transmission line 23L in 2010. It has deteriorated to the point that a complete rebuild of the line is required. The justification for the rebuild of transmission line 23L is contained in report *3.1 Transmission Line Rebuild*.

Transmission line 23L will be rebuilt to a 66 kV standard whether it is operated at 66 kV or 33 kV as there is little difference in construction costs at these voltages. However additional substation expenditures are required to enable operation of the transmission line at 66 kV.

As energy costs increase, so do the costs associated with losses. The impact of increased energy cost on losses would be less by operating 23L transmission line at 66 kV rather than 33 kV. Further, the removal of the 33/66 kV transformer at Mobile substation, which would no longer be needed, would also reduce losses. Removing the 33/66 kV transformer at Mobile substation from the system will also avoid the future cost associated with the replacement of that asset.

2.0 Description of Existing System

Figure 1 shows transmission line 23L as well as other plants, substations and transmission lines in the vicinity of Mobile substation and Pierre’s Brook plant.

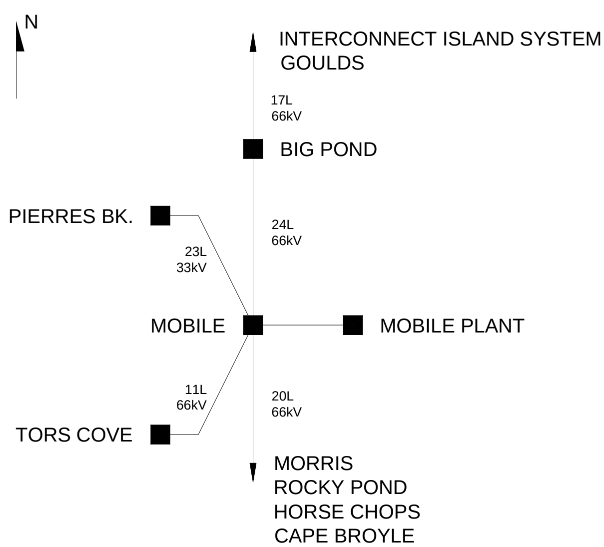

Figure 1

Transmission line 23L operates at 33 kV and electrically connects the Pierre's Brook plant to Mobile substation. At Mobile substation a 66/33 kV transformer enables connection of the 33 kV supply from Pierre's Brook plant to the 66 kV transmission system for the Southern Shore generation and substation loads, and further to the Island interconnected system.

3.0 Description of Proposed Modifications

To achieve energy savings, Newfoundland Power is proposing to increase the operating voltage of transmission line 23L from 33 kV to 66 kV.

Modifications are required at both Mobile substation and Pierre’s Brook plant locations to operate transmission line 23L at 66 kV.

At Mobile substation, the 33/66 kV transformer will be removed. Other changes to the Mobile substation include replacement of the 33 kV breaker with a 66 kV breaker, installation of manual switches associated with the breaker and relaying upgrades.

At Pierre's Brook plant, the transformer, which has a dual 33/66 kV winding, can be reconfigured to operate at 66 kV. Other changes to the Pierre's Brook plant include installation of 66 kV lightning arrestors and replacement of transformer fuses.

Increasing the operating voltage for transmission line 23L from 33 kV to 66 kV at the same time as the transmission line 23L rebuild enables any plant downtime associated with the voltage change to take place at the same time as the transmission line rebuild. Therefore, there would be no lost production at Pierre's Brook plant as a consequence of changes necessary to operate the transmission line at 66 kV.

There are additional savings associated with the removal of the 33/66 kV transformer at Mobile. The transformer was purchased in 1963 and is now 46 years old. The transmission line voltage conversion removes the requirement to replace this transformer and its breaker when they reach the end of their useful lives. Further, periodic maintenance will no longer performed on this unit or its replacement.

4.0 Technical Analysis

Newfoundland Power’s review of the feasibility of operating transmission line 23L at 66 kV rather than 33 kV indicates that there are no technical problems associated with the conversion.

The annual energy savings associated with the voltage conversion of transmission line 23L are 251,096 kWh. These savings are composed of both reductions in line losses and removal of losses associated with the 33/66 kV transformer at Mobile. These calculations are based on using a typical year's loading data for transmission line 23L to simulate line losses and the transformer losses, both at 33 kV and 66 kV.

5.0 Economic Analysis

The economic analysis calculates a levelized cost of energy based on incremental capital costs, changes to operating costs and energy savings. The levelized cost of energy in ¢/kWh is then compared to the avoided cost of electricity generation to judge the project's economic viability.

Table 1 shows the capital cost breakdown for the project as noted in Schedule B.

Table 1
Convert 23L to 66KV
(000s)

Substation	**Budget**
Pierre's Brook (PBK)	$ 24
Mobile (MOB)	262
Total	**$ 286**

As already mentioned, there will be future transformer maintenance savings[1] associated with the removal of the 33/66 kV transformer. These are included as cost reductions in the analysis.

To evaluate the economic impact of the proposed modifications, the cumulative present worth revenue requirement of the $286,000 conversion cost was calculated using a weighted average incremental cost of capital of 8.58%.

With this cumulative present worth, the levelized unit cost of the annual energy savings is 0.77¢/kWh. Appendix A contains the associated economic analysis calculation sheet.

The existing 33/66 kV transformer at Mobile substation is 46 years old. Further, the breaker associated with the transformer is in excess of 50 years old and would be replaced at approximately the same time as the transformer replacement, or earlier. The economic analysis gives a credit in 2021[2] for the replacement of both the transformer and the breaker.

The assumption made for the remaining life of the 46 year old transformer has a material impact[3] on the levelized cost of undertaking this project. If for example, the transformer were to remain in service for an additional 50 years the levelized cost would approach 10¢/kWh.

1 Savings associated for transformer maintenance are assumed to be $19,000 on a 10 year cycle, as shown in Appendix A

2 Retirement date of transformer is based on 50% probability of failure for the 46 year old transformer in the year 2021.

3 The future timing of the transformer replacement is such that if the transformer requires replacement sooner that the estimated date of 2021, then the levelized cost would be less than 0.77¢/kWh. If the transformer were to remain in service longer than estimated, and require replacement after 2021, then the levelized cost would be greater than 0.77¢/kWh.

The probability that the existing transformer will remain in service for an additional 50 years is small compared to the probable remaining life of 11 years. However, the 10¢/kWh cost of energy is less than the cost of electricity currently supplied from the Holyrood thermal generating plant at 12.06 ¢/kWh[4].

The economic analysis calculation sheet in Appendix A clearly indicates that the project is economic when compared to the cost of oil used at Holyrood.

6.0 Concluding

Operating 23L transmission line, connecting Pierre's Brook substation to Mobile substation, at 66 kV rather than 33 kV is technically and economically feasible.

This will save 251,096 kWh of electric energy annually and displace approximately 400 barrels of oil from being burned at the Holyrood thermal plant.

It is recommended that substation facilities be put in place to operate 23L transmission line at 66 kV.

4 Based on 630 kWh/bbl conversion efficiency of Holyrood and oil forecast from Hydro of $75.95/bbl dated March 31, 2009

Appendix A

Levelized Unit Cost of Energy Savings

Present Worth Analysis

Weighted Average Incremental Cost of Capital 8.58%
PW Year 2009

Year	Substations 46.2yrs 8% CCA	Capital Revenue Rqmt	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2010	286,000	30,638	-19,000	0	-11,638	-10,718	-10,718	4.63	0.77
2011	0	30,177	0	0	-30,177	-25,597	-36,315	12.02	0.77
2012	0	30,214	0	0	-30,214	-23,602	-59,917	12.03	0.77
2013	0	30,152	0	0	-30,152	-21,693	-81,610	12.01	0.77
2014	0	30,038	0	0	-30,038	-19,903	-101,513	11.96	0.77
2015	0	29,875	0	0	-29,875	-18,231	-119,744	11.90	0.77
2016	0	29,667	0	0	-29,667	-16,673	-136,417	11.81	0.77
2017	0	29,418	0	0	-29,418	-15,227	-151,645	11.72	0.77
2018	0	29,131	0	0	-29,131	-13,887	-165,532	11.60	0.77
2019	0	28,810	0	0	-28,810	-12,649	-178,180	11.47	0.77
2020	-13,154	27,047	-22,720	0	-4,327	-1,750	-179,930	1.72	0.77
2021	-584,733	-35,955	0	0	35,955	13,389	-166,541	-14.32	0.77
2022	0	-35,425	0	0	35,425	12,150	-154,391	-14.11	0.77
2023	0	-35,932	0	0	35,932	11,350	-143,041	-14.31	0.77
2024	0	-36,258	0	0	36,258	10,548	-132,494	-14.44	0.77
2025	0	-36,496	0	0	36,496	9,778	-122,716	-14.53	0.77
2026	0	-36,652	0	0	36,652	9,044	-113,672	-14.60	0.77
2027	0	-36,732	0	0	36,732	8,347	-105,325	-14.63	0.77
2028	0	-36,743	0	0	36,743	7,690	-97,635	-14.63	0.77
2029	0	-36,690	0	0	36,690	7,072	-90,563	-14.61	0.77
2030	0	-36,578	0	0	36,578	6,493	-84,069	-14.57	0.77
2031	0	-36,412	0	0	36,412	5,953	-78,116	-14.50	0.77
2032	0	-36,197	0	0	36,197	5,450	-72,666	-14.42	0.77
2033	0	-35,936	0	0	35,936	4,983	-67,682	-14.31	0.77
2034	0	-35,632	0	0	35,632	4,551	-63,131	-14.19	0.77
2035	0	-35,290	0	0	35,290	4,151	-58,980	-14.05	0.77
2036	0	-34,913	0	0	34,913	3,782	-55,198	-13.90	0.77
2037	0	-34,502	0	0	34,502	3,442	-51,756	-13.74	0.77
2038	0	-34,062	0	0	34,062	3,130	-48,626	-13.57	0.77
2039	0	-33,593	0	0	33,593	2,843	-45,783	-13.38	0.77
2040	0	-33,099	0	0	33,099	2,580	-43,203	-13.18	0.77
2041	0	-32,582	0	0	32,582	2,339	-40,864	-12.98	0.77
2042	0	-32,043	0	0	32,043	2,118	-38,746	-12.76	0.77
2043	0	-31,484	0	0	31,484	1,917	-36,829	-12.54	0.77
2044	0	-30,907	0	0	30,907	1,733	-35,096	-12.31	0.77
2045	0	-30,314	0	0	30,314	1,565	-33,531	-12.07	0.77
2046	0	-29,704	0	0	29,704	1,413	-32,118	-11.83	0.77
2047	0	-29,081	0	0	29,081	1,274	-30,844	-11.58	0.77
2048	0	-28,444	0	0	28,444	1,147	-29,697	-11.33	0.77
2049	0	-27,795	0	0	27,795	1,033	-28,664	-11.07	0.77
2050	0	-27,135	0	0	27,135	929	-27,735	-10.81	0.77
2051	0	-26,465	0	0	26,465	834	-26,901	-10.54	0.77
2052	0	-25,786	0	0	25,786	748	-26,153	-10.27	0.77
2053	0	-25,098	0	0	25,098	671	-25,482	-10.00	0.77
2054	0	-24,402	0	0	24,402	601	-24,881	-9.72	0.77
2055	0	-23,699	0	0	23,699	537	-24,344	-9.44	0.77
2056	0	-31,529	0	0	31,529	658	-23,686	-12.56	0.77
2057	0	-28,060	0	0	28,060	540	-23,146	-11.18	0.77
2058	0	-26,632	0	0	26,632	472	-22,674	-10.61	0.77
2059	0	-25,197	0	0	25,197	411	-22,263	-10.03	0.77
2060	0	-23,757	0	0	23,757	357	-21,906	-9.46	0.77

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects an income tax rate of 32.0%.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55%	6.60	3.63
Common Equity	45%	11.00	4.95
Total	**100%**		**8.58**

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.

Transmission Line Rebuild

June 2009

Prepared by:

Trina L. Troke, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
TRINA L. TROKE
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1.0 Transmission Line Rebuild Strategy

Transmission lines play a critical role in providing reliable electrical service to customers. The Company ensures that transmission lines are maintained in a manner consistent with their critical role in service delivery.

In 2006, Newfoundland Power ("The Company") submitted its *Transmission Line Rebuild Strategy* outlining a 10-year plan to rebuild aging transmission lines. This plan prioritized the investment in rebuild projects based on physical condition, risk of failure, and potential customer impact in the event of a failure.

The *Transmission Line Rebuild Strategy* is regularly updated to ensure that it reflects the latest reliability data, inspection information, and condition assessments.

Appendix A contains the updated Transmission Line Rebuild Strategy Schedule.

2.0 Transmission Line Rebuild Projects Planned for 2010

In 2010, the Company plans to rebuild transmission line 23L and sections of transmission lines 24L and 110L. Appendix B contains topographic views of each of the lines to be rebuilt. Appendix C contains photographs of the existing lines.

These lines are each more than 45 years old and there is deterioration of the poles, crossarms, hardware, and conductor. This makes the lines vulnerable to large scale damage when exposed to heavy wind, ice, and snow loading, thus increasing the risk of power outages. Inspections have identified evidence of decaying wood, worn hardware and damage to insulators. In addition, the steel core of the 110L conductor shows evidence of corrosion which reduces the physical strength and electrical current carrying capacity of the conductor.

2.1 Transmission Line 23L ($826,000)

23L is a 33 kV radial transmission line between Pierre's Brook Plant and Mobile Substation. Constructed in 1942, it is 5.5 km in length and is Newfoundland Power's oldest transmission line connecting the Company's 4.3 MW Pierre's Brook Hydroelectric plant to the Island interconnected system. No customers are directly served by 23L.

Inspections have identified deterioration to poles and crossarms due to decay, woodpecker holes, insect damage, splits and checks, as well as corrosion and wear to hardware. Many of these components are in advanced stages of deterioration and require replacement. A number of the wooden poles are original vintage (67 years old) and have surpassed their normal life expectancy.

Many of the insulators on the line are pin-type (tie-top) and not the more robust line post (clamp-top) insulators that are have been standard for the Company's transmission lines for many years. The conductor is non-standard 3/0 copper.

The justification for conversion of 23L to 66 kV is contained in report ***2.3** Convert 23L to 66 kV to Reduce Losses.* The 23L transmission line requires replacement due to its deteriorated condition. It is recommended that it be rebuilt using 66 kV construction standards. This will provided added benefit from a decrease in electrical losses and an increase in energy efficiency.

Recent inspections have determined the transmission line has reached a point where it must be rebuilt to continue to provide safe, reliable operation.

Based on the overall deteriorated condition of the line, the associated safety and reliability concerns, and the energy efficiency benefits associated with this project, it is recommended that the line be rebuilt in 2010 at an estimated cost of $826,000.

2.2 Transmission Line 24L ($1,161,000)

24L is a 66kV radial transmission line between Bay Bulls Big Pond Substation and Mobile Substation. It is 20 kilometres in length and was originally constructed in 1954 and 1964. The H-Frame section constructed in 1954 was completely rebuilt in 2002, and a section of the 1964 vintage single pole section was rebuilt in 2003. Only a 7.7 kilometre section of the original wooden single pole structures remains.

Inspections have identified deterioration due to decay, splits and checks in the poles and crossarms, and corrosion and wear to other hardware. Many of these components are in advanced stages of deterioration and require replacement.

The poles, crossarms and hardware are generally deteriorated and in a weakened state. This combined with the long spans, many in excess of 100 metres, make the line more susceptible to damage and place the line at risk of large scale damage should it become exposed to wind, ice or snow loading.

24L is a critical transmission line as it connects 4,600 customers, 7 hydroelectric plants and 9 privately-owned wind generation units[1] to the Island interconnected system. The copper conductor on this 7.7 kilometre section of transmission line is small in comparison to the Company's standard transmission line conductors. As a result, the electrical losses over this section of line are significant when all generation sources are on-line.

Based on the overall condition of this section of 24L, it is recommended that the remaining 7.7 km be rebuilt in 2010 at an estimated cost of $1,161,000.

2.3 Transmission Line 110L ($2,178,000)

Constructed in 1958, 110L is a 66 kV transmission line between Clarenville Substation and Lockston Substation on the Bonavista Peninsula. The line is 79 km in length and is of single wood pole construction.

[1] This represents a combined generating capacity of approximately 69 MW.

110L serves approximately 4,300 customers on the Bonavista Peninsula between Milton and Lockston. This line also connects the Company's Lockston hydro plant to the main electrical grid.

The conductor is damaged and deteriorated in many places and has been subjected to ice loading since its original installation. The steel core and the aluminum strands are corroded. This reduces the physical strength and the electrical capacity of the conductor. This deterioration is such that the line has been de-rated to about one-half of its original electrical current carrying capacity for safety reasons.

Since 2001, there have been several outages on this line due to wind and ice conditions which cause the conductors to slap together. This results in conductor damage and often conductor failure.

Sections of 110L have already been upgraded. Most recently, the 21 km section of line extending between the Company's Lockston plant and Summerville substation was completely rebuilt. Another 4.9 km section of the line is approved for rebuilding as part of the Company's 2009 Capital Budget Application.

Based on the condition of the remaining sections of the line, it is recommended that another 14.5 km of 110L be rebuilt in 2010 at an estimated cost of $2,178,000.

Appendix A

Transmission Line Rebuild Strategy Schedule

Transmission Line Rebuilds
2010-2014
($000)

Line	Year	2010	2011	2012	2013	2014
012L KBR-MUN	1950		590			
013L SJM-SLA	1962					605
014L SLA-MUN	1950			235		
015L SLA-MOL	1958					131
016L PEP-KBR	1950		730			
018L GOU-GDL	1951				777	
021L 20L-HCP	1952		822			
023L MOB-PBK	1942	826				
024L MOB-BIG	1964	1,161				
025L GOU-SJM	1954		1,443			
030L RRD-KBR	1959			806		
032L OXP-RRD	1959					350
035L OXP-KEN	1963					949
068L HGR-CAR	1951					900
069L KEN-SLA	1951					819
110L CLV-LOK	1958	2,178		1,668	2,910	
124L CLV-GAM	1964			810		
	Total	**$4,165**	**$3,585**	**$3,519**	**$3,687**	**$3,754**

Transmission Line Rebuilds
2015-2021
($000)

Line	Year	2015	2016	2017	2018	2019	2020	2021
041L CAR-HCT	1958		3,553					
049L HWD-CHA	1966						595	
057L BRB-HGR	1958	3,228						
100L SUN-CLV	1964							2,978
101L GFS-RBK	1957				6,012			
102L GAN-RBK	1958					6,356	6,829	
124L CLV-GAM	1964							3,750
301L SPO-GRH	1959		208					
302L SPO-LAU	1959			5,196				
403L TAP-ROB	1960							919
	Total	**$3,228**	**$3,761**	**5,196**	**$6,012**	**$6,356**	**$7,424**	**$7,647**

Appendix B

Topographic Maps of
Transmission Lines 23L, 24L, and 110L

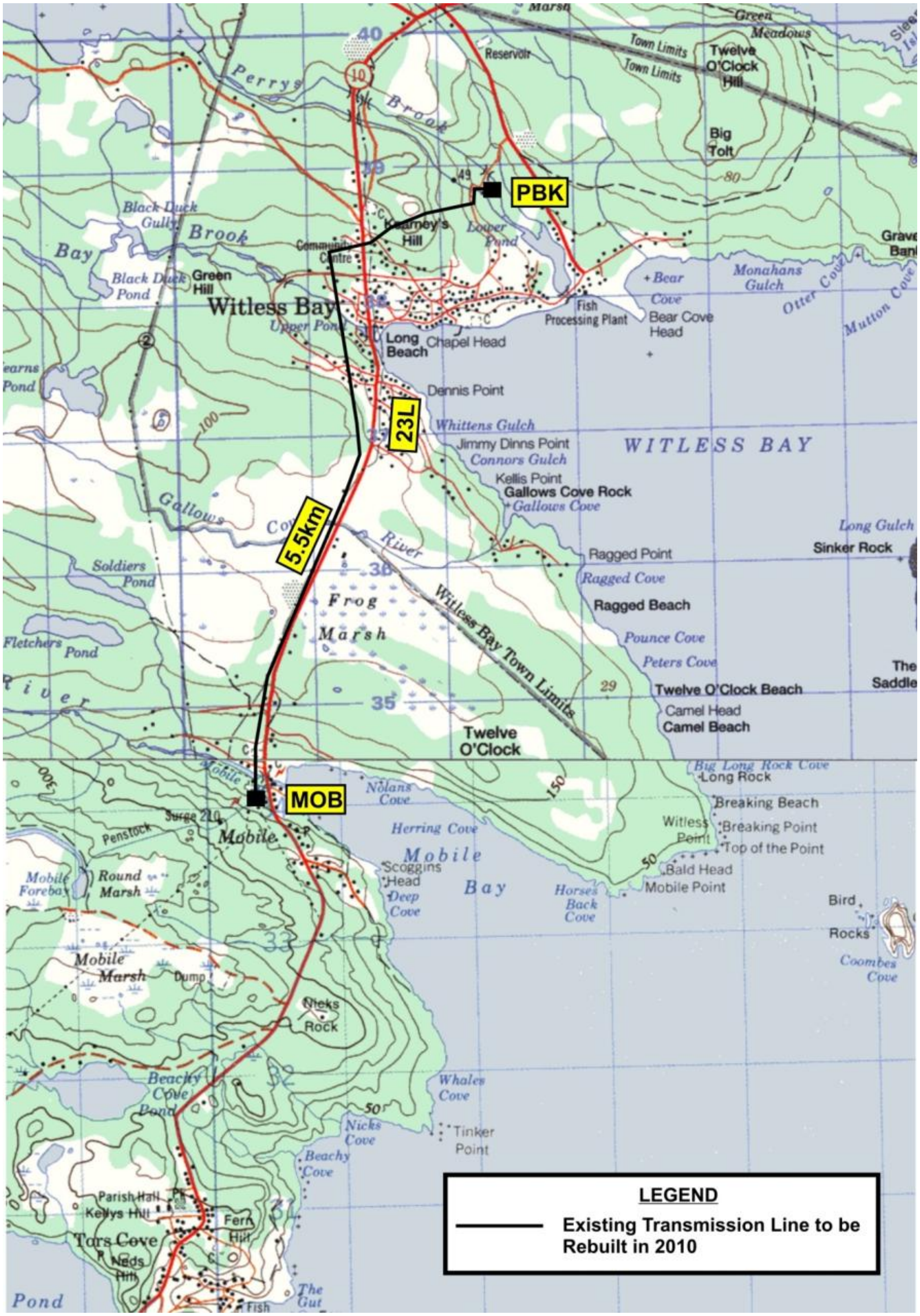


Figure 1 – Topographic Map 23L

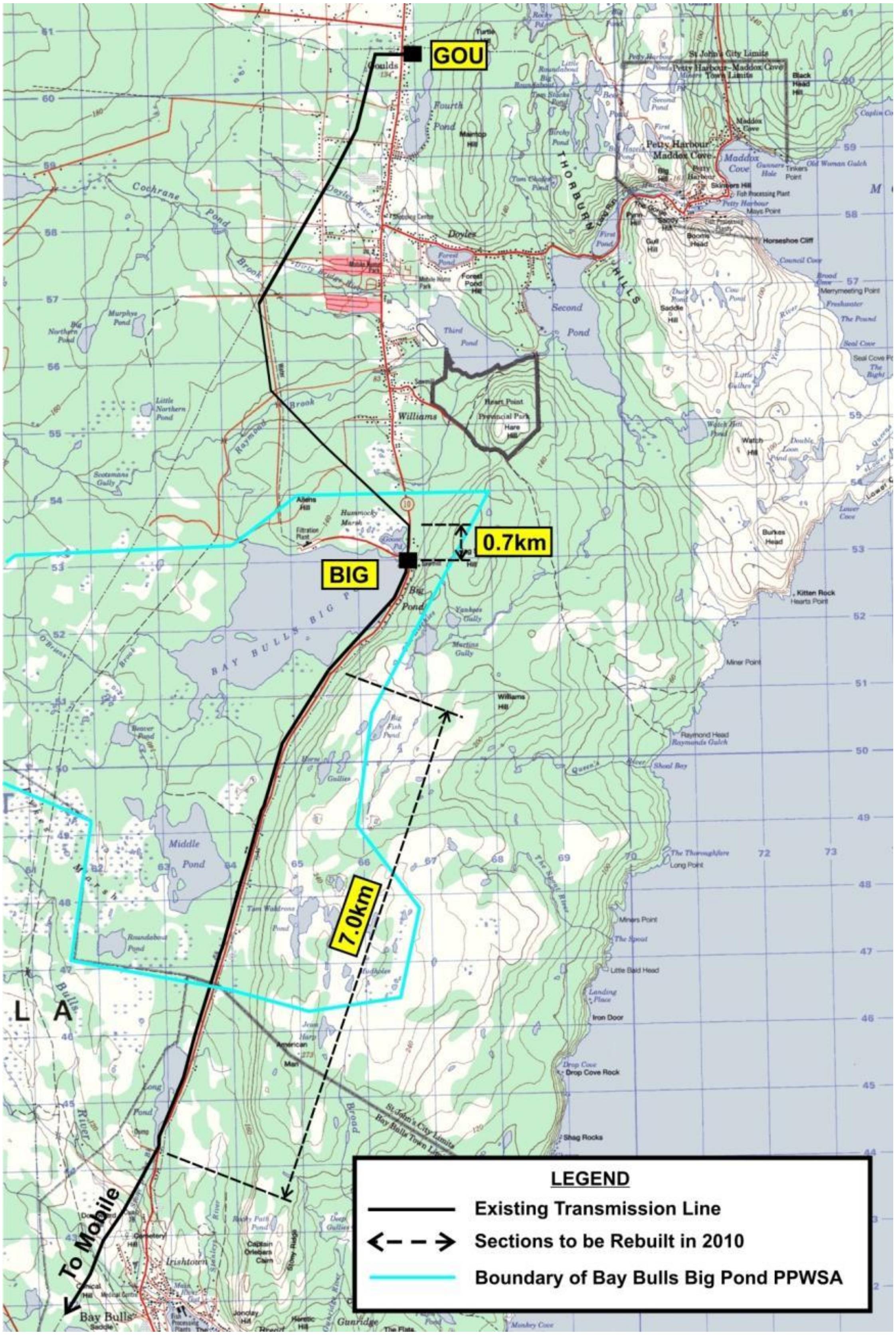


Figure 2 – Topographic Map 24L

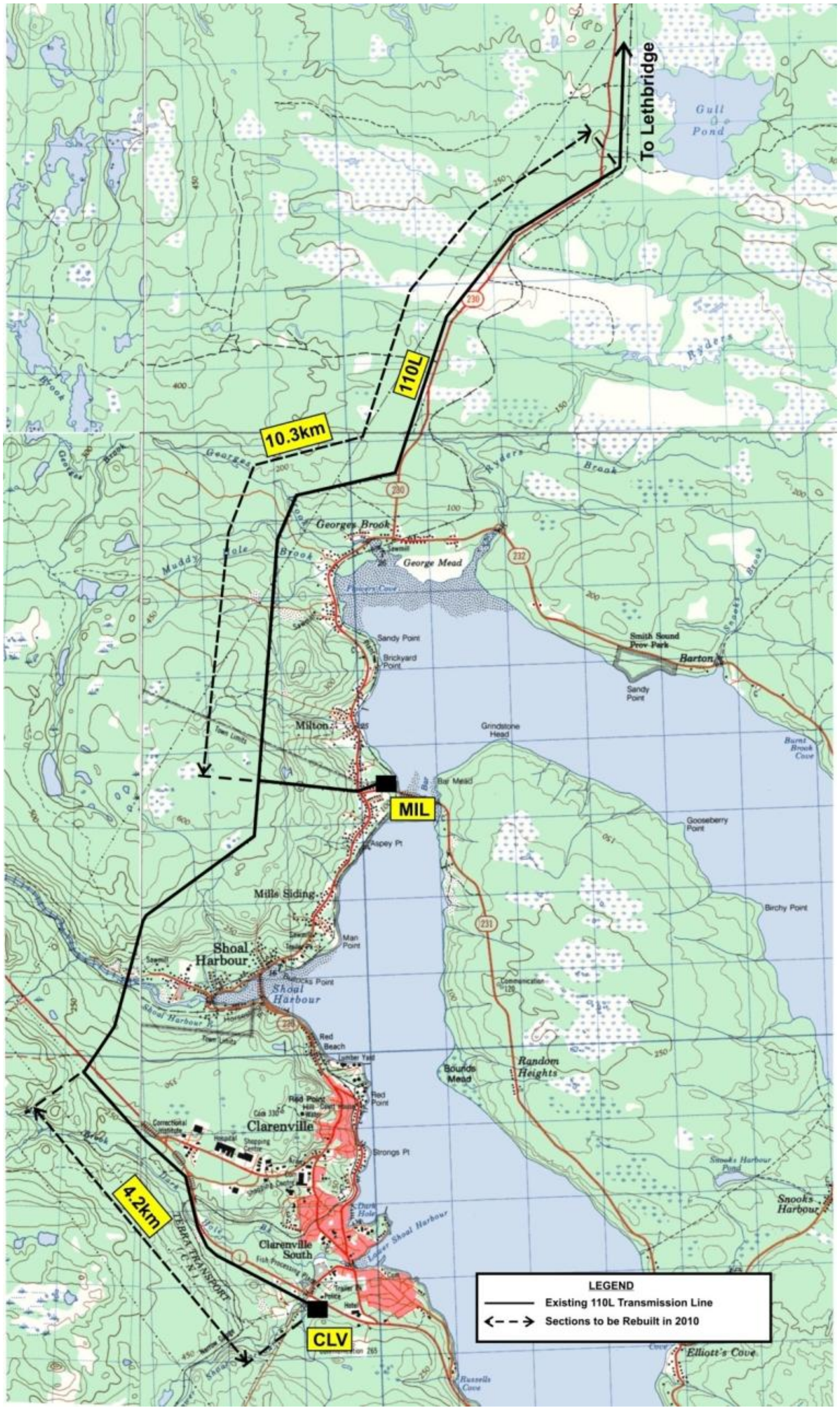
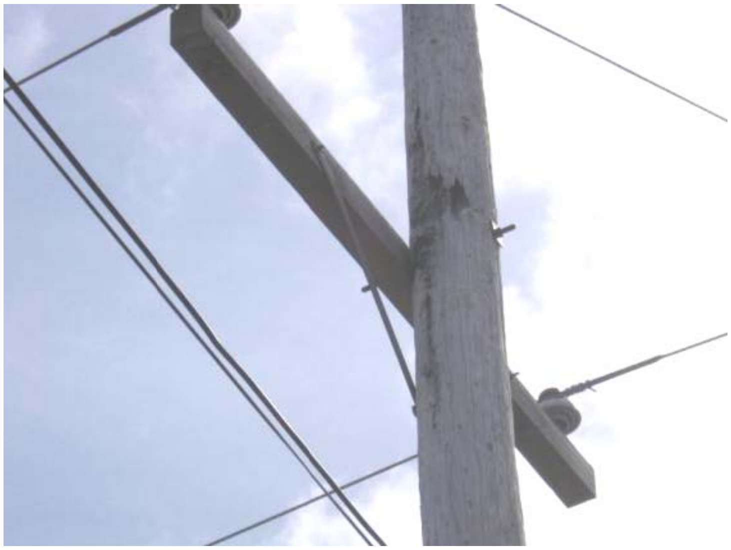


Figure 3 – Topographic Map 110L

Appendix C

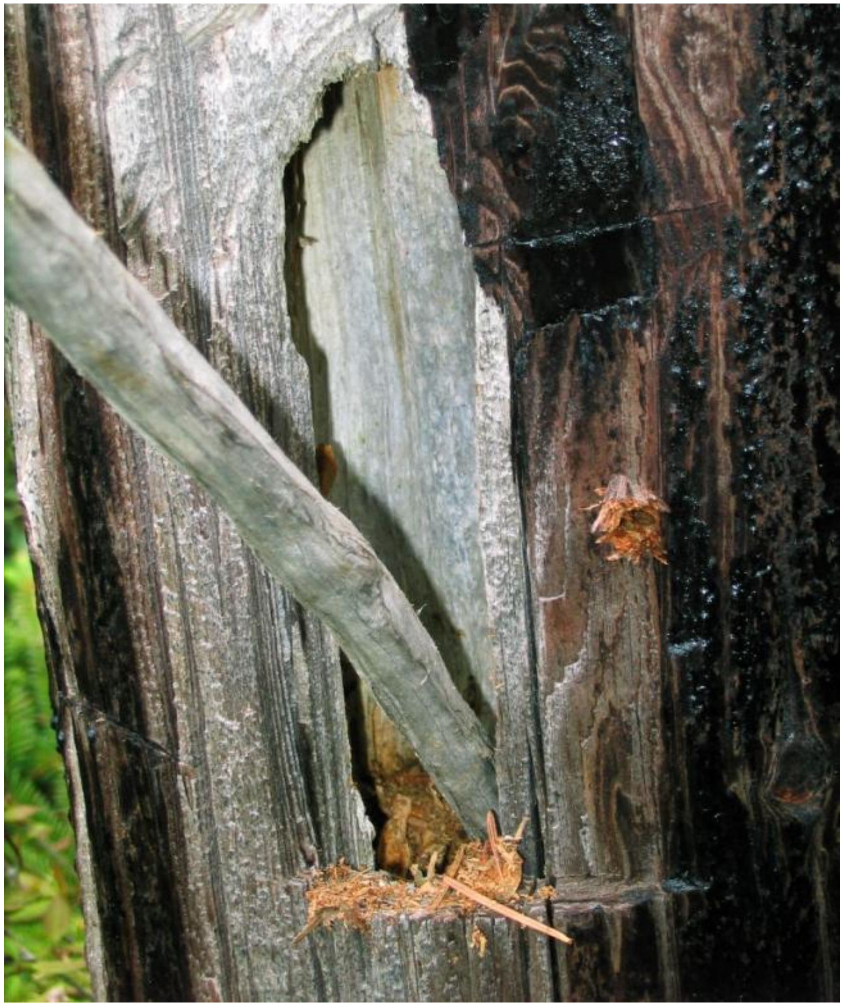
Photographs of Transmission Lines
23L, 24L, and 110L

Transmission Line 23L



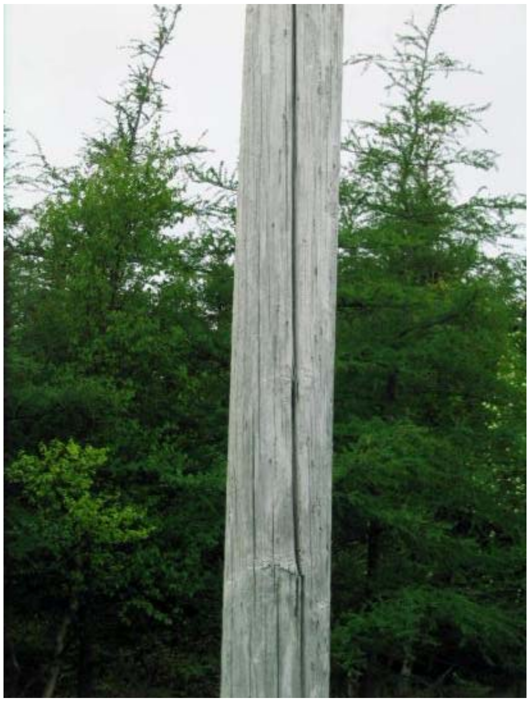
Burn Marks on Pole Caused by Flashover

Woodpecker Hole in Pole



Hole and Rot in Pole

Transmission Line 24L



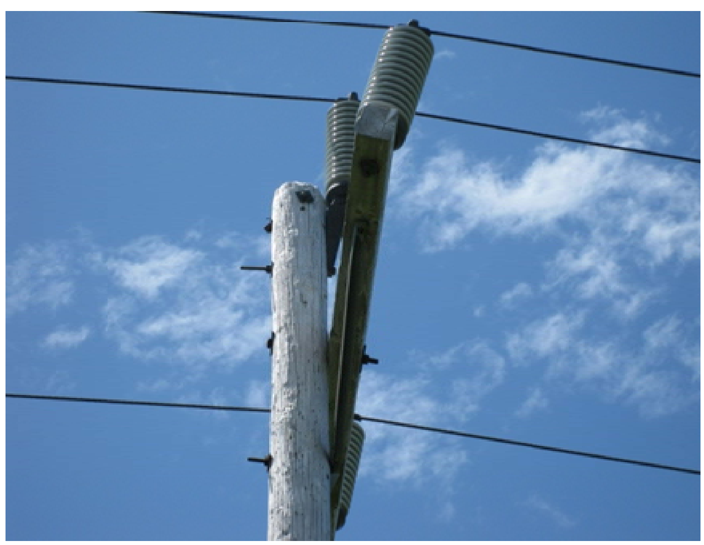
Deteriorated Pole

Deteriorated Crossarm

Deteriorated Crossarm

Deteriorated Pole

Pole Crack between Bolts



Leaning Insulator

Deteriorated Crossarm

Split Pole

Transmission Line 110L

110L Ice Storm Damage December 2003

110L Broken Conductor - Ice Build Up December, 2003

Deteriorated Pole 110L

Deteriorated Pole 110L

Distribution Reliability Initiative

June 2009

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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. On an ongoing basis Newfoundland Power examines its actual distribution reliability performance to assess where 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 based on data for 2004 - 2008.

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: 2008

In 2008, the Company completed Distribution Reliability Initiative projects on sections of BOT-01 and GLV-02 feeders. Table 1 shows the cost of the work completed in 2008.

Table 1

Distribution Reliability Initiative
2008
($000s)

Feeder	**2008**
BOT–01	630
GLV–02	781
Total	**$1,411**

3.0 Distribution Reliability Initiative Projects: 2009

In 2009, the Company will continue the Distribution Reliability Initiative. The 2009 Capital Budget Application proposed work on the GLV-02 and LEW-02 feeders. The work is a continuation of projects initially proposed in the 2006 Capital Budget Application and detailed in *4.2.2 Lewisporte-02 Feeder Study* and *2.1.3 Glovertown-02 Feeders Study* filed with that application. Work was also proposed for the NWB-02 feeder. A detailed analysis was provided in 4*.2.1 Northwest Brook NWB-02 Feeder Study* filed with the 2009 Capital Budget Application. The budgeted expenditure in 2009 is detailed in Table 2.

Table 2

Distribution Reliability Initiative
2009
($000s)

Feeder	**2009**
LEW-02	313
GLV–02	457
NWB–02	496
Total	**1,266**

The 2009 Budget was prepared in early 2008. The five year reliability data available at the time covered the period from 2003 to 2007.

A revised analysis for each of the proposed 2009 projects has been completed to include 2008 data. The analysis is detailed in Tables 3, 4 and 5.

<u>LEW-02</u>

The LEW-02 project was intended to have been a two year project commencing in 2006. Upgrades started in 2006 where a substantial amount of the work was completed. Work was postponed in 2007 to accommodate the rebuild required at the Rattling Brook Hydro Plant. Work was again postponed in 2008 due to improving overall reliability statistics on the feeder and to accommodate priority work on the BOT-01 and GLV-02 feeders. Reliability has improved substantially since 2005. There have been no feeder level outages in the past 3 years. Reliability data for the most recent five year period 2004 – 2008 is shown in Table 3.

Table 3

LEW-02 – Reliability Analysis

	2004	**2005**	**2006**	**2007**	**2008**
SAIDI	12.54	19.68	0.73	1.04	3.54
SAIFI	7.55	4.36	1.02	0.41	1.22

In 2008 SAIDI did increase slightly however the increase was due to a single insulator failure caused by a lightning strike. Excluding this event the 2008 SAIDI was 1.23.

Based on the latest reliability data no further work on LEW-02 under the Distribution Reliability Initiative is required at this time.

<u>GLV-02</u>

The GLV-02 project was intended to be a 3 year project commencing in 2006. Upgrades started in 2006. Work was postponed in 2007 to accommodate the rebuild required at the Rattling Brook Hydro Plant and resumed in 2008. 2008 reliability shows a substantial improvement.

Table 4

GLV-02 – Reliability Analysis

	2004	**2005**	**2006**	**2007**	**2008**
SAIDI	5.87	8.46	10.44	8.77	3.22
SAIFI	4.24	3.88	3.55	3.56	3.18

While both SAIDI and SAIFI were above the company average, the larger 2008 outages were due to damages by an outside party and an unbalance during switching. Excluding these events which were not due to the age or condition of the feeder, SAIDI and SAIFI for 2008 on GLV-02 were 1.59 and 1.15 respectively.

Based on the latest reliability data no further work on GLV-02 under the distribution Reliability Initiative is required at this time.

<u>NWB-02</u>

The NWB-02 project is expected to be completed over 3 years commencing in 2009. The 2008 reliability numbers show continued poor overall reliability on the feeder.

Table 5

NWB-02 – Reliability Analysis

	2004	**2005**	**2006**	**2007**	**2008**
SAIDI	12.17	4.60	8.98	4.82	9.51
SAIFI	4.85	2.63	5.33	1.25	3.10

Work will proceed on this feeder as planned.

The work proposed for the LEW-02 and GLV-02 feeders under the Distribution Reliability Initiative for 2009 is cancelled. Work proposed for NWB-02 will continue as planned. A revised expenditure estimate is detailed in Table 6.

Table 6

Distribution Reliability Initiative
2009 (Revised)
($000s)

Feeder	**2009**
LEW-02	0
GLV–02	0
NWB–02	541
Total	**541**

4.0 Distribution Reliability Initiative Projects: 2010

The 2010 Capital Budget Application includes the continuation of the proposed work on NWB-02 as described in Section 3.0 of this study.

The examination of the worst performing feeders as listed in Appendix A and B has determined that other than the proposed work on NWB-02, no work is required on other feeders under the Distribution Reliability Initiative at this time.

Table 7 shows the proposed capital expenditures for the Distribution Reliability Initiative for 2010.

Table 7

Distribution Reliability Initiative
2010
($000s)

Feeder	**2010**
NWB–02	447

Appendix A

Distribution Reliability Data

Unscheduled Distribution Related Outages Five-Year Average 2004-2008 Sorted By Customer Minutes of Interruption				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
LEW-02	4,051	626,948	2.91	7.51
BOT-01	4,906	620,881	3.01	6.34
GLV-02	4,699	563,465	3.68	7.35
NWB-02	3,574	500,623	3.43	8.02
HOL-01	2,991	438,427	1.50	3.66
DUN-01	3,323	414,391	3.52	7.32
DOY-01	4,119	401,180	2.62	4.25
GFS-06	2,453	374,083	1.46	3.71
KEL-01	2,772	361,704	1.54	3.34
MIL-02	3,696	358,874	2.69	4.35
BCV-02	3,233	349,994	2.12	3.83
HWD-07	6,068	341,262	2.26	2.11
ROB-01	2,313	315,399	2.12	4.83
CAB-01	3,985	309.023	3.34	4.32
CHA-01	6,042	305,422	2.81	2.36
Company Average	**956**	**84,530**	**1.25**	**1.74**

Unscheduled Distribution Related Outages Five-Year Average 2004-2008 Sorted By Distribution SAIFI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
GLV-02	4,699	563,465	3.68	7.35
NWB-02	3,574	500,623	3.43	8.02
GBS-02	1,538	113,420	3.41	4.19
CAB-01	3,985	309.023	3.34	4.32
BOT-01	4,906	620,881	3.01	6.34
LEW-02	4,051	626,948	2.91	7.51
GRH-02	2,267	195,926	2.87	4.13
CHA-01	6,042	305,422	2.81	2.36
MIL-02	3,696	358,874	2.69	4.35
DOY-01	4,119	401,180	2.62	4.25
FER-01	1,644	69,481	2.61	1.84
MMT-01	1,187	69,999	2.58	2.54
ROB-02	498	44,416	2.48	3.68
WES-01	958	52,884	2.47	2.27
Company Average	**956**	**84,530**	**1.25**	**1.74**

Unscheduled Distribution Related Outages Five-Year Average 2004-2008 Sorted By Distribution SAIDI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
GPD-01	277	130,642	1.17	9.23
NWB-02	3,574	500,623	3.43	8.02
LEW-02	4,051	626,948	2.91	7.51
GLV-02	4,699	563,465	3.68	7.35
DUN-01	3,323	414,391	3.52	7.32
BOT-01	4,906	620,881	3.01	6.34
ROB-01	2,313	315,399	2.12	4.83
PJN-01	186	38,603	1.34	4.63
BUC-02	295	43,048	1.88	4.57
MIL-02	3,696	358,874	2.69	4.35
CAB-01	3,985	309.023	3.34	4.32
SCT-02	420	62,504	1.72	4.27
DOY-01	4,119	401,180	2.62	4.25
HOL-02	881	121,145	1.84	4.22
GBS-02	1,538	113,420	3.41	4.19
Company Average	**956**	**84,530**	**1.25**	**1.74**

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	A substantial amount of work was completed on this feeder since 2006. Reliability has improved considerably. No further work is required at this time.
LEW-02	A substantial amount of work was completed on this feeder since 2006. Reliability has improved considerably. No further work is required at this time.
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 and a broken pole in 2008. No work is required at this time.
ROB-01	The ROB-01 feeder has displayed consistently poor reliability from 2004 – 2006 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. Reliability improved in 2008. No work is required at this time.
BOT-01	A substantial amount of work was completed on this feeder since 2006. Reliability has improved considerably. No further work is required at this time.
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 scheduled for work under the Distribution Reliability Initiative.
WES-01	Reliability statistics were poor in 2007. Work was carried out under the Rebuild Distribution Lines program in 2008 and there have been no reliability issues since that time. 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.
HOL-02	Poor overall reliability is due to a storm in March 2008. No work is required at this time.
FER-01	Reliability statistics were poor in 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 2004. Work was carried out under the Rebuild Distribution Lines program in 2005 and there have been no reliability issues since 2005. Poor statistics in 2008 were due to a broken cutout and a broken insulator. 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 or 2008. 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.
KEL-01	Reliability statistics were poor in 2006. Work was carried out under the Rebuild Distribution Lines program in 2006 and there have been no reliability issues since then. No work is required at this time.
HWD-07	HWD-07 overall reliability statistics are good but due to the large number of customer on the feeder ranks high on the list sorted by customer minutes. No reliability 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.
MMT-01	Reliability statistics were poor in 2006. Work was carried out under the Rebuild Distribution Lines program in 2006 and there have been no reliability issues since then. No work is required at this time.
ROB-02	Reliability statistics were poor in 2004. Work was carried out under the Rebuild Distribution Lines program in 2005 and there have been no reliability issues since then. No work is required at this time.
BUC-02	Reliability problems in 2008 were due to three insulator failures in 2008. No work is required at this time but the feeder will be inspected in 2009.
PJN-01	Reliability statistics were poor in 2005 & 2006. Work was carried out under the Rebuild Distribution Lines program in 2007 and there have been no reliability issues since then. No work is required at this time.
SCT-02	Reliability problems in 2008 were due to a storm in March. No work is required at this time.

St. John's Downtown Underground Distribution Project: Relocation of SJM-03 Feeder

June 2009

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PROVINCE OF NEWFOUNDLAND

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1.0 Background

St. John's Main ("SJM") substation supplies electricity to the area surrounding St. John's harbour, including the downtown core of the City of St. John's (the "City"). Much of the electrical system in this area consists of a series of duct banks, manholes, switches and cables that form the downtown underground distribution system.

SJM substation is located on Southside Road, just east of the Pitts Memorial Drive overpass. There are twelve distribution feeders that originate at SJM substation, each of which exits the substation via an underground cable.[1] Nine of these feeders pass under the Waterford River in a duct bank.[2]

The main trunk of the downtown underground system is comprised of three feeders: SJM-03, SJM-07 and SJM-08. This trunk runs underground along Water Street from Pitts Memorial Drive at Hutchings Street, east to the Sir Humphrey Gilbert Building. It supplies the downtown core of St. John's including the commercial areas of Water Street, Harbour Drive, and parts of Duckworth Street and New Gower Street, including Mile One Stadium and City Hall.

The cable technology originally installed in the downtown underground system is no longer manufactured.[3] Changes in safety practices and the condition of the existing Water Street underground infrastructure have required modifications to the underground system over the past decade.[4]

In 2008, the City began excavating streets and related civil infrastructure in the Water Street West and Harbour Drive areas as part of the Harbour Interceptor Sewer Project. In Order No. P.U. 19 (2008), Newfoundland Power ("the Company") received approval to upgrade its civil infrastructure in conjunction with the Harbour Interceptor Sewer Project.[5] This work is ongoing and is expected to be completed in 2009.[6]

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1 Three of these feeders, SJM-10, SJM-11 and SJM-12, become aerial just outside the substation and supply customers on Southside Road, Topsail Road and Shea Heights.

2 Of these, five feeders, SJM-02, SJM-04, SJM-06, SJM-09 and SJM-13, become aerial at various locations and supply primarily residential areas from Leslie Street and Symonds Avenue to Bond Street and Prescott Street. SJM-14 is an underground feeder that supplies the Delta Hotel, 100 New Gower Street and the John Cabot Building.

3 The existing Newfoundland Power underground infrastructure beneath Water Street utilizes paper-insulated lead-covered ("PILC") cables installed in duct banks (100 mm diameter fibre ducts encased in concrete) buried under the street.

4 Between 2002 and 2003, two sections of the Water Street underground system between Baird's Cove and the Sir Humphrey Building were upgraded with new duct banks, cables and switches. In 2008 and 2009, installation of new duct banks, manholes, and switch pads is being undertaken in coordination with the Harbour Interceptor Sewer Project.

5 The term *civil infrastructure* refers to the concrete duct banks and manholes, and does not include underground cables, terminations or switches.

6 A report entitled *Water Street Underground Project Replacement of Civil Infrastructure* was submitted to the Board in 2008 as a supplement to Newfoundland Power's 2008 Capital Budget Application. This report detailed the condition of the assets and recommended the installation of new underground duct banks along Water Street and Harbour Drive from Hutchings Street to Beck's Cove.

2.0 Assessment

Newfoundland Power has completed an assessment of the main trunk feeders of the downtown underground system. With the exception of small sections that have been replaced in recent years, the downtown underground system is more than 40 years old.[7]

The three feeders in the downtown underground trunk are all located in the same duct bank extending from Hutchings Street to Beck's Cove on the north side of Water Street. This presents certain physical risks to the underground trunk.[8] It also presents electrical risks associated with three 40-year old feeders being in close proximity to one another.[9]

An N-1 contingency analysis was performed on the downtown underground trunk.[10] This analysis examined feeder loads, cable loading capacities and system configuration to determine vulnerabilities associated with the loss of any one cable section of a feeder.[11] The analysis indicated that single contingencies on either SJM-03 or SJM-08 would result in an inability for Newfoundland Power to fully serve the St. John's downtown core under high load conditions.

Relocation of a section of SJM-03 feeder between Hutchings Street and Beck's Cove, and installation of a new switch connecting SJM-03, SJM-07 and SJM-08, will reduce the risks associated with the over 40-year old underground trunk. It will also allow Newfoundland Power to fully serve the St. John's downtown core in the event of a single cable failure on the underground trunk. [12]

3.0 Project Description

This project involves relocation of the section of SJM-03 feeder between Hutchings Street and Beck's Cove. This section of the feeder will be relocated from existing duct banks on the north side of Water Street to duct banks on the south side of Water Street and Harbour Drive which are currently under construction. Attachment B shows the geographic location of the planned feeder route.

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7 The downtown underground system was installed in the mid 1960s.

8 These physical risks range from the risk of three feeders being crushed by collapse of the duct bank to inadvertent damage by third parties.

9 A primary electrical risk is that associated with an over-heated conductor or a cable fault on one feeder. The proximity of the over-heated conductor or faulted feeder to other feeders in an underground system can create a chain reaction causing failure of the other feeders. This vulnerability was determined to be the root cause of the July 2008 power outage in downtown Vancouver, B.C. (See: *BC Hydro Report, Downtown Vancouver Outage: July 14, 2008 Findings and Recommendations,* page 5).

10 For underground distribution systems, N-1 design, or single-contingency design, permits any one cable to be removed from service while the remaining system carries the load.

11 Attachment A contains feeder loading information for the St. John's Main substation. No feeder overload conditions currently exist in the three feeders in downtown underground trunk. By relocating a section of SJM-03 and installing a new switch, N-1 design is achieved within current capacity limits of the downtown underground trunk.

12 The loss of SJM-03 under high load conditions would result in extended outages to customers from Prescott Street to Atlantic Place. The loss of SJM-08 under high load conditions would result in extended outages to customers in the area of George Street, the Murray Premises, the Supreme Court Building, and Scotia Centre.

The feeder relocation includes the installation of three 1,100 metre 500 MCM cross-linked polyethylene single phase cables in the new duct banks.

The project also includes the installation of a new padmount switch at the intersection of Beck's Cove and Harbour Drive. The switch installation will be a 5 compartment 12.5 kV padmount switch.

This switch will connect the SJM-03, SJM-07 and SJM-08 feeders. It will permit load transfers between the three feeders. Attachments C and D show feeder schematic diagrams of the existing and reconfigured downtown underground trunk, respectively.

4.0 Project Cost

Table 1 provides a breakdown of the estimated cost of the relocation of SJM-03 feeder in 2010.

Table 1
Project Cost

Description	**Estimate**
Material[13]	$465,000
Labour Internal	35,000
Engineering	25,000
Other	25,000
Total	**$550,000**

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[13] Material includes the cost of purchase and installation of the new cable and purchase of the new switch.

Attachment A

St. John's Main Substation Feeder Loadings

St. John's Main Substation Feeders
Peak Load and Planning Capacities

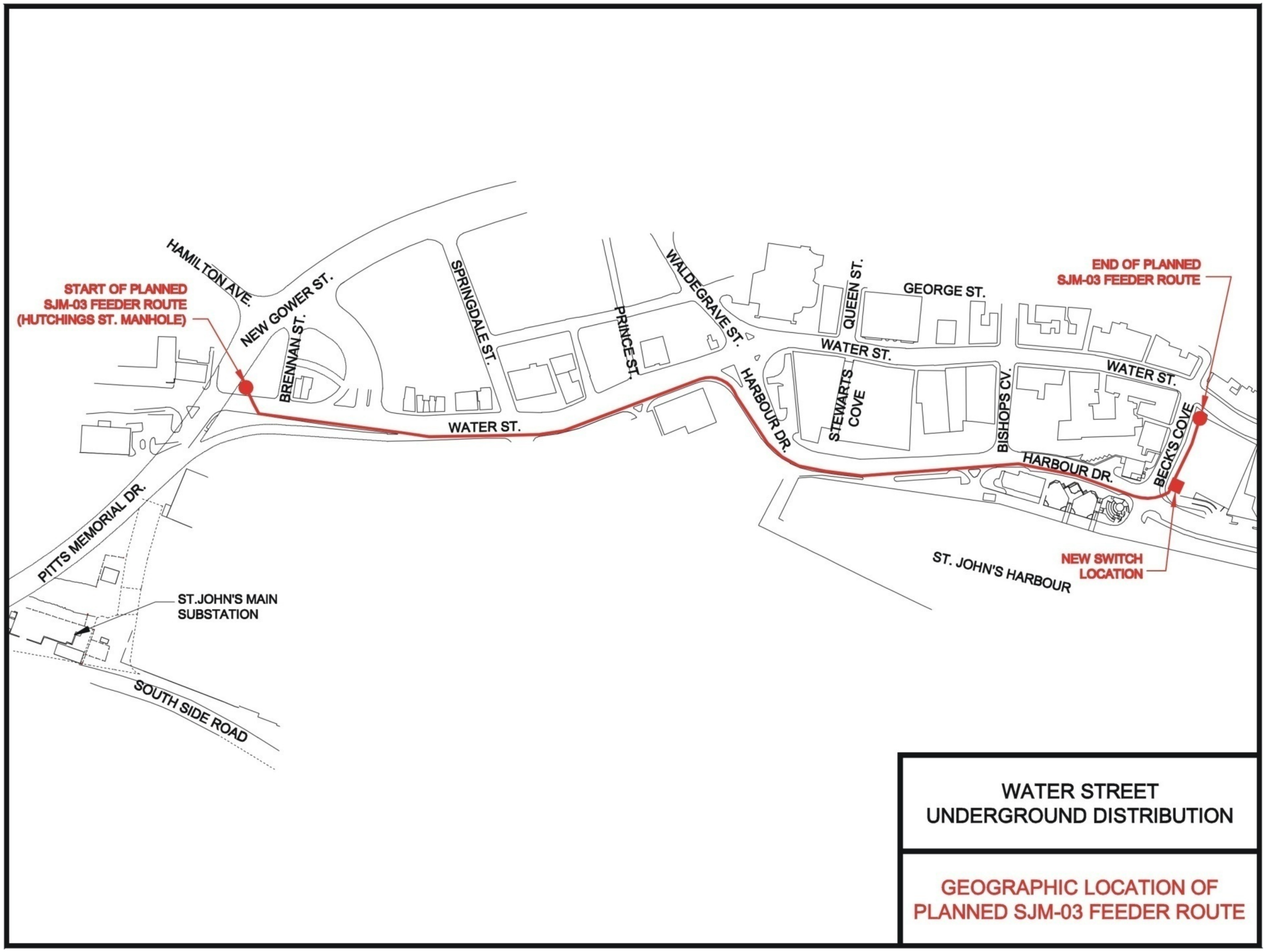
Feeder Designation	Trunk Location	Area Supplied	2008 Loading MVA	Trunk Capacity MVA
SJM-02	Job's Bridge Crossing	Aerial Network	2.9	5.7
SJM-03	Job's Bridge Crossing	Downtown U/G Network	3.1	5.7
SJM-04	Job's Bridge Crossing	Aerial Network	4.7	5.7
SJM-06	Job's Bridge Crossing	Aerial Network	3.3	5.7
SJM-07	Job's Bridge Crossing	Downtown U/G Network	3.1	5.7
SJM-08	Job's Bridge Crossing	Downtown U/G Network	4.3	5.7
SJM-09	Job's Bridge Crossing	Aerial Network	4.1	5.7
SJM-10	Southside Road	Aerial Network	2.4	7.1
SJM-11	Southside Road	Aerial Network	7.4	10.2
SJM-12	Southside Road	Aerial Network	1.9	3.1
SJM-13	Job's Bridge Crossing	Aerial Network	6.3	5.7
SJM-14	Job's Bridge Crossing	New Gower Underground	3.4	5.7

Feeder SJM-13 is the only one of these feeders that has exceeded its capacity limit.[14]

[14] The overload on SJM-13 will be addressed through a load transfer of 1.2 MVA to SJM-06 in 2009.

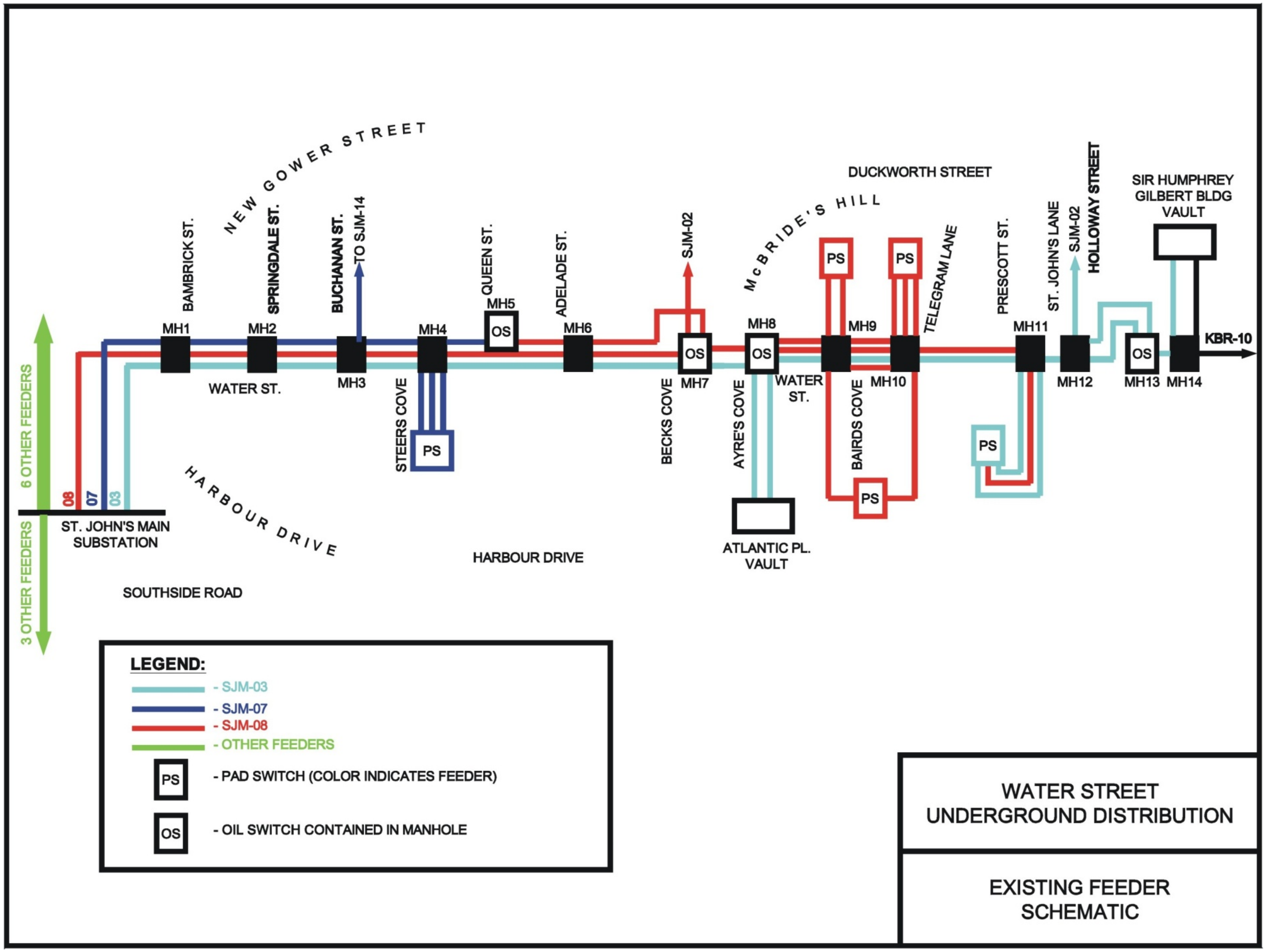
Attachment B

Geographic Location


HAMILTON AVE.
NEW GOWER ST.
START OF PLANNED
SJM-03 FEEDER ROUTE
(HUTCHINGS ST. MANHOLE)
BRENNAN ST.
SPRINGDALE ST.
PRINCE ST.
WALDEGRAVE ST.
QUEEN ST.
GEORGE ST.
END OF PLANNED
SJM-03 FEEDER ROUTE
WATER ST.
WATER ST.
WATER ST.
HARBOUR DR.
STEWARTS COVE
BISHOPS CV.
HARBOUR DR.
BECK'S COVE
PITTS MEMORIAL DR.
ST. JOHN'S HARBOUR
NEW SWITCH
LOCATION
ST.JOHN'S MAIN
SUBSTATION
SOUTH SIDE ROAD
WATER STREET
UNDERGROUND DISTRIBUTION
GEOGRAPHIC LOCATION OF
PLANNED SJM-03 FEEDER ROUTE

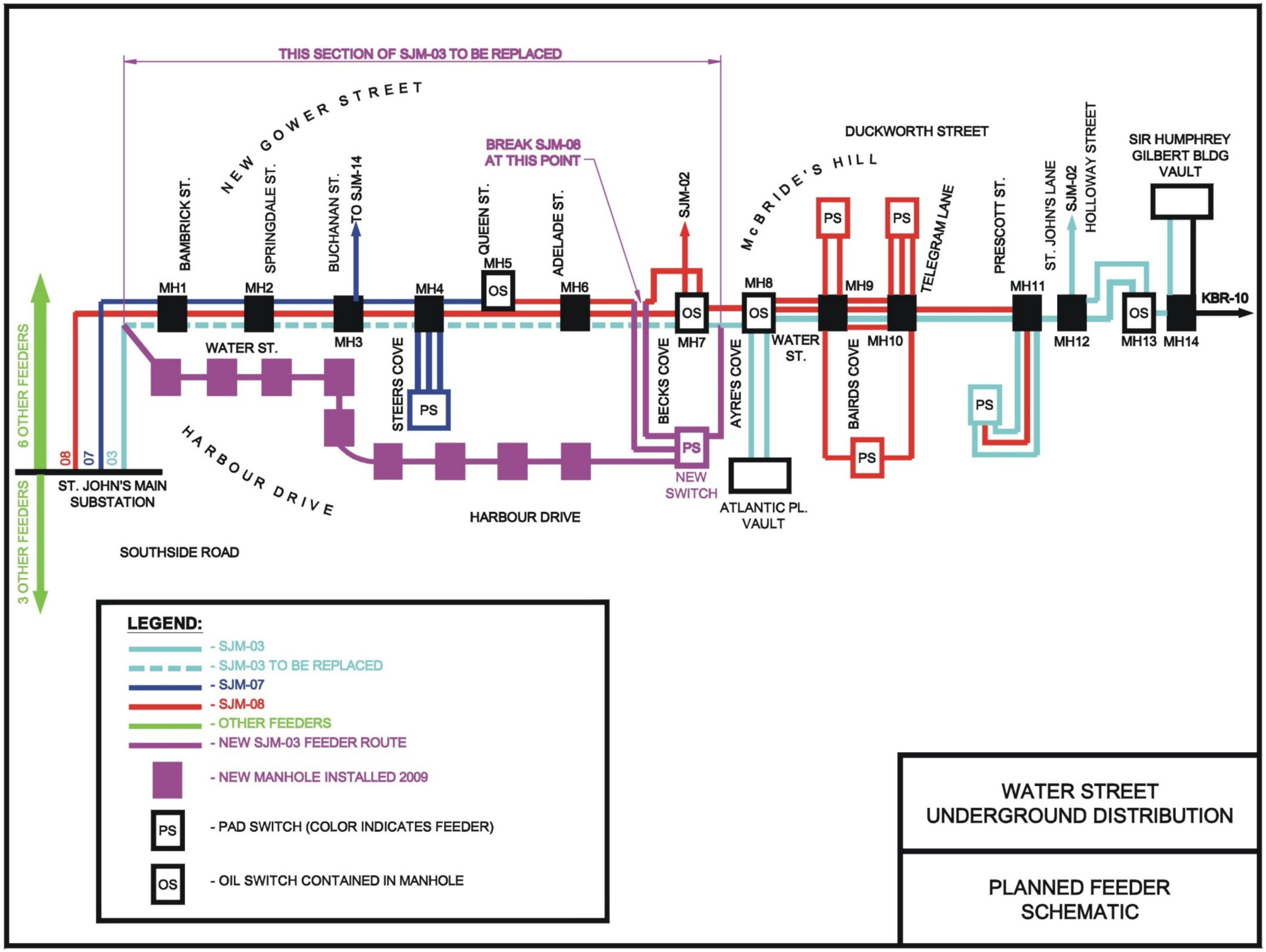
Attachment C

Existing Feeder Schematic Diagram


NEW GOWER STREET
DUCKWORTH STREET
McBRIDE'S HILL
BAMBRICK ST.
SPRINGDALE ST.
BUCHANAN ST.
TO SJM-14
QUEEN ST.
ADELADE ST.
SJM-02
TELEGRAM LANE
PRESCOTT ST.
ST. JOHN'S LANE
SJM-02
HOLLOWAY STREET
SIR HUMPHREY GILBERT BLDG VAULT
MH1
MH2
MH3
MH4
MH5
MH6
MH7
MH8
MH9
MH10
MH11
MH12
MH13
MH14
OS
PS
KBR-10
WATER ST.
WATER ST.
STEERS COVE
BECKS COVE
AYRE'S COVE
BAIRDS COVE
ATLANTIC PL. VAULT
6 OTHER FEEDERS
3 OTHER FEEDERS
08
07
03
ST. JOHN'S MAIN SUBSTATION
HARBOUR DRIVE
HARBOUR DRIVE
SOUTHSIDE ROAD
LEGEND:
- SJM-03
- SJM-07
- SJM-08
- OTHER FEEDERS
- PAD SWITCH (COLOR INDICATES FEEDER)
- OIL SWITCH CONTAINED IN MANHOLE
WATER STREET UNDERGROUND DISTRIBUTION
EXISTING FEEDER SCHEMATIC

Attachment D

Reconfigured Feeder Schematic Diagram


THIS SECTION OF SJM-03 TO BE REPLACED
NEW GOWER STREET
BREAK SJM-08 AT THIS POINT
DUCKWORTH STREET
McBRIDE'S HILL
BAMBRICK ST.
SPRINGDALE ST.
BUCHANAN ST.
TO SJM-14
QUEEN ST.
ADELADE ST.
SJM-02
TELEGRAM LANE
PRESCOTT ST.
ST. JOHN'S LANE
SJM-02
HOLLOWAY STREET
SIR HUMPHREY GILBERT BLDG VAULT
MH1
MH2
MH3
MH4
MH5
MH6
MH7
MH8
MH9
MH10
MH11
MH12
MH13
MH14
OS
PS
KBR-10
WATER ST.
STEERS COVE
BECKS COVE
AYRE'S COVE
WATER ST.
BAIRDS COVE
NEW SWITCH
ATLANTIC PL. VAULT
6 OTHER FEEDERS
3 OTHER FEEDERS
08
07
03
ST. JOHN'S MAIN SUBSTATION
HARBOUR DRIVE
HARBOUR DRIVE
SOUTHSIDE ROAD
LEGEND:
- SJM-03
- SJM-03 TO BE REPLACED
- SJM-07
- SJM-08
- OTHER FEEDERS
- NEW SJM-03 FEEDER ROUTE
- NEW MANHOLE INSTALLED 2009
- PAD SWITCH (COLOR INDICATES FEEDER)
- OIL SWITCH CONTAINED IN MANHOLE
WATER STREET UNDERGROUND DISTRIBUTION
PLANNED FEEDER SCHEMATIC

Feeder Additions for Load Growth

June 2009

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1.0 Introduction

As load increases on an electrical system, the components of the system can become overloaded. These overload conditions can occur at the substation level, on equipment such as transformers, breakers and reclosers, or on specific sections of distribution line conductor.

When an overload condition has been identified, it can often be mitigated through operating practices such as feeder balancing or load transfers.[1] Such practices are low cost solutions and are completed as normal operating procedures. However, in some cases it becomes necessary to complete upgrades to the distribution system to either increase capacity or alter system configuration in order to complete a load transfer.

This report identifies five overload conditions proposed to be addressed as part of the 2010 Capital Budget. One situation requires a transfer of load from overloaded substation transformers at Hardwoods substation. The remaining four situations will be addressed by increasing capacity on overloaded sections of conductor on distribution feeders. The overload conditions described in this report can each be attributed to commercial and residential customer growth in the Northeast Avalon portion of the Company's service territory.

2.0 Voltage Conversion HWD-02 ($115,000)

In 2010, a transfer of a section of Hardwoods Substation feeder HWD-02 to Kenmount Substation feeder KEN-03 will transfer 1.8 MVA of load from the overloaded Hardwoods transformers onto the transformers in Kenmount Substation. To complete this load transfer, a voltage conversion must be completed on a section of HWD-02 (12.5kV) before it can be transferred to KEN-03 (25kV).

Transformers No. 1 and No. 2 at Hardwoods substation are approaching their design capacity. The winter 2008 peak load on the two 12.5 kV distribution power transformers at Hardwoods substation reached 96% of the rated capacity for these two transformers. The forecast winter 2009 peak load for these two transformers is expected to reach 102% of the rated capacity.

This overload condition can be attributed to growth on the HWD 12.5 kV feeders, including the commercial growth in the area of Glencoe Drive, and the addition of Commonwealth Gardens Subdivision.

There are typically three 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 typically the least cost alternative as it defers the purchase of an additional transformer to a future date.

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[1] Feeder balancing involves transferring load from one phase to another on a three phase distribution feeder in order to balance the amount of load on each phase. Load transfers involve transferring load from one feeder to another.

The cost of adding transformer capacity to address the Hardwoods Substation transformer overload would be in the range of $2.5 to $3 million. At a cost of $115,000, transferring a section of HWD-02 to KEN-03 to address the overload is least cost.[2]

Another benefit associated with converting the HWD-02 feeder to 25kV and transferring it to the Kenmount feeder is that it creates a 25 kV tie point between the Hardwood and Kenmount substations. In the event of an outage at either substation, some customers can be transferred to the other substation to limit the duration of customer power interruptions.

3.0 Overloaded Conductor

3.1 General

An overloaded section of conductor on a distribution line is at risk of failure. Failures are caused by heating of the conductor as the current exceeds its capacity ratings. As a result, the conductor will have excessive sag, which may result in the conductor coming into contact with other conductors or the conductor breaking, causing a fault and subsequent power interruption.

An analysis of distribution feeders in the Northeast Avalon area was completed using a distribution feeder computer modelling application to identify sections of feeders that may be overloaded. Overload conditions that were identified using the computer modelling application were followed up with field visits to ensure the accuracy of information. Where necessary, load measurements were taken to verify the results of the computer simulation. The analysis used conductor capacity ratings based on Newfoundland Power's Distribution Planning Guidelines. These ratings are shown in Appendix A.

3.2 Alternatives for Overloaded Conductor

There are several alternatives for dealing with a conductor overload condition. Each alternative may not be applicable to every overload condition. They are dependent on factors such as; available tie points to surrounding feeders, the amount of conductor overload, physical limitations of line construction, or the effect of offloading strategies for surrounding feeders.

Alternative #1 – Feeder Balancing
In some cases, conductor may be overloaded on only one phase of a three phase line. In this situation, it may be possible to remove the overload condition by balancing the downstream loads through load transfers from the highly loaded phase to one of the more lightly loaded phases. This is only applicable in situations where all three phases are not overloaded.

Alternative #2 – Load Transfer
On a looped system if a tie point exists downstream of the overload condition, it may be possible to transfer a portion of load to an adjacent feeder. However, consideration must be given to the

[2] The cost of adding transformer capacity by replacing a transformer would tend to be lower than the cost associated with adding capacity by adding another transformer. Delaying the need to invest $2.5 to $3 million will have a present value benefit of approximately $160,000 to $190,000 per year.

loading on the adjacent feeder to ensure a new overload condition is not created. Also, the effect of the offloading strategy for surrounding feeders must also be considered.

Alternative #3 – Upgrade Conductor
The overload condition can be eliminated by increasing the conductor size on the overloaded section. This will improve load transfer capabilities for the feeder, and will not add to the total load or cause an overload condition on the adjacent feeder.

Every alternative was considered for each conductor overload condition identified in this report. For each case, the most cost effective alternative that would maintain the appropriate level of system flexibility was selected.

3.3 Overloaded Feeders

A total of 4 feeders with sections of overloaded conductor are identified in this report. Each overloaded section identified was evaluated using all three available alternatives identified in section 3.1.

Broad Cove Substation Feeder BCV-03 ($70,000)
A 1.8 km section of this feeder is overloaded. The overloaded section is along Thorburn Road between the St. Thomas Line intersection and the Dogberry Hill Road intersection (See Single Line Drawing in Appendix C). The conductor in this section is # 4 copper and is rated for 153 amps per phase. The peak loads on phases A, B and C of this section are 225 amps, 243 amps and 83 amps respectively.

This overload condition can be attributed to growth on this feeder in the Dogberry Hill Road and Dogberry Hill Road Extension areas, including the addition of Thorburn Woods Subdivision. Continued growth is expected as development continues in this area, including an additional phase of Thorburn Woods.

Feeder balancing is not an option for this overload condition, due to the fact that the combined peak currents exceed the total capacity of the three phase conductors. Also, there is no existing tie point that would allow load to be transferred to an adjacent feeder, and construction of a tie point is not a feasible alternative. Therefore, the least cost option for this overload condition is to upgrade the conductor. In this case, upgrading to 4/0 aluminum conductor, rated at 356 amps per phase, would eliminate the overload condition.

Hardwoods Substation Feeder HWD-07 ($170,000)
A 2 km section of the feeder is overloaded. The overloaded section is along Paradise Road between the Topsail Road intersection and Starlight Drive intersection (See Single Line Drawing in Appendix C). The conductor in this section is a combination of 1/0 aluminum and 2/0 aluminum, which are rated for 228 amps and 265 amps respectively. The peak loads on phases A, B and C of this section are 336 amps, 243 amps and 312 amps respectively.

This overload condition can be attributed to growth on this feeder. The areas along St. Thomas Line and Paradise Road have experienced high growth, especially with several new subdivisions surrounding Adams Pond in Paradise. This growth is expected to continue as more subdivision development is planned in the Adams Pond area and along St. Thomas Line.

Feeder balancing is not an option for this overload condition, due to the fact that the combined peak currents exceed the total capacity of the three phase conductors. There is a tie point to Chamberlains substation through CHA-02 feeder, and a load transfer of 4.2 MVA from HWD-07 to CHA-02 is planned for 2009 as part of Newfoundland Power's operating work. The purpose of this transfer is to reduce the substation transformer loading on HWD-T3. It will also reduce the current on the overloaded section of line on HWD-07 by approximately 97 amps per phase. The 4.2 MVA load transfer will remove the overload condition on the 2/0 section of line, however the 1/0 section of line will remain overloaded. It is recommended that the 2 km section of HWD-07 be upgraded to 477 aluminum conductor, rated at 590 amps per phase.

Oxen Pond Substation Feeder OXP-01 ($50,000)
A 1 km section of this feeder is overloaded. The overloaded section is along Thorburn Road, between the Mount Scio Road intersection and Grovesdale Subdivision (See Single Line Drawing in Appendix C). The conductor in this section is #4 copper conductors and is rated for 153 amps per phase. The peak loads on phases A, B and C of this section are 152 amps, 150 amps and 159 amps respectively.

This overload condition can be attributed to growth in Grovesdale Subdivision. A new phase of this subdivision will be completed in 2009, which will add to the load growth on the feeder.

Feeder balancing is not an option for this overload condition, due to the fact that the combined peak currents exceed the total capacity of the three phase conductors. Also, there is no tie point that would allow load to be transferred to an adjacent feeder, and construction of a tie point is not a feasible alternative. Therefore, the least cost option for this overload condition is to upgrade the conductor. In this case, upgrading to 4/0 aluminum conductor, rated at 356 amps per phase, would eliminate the overload condition.

Stamps Lane Substation Feeder SLA-11 ($60,000)
A 0.75 km section of this feeder is overloaded. The overloaded section is along Ropewalk Lane (See Single Line Drawing in Appendix C). The conductor in this section is 1/0 copper and is rated for 283 amps per phase. The peak loads on phases A, B and C of this section are 287 amps, 321 amps and 258 amps respectively.

This overload condition can be attributed to the residential growth around Mundy Pond, including Willow Grove, Alderberry Lane and Alderberry Fields Subdivisions.

Feeder balancing is not an option for this overload condition, due to the fact that the combined peak currents exceed the total capacity of the three phase conductors. There is a tie point to Molloy's Lane substation through MOL-08 feeder that could be used to eliminate the overload condition. However, the tie point provides backup to MOL-08. The 1/0 copper section of SLA-11 limits the amount of load that can be transferred from MOL-08 onto SLA-11. Therefore, it is recommended that this section is upgraded to 477 aluminum conductor, rated at 590 amps per phase.

4.0 Project Cost

The following are the estimated project costs for 2010.

Table 1
Project Costs

Description	**Cost Estimate**
Convert HWD-02 to 25 kV	$115,000
Upgrade 1.8 km on BCV-03	$70,000
Upgrade 2km on HWD-07	$170,000
Upgrade 1km on OXP-01	$50,000
Upgrade 0.75km on SLA-11	$60,000
Total	**$465,000**

5.0 Recommendations

Based on the information provided in this report, the capital expenditures recommended to be undertaken in 2010 are:

- Convert section of HWD-02, containing 1.8 MVA of load, to 25 kV and transfer this section to KEN-03
- Upgrade 1.8 km on BCV-03 to 4/0 AASC conductor
- Upgrade 2km on HWD-07 to 477 AASC conductor
- Upgrade 1km on OXP-01 to 4/0 AASC conductor
- Upgrade 0.75km on SLA-11 to 477 AASC conductor

Converting HWD-02 to 25 kV and transferring 1.8 MVA of load to Kenmount substation will alleviate an overload condition on the 12.5 kV transformers at Hardwoods substation.

The upgrades for BVC-03, HWD-07, OXP-01 and SLA-11 will alleviate the conductor overload condition identified in this report.

The estimated cost to complete this work in 2010 is $465,000.

Appendix A

Distribution Planning Guidelines

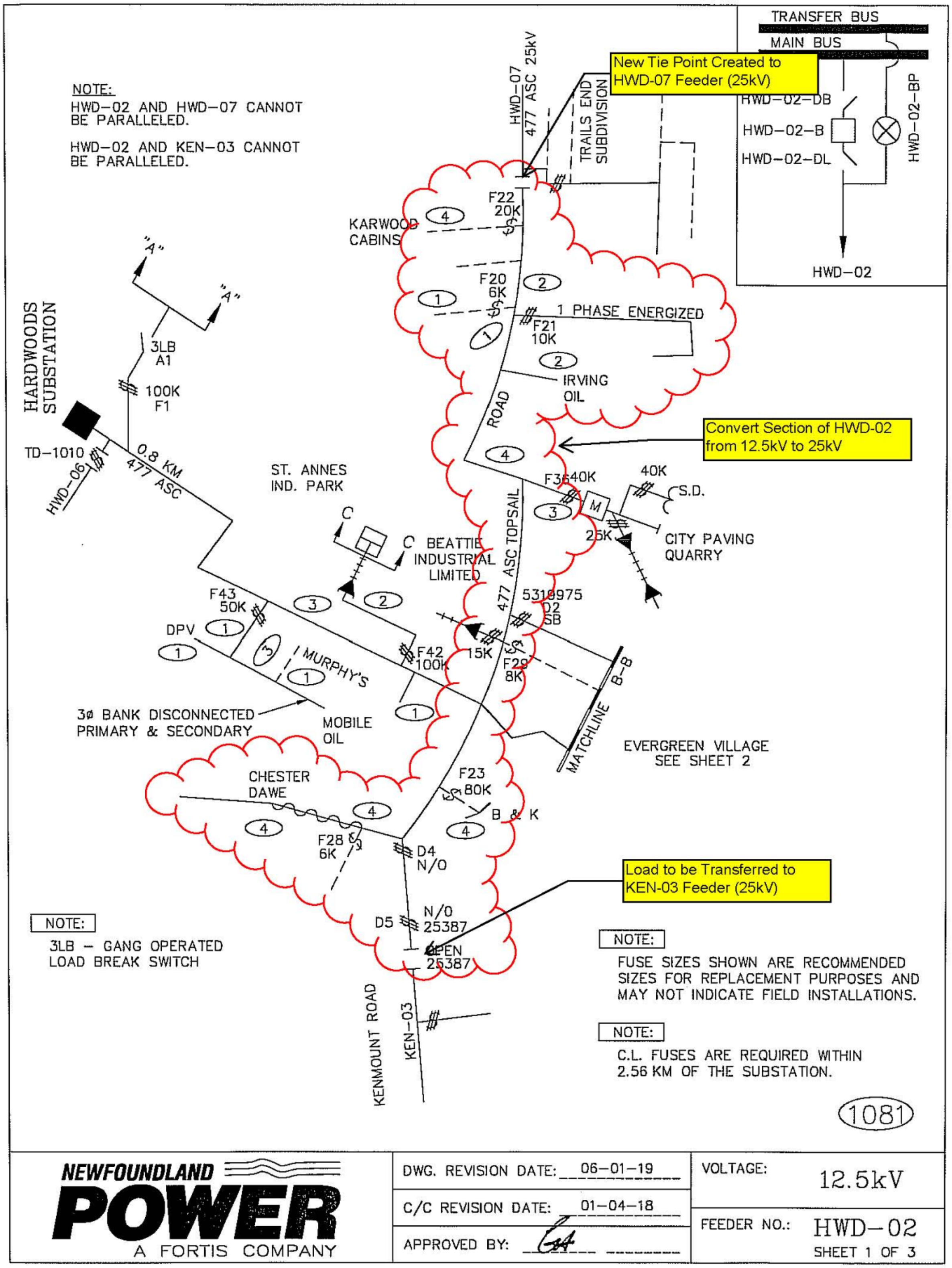
Conductor Ampacity Ratings

Aerial Conductor Capacity Ratings						
Size and Type	Continuous Winter Rating[3]	Continuous Summer Rating[4]	Planning Ratings CLPU Factor[5] = 2.0 Sectionalizing Factor[6] = 1.33			
	Amps	Amps	Amps	MVA		
				4.16 kV	12.5 kV	25.0 kV
1/0 AASC	303	249	228	1.6	4.9	9.8
4/0 AASC	474	390	356	2.6	7.7	15.4
477 ASC	785	646	590	4.2	12.7	25.5
#2 ACSR	224	184	168	1.2	3.6	7.3
2/0 ACSR	353	290	265	1.9	5.7	11.4
266 ACSR	551	454	414	3.0	8.9	17.9
397 ACSR	712	587	535	3.9	11.6	23.1
#4 Copper	203	166	153	1.1	3.3	6.6
1/0 Copper	376	309	283	2.0	6.1	12.2
2/0 Copper	437	359	329	2.4	7.1	14.2

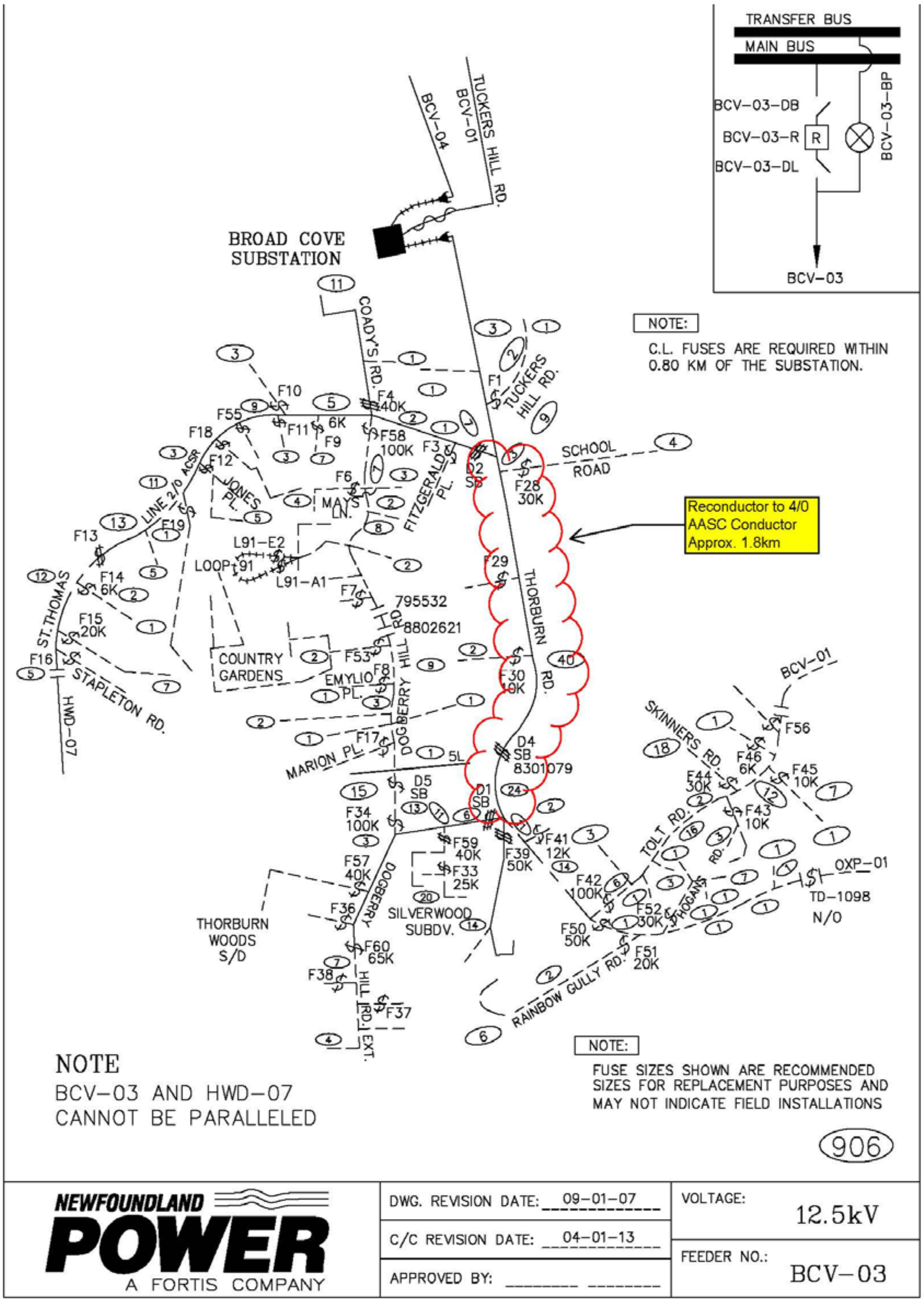
[3] The winter rating is based on ambient conditions of 0ºC and 2ft/s wind speed.
[4] The summer rating is based on ambient conditions of 25ºC and 2ft/s wind speed.
[5] Cold Load Pick Up: Occurs when power is restored after an extended outage. On feeders with electric heat, the load on the feeder can be 2.0 times as high as the normal winter peak load. This is the result of all electric heat coming on at once when power is restored. The duration of CLPU is typically between 20 minutes and 1 hour.
[6] Sectionalizing factor: Two-stage sectionalizing in used during CLPU conditions to increase the Planning Rating of aerial conductors. Restoring power to one section of the feeder at a time reduces the overall effect of CLPU. The sectionalizing factor is the fraction of the load that is restored in the first stage multiplied by the CLPU factor. The optimal portion of the total load on a feeder that is restored in the first stage is 0.66, resulting in a sectionalizing factor of 0.66 x 2.0 = 1.33.

Appendix B

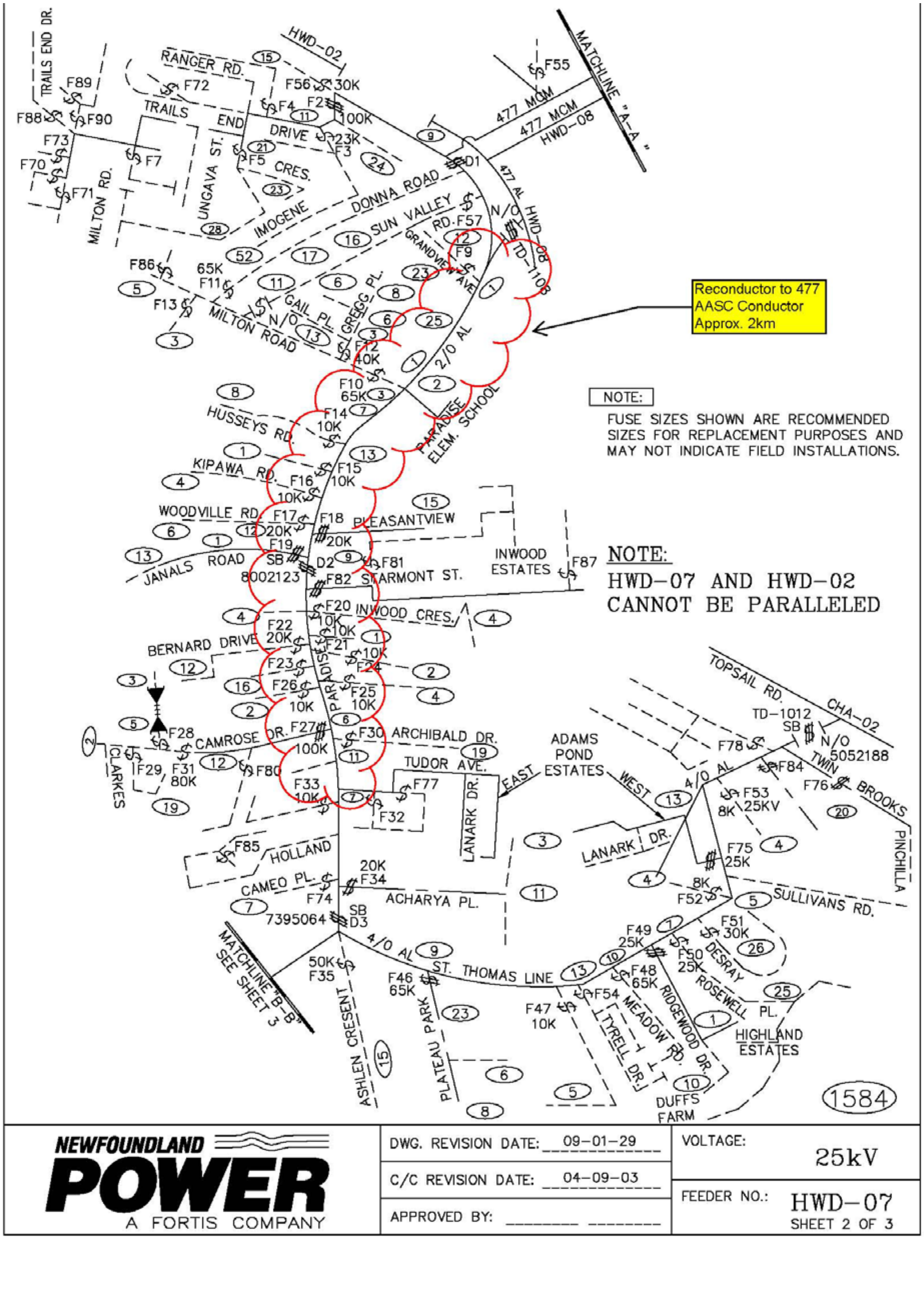
Feeder Single Line Drawings

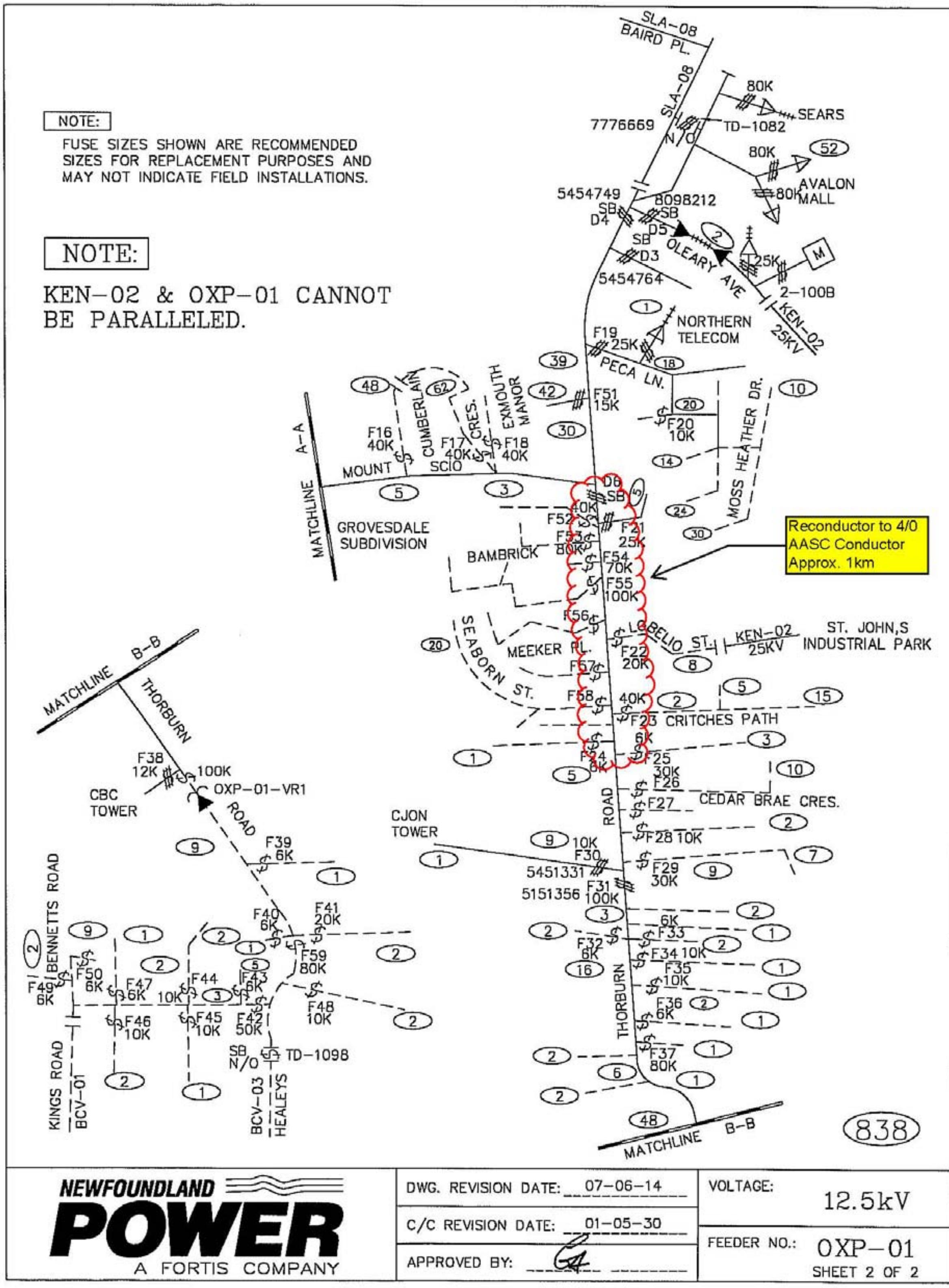


TRANSFER BUS
MAIN BUS
New Tie Point Created to HWD-07 Feeder (25kV)
HWD-02-DB
HWD-02-B
HWD-02-DL
HWD-02-BP
HWD-02
HWD-07 477 ASC 25kV
TRAILS END SUBDIVISION
NOTE:
HWD-02 AND HWD-07 CANNOT BE PARALLELED.
HWD-02 AND KEN-03 CANNOT BE PARALLELED.
F22 20K
KARWOOD CABINS
F20 6K
1 PHASE ENERGIZED
F21 10K
IRVING OIL
ROAD
Convert Section of HWD-02 from 12.5kV to 25kV
HARDWOODS SUBSTATION
3LB A1
100K F1
TD-1010
HWD-06
0.8 KM 477 ASC
ST. ANNES IND. PARK
F36 40K
40K
S.D.
M
25K
CITY PAVING QUARRY
BEATTIE INDUSTRIAL LIMITED
477 ASC TOPSAIL
5319975 D2 SB
F43 50K
DPV
MURPHY'S
F42 100K
15K
F29 8K
B-B
MATCHLINE
3ø BANK DISCONNECTED PRIMARY & SECONDARY
MOBILE OIL
EVERGREEN VILLAGE SEE SHEET 2
CHESTER DAWE
F23 80K
B & K
F28 6K
D4 N/O
Load to be Transferred to KEN-03 Feeder (25kV)
NOTE:
3LB – GANG OPERATED LOAD BREAK SWITCH
D5
N/O 25387
OPEN 25387
NOTE:
FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS.
NOTE:
C.L. FUSES ARE REQUIRED WITHIN 2.56 KM OF THE SUBSTATION.
KENMOUNT ROAD
KEN-03
1081
NEWFOUNDLAND POWER
A FORTIS COMPANY
DWG. REVISION DATE: 06-01-19
C/C REVISION DATE: 01-04-18
APPROVED BY:
VOLTAGE: 12.5kV
FEEDER NO.: HWD-02
SHEET 1 OF 3

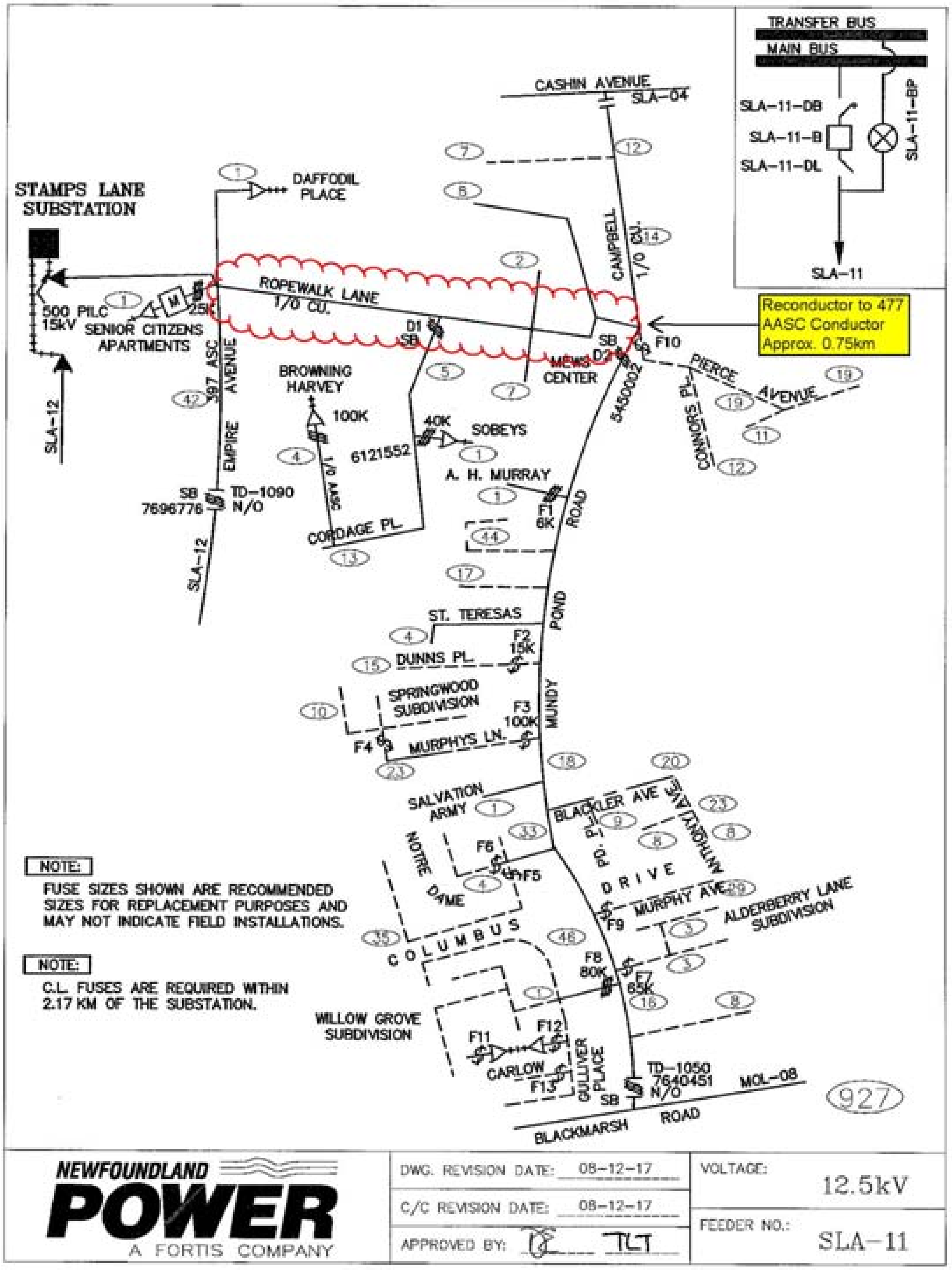


TRANSFER BUS
MAIN BUS
BCV-03-DB
BCV-03-R
BCV-03-DL
BCV-03-BP
BCV-03
BROAD COVE SUBSTATION
TUCKERS HILL RD.
BCV-01
BCV-04
NOTE:
C.L. FUSES ARE REQUIRED WITHIN 0.80 KM OF THE SUBSTATION.
Reconductor to 4/0 AASC Conductor Approx. 1.8km
COADY'S RD.
SCHOOL ROAD
THORBURN RD.
FITZGERALD PL.
JONES PL.
MAY'S LN.
LINE 2/0 ACSR
LOOP 91
L91-E2
L91-A1
795532
8802621
COUNTRY GARDENS
EMYLIO PL.
ST. THOMAS
STAPLETON RD.
HWD-07
MARION PL.
DOGBERRY HILL RD.
SKINNERS RD.
TOLT RD.
RAINBOW GULLY RD.
SILVERWOOD SUBDV.
THORBURN WOODS S/D
HILL RD. EXT.
OXP-01
TD-1098
N/O
8301079
NOTE
BCV-03 AND HWD-07 CANNOT BE PARALLELED
NOTE:
FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS
906
NEWFOUNDLAND POWER
A FORTIS COMPANY
DWG. REVISION DATE: 09-01-07
C/C REVISION DATE: 04-01-13
APPROVED BY:
VOLTAGE: 12.5kV
FEEDER NO.: BCV-03


Reconductor to 477 AASC Conductor Approx. 2km
NOTE:
FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS.
NOTE:
HWD-07 AND HWD-02 CANNOT BE PARALLELED
MATCHLINE "A-A"
MATCHLINE "B-B" SEE SHEET 3
477 MCM
477 MCM HWD-08
477 AL
2/0 AL
4/0 AL
TD-1108
TD-1012
CHA-02
HWD-02
TRAILS END DR.
RANGER RD.
TRAILS END DRIVE
UNGAVA ST.
MILTON RD.
CRES.
IMOGENE
DONNA ROAD
SUN VALLEY RD.
GRANDVIEW AVE.
GAIL PL.
GREGG PL.
MILTON ROAD
HUSSEYS RD.
KIPAWA RD.
WOODVILLE RD.
PLEASANTVIEW
JANALS ROAD
STARMONT ST.
INWOOD ESTATES
INWOOD CRES.
BERNARD DRIVE
PARADISE RD.
PARADISE ELEM. SCHOOL
CAMROSE DR.
ARCHIBALD DR.
TUDOR AVE.
CLARKES
ADAMS POND ESTATES
EAST
WEST
LANARK DR.
HOLLAND
CAMEO PL.
ACHARYA PL.
TOPSAIL RD.
TWIN BROOKS
PINCHILLA
SULLIVANS RD.
ST. THOMAS LINE
DESRAY
ROSEWELL PL.
HIGHLAND ESTATES
RIDGEWOOD DR.
MEADOW RD.
TYRELL DR.
DUFFS FARM
PLATEAU PARK
ASHLEN CRESENT
SB 8002123
SB D3 7395064
N/O 5052188
1584
NEWFOUNDLAND POWER
A FORTIS COMPANY
DWG. REVISION DATE: 09-01-29
C/C REVISION DATE: 04-09-03
APPROVED BY:
VOLTAGE: 25kV
FEEDER NO.: HWD-07
SHEET 2 OF 3



NOTE:
FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS.
NOTE:
KEN-02 & OXP-01 CANNOT BE PARALLELED.
Reconductor to 4/0 AASC Conductor Approx. 1km
SLA-08
BAIRD PL.
SEARS
AVALON MALL
O'LEARY AVE
NORTHERN TELECOM
KEN-02 25KV
PECA LN.
MOSS HEATHER DR.
CUMBERLAIN CRES.
EXMOUTH MANOR
MOUNT SCIO
MATCHLINE A-A
GROVESDALE SUBDIVISION
BAMBRICK
SEABORN ST.
MEEKER PL.
LOBELIO ST.
KEN-02 25KV
ST. JOHN,S INDUSTRIAL PARK
CRITCHES PATH
CEDAR BRAE CRES.
THORBURN ROAD
MATCHLINE B-B
CBC TOWER
OXP-01-VR1
CJON TOWER
BENNETTS ROAD
KINGS ROAD
BCV-01
BCV-03
HEALEYS
TD-1098
838
NEWFOUNDLAND POWER
A FORTIS COMPANY
DWG. REVISION DATE: 07-06-14
C/C REVISION DATE: 01-05-30
APPROVED BY:
VOLTAGE: 12.5kV
FEEDER NO.: OXP-01
SHEET 2 OF 2


TRANSFER BUS
MAIN BUS
SLA-11-DB
SLA-11-B
SLA-11-DL
SLA-11-BP
SLA-11
CASHIN AVENUE
SLA-04
STAMPS LANE SUBSTATION
DAFFODIL PLACE
ROPEWALK LANE 1/0 CU.
CAMPBELL 1/0 CU.
Reconductor to 477 AASC Conductor Approx. 0.75km
500 PILC 15kV
SENIOR CITIZENS APARTMENTS
MEWS CENTER
F10
PIERCE AVENUE
CONNORS PL.
BROWNING HARVEY
100K
40K
SOBEYS
6121552
A. H. MURRAY
5450002
EMPIRE AVENUE
397 ASC
SLA-12
SB 7696776
TD-1090 N/O
CORDAGE PL.
F1 6K
ST. TERESAS
F2 15K
DUNNS PL.
SPRINGWOOD SUBDIVISION
F3 100K
MURPHYS LN.
F4
MUNDY POND ROAD
SALVATION ARMY
BLACKLER AVE
ANTHONY AVE.
PD. PL.
NOTRE DAME
F6
F5
DRIVE
MURPHY AVE.
ALDERBERRY LANE SUBDIVISION
COLUMBUS
F9
F8 80K
F7 65K
NOTE:
FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS.
NOTE:
C.L. FUSES ARE REQUIRED WITHIN 2.17 KM OF THE SUBSTATION.
WILLOW GROVE SUBDIVISION
F11
F12
CARLOW
F13
GULLIVER PLACE
SB
TD-1050 7640451 N/O
MOL-08
BLACKMARSH ROAD
927
NEWFOUNDLAND POWER
A FORTIS COMPANY
DWG. REVISION DATE: 08-12-17
C/C REVISION DATE: 08-12-17
APPROVED BY: TLT
VOLTAGE: 12.5kV
FEEDER NO.: SLA-11

Kenmount Road Building Renovations
3rd Floor HVAC System and Roof Upgrades

June 2009

Prepared By:

Shaun Marshall, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
SHAUN MARSHALL
SIGNATURE
2009.6.16
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

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Page

1.0 Introduction

The Kenmount Road Office Building is the corporate head office for Newfoundland Power. The building provides offices for the following departments: Information Services, Human Resources, Safety, Environment, Finance, Engineering, and Regulatory Affairs along with the Company Executive.

The building has four levels of office space with the basement having a gross floor area of 1,348 m^2 and the main, second and third floors each having 1,172 m^2 for a total gross floor area of 4,864 m^2.

The Kenmount Road office building was built in 1968 as a two storey structure with one air handling unit that serviced both floors. In 1979 two additional floors were added to the building with each floor having its own air-handling system. At that time, the selected roof application was a four-ply built-up asphalt and gravel roof.

Due to operational issues, physical condition, efficiency, age, and comfort issues, the ground and first floor HVAC system was replaced in 2008.[1] The new HVAC system servicing the bottom two floors has a life expectancy of 30 years.

Newfoundland Power has retained the services of external expertise to evaluate the HVAC systems and roof respectively. These evaluations included a condition assessment and recommendations for upgrades or replacement.

2.0 Existing System and Condition

2.1 Second and Third Floor HVAC System

With the addition of the second and third floors in 1979, a VAV[2] air handling system was installed on each floor. This system consists of an indoor air handling unit for each floor which has a supply fan, electric heating coil, and chilled water cooling coil, filters, a mixing box and a control system. The cooling is achieved using a chilled water system which supplies chilled water to a cooling coil in each unit. The chilled water system consists of a roof mounted air-cooled condensing unit and a liquid cooler located in the third floor Mechanical Room. The controls for this system are pneumatic with modifications made to introduce a DDC[3] interface.

The air handling units for the second and third floor systems are 30 years old and in poor condition. There is damage to the heating surfaces and corrosion on structural components. Thermal insulation is in poor shape with pieces missing. The roof mounted condensers are also in poor condition with corrosion on the frame and casing. The HVAC systems do not have a free

---

1 Completed as part of the 2007 Capital Budget approved under Board Order P.U. 27 (2007)

2 Variable air volume (VAV) is a technique for controlling the capacity of a heating, ventilating, and/or air-conditioning (HVAC) system. A VAV box measures and controls the amount of supply air into an area.

3 Direct Digital Control (DDC) is used to control HVAC devices (such as VAVs) with microprocessors performing the control logic. DDC systems receive analog and digital inputs from sensors and devices installed in the HVAC system and through programmed logic provide control of the HVAC operation.

cooling cycle[4] similar to the unit serving the lower two floors. Also, the second and third floor systems do not have a return air fan to allow the removal of air to take advantage of free cooling when available.

The operational deficiencies with the second and third floor systems are as follows:

- The air handling unit static pressure controller is a motorized damper which does not provide the accurate control needed in a VAV system.
- The system does not have a return air fan which results in poor air circulation and the inability to provide free cooling when outdoor conditions permit.
- The system is not balanced due to building modifications that have taken place since 1979.
- Minimum fresh air standard of 7.0 l/s is not being met.[5]
- Washroom exhaust fans do not have a heat recovery system, which results in wasted energy to constantly heat the fresh air coming into the system.
- The cooling system uses Freon R-22 refrigerant[6].
- There are comfort issues experienced on both floors.
- Maintenance costs have increased in recent years.

In April 2006 Newton Engineering completed an analysis of the HVAC systems at Kenmount Road building. This analysis was filed as part of the 2007 Capital Budget Application in support of a project to replaced the HVAC systems on the lower two floors. The analysis identified that the HVAC systems on all four floors of the Kenmount Road building were reaching the end of their useful lives. Priority was placed on replacing the HVAC system on the lower two floors for the 2007 capital budget project.

Recent operating experience with the second and third floor HVAC systems has confirmed that they are at the end of their useful life. Throughout the winter of 2009 there were 7 separate service calls to address heating concerns on the third floor at a cost of $4,300.

The second and third floor HVAC systems are at the end of life and should be replaced.

---

4 Free cooling is an economic method of utilising low external air temperatures to assist in air conditioning systems, whereby cool external air is used instead of air-conditioned internal air.

5 ASHRAE Standard "Ventilation for Acceptable Indoor Air Quality" establishes the 7.0 l/s per person measure.

6 Freon 22 is scheduled to be phased out of newly manufactured equipment by 2010, with a 99.5% phase out and discontinued production of Freon 22 gas by 2020.

2.2 Roof

With the addition of the second and third floors in 1979 a four-ply built-up asphalt and gravel roofing system was installed.[7]

The life expectancy of a 4-ply built-up roof is 20 years. The Kenmount Road building roof is 30 years old.

General Contractor W. L. Gordon Construction has completed inspections of the Kenmount Road roof system over the past 6 years. The most recent inspection report is included in Appendix A.

The concerns with the roof are as follows:

- Gravel protective surfacing has eroded with wind scouring on all corners of the building. The waterproofing is now exposed and has started to deteriorate as it weathers. This exposure has caused deterioration of the membrane, allowing water infiltration.
- Felt ridges are present in several areas spanning the length of the roof. Accelerated deterioration has occurred in these exposed areas, as the gravel has been dislodged.
- One large blister has developed near the low point of the roof. This is a result of the felt delaminating. The gravel has been displaced and the felt deteriorated.
- A number of leaks have occurred over recent years, resulting in interior damage.

The Kenmount Road roof system is at the end of life and should be replaced.

3.0 Project Cost

Table 1 includes the 2010 capital expenditures for replacing the third floor HVAC system.

Table 1
2010 Capital Expenditures
Replace Third Floor HVAC System

Description	**Cost Estimate**
Engineering	$30,000
Labour	20,000
Material	300,000
Total	**$350,000**

[7] A built-up roof is a roof consisting of multiple plies of roof felts laminated together with bitumen. Built-up roof material can consist of bitumen-saturated felt, coated felt, polyester felt or other fabrics. A surfacing is generally applied and can be asphalt, aggregate (gravel or slag), emulsion or a granule-surfaced cap sheet.

Table 2 includes the 2010 capital expenditures for replacing the Kenmount Road roof system.

Table 2
2010 Capital Expenditures
Replace Roof System

Description	Cost Estimate
Engineering	$17,000
Labour	-
Material	175,000
Total	**$192,000**

4.0 Recommendations and Conclusion

The second and third floor HVAC system is in poor condition and should be replaced for reasons outlined in section 2.1. It is recommended that this system be replaced with a more energy efficient system in two phases in 2010 and 2011.[8] The cost to replace the third floor HVAC system in 2010 is estimated at $350,000.

The current built-up roof is 10 years beyond its expected life. The condition of the roof is such that repairs will not extend the life of the roofing system any further. Therefore, the roof should be resurfaced in 2010. The cost to replace the Kenmount Road roof system in 2010 is estimated at $192,000.

Based on these assessments, the third floor HVAC system and the roof on the Kenmount Road building should be replaced in 2010.

It is recommended that replacement of the second floor HVAC system occur in 2011.

[8] Experience with the 2008 HVAC renovation on the lower two floors suggests that replacing one floor per year would offer logistical advantages. This approach allows the third floor system, chiller, and condensing unit to be replaced in 2010. The second floor system will be replaced in 2011.

Appendix A

Roof Inspection Report
55 Kenmount Road

By: W.L Gordon Construction

Roof at 55 Kenmount

Report

Prepared by:

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St. John's, Newfoundland, Canada
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Document No. 03001-003

May 25, 2009

DOCUMENT APPROVAL SHEET

Approvals	Signature	Date
Project Manager	Wins Gordon, President	May 25, 2009

Table of Contents

1.0 Introduction

The following report details the results of our inspection of the roof at 55 Kenmount Road. It provides a summary of the present condition, a safety evaluation, test results and a recommendation for replacing the roof.

2.0 Present Condition

2.1 Visual Inspection

2.1.1 Description of Roof

The roofing system is comprised of four-ply built-up asphalt and gravel. The age of the system appears to be in excess of 20 years. There are indications of previous repairs by asphalt flooding.

Based on our visual inspection of the roof, the following observations were made:

1. Gravel protective surfacing has eroded with wind scouring on all corners of the building. The waterproofing asphalt is now exposed to the elements and has already started to alligator as it weathers and the oils dry out. This unprotected exposure will accelerate the deterioration of the membranes as the felts gradually become bare and susceptible to water infiltration.
2. Felt ridges are present in several areas running most of the length of the roof, some as high as 3 to 4 inches. If this is left unchecked, accelerated deterioration of the membrane in these areas will occur due to the felts and asphalt being left exposed directly to the elements as the gravel has now been removed from these localized areas. There are a few hundred feet of noticeable ridges.
3. One large felt blister was observed near the low point of the roof, near a drain. This measured approximately 24" x 18" and 18" high. This is where the felts have delaminated. Again the gravel has been displaced and the felts will now deteriorate at an accelerated rate in this area if maintenance isn’t carried out.
4. The roof-top mounted units are all mounted and waterproofed to the roof deck by means of pitch pans or pitch pockets. These pitch pockets are currently filled to the required height with what appears to be a good quality mastic.
5. Recent Patching and repairing have been done in several locations
6. Ice and snow buildup around drains cause excessive water buildup
7. On several occasions water infiltration has occurred some with damaging effects
8. As to date there are still problems with water infiltration this will probably continue.
9. One roof top AC unit has been removed from service and disconnected this unit along with pitch pans should be removed.
10. If other units are scheduled to be replaced this should be done prior to roof work.

In general the roof membrane has deteriorated to a point that it no longer could be expected to maintain a water proof system.

A diagram of the roof, which indicates the locations of roof hardware, vents (P.V.), drains (R.D.), AC units, core tests taken and damaged areas is provided . Also, some photos are provided.




2.1.2 Safety Evaluation

1. A safety evaluation of roof access and a fall protection system should be made.
2. Because this is a flat roof with a built-up ledge on the perimeter, ice buildup should not pose a great hazard for personnel.
3. Periodic maintenance should be performed on roof objects to ensure that loose hardware does not pose a hazard to personnel.

2.2 Core Testing Results

Core testing was not carried out at this time but the results from the most recent core test are as follows:

Core testing was performed at three locations on the roof, as follows:

- Test # 1: North Side of Roof
- Test # 2: Centre of Roof
- Test # 3: Southwest Corner of Roof

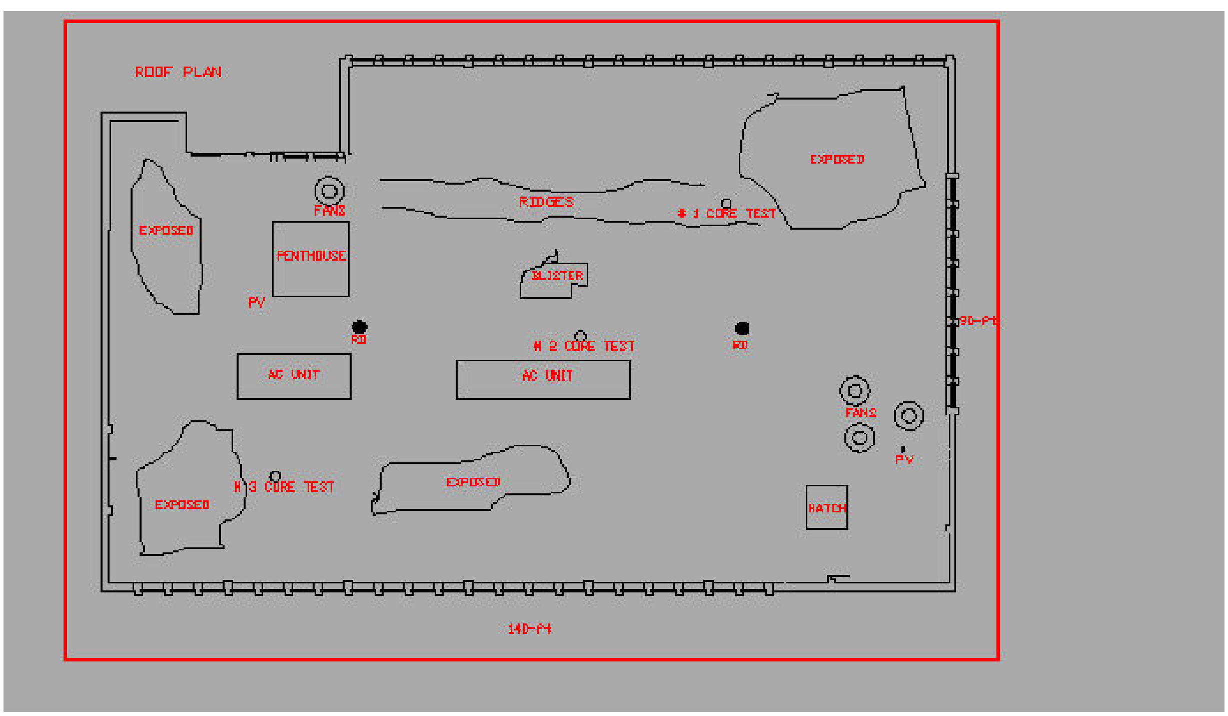
Beneath the four-ply built-up asphalt and gravel surface, the roofing system is comprised of a vapor barrier base sheet and two layers of 2” fiberglass insulation.

Of the three tests performed, moisture was detected only at the centre roof location in Test # 2. The R value of any insulation that has become wet will be reduced. It would only be fair to assume that a much greater area of insulation has been affected due to the water infiltrating.

2.3 Infrared Imaging

Weather conditions made infrared imaging unpractical at this time.

But as the results of the previous imaging indicated wet locations which probably increased in area.



3.0 Roof Replacement Recommendations

- Two Ply Torch-on
- Removal of existing roof system
- Clean and prime concrete deck with Elastocol 500 primer
- Torch Elastophene sp vapor barrier
- Adhere 2 layers of 3 in polyisocyanurate with insta-stik adhesive
- Adhere 1 layer 3mm sopraboard
- Torch apply Sopralene flam 180 base sheet
- Torch apply Sopralene flam 250 GR cap

System Control Centre
Uninterruptible Power Supply Replacement

June 2009

Prepared by:

Jack Casey, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
J. W. CASEY
SIGNATURE
PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

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Page

1.0 Introduction

Newfoundland Power's ("the Company's") Supervisory Control and Data Acquisition ("SCADA") system and associated communications equipment are integral to the provision of least cost reliable customer service. Like most computers and communication network components the SCADA system is sensitive to power quality and its normal operation can be disrupted by disturbances in power quality and power outages.

Newfoundland Power's SCADA system and associated communications equipment[1] is protected from power quality disturbances by an uninterruptible power supply ("UPS"). The UPS provides a continuous supply of electrical power that is conditioned by eliminating harmful voltage sags and surges that can damage sensitive electronic equipment.

Newfoundland Power has determined that the existing UPS system is at the end of its service life. It is operating at maximum capacity and is no longer capable of providing the redundancy or standby capability that the system was initially designed for.

It is recommended that the Company proceed with the replacement of the UPS system to ensure the continued provision of reliable power for the System Control Centre ("SCC") SCADA system and least cost reliable customer service.

2.0 Background

The existing UPS is located at the SCC in St. John's. The UPS was originally installed in 1988 in the former Rattling Brook Control Centre. In 1994, the Rattling Brook Control Centre was decommissioned and the UPS was stored at this location until the new SCC was constructed in 1999. Once construction of the new SCC was complete, the UPS was relocated from Rattling Brook to the new SCC.

The SCC serves as the Control Authority for all Company operations associated with the control and monitoring of the electricity system. The SCC operates 24 hours each day, 365 days a year ensuring the safe reliable operation of all electricity system equipment. The SCADA system is the main application used to control and monitor this equipment and the UPS is essential to ensure the reliable operation of the SCADA system.

The UPS has operated reliably since the relocation in 1999. However it is currently at the maximum rated capacity and is no longer capable of providing the redundancy or standby capability that the system was initially designed for. There have been instances where the UPS has become overloaded and tripped offline. Each of these incidents has exposed the SCADA and communications systems to power quality disturbances and service interruptions.

[1] The UPS at the SCC building provides conditioned power to 7 SCADA servers, 10 SCADA workstations, 10 Information Systems Servers, 10 Corporate Network workstations, SCADA Communications equipment, Corporate Network Communications equipment, and the Company VHF Radio network.

3.0 UPS System Assessment

The UPS has two principal functions: (1) it conditions the power supply by removing voltage sags and surges, thereby protecting sensitive electronic equipment from damage; and (2) in the event of an interruption in the normal power supply to the building, it supplies emergency power from batteries enabling essential equipment to operate normally until the backup diesel generator is operational.

The UPS was manufactured in 1988 by Staticon Ltd. The unit is a double conversion design which provides conditioned power using a rectifier and inverter pair.[2] This model of UPS is no longer manufactured or supported by the vendor and spare parts are no longer available.[3]

The UPS arrangements consist of 2 Staticon rectifier and inverter pairs, ("UPS1" and "UPS2"), Each UPS rectifier input section is supplied from a 60 Amp 120/208 Volt three phase supply from the emergency services electrical panel. Each inverter unit output rating is 120 Volts, 67 Amps single phase 60 Hz.

The original design provided full redundancy between UPS1 and UPS2. Both UPS1 and UPS2 had sufficient capacity to carry a minimum SCADA configuration capable of monitoring and controlling the electricity system during an equipment outage on either UPS system. Only the loss of both UPS1 and UPS2 would cause the SCADA system to completely lose power.

This redundancy no longer exists due to increased loading on the system as a result of additional computer and communications equipment. The additional computer and communications equipment is necessary as the SCADA operation has become increasingly dependent upon information system applications and contingencies related to disaster recovery.[4]

UPS1 and UPS2 each have their own battery bank, with each battery bank having 60 individual cells. Each cell is rated at 2.2 volts with the entire 60 cell bank originally rated at 600 amp-hours ("AH")[5]. The initial design of the UPS provided approximately 16 hours of standby capability.[6] Under the current loading the UPS system has approximately 7.5 hours of standby capability.

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2 A rectifier converts alternating current electricity into direct current electricity. In the UPS application the direct current electricity is used to charge a standby battery. The inverter converts direct current electricity from the battery into alternating current electricity to supply standard (120 VAC 60 Hz) equipment.

3 Recent commentary from the UPS vendor indicated that "The equipment in question is approximately 21 years old. Replacement parts for this equipment may be not readily available and may require substitution. Module repair is done on a case by case basis and component availability is not guaranteed. We would strongly recommend replacement in view of the nature of the equipment it is supporting".

4 Online databases are now essential for providing customer service, creating work permits and accessing emergency response plans. To ensure access to these applications in the event of communications failure, information system servers must now reside at the SCC.

5 An amp-hour is a measure on energy storage equivalent to the ability to supply 1 amp of current for a1 hour duration.

6 The initial design was based on 90% conversion efficiency and 40% rated load on the inverters.

The battery banks were purchased in July 1988 and are now 21 years old. At the time of purchase the supplier quoted a service life between 15 and 20 years. The battery banks have achieved the maximum service life due to good maintenance practices and tight control on the operating environment in the battery room. However, they are at the end of their useful life and require replacement.

The current steady state loading for each UPS is shown in Table 1.

Table 1
UPS Steady State Loading

UPS1	50 Amps	6.0 KW
UPS2	53 Amps	6.4 KW

The steady state loads are the base loading for the equipment. In addition to steady state loads the UPS also supplies intermittent loads that cycle on and off over time. These intermittent loads include laser printers that can demand up to 6 amps instantaneously. The combined effect of both the steady state and intermittent loads frequently places the individual UPS systems at or near the output breakers trip setting.

4.0 UPS System Replacement

The existing UPS system and associated battery bank is 21 years old and has reached the end of its useful life. The technology is no longer supported and due to increased loading associated with the installation of additional computer and communications equipment the UPS arrangement is no longer able to provide the redundancy or standby capability that the system was initially designed for.

It is recommended that a replacement system be installed with sufficient capacity to restore the redundant capability and to ensure the continued provision of reliable standby power for the SCC SCADA system. The recommended replacement system will be comprised of two 30 KVA, (24 kW) units, connected in a parallel arrangement, with enough battery capacity to supply the existing critical load for 16 hours.

Table 2 provides a breakdown of the estimated costs for replacing the existing UPS system.

Table 2
Replacement Cost Estimate

Item	Description	Cost
1	Material	$195,000
2	Engineering & Other	$30.000
	Total	**$225,000**

5.0 Recommendations

The Company's SCADA system and associated communications equipment are integral to the provision of least cost reliable customer service. The reliability of the Company's SCC based SCADA system, Information System servers and critical communications equipment is dependent on a reliable UPS.

The existing UPS is 21 years old, is at the end of its service life, is operating at maximum capacity and is no longer capable of providing the redundancy or standby capability provided for in the initial design.

This project, for which there is no feasible alternative, is required to ensure the continued provision of reliable standby power for the SCC SCADA system. A 2010 budget of $225,000 for SCC UPS replacement is recommended.

Appendix A
UPS Schematic Diagram

SCC UPS – Technical Description

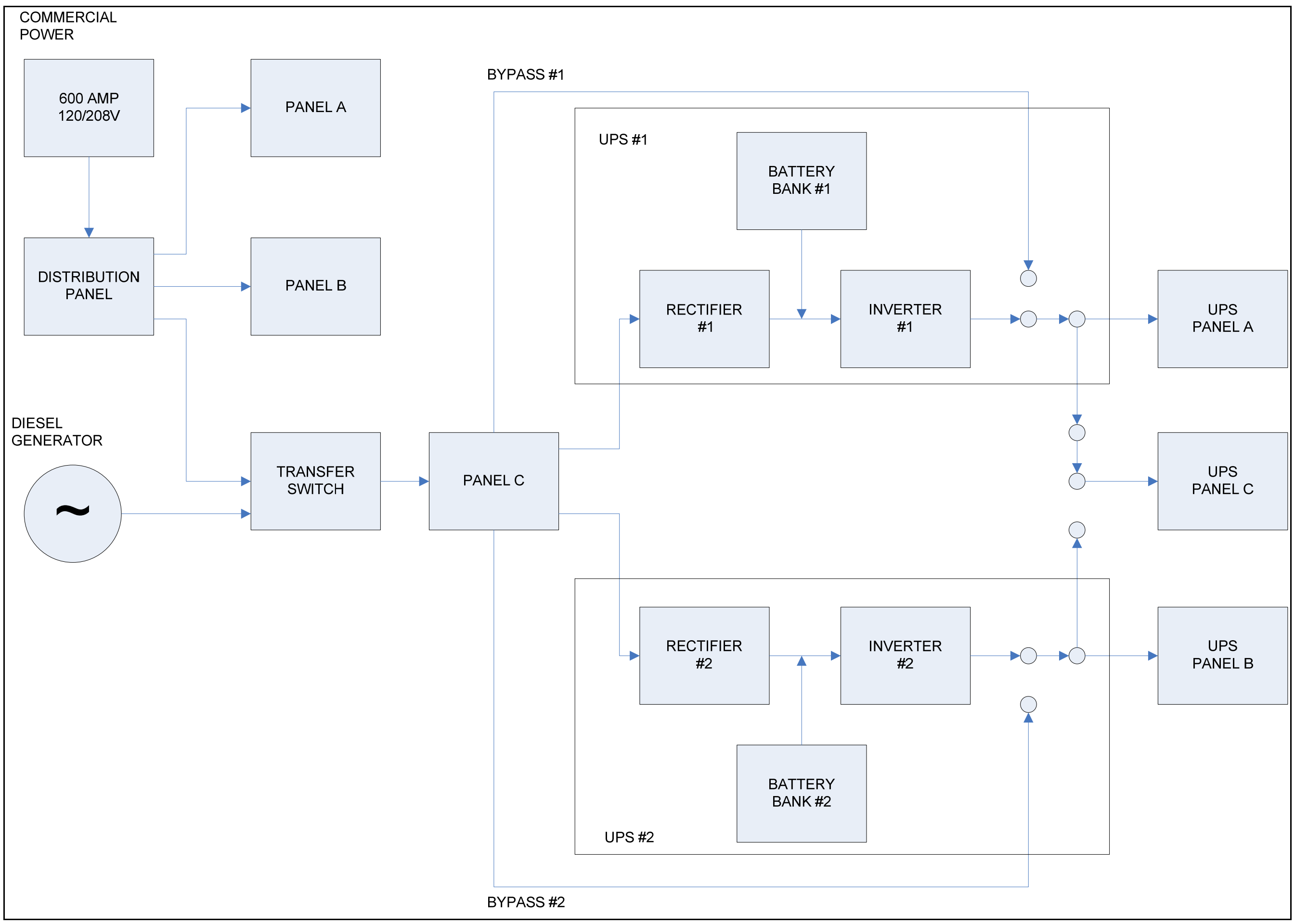

Figure 1

Newfoundland Power SCC UPS Layout

2010 Application Enhancements

June 2009

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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 and the Telvent OASyS SCADA system, as well as internally developed software such as the Customer Service System (CSS) and the Outage Management System.

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 2010.

2.0 Customer Systems Enhancements

Customer Systems 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 2010, enhancements are proposed in the areas of customer interaction (via CSS functionality improvements), meter management and customer finance plans.

Table 1 summarizes the cost associated with these items.

Table 1
Customer Service System Enhancements
Project Expenditures
($000s)

Cost Category	**2010 Estimate**
Material	-
Labour – Internal	275
Labour – Contract	-
Engineering	-
Other	-
Total	**275**

2.1 Customer Interaction Enhancements ($92,000)

Description

The purpose of this item is to improve the Company's response to customers' new service requests and name change (moving) requests. This item involves providing a more effective means to capture customer information in CSS during *customer-agent* phone interactions. In addition, customer contact information tracking will be improved to better reflect customer preferences and enable flexibility, for example with regard to multiple email addresses, daytime (primary) phone number, third party contact information and customer identification options.

Operating Experience

In 2008, the Company received and processed approximately 4,000 new service requests and 43,000 name change (moving) requests from customers. The data captured and processed in handling these types of interactions with customers has evolved since the CSS system was initially implemented. For example, requests from customers to join eBills or verify email addresses were not originally part of the *customer-agent* phone interaction. The effectiveness of the overall CSS system usability has been affected by the series of changes implemented to meet these requirements.

Currently agents often write down information regarding customer requests as it is given by the customer, and then navigate through several CSS screens in order to capture and process that information. This often results in pauses in the *customer-agent* interaction, ultimately causing unnecessary delays for the customer and inefficiencies in the Contact Centre. Improvements to the on-line screen presentation and navigation of CSS have been identified in order to remedy this situation.

Justification

This item is justified on improved customer service and process efficiency.

Enhancing the current CSS on-line screen presentation and navigation will allow for a more efficient and effective *customer-agent* phone interaction. This will result in decreased time spent on the phone, enhancing the overall customer experience.

Matching the system navigation flow to common customer request patterns will also reduce the requirement for agent training and enable less experienced agents to effectively handle the customer request.

A financial analysis of the costs and benefits associated with this project indicates a positive net present value of $9,408 over the next 5 years. The financial analysis is included in Appendix A.

2.2 Meter Management Enhancements ($70,000)

Description

The purpose of this item is to improve the meter management life cycle, from initial receiving to premise installation and ultimately the removal/replacement or retirement of the meter.

This enhancement will introduce hand-held bar code technology in areas where meter data is processed. This will improve the efficiency and effectiveness of meter management by reducing reliance on paper-based records and simplifying procedures for managing meter data.

Operating Experience

The Company manages approximately 40,000 metering activities annually including installations, removals and replacements. The Company's Meter Shop located at Duffy Place administers the process of purchasing meters, distributing them to the Company's area offices, and processing meters returned from the field to be either reconditioned and recertified or destroyed.

Currently, the Meter Shop uses older bar coding technology that was redeployed after being retired from another application. All other operating areas rely on paper-based procedures supplemented by spreadsheets. Spreadsheets are used to record and track the status of meter equipment, requiring employees to perform repetitive, inefficient work procedures. This results in data collection and keying errors, requiring additional effort to get the necessary data to process the meter.

Justification

This item is justified on process efficiency and consistency improvements throughout the Company's operating areas. The enhancement will improve Meter Shop and area office meter management processes. Reducing the amount of manual data entry and the number of touch points between employees involved in the processes will result in process efficiencies and improved meter equipment data quality.

A financial analysis of the costs and benefits associated with this item indicates a positive net present value of $7,016 over the next 5 years. The financial analysis is included in Appendix A.

2.3 Customer Finance Plan Enhancements ($113,000)

Description

The purpose of this item is to improve the Company's ability to offer and administer customer finance plans. This enhancement will improve the presentation of finance plan information on the customer bill, reducing the number of customer calls to the Contact Centre. The tracking of finance plan charges and payments will be improved, and flexibility will be enhanced to accommodate additional finance plans, particularly those related to customer energy conservation.

Operating Experience

The Company offers on-the-bill financing as a component of its customer energy conservation programming, and for customer convenience purposes. Examples of current finance plans include home insulation improvements, electric hot water tanks, and electrical wiring upgrades. Approximately 4,200 customer finance plans are administered annually, resulting in an average of 55,200 transactions annually. Existing CSS system functionality limits the Company's ability to offer additional financing plans and to effectively manage additional customer participation in these plans.

Customers' monthly finance plan charges and payments are currently tracked based on the date a customer bill is produced. This can result in miscommunication with customers, confusing presentation of information on the customer bill, and additional complexity in processing customer account adjustments. Customers often misinterpret their finance plan balance, particularly when customer payments are not received by the due date.

Justification

This item is justified on improved customer service.

Enhancing the customer finance plan process will make it easier for customers to understand finance plan billing information, and reduce the number of customer inquiries related to finance plans. It will also enable further customer finance plan participation, particularly in support of customer energy conservation programming.

3.0 Operations and Engineering Systems Enhancements

Operations and Engineering Systems Enhancements include 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 2010, enhancements are proposed for work scheduling and tracking, third party contract management and project document management.

Table 2 summarizes the cost associated with this item.

Table 2
Operations and Engineering Enhancements
Project Expenditures
($000s)

Cost Category	**2010 Estimate**
Material	-
Labour – Internal	154
Labour – Contract	-
Engineering	12
Other	80
Total	**246**

3.1 Work Scheduling and Tracking Enhancements ($156,000)

Description

The purpose of this item is to improve the Company's ability to schedule and track activity such as new service connections, construction and maintenance activities.

This enhancement will consolidate work orders into a single view for scheduling and tracking. This will improve the Company's ability to prioritize and assign the work to crews and support improved response to customer inquiries regarding work status.

Operating Experience

The scheduling and tracking of work orders is largely a manual process relying on output from a number of systems. The lack of consolidated and timely information can result in inefficiencies in the scheduling process.

Justification

This item is justified on the basis of process efficiency improvements. Work order management will be improved by consolidating information on outstanding work orders in a single view, with functionality to manipulate, schedule and assign work.

A financial analysis of the costs and benefits associated with this item results in a positive net present value of $15,919 over the next 5 years. The financial analysis is included in Appendix A.

3.2 Third Party Contract Management ($50,000)

Description

The purpose of this item is to improve the processes related to executing support structure work request contracts the Company manages with third parties.

Operating Experience

The Company owns approximately 200,000 support structures that are jointly used by third parties. Work requests are received to attach new facilities or to modify existing attachments on these support structures. Currently, requests are communicated between the companies via email making it difficult to consolidate requests. This has resulted in discrepancies regarding work scope and billing.

Justification

Creating a database to manage third party work on the Company's business partner internet site (extranet) will centralize data capture and reduce the risk of work scope and billing discrepancies.

A financial analysis of the costs and benefits associated with this project results in a positive net present value of $8,888 over the next 5 years. The financial analysis is included in Appendix A.

3.3 Document Management Improvements ($40,000)

Description

This item involves improvements to the document management and team collaboration processes used in the delivery of construction projects.

Operating Experience

The Company manages over 50 substation construction projects annually. These projects often involve teams of 12 – 15 employees in various locations throughout the province and require the creation and sharing of project documents. Example documents include drawings, materials lists, technical specifications, and safety and environmental plans, permits and inspections. These project documents are currently stored in shared electronic file folders, organized by asset classes, projects and phases, but may be updated in the field or copied and shared via email. This situation leads to document version control issues and difficulty locating relevant documents.

Justification

Enhancing the technology to support construction project document management will improve document management practices.

4.0 Internet/Intranet Enhancements

Internet/Intranet Enhancements include enhancements to the Company's web-based applications. The information technology in this category includes the Company's Internet site, providing public information and customer services; the takeCHARGE! website supporting the joint Newfoundland and Labrador Hydro and Newfoundland Power customer energy conservation initiative; and the Company's intranet site, providing employee self-service, project collaboration and other corporate applications.

For 2010, enhancements are proposed for the Customer Service and Energy Conservation websites.

Table 3 summarizes the cost associated with this item.

Table 3
Internet/Intranet Enhancements
Project Expenditures
($000s)

Cost Category	**2010 Estimate**
Material	-
Labour – Internal	141
Labour – Contract	-
Engineering	-
Other	125
Total	266

4.1 Customer Service Internet Enhancements ($105,000)

Description

This item includes expanding customer self service options available on the Company's website. For 2010, additional functionality will include customer statement of account and increased customer credit management information.

Enhancements to website security are also proposed to improve the customer profile management features. This will ensure the effective protection and privacy of customer information.

Operating Experience

In 2008, the Company's website received more than 470,000 visits, a 20% increase over 2007. Customers are increasingly choosing to use electronic means to do business with the Company at their convenience.

The Company responds to approximately 300 customer requests for a statement of account annually. Business owners with multiple electricity accounts often request statements of account based on the customer's financial year-end. Currently, customers phone the Contact Centre and an agent produces the statement of account and forwards it to the customer by email, fax or mail.

In 2008, the Company received over 138,000 customer calls regarding credit matters. Extending customer self-service to display account balance information, including requirements of payment arrangements for accounts in arrears, will allow customers to access this information at a time convenient to them, reducing calls to the Contact Centre.

Internet security is an issue that companies must manage on a continual basis. The risk and frequency of potential internet threats such as viruses, identity theft and internet fraud continue to increase. The company must invest in appropriate methods to ensure the security and privacy of customer information.

Justification

This item is justified primarily on improved customer service and effective protection of customer information.

4.2 Energy Conservation Website Enhancements ($161,000)

Description

The purpose of this item is to develop and implement Internet based functionality in support of the Company's energy conservation initiatives. This functionality will include tools and related information that allow customers to assess their energy conservation behaviour and evaluate opportunities for improvement.

Enhancements proposed for 2010 include online application forms to allow customers and participating retailers to submit applications for energy conservation program rebates and financing, "what if" calculators to allow customers to compare Energy Star® appliances and windows to standard models, and other interactive tools to assist customers in learning how to save energy and money in their homes and businesses.

The addition of website security functionality is also being proposed in order to ensure the effective protection and privacy of customer information.

Operating Experience

In 2008, Newfoundland and Labrador Hydro and Newfoundland Power launched the joint takeCHARGE! energy conservation initiative. This included a new website takeCHARGE! to provide residents of Newfoundland and Labrador access to information and tools regarding energy efficiency and conservation. This website is an integral part of the Company's customer energy conservation portfolio.

Justification

This item is justified on improved customer service by providing customers with energy conservation tools and information integral to the Company's customer energy conservation portfolio.

5.0 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 operational efficiency.

Operating Experience

Examples of previous work completed under this budget item include developing an application to track customer participation and rebates provided through the Company's energy conservation programs, as well as implementing changes to the Human Resource management system in response to new collective agreements.

Justification

Work completed as part of Various Minor Enhancements is justified on the basis of improved customer service, operating efficiencies, or compliance with regulatory and legislative requirements.

Appendix A

Net Present Value Analysis

CUSTOMER INTERACTION ENHANCEMENTS

Net Present Value Analysis

		Additions			**Cost Increases**		**Cost Benefits**						
	Year	**New Software** **A**	**New Hardware** **B**	**Tax Deductions** **C**	**Labour** **D**	**Non-Lab**	**Labour** **E**	**Non-Lab**	**Net Savings** **F**	**Income Tax** **G**	**After-Tax Cash Flow** **H**	**After-Tax Discounted Cash Flow** **I**	**Cumulative Discounted Cash Flow** **J**
0	2010	($92,000)	$0	$46,000	$0	$0	$10,000	$0	$10,000	$11,520	($70,480)	($70,480)	($70,480)
1	2011			$46,000	$0	$0	$26,664	$0	$26,664	$5,897	$32,562	$30,312	($40,168)
2	2012			$0	$0	$0	$27,731	$0	$27,731	($8,042)	$19,689	$17,063	($23,105)
3	2013			$0	$0	$0	$28,840	$0	$28,840	($8,364)	$20,476	$16,519	($6,585)
4	2014			$0	$0	$0	$29,993	$0	$29,993	($8,698)	$21,295	$15,994	$9,408
	5 Yr	Present Value (See Note K) @ 7.42%										$9,408	

Notes:

A Is the sum of the software additions by year.
B Is the sum of the hardware additions by year.
C Is the Capital Cost Allowance deduction. The Capital Cost Allowance for New Software reflects a 50% rule for capitalizing additions.
D Is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated using the GDP Deflator.
E Is the reduced costs. The cost estimates are escalated using the GDP Deflator.
F Is the sum of columns D and E.
G Is the impact on taxes from the CCA and cost expenditures. It is equal to column C less column F times the tax rate.
H Is the after tax cash flow which is the sum of the capital expenditure (column A + B) plus net savings (column F) plus income tax (column G).
I 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.
J Is the cumulative value of the discounted cash flow in column I.
K Is the present value of the after tax cash flows and equal to the sum of column I.

METER MANAGEMENT ENHANCEMENTS

Net Present Value Analysis

		Additions			Cost Increases		Cost Benefits						
	Year	New Software A	New Hardware B	Tax Deductions C	Labour D	Non-Lab	Labour E	Non-Lab	Net Savings F	Income Tax G	After-Tax Cash Flow H	After-Tax Discounted Cash Flow I	Cumulative Discounted Cash Flow J
0	2010	($70,000)	($10,000)	$45,000	$0	$0	$10,000	$0	$10,000	$11,200	($58,800)	($58,800)	($58,800)
1	2011			$35,000	$0	$0	$22,296	$0	$22,296	$3,875	$26,170	$24,363	($34,437)
2	2012			$0	$0	$0	$23,187	$0	$23,187	($6,724)	$16,463	$14,267	($20,170)
3	2013			$0	$0	$0	$24,115	$0	$24,115	($6,993)	$17,122	$13,813	($6,357)
4	2014			$0	$0	$0	$25,079	$0	$25,079	($7,273)	$17,806	$13,373	$7,016
	5 Yr	Present Value (See Note K) @ 7.42%										$7,016	

Notes:

A Is the sum of the software additions by year.
B Is the sum of the hardware additions by year. The $10,000 under New Hardware is included in the PC Infrastructure Budget.
C Is the Capital Cost Allowance deduction. The Capital Cost Allowance for New Software reflects a 50% rule for capitalizing additions.
D Is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated using the GDP Deflator.
E Is the reduced costs. The cost estimates are escalated using the GDP Deflator.
F Is the sum of columns D and E.
G Is the impact on taxes from the CCA and cost expenditures. It is equal to column C less column F times the tax rate.
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J Is the cumulative value of the discounted cash flow in column I.
K Is the present value of the after tax cash flows and equal to the sum of column I.

WORK SCHEDULING AND TRACKING ENHANCEMENTS

Net Present Value Analysis

		Additions			Cost Increases		Cost Benefits						
	Year	New Software	New Hardware	Tax Deductions	Labour	Non-Lab	Labour	Non-Lab	Net 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	J
0	2010	($156,000)	$0	$78,000	$0	$0	$12,000	$0	$12,000	$21,120	($122,880)	($122,880)	($122,880)
1	2011			$78,000	$0	$0	$46,544	$0	$46,544	$9,594	$56,138	$52,260	($70,620)
2	2012			$0	$0	$0	$48,406	$0	$48,406	($14,038)	$34,368	$29,784	($40,835)
3	2013			$0	$0	$0	$50,342	$0	$50,342	($14,599)	$35,743	$28,836	($11,999)
4	2014			$0	$0	$0	$52,356	$0	$52,356	($15,183)	$37,173	$27,918	$15,919
	5 Yr	Present Value (See Note K) @ 7.42%										$15,919	

Notes:

A Is the sum of the software additions by year.
B Is the sum of the hardware additions by year.
C Is the Capital Cost Allowance deduction. The Capital Cost Allowance for New Software reflects a 50% rule for capitalizing additions.
D Is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated using the GDP Deflator.
E Is the reduced costs. The cost estimates are escalated using the GDP Deflator.
F Is the sum of columns D and E.
G Is the impact on taxes from the CCA and cost expenditures. It is equal to column C less column F times the tax rate.
H Is the after tax cash flow which is the sum of the capital expenditure (column A + B) plus net savings (column F) plus income tax (column G).
I 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.
J Is the cumulative value of the discounted cash flow in column I.
K Is the present value of the after tax cash flows and equal to the sum of column I.

THIRD PART CONTRACT MANAGEMENT

Net Present Value Analysis

		Additions			Cost Increases		Cost Benefits						
	Year	**New Software**	**New Hardware**	**Tax Deductions**	**Labour**	**Non-Lab**	**Labour**	**Non-Lab**	**Net 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**	**J**
0	2010	($50,000)	$0	$25,000	$0	$0		$0	$0	$8,000	($42,000)	($42,000)	($42,000)
1	2011			$25,000	$0	$0	$17,472	$0	$17,472	$2,296	$19,768	$18,403	($23,597)
2	2012			$0	$0	$0	$18,171	$0	$18,171	($5,270)	$12,901	$11,181	($12,417)
3	2013			$0	$0	$0	$18,898	$0	$18,898	($5,480)	$13,417	$10,825	($1,592)
4	2014			$0	$0	$0	$19,654	$0	$19,654	($5,700)	$13,954	$10,480	$8,888
	5 Yr	Present Value (See Note K) @ 7.42%										$8,888	

Notes:

A Is the sum of the software additions by year.
B Is the sum of the hardware additions by year.
C Is the Capital Cost Allowance deduction. The Capital Cost Allowance for New Software reflects a 50% rule for capitalizing additions.
D Is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated using the GDP Deflator.
E Is the reduced costs. The cost estimates are escalated using the GDP Deflator.
F Is the sum of columns D and E.
G Is the impact on taxes from the CCA and cost expenditures. It is equal to column C less column F times the tax rate.
H Is the after tax cash flow which is the sum of the capital expenditure (column A + B) plus net savings (column F) plus income tax (column G).
I 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.
J Is the cumulative value of the discounted cash flow in column I.
K Is the present value of the after tax cash flows and equal to the sum of column I.

2010 System Upgrades

June 2009

NEWFOUNDLAND POWER
A FORTIS COMPANY

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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 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 ($786,000)

For 2010, the project includes upgrades to the development tools used to support and operate corporate applications including the Customer Service System (CSS), contact centre technology, reporting software, substation maintenance (mobile) application, customer correspondence software, and engineering design software.

Table 1 summarizes the cost associated with these items.

Table 1
Business Applications Upgrades
Project Expenditures
($000s)

Cost Category	2010 Estimate
Material	52
Labour – Internal	564
Labour – Contract	-
Engineering	15
Other	155
Total	**786**

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 2010, upgrades include:

1) Development Tool Upgrade – $230,000

   This item involves the upgrade of software development tools and related components used to operate corporate applications including CSS. The Powerhouse and Axiant programming languages from IBM-Cognos, as well as the OpenVMS server operating system, will be upgraded to the most current compatible versions supported by the vendors.

   The versions of Powerhouse and Axiant currently used by the Company are no longer supported by the vendor.

   This upgrade will enable the Company to sustain an acceptable level of support and maintenance for CSS and other corporate applications.

2) Contact Centre Technology Upgrade - $190,000

   This item involves an upgrade to the Company's Contact Centre technology from Aspect Communications. The components to be upgraded include the Contact Centre Agent telephone interface software which is no longer supported by the vendor, the agent call routing software, and the Interactive Voice Response (IVR) software (used to direct and respond to customer inquiries via phone menu options) which will not be supported by the vendor after 2010.

   This upgrade will enable the Company to sustain an acceptable level of support and maintenance for the Contact Centre technology.

3) Reporting Software Upgrade - $120,000

   This item involves an upgrade to the Company's reporting software Impromptu and PowerPlay from IBM-Cognos. This software is used to deliver and operate several corporate reporting applications including employee self-service, outage reporting statistics (SAIDI/SAIFI) and customer information reporting.

   The reporting software versions currently in use are no longer supported by the vendor. This upgrade will enable the Company to sustain an acceptable level of support and maintenance for its reporting software.

4) Substation Inspection (Mobile) Application Upgrade - $113,000

   This item involves an upgrade to the Company's substation inspection software. This software is used on mobile computing devices to record field inspection results. The current application platform does not effectively support new inspection procedures due to limited data storage capacity and poor application response time performance.

This upgrade will enable the Company to sustain an acceptable level of operational efficiency.

5) Customer Correspondence Software Upgrade - $73,000

This item involves an upgrade to the Company's customer correspondence software PlanetPress from Objectif Lune. This software is used to format and render both paper-based and electronic customer bills and letters.

The software versions currently in use are no longer supported by the vendor. This upgrade will enable the Company to sustain an acceptable level of support and maintenance for its customer correspondence software.

6) Engineering Design Software Upgrade - $60,000

This item involves an upgrade to the engineering design software, AutoCAD LT, used by the Company's technical staff throughout the province.

The version of this software currently in use is not compatible with the currently available version of AutoCAD. This requires conversion of engineering drawings, maps and documents in order to share information among technical staff in the Company and external parties with whom the Company collaborates.

This upgrade will ensure compatibility with the currently available version of the software, resulting in an acceptable level of operational efficiency.

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 to ensure 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 ($52,000)

Information Technology ("IT") management upgrades involve the upgrades necessary to maintain IT controls that ensure the integrity and availability of customer, electrical system, and corporate data.

Table 2 summarizes the cost associated with these items.

Table 2
IT Management Upgrades
Project Expenditures
($000s)

Cost Category	2010 Estimate
Material	15
Labour – Internal	22
Labour – Contract	-
Engineering	-
Other	15
Total	**52**

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 2010, this project includes replacement of software used to monitor the Company's production databases. Effective database monitoring ensures an acceptable level of system availability, hence a sustained level of customer service and operational efficiency. Accordingly, the Company's current version of the software, Oracle Enterprise Manager, is no longer supported by the vendor.

Operating Experience

The Company depends on the stable operation of its over 50 business applications such as CSS, Outage Management and Avantis to sustain an effective level of customer service and employee productivity. The vast majority of these applications interact with one or more databases. The Company's reliance on database technologies has steadily increased over the past 10 years. The requirement to monitor all aspects of these individual databases has become increasingly important to ensure the integrity and availability of customer, electrical system, and corporate data.

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 price annual 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 of the 2009 Capital Budget Application.

Operating Experience

This project includes year two of three for the Microsoft Enterprise Agreement (2009 – 2011).

Justification

The Microsoft Enterprise Agreement is the least cost option to ensuring access to current Microsoft software products.

2010 Shared Server Infrastructure

June 2009

1.0 Introduction

Shared Server Infrastructure consists of over 100 shared servers that are used for production, testing, and disaster recovery of Newfoundland Power's ("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 operations, 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	2010 Estimate
Material	388
Labour – Internal	187
Labour – Contract	-
Engineering	-
Other	85
Total	**660**

For 2010, this project includes:

1. The replacement of servers that operate the Company's Computer Telephony Integration (CTI) application used to receive and route incoming customer calls in the Contact Centre. These servers are seven (7) years old and have reached the end of life. This project is related to the *System Upgrades* project. The budget for this item is $65,000.

2. The replacement of the corporate reporting servers that are currently eight (8) years old and have reached the end of life. This project is related to the *System Upgrades* project. The budget for this item is $57,000.

3. The replacement of the Customer Correspondence servers that are seven (7) years old and have reached the end of life. This project is related to the *System Upgrades* project. The budget for this item is $52,000.

4. The replacement of servers and other equipment responsible for operating the data backup system. These servers are six (6) years old and no longer have the capacity and processing power required to sustain the current load and expansion of the Company's backup and recovery environment. The budget for this item is $83,000.

5. The replacement of user authentication servers that are eight (8) years old and have reached the end of life. These servers provide employees' access to corporate applications. The budget for this item is $25,000.

6. The replacement of the corporate firewall infrastructure. This hardware is seven (7) years old and has reached the end of life. This project also includes the addition of security products for vulnerability management and notebook encryption technology for enterprise data protection. The budget for this project is $250,000.

7. The replacement of the servers used for voice communications, and call recording at the System Control Center. These servers are nine (9) years old and have reached the end of life. The budget for this item is $76,000.

8. Expansion to the physical security of the Company's facilities that contain computing infrastructure. This item involves the addition, upgrade and replacement of hardware components and related technology including cameras, intruder detection, and security monitoring. These components will primarily be located at the Duffy Place location in St. John's to facilitate increased coverage of the building, warehouse and yard. The budget for this item is $52,000.

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 employees and customers. 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[1] 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 is about 7 years.

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. 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 2010 is 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.

[1] Gartner Inc. is the leading provider of research and analysis on the global Information Technology industry.

Rate Base:
Additions, Deductions & Allowances

June 2009

Table of Contents

1.0 Introduction

1.1 General

In the 2010 Capital Budget Application (the "Application"), Newfoundland Power seeks final approval of its 2008 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2008 average rate base of $820,876,000 is set out in Schedule D to the Application.

To meet the cost of service standard, rate base, as calculated in accordance with the Asset Rate Base Method, should reflect what the utility must finance. For investment in utility plant, it is the depreciated value of the plant that must be effectively financed. However, for rate base to fully reflect the financing requirements associated with the provision of regulated service, it must also be adjusted to reflect other costs required to provide service.

Conceptually, additions to rate base are costs that have been incurred to provide service but have not yet been recovered through customer rates. Deductions from rate base represent amounts that have been recovered through customer rates in advance of the required utility payment for those costs. Rate base allowances simply reflect the cost associated with maintaining the required working capital and inventories necessary to provide service. Each of these items affect what the utility must finance.

In Order No. P.U. 32 (2007), the Board approved Newfoundland Power's calculation of rate base in accordance with the Asset Rate Base Method. That calculation included the additions to, deductions from, and allowances in rate base which are more fully described in this report.

1.2 Compliance and Related Matters

In Order No. P.U. 19 (2003), the Board, in effect, ordered Newfoundland Power file with its capital budget applications (i) evidence related to changes in deferred charges, including pension costs, and (ii) a reconciliation of average rate base and average invested capital.

Commencing in 2008, Newfoundland Power's rate base is calculated in accordance with the Asset Rate Base Method. This includes provision for allowances calculated in accordance with accepted regulatory practice. The use of allowances versus average year-end balances result in permanent differences between Newfoundland Power's average rate base and average invested capital. Accordingly, they are, in effect, the principal reconciling items between the Company's average rate base and average invested capital.

This report provides evidence relating to (i) changes in deferred charges including pension costs and (ii) the cash working capital allowance and materials and supplies allowance included in rate base. In the circumstances, this complies with the requirements of Order No. P.U. 19 (2003).

To provide the Board with a comprehensive overview of those items in Newfoundland Power's rate base other than plant investment, this report reviews *all* additions, deductions and allowances included in rate base.

Four years of data is provided in this report. This includes two historical years, the current year and following year. In addition, the data presented is year-end data. This is consistent with past evidence submitted in compliance with Order No. P.U. 19 (2003).

2.0 Additions to Rate Base

2.1 Summary

Table 1 summarizes Newfoundland Power's additions to rate base for 2007 and 2008 and the forecast additions for 2009 and 2010.

Table 1
Additions to Rate Base
2007-2010F
($000s)

	2007	2008	2009F	2010F
Deferred Charges	97,453	100,723	103,964	104,298
Weather Normalization Reserve	10,516	5,910	2,683	1,317
Deferred Replacement Energy Costs	1,147	766	383	-
Cost Recovery Deferral - Depreciation	11,586	7,724	3,861	-
Cost Recovery Deferral - Conservation	-	-	1,516	1,137
Customer Finance Programs	1,811	1,776	1,750	1,750
Total Additions	122,513	116,899	114,157	108,502

Additions to rate base were approximately $117 million in 2008. This is approximately $5.6 million less than 2007. The lower forecast additions to rate base through 2010 reflect the effect of the amortizations of a number of deferred costs approved by the Board in Order No. P.U. 32 (2007).

This section outlines the additions to rate base in further detail.

2.2. Deferred Charges

Table 2 shows details of changes in Newfoundland Power's deferred charges from 2007 through 2010.

Table 2
Deferred Charges
2007-2010F
($000s)

	2007	2008	2009F	2010F
Deferred Pension Costs	96,654	100,196	103,723	104,298
Deferred Capital Stock Issue Costs	137	75	38	-
Deferred Credit Facility Issue Costs	59	50	-	-
Deferred Hearing Costs	603	402	203	-
Total Deferred Charges	97,453	100,723	103,964	104,298

2.2.1 Deferred Pension Costs

Deferred pension costs are the largest component of Newfoundland Power's deferred charges. The difference between pension plan *funding* and pension plan *expense* associated with the Company's defined benefit pension plan is captured as a deferred pension cost in accordance with Order No. P.U. 17 (1987).[1]

Table 3 shows details of changes in Newfoundland Power's deferred pension costs from 2007 through 2010.

Table 3
Deferred Pension Costs
2007-2010F
($000s)

	2007	2008	2009F	2010F
Deferred Pension Costs, January 1st	90,122	96,654	100,196	103,723
Pension Plan Funding	10,904	5,425	4,866	4,999
Pension Plan Expense	(4,372)	(1,883)	(1,339)	(4,424)
Deferred Pension Costs, December 31st	96,654	100,196	103,723	104,298

For 2008, deferred pension costs were approximately $100 million.

[1] Deferred pension costs were approved for inclusion in average rate base in Order No. P.U. 19 (2003).

2.2.2. Deferred Capital Stock Issue Costs

Deferred capital stock issue costs are related to the issuance of capital stock. They are amortized over 20 years.

Table 4 shows details of Newfoundland Power's amortization of capital stock issue costs from 2007 through 2010.

Table 4
Deferred Capital Stock Issue Costs
2007-2010F
($000s)

	2007	2008	2009F	2010F
Balance, January 1st	199	137	75	38
Amortization	(62)	(62)	(37)	(38)
Balance, December 31st	137	75	38	-

For 2008, the deferred capital stock issue costs were $75,000. The deferred capital stock issue costs will be fully amortized by 2010.

2.2.3. Deferred Credit Facility Issue Costs

In Order P.U. 1 (2005), the Board approved Newfoundland Power's issue of a $100 million committed revolving term credit facility. In Order No. P.U. 22 (2008), the Board approved the extension of the maturity date of the Company's 3-year committed revolving credit facility from 2009 to 2011. The Company incurred $50,000 in credit facility issue costs in 2008 relating to this renewal.

Table 5 shows details of Newfoundland Power's amortization of deferred credit facility issue costs from 2007 through 2010.

Table 5
Deferred Credit Facility Issue Costs
2007-2010F
($000s)

	2007	2008	2009F	2010F
Balance, January 1st	118	59	50	-
Cost	-	50	-	-
Amortization	(59)	(59)	(50)	-
Balance, December 31st	59	50	-	-

For 2008, the deferred credit facility costs were $50,000. The deferred credit facility costs will be fully amortized in 2009.

2.2.4. Deferred Hearing Costs
In Order No. P.U. 32 (2007), the Board approved the estimated external costs related to the Company's 2008 General Rate Application be deferred and amortized equally over three years beginning in 2008.

Table 6 shows details of the changes in Newfoundland Power's deferred hearing costs from 2007 through 2010.

Table 6
Deferred Hearing Costs
2007-2010F
($000s)

	2007	**2008**	**2009F**	**2010F**
Balance, January 1st	-	603	402	203
Cost	603	-	-	750
Amortization	-	(201)	(199)	(953)
Balance, December 31st	603	402	203	-

For 2008, the deferred hearing costs were $402,000. The deferred hearing costs associated with the Company's 2008 General Rate Application will be fully amortized in 2010.

Hearing costs associated with the Company's 2010 General Rate Application have been proposed to be fully recovered in 2010; however, this Application is currently outstanding and has not yet been considered by the Board.

2.3 Weather Normalization Reserve

In Order No. P.U. 1 (1974), the Board approved that rate base be adjusted for the balance in the Weather Normalization Reserve.

Table 7 shows details of changes in the balance of the Weather Normalization Reserve from 2007 through 2010.

Table 7
Weather Normalization Reserve
2007-2010F
($000s)

	2007	**2008**	**2009F**	**2010F**[2]
Balance, January 1st	11,809	10,516	5,910	2,683
Operation of the reserve	(187)	(3,240)	(1,861)	-
Amortization	(1,106)	(1,366)	(1,366)	(1,366)
Balance, December 31st	10,516	5,910	2,683	1,317

For 2008, the Weather Normalization Reserve balance was $5.9 million. This balance was approved by the Board in Order No. P.U. 12 (2009).

2.4 Deferred Energy Replacement Costs

During the construction period of the Rattling Brook refurbishment project in 2007, Newfoundland Power purchased energy from Newfoundland and Labrador Hydro (“Hydro”) to replace the normal production of the Rattling Brook hydroelectric plant. In Order No. P.U. 39 (2006), the Board ordered Newfoundland Power to defer recovery of an after-tax amount of $1.1 million 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 over three years beginning in 2008.

[2] The 2010 forecast balance for the Weather Normalization Reserve assumes normal stream-flows and weather patterns.

Table 8 shows details of the amortization of the deferred energy replacement costs from 2007 through 2010.

Table 8
Deferred Energy Replacement Costs
2007-2010F
($000s)

	2007	**2008**	**2009F**	**2010F**
Balance, January 1st	-	1,147	766	383
Cost	1147	-	-	-
Amortization	-	(381)	(383)	(383)
Balance, December 31st	1147	766	383	-

For 2008, the deferred energy replacement costs were $766,000. The balance of the deferred replacement energy cost will be fully amortized in 2010.

2.5 Cost Recovery Deferral-Depreciation

In Order No. P.U. 32 (2007), the Board approved a three year amortization of $11.6 million in deferred costs related to depreciation.[3]

Table 9 shows details of the amortization of the deferred cost recovery related to depreciation from 2007 through 2010.

Table 9
Cost Recovery Deferral-Depreciation
2007-2010F
($000s)

	2007	**2008**	**2009F**	**2010F**
Balance, January 1st	5,793	11,586	7,724	3,861
Cost	5,793	-	-	-
Amortization	-	(3,862)	(3,863)	(3,861)
Balance, December 31st	11,586	7,724	3,861	-

For 2008, the cost recovery deferral was $7.7 million. The balance of the deferred cost recovery related to depreciation will be fully amortized in 2010.

[3] In Order Nos. P.U. 40 (2005) and P.U. 39 (2006), the Board approved the deferred recovery of $5.8 million in depreciation costs in each of 2006 and 2007, respectively.

2.6 Cost Recovery Deferral-Conservation

Table 10 shows details of forecast amortization of the deferred cost recovery related to conservation in 2009 and 2010.

Table 10
Cost Recovery Deferral-Conservation
2007-2010F
($000s)

	2007	**2008**	**2009F**	**2010F**
Balance, January 1st	-	-	-	1,516
Cost	-	-	1,516	-
Amortization	-	-	-	(379)
Balance, December 31st	-	-	1,516	1,137

For 2008, Newfoundland Power did not defer costs related to conservation.

In Order No. P.U. 13 (2009), the Board approved the deferred recovery of certain forecast 2009 conservation costs. These costs are currently estimated at $1.5 million.

Newfoundland Power is proposing in the 2010 General Rate Application to recover the deferred conservation costs over a 4 year period beginning 2010. This Application is currently outstanding and has not yet been considered by the Board.

2.7 Customer Finance Programs

Customer finance programs are loans provided to customers for the purchase and installation of products and services related to conservation programs and contributions in aid of construction (“CIAC”).

Table 11 shows details of changes to balances related to customer finance programs for 2007 through 2010.

Table 11
Customer Finance Programs
2007-2010F
($000s)

	2007	**2008**	**2009F**	**2010F**
Balance, January 1st	1,728	1,811	1,776	1,750
Change	83	(35)	(26)	-
Balance, December 31st	1,811	1,776	1,750	1,750

For 2008, the customer finance programs balance was $1.8 million.

3.0 Deductions from Rate Base

3.1 Summary

Table 12 summarizes Newfoundland Power's deductions from rate base for 2007 and 2008 and the Company's forecasts for 2009 and 2010.

Table 12
Deductions from Rate Base
2007-2010F
($000s)

	2007	2008	2009F	2010F
2005 Unbilled Revenue	16,446	9,236	4,618	-
Accrued Pension Liabilities	2,943	3,142	3,380	3,624
Municipal Tax Liability	4,089	2,727	1,365	-
Future Income Taxes	-	1,184	3,050	1,764
Purchased Power Unit Cost Variance Reserve	1,650	895	448	-
Demand Management Incentive Account	-	426	-	-
Customer Security Deposits	612	785	643	643
Accrued OPEBs Liability	-	-	-	5,674
Total Deductions	25,740	18,395	13,504	11,705

Deductions from rate base were approximately $18.4 million in 2008. Newfoundland Power's deductions from rate base in 2008 have decreased approximately $7.3 million from 2007. The forecast reduction through 2010 primarily reflects the effect of amortizations approved by the Board in Order No. P.U. 32 (2007).

This section outlines the deductions from rate base in further detail.

3.2 2005 Unbilled Revenue

Table 13 shows details of the amortization of the 2005 unbilled revenue from 2007 through 2010.

Table 13
2005 Unbilled Revenue
2007-2010F
($000)

	2007	2008	2009F	2010F
January 1, Balance	19,160	16,446	9,236	4,618
Amortization	(2,714)	(7,210)	(4,618)	(4,618)
December 31, Balance	16,446	9,236	4,618	-

For 2008, the 2005 unbilled revenue balance was $9.2 million.

In Order No. P.U. 32 (2007), the Board approved a three year amortization of the remaining balance of the 2005 unbilled revenue. In addition, the Board approved the amortization of $2.6 million in 2008 to offset an income tax payment related to the 2005 tax settlement. The balance of the 2005 unbilled revenue will be fully amortized in 2010.

3.3 Accrued Pension Liabilities

Accrued pension liabilities are the cumulative costs of Newfoundland Power's unfunded pension plans net of associated benefit payments.

Table 14 shows details of changes related to accrued pension liabilities for 2007 through 2010.

Table 14
Accrued Pension Liabilities
2007-2010F
($000)

	2007	2008	2009F	2010F
January 1, Balance	2,690	2,943	3,142	3,380
Change	253	199	238	244
December 31, Balance	2,943	3,142	3,380	3,624

For 2008, the accrued pension liabilities were $3.1 million.

3.4 Municipal Tax Liability

The municipal tax liability is a timing difference related to the recovery and payment of municipal taxes. In Order No. P.U. 32 (2007), the Board approved a three year amortization of the municipal tax liability beginning in 2008.

Table 15 shows details of the amortization of the municipal tax liability from 2007 through 2010.

Table 15
Municipal Tax Liability
2007-2010F
($000)

	2007	**2008**	**2009F**	**2010F**
January 1, Balance	4,089	4,089	2,727	1,365
Amortization	-	(1,362)	(1,362)	(1,365)
December 31, Balance	4,089	2,727	1,365	-

For 2008, the municipal tax liability was $2.7 million. The balance of the municipal tax liability will be fully amortized in 2010.

3.5 Future Income Taxes

Future income taxes result from timing differences related to the payment of income taxes and the recognition of income taxes for financial reporting and regulatory purposes. Currently, Newfoundland Power recognizes future income taxes with respect to timing differences related to plant investment[4] and pension costs.[5]

Table 16 shows details of changes in the future income taxes from 2007 through 2010.

Table 16
Future Income Taxes
2007-2010F
($000)

	2007	**2008**	**2009F**	**2010F**
January 1, Balance	-	-	1,184	3,050
Change	-	1,184	1,866	(1,286)
December 31, Balance	-	1,184	3,050	1,764

[4] In Order Nos. P.U. 20 (1978), P.U. 21 (1980) and P.U. 17 (1987), the Board approved the Company's use of the Tax Accrual Accounting to recognize future income tax liabilities associated with plant investment.

[5] In Order No. P.U. 32 (2007), the Board approved the use of tax accrual accounting to recognize future income taxes related to timing differences between pension funding and pension expense.

For 2008, future income taxes were $1.2 million.

In the 2010 General Rate Application, Newfoundland Power is proposing to adopt accrual accounting for income tax related to employee future benefits for regulatory purposes.[6] The reduction in future income taxes forecast in 2010 reflects the rate base effects of this proposal. This Application is currently outstanding and has not yet been considered by the Board.

3.6 Purchased Power Unit Cost Variance Reserve

In Order No P.U. 32 (2007), the Board approved a three year amortization of a $2.1 million credit balance in the Purchase Power Unit Cost Variance Reserve beginning in 2008.

Table 17 shows details of the amortization of Purchase Power Unit Cost Variance Reserve from 2007 through 2010.

Table 17
Purchase Power Unit Cost Variance Reserve
2007-2010F
($000)

	2007	**2008**	**2009F**	**2010F**
January 1, Balance	1,342	1,650	895	448
Change	308	(308)	-	-
Amortization	-	(447)	(447)	(448)
December 31, Balance	1,650	895	448	-

For 2008, the Purchase Power Unit Cost Variance Reserve balance was $895,000. This balance will be fully amortized in 2010.

[6] See the 2010 General Rate Application, Volume 2: Supporting Materials, Tab 4.

3.7 Demand Management Incentive Account

In Order No. P.U. 32 (2007) the Board approved the Demand Management Incentive Account (the "DMI Account") to replace the Purchase Power Unit Cost Variance Reserve.

Table 18 shows details of the amortization of the DMI Account from 2008 through 2010.

Table 18
DMI Account
2007-2010F
($000)

	2007	**2008**	**2009F**	**2010F**
January 1, Balance	-	-	426	-
Change	-	426	(426)	-
December 31, Balance	-	426	-	-

For 2008, the DMI Account balance was $426,000. In Order No P.U. 21 (2009), the Board approved the transfer of this balance to the Rate Stabilization Account.

3.8 Customer Security Deposits

Customer security deposits are provided by customers in accordance with the Schedule of Rates, Rules and Regulations.

Table 19 shows details on the changes in customer security deposits from 2007 through 2010.

Table 19
Customer Security Deposits
2007-2010F
($000)

	2007	**2008**	**2009F**	**2010F**
January 1, Balance	736	612	785	643
Change	(124)	173	(142)	-
December 31, Balance	612	785	643	643

For 2008, the balance of customer security deposits was $785,000.

3.9 Accrued OPEBs Liability

Newfoundland Power's other post employment benefits ("OPEBs") are comprised of retirement allowances for retiring employees as well as health, medical and life insurance for retirees and their dependents.

Table 20 shows details of the changes related to the accrued OPEBs liability from 2007 through 2010.

Table 20
Accrued OPEBs Liability
2007-2010F
($000)

	2007	2008	2009F	2010F
Regulatory Asset	34,527	41,074	46,172	46,172
Regulatory Liability	(34,527)	(41,074)	(46,172)	(51,846)
Net OPEBs Liability	-	-	-	(5,674)

Newfoundland Power currently recognizes OPEBs costs on a cash basis. On the cash basis, the OPEBs asset and the OPEBs liability are equal. As a result, there is no impact on Newfoundland Power's 2008 rate base due to OPEBs costs.

In the 2010 General Rate Application, Newfoundland Power is proposing to adopt the accrual method for the recognition of OPEBs.[7] The net OPEBs liability included in rate base for 2010 is, in effect, the difference between the accounting of OPEBs on a cash basis versus an accrual basis.

4.0 Rate Base Allowances

The cash working capital allowance together with the materials and supplies allowance form the total allowances that are included in the Company's rate base. This represents the average amount of investor-supplied working capital necessary to provide service.

[7] Under the accrual method, OPEBs costs are recognized as an expense as employees earn the benefits that they will receive after retirement.

4.1 Cash Working Capital Allowance

The cash working capital allowance recognizes that a utility must finance the cost of its operations until it collects the revenues to recover those costs.

Table 21 shows details on changes in the cash working capital allowance from 2007 through 2010.

Table 21
Rate Base Allowances
Cash Working Capital Allowance
2007-2010F
($000)

	2007	2008	2009F	2010F
Gross Operating Costs	379,980	382,799	395,883	407,412
Income Taxes	12,432	20,131	14,304	21,905
Municipal Taxes Paid	-	12,394	12,749	13,346
Non-Regulated Expenses	(111)	(995)	(1,042)	(1,165)
Total Operating Expenses	392,301	414,329	421,894	441,498
Cash Working Capital Factor	1.7%	2.1%[8]	2.1%	2.0%[9]
	6,669	8,701	8,860	8,830
HST Adjustment	-	1,015	1,015	436
Cash Working Capital Allowance	6,669	9,716	9,875	9,266

For 2008, the cash working capital allowance was $9.7 million.

The cash working capital allowance for 2010 is based on the 2010 General Rate Application. This Application is currently outstanding and has not yet been considered by the Board.

[8] The calculation of 2008 rate base including a cash working capital allowance based upon a cash working capital factor of 2.1% was approved by the Board in Order No. P.U. 32 (2007).

[9] In the 2010 General Rate Application, Newfoundland Power completed a lead/lag study for purposes of calculating the cash working capital allowance for inclusion in the 2010 rate base.

4.2 Materials and Supplies Allowance

Including a materials and supplies allowance in rate base provides a utility a means to reasonably recover the cost of financing its inventories that are not related to the expansion of the electrical system.[10]

Table 22 shows details on changes in the materials and supplies allowance from 2007 through 2010.

Table 22
Rate Base Allowances
Materials and Supplies Allowance
2007-2010F
($000)

	2007	2008	2009F	2010F
Average Materials and Supplies	5,377	5,369	5,498	5,579
Expansion Factor[11]	18.3%	19.4%	19.4%	20.2%
Expansion	984	1,042	1,067	1,126
Materials and Supplies Allowance	4,393	4,327	4,431	4,453

For 2008, the materials and supplies allowance was $4.3 million.

The materials and supplies allowance for 2010 is based on the 2010 General Rate Application. This Application is currently outstanding and has not yet been considered by the Board.

10 Financing costs for inventory related to the expansion of the electrical system are recovered through the use of an allowance for funds used during construction and are capitalized upon project completion.

11 The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of 2008 rate base including a materials and supplies allowance based upon an expansion factor of 19.4% was approved by the Board in Order No. P.U. 32 (2007). The expansion factor for 2010 is based on a review of actual inventories used for expansion projects in 2008.