WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

DELIVERED BY HAND

July 15, 2016

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

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

Ladies & Gentlemen:

Re: Newfoundland Power's 2017 Capital Budget Application

A. 2017 Capital Budget Application

Enclosed are the original and 12 copies of Newfoundland Power Inc.'s (the "Company") 2017 Capital Budget Application and supporting materials (the "Filing").

The Filing outlines a proposed 2017 Capital Budget totaling $89,411,000. Included in that total are 2017 capital expenditures of $195,000 previously approved in Order No. P.U. 40 (2014) (the "2015 Capital Order") and $4,957,000 previously approved in Order No. P.U. 28 (2015) (the "2016 Capital Order"). Those previously approved expenditures relate to multi-year projects proposed in the 2015 Capital Budget Application and the 2016 Capital Budget Application. The Filing also outlines multi-year projects commencing in 2017 that include proposed 2018 capital expenditures totaling $1,431,000. In addition, the Filing seeks approval of a 2015 rate base in the amount of $1,019,082,000.

B. Compliance Matters

B.1 Board Orders

In the 2016 Capital Order, the Board required a progress report on 2016 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.

Newfoundland Power Inc.
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These requirements are specifically addressed in the Filing in the following:

1. *2016 Capital Expenditure Status Report*: this meets the requirements of the 2016 Capital Order;

2. *2017 Capital 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 *2017 Capital Plan* provides a breakdown of the overall 2017 Capital Budget by definition, classification, and materiality segmentation as described in the Guidelines. Pages i through viii of Schedule B to the formal application provide details of these categorizations by project.

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 and 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,

Gerard M. Hayes
Senior Counsel

Enclosures

c. Geoffrey Young
Newfoundland and Labrador Hydro

Thomas Johnson, QC
O'Dea Earle Law Offices

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Newfoundland Power Inc.
2017 Capital Budget Application
Filing Contents

Application

Application

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Schedule B *2017 Capital Projects Summary*
Schedule C *Multi-Year Projects*
Schedule D *Computation of Average Rate Base*

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1.2 Public Safety Around Dams
1.3 Tors Cove Hydro Plant Refurbishment

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2.1 2017 Substation Refurbishment and Modernization
2.2 2017 Additions Due to Load Growth

Transmission

3.1 2017 Transmission Line Rebuild

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4.1 Distribution Reliability Initiative
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4.3 Vault Refurbishment and Modernization

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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 a 2017 Capital Budget of $89,411,000;

(b) approving certain capital expenditures related to multi-year projects commencing in 2017; and

(c) fixing and determining a 2015 rate base of $1,019,082,000

2017 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 a 2017 Capital Budget of $89,411,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2017; and
(c) fixing and determining a 2015 rate base of $1,019,082,000

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 2017 Capital Budget in the amount of $89,411,000, which includes forecast 2017 capital expenditures previously approved in Order No. P.U. 40 (2014), Order No. P.U. 28 (2015), and also includes an estimated amount of $1,500,000 in contributions in aid of construction that the Applicant intends to demand from its customers in 2017. All contributions to be recovered from customers shall be calculated in a manner approved by the Board.

3. Schedule B to this Application provides detailed descriptions of the projects for which the proposed capital expenditures included in Newfoundland Power's 2017 Capital Budget are required.

4. Schedule C to this Application is a listing of multi-year projects including:

   (a) ongoing projects for which capital expenditures were approved in Order No. P.U. 40 (2014);

   (b) ongoing projects for which capital expenditures were approved in Order No. P.U. 28 (2015); and

   (c) projects which will commence as part of the 2017 Capital Budget but will not be completed in 2017.

(c) projects which will commence as part of the 2017 Capital Budget but will not be completed in 2017.

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

6. Schedule D to this Application shows Newfoundland Power's actual average rate base for 2015 of $1,019,082,000.

7. Communication with respect to this Application should be forwarded to the attention of Liam P. O'Brien and Gerard M. Hayes, Counsel to Newfoundland Power.

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

(a) pursuant to Section 41 of the Act, approving Newfoundland Power's 2017 Capital Budget in the amount of $89,411,000 as set out in Schedules A and B to the Application;

(b) pursuant to Section 41 of the Act, approving Newfoundland Power's purchase and construction in 2018 of improvements and additions to its property in the amount of $1,431,000, as set out in Schedule C to the Application;

(c) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2015 in the amount of $1,019,082,000 as set out in Schedule D to the Application.

DATED at St. John's, Newfoundland and Labrador, this 15th day of July, 2016.

NEWFOUNDLAND POWER INC.

Liam P. O'Brien 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 a 2017 Capital Budget of $89,411,000;

(b) approving certain capital expenditures related to multi-year projects commencing in 2017; and

(c) fixing and determining a 2015 rate base of $1,019,082,000

AFFIDAVIT

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

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

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

SWORN to before me at St. John's in the Province of Newfoundland and Labrador this 15th day of July, 2016:

Barrister

Gary Murray

2017 CAPITAL BUDGET SUMMARY

Asset Class	Budget (000s)
1. Generation - Hydro	$ 3,745
2. Generation - Thermal	234
3. Substations	16,593
4. Transmission	6,711
5. Distribution	47,034
6. General Property	1,502
7. Transportation	3,456
8. Telecommunications	98
9. Information Systems	5,288
10. Unforeseen Allowance	750
11. General Expenses Capitalized	4,000
Total	**$ 89,411**

2017 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
1. Generation – Hydro		
Facility Rehabilitation	$ 1,607	2
Public Safety Around Dams	662	4
Tors Cove Plant Refurbishment	1,476	6
Total Generation – Hydro	**$ 3,745**	
2. Generation – Thermal		
Facility Rehabilitation Thermal	$ 234	9
Total Generation – Thermal	**$ 234**	
3. Substations		
Substations Refurbishment and Modernization	$ 8,875	12
Replacements Due to In-Service Failures	3,851	15
Additions Due to Load Growth	2,574	17
PCB Bushing Phase-out	1,009	19
Substation Feeder Termination	284	22
Total Substations	**$ 16,593**	
4. Transmission		
Transmission Line Rebuild[2]	$ 6,711	25
Total Transmission	**$ 6,711**	

1 Project descriptions can be found in Schedule B at the page indicated.
2 Includes the rebuild of 57L (Bay Roberts to Harbour Grace substations) which is a multi-year project that includes $1,717,000 in expenditures approved in Order No. P.U. 28 (2015).

2017 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[3]
5. Distribution		
Extensions	$ 11,834	29
Meters	4,391	31
Services	3,564	34
Street Lighting	2,049	37
Transformers	6,103	40
Reconstruction	4,908	42
Rebuild Distribution Lines	4,023	44
Relocate/Replace Distribution Lines for Third Parties	2,266	47
Trunk Feeders	1,834	49
Feeder Additions for Growth	1,430	51
Distribution Reliability Initiative	1,415	53
Distribution Feeder Automation	568	55
St. John's Main Underground Refurbishment[4]	2,440	57
Allowance for Funds Used During Construction	209	59
Total Distribution	**$ 47,034**	
6. General Property		
Tools and Equipment	$ 475	62
Additions to Real Property	471	65
Company Buildings Renovations – Stephenville	351	67
Standby and Emergency Power – Stephenville	205	69
Total General Property	**$ 1,502**	
7. Transportation		
Purchase Vehicles and Aerial Devices	$ 3,456	72
Total Transportation	**$ 3,456**	

[3] Project descriptions can be found in Schedule B at the page indicated.
[4] This is a multi-year project that includes $2,440,000 in expenditures approved in Order No. P.U. 28 (2015).

2017 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[5]
8. Telecommunications		
Replace/Upgrade Communications Equipment	$ 98	76
Total Telecommunications	**$ 98**	
9. Information Systems		
Application Enhancements	$ 1,003	79
System Upgrades[6]	1,676	81
Personal Computer Infrastructure	485	83
Shared Server Infrastructure	661	86
Network Infrastructure	388	88
Outage Management System Replacement[7]	875	90
Geographic Information System Improvements	200	92
Total Information Systems	**$ 5,288**	
10. Unforeseen Allowance		
Allowance for Unforeseen Items	$ 750	95
Total Unforeseen Allowance	**$ 750**	
11. General Expenses Capitalized		
General Expenses Capitalized	$ 4,000	97
Total General Expenses Capitalized	**$ 4,000**	

5 Project descriptions can be found in Schedule B at the page indicated.
6 This is a multi-year project that includes $195,000 in expenditures for the Microsoft Enterprise Agreement approved in Order No. P.U. 40 (2014).
7 This is a multi-year project that includes $800,000 in expenditures approved in Order No. P.U. 28 (2015).

2017 CAPITAL PROJECTS SUMMARY

2017 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; and
   - Expenditures over $500,000

This 2017 Capital Project Summary provides a summary of the planned capital expenditures contained in Newfoundland Power’s (the “Company”) 2017 Capital Budget Application by definition (pages ii 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
2017 Capital Projects by Definition
(000's)

Clustered	**$21,708**	**Page**
Distribution	**3,264**	
Feeder Additions for Growth	1,430	51
Trunk Feeders	1,834	49
Substations	**11,733**	
Additions Due to Load Growth	2,574	17
Substations Refurbishment & Modernization	8,875	12
Substation Feeder Termination	284	22
Transmission	**6,711**	
Transmission Line Rebuild	6,711	25

Pooled	**$59,233**	**Page**
Distribution	**41,330**	
Distribution Reliability Initiative	1,415	53
Extensions	11,834	29
Meters	4,391	31
Rebuild Distribution Lines	4,023	44
Reconstruction	4,908	42
Relocate/Replace Distribution Lines for Third Parties	2,266	47
Services	3,564	34
Street Lighting	2,049	37
Transformers	6,103	40
AFUDC	209	59
Distribution Feeder Automation	568	55
General Property	**1,297**	
Additions to Real Property	471	65
Tools and Equipment	475	62
Company Building Renovations – Stephenville	351	67
Generation	**3,979**	
Facility Rehabilitation	1,607	2
Facility Rehabilitation Thermal	234	9
TCV Plant Refurbishment	1,476	6
Public Safety Around Dams	662	4
Information Services	**4,213**	
Application Enhancements	1,003	79
Network Infrastructure	388	88
Personal Computer Infrastructure	485	83
Shared Server Infrastructure	661	86
System Upgrades	1,676	81

Pooled (continued)		**Page**
Substations	**4,860**	
Replacement Due to In-Service Failures	3,851	15
PCB Bushing Phase-out	1,009	19
Telecommunications	**98**	
Replace/Upgrade Communications Equipment	98	76
Transportation	**3,456**	
Purchase Vehicles and Aerial Devices	3,456	72

Other	**$8,470**	**Page**
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	95
Distribution	**2,440**	
St. John's Main Underground Refurbishment	2,440	57
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	97
General Property	**205**	
Standby and Emergency Power- Stephenville	205	69
Information Services	**1,075**	
Geographic Information System Improvements	200	92
Outage Management System	875	90

Project Clustering

Clustered expenditures are those which would logically be undertaken together. Clustered expenditures are either inter-dependent or related. Inter-dependent items are necessarily linked together, as one item necessarily triggers the other. Related items are not necessarily linked to each other, but are nonetheless logically undertaken together.

In 2017, the following projects have expenditures which are clustered:

1. The *Trunk Feeders* Distribution project involving the replacement of distribution plant underbuilt on poles shared with transmission line 32L has aspects which are clustered with the *Transmission Line Rebuild* project. Transmission line 32L in St. John's shares pole line infrastructure with distribution line RRD-08 from Ridge Road Substation. The replacement of the transmission pole line infrastructure necessitates the replacement of the distribution plant that shares those same structures. These items are inter-dependent, and are therefore clustered.

2. The *Substations Refurbishment and Modernization* Substations project has aspects which are clustered with the *Additions Due to Load Growth* Substations project. In 2017, additional transformer capacity will be added to Chamberlains Substation to accommodate customer load growth. To coincide with the installation of the necessary

power transformers, the refurbishment and modernization of Chamberlains Substation is also scheduled for 2017. Completing the capacity addition and refurbishment projects in the same year will minimize the customer service interruptions associated with installing a portable substation and improve productivity by combining project planning and execution for both projects. These projects are related, and are therefore clustered.

3. The *Feeder Additions for Growth* Distribution project has aspects which are clustered with the *Substation Feeder Termination* Substations project. In 2017, a new distribution feeder will be added to Chamberlains Substation. The new feeder will be constructed under the *Feeder Additions for Growth* Distribution project and terminated at Chamberlains Substation under the *Substation Feeder Termination* Substations projects. These items are inter-dependent, and are therefore clustered.

Summary of
2017 Capital Projects by Classification
(000's)

Normal Capital	**$86,737**	**Page**
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	95
Distribution	**47,034**	
AFUDC	209	59
Distribution Feeder Automation	568	55
Distribution Reliability Initiative	1,415	53
Extensions	11,834	29
Feeder Additions for Growth	1,430	51
Meters	4,391	31
Rebuild Distribution Lines	4,023	44
Reconstruction	4,908	42
Relocate/Replace Distribution Lines for Third Parties	2,266	47
Services	3,564	34
Street Lighting	2,049	37
St. John's Main Underground Refurbishment	2,440	57
Transformers	6,103	40
Trunk Feeders	1,834	49
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	97
General Property	**1,502**	
Additions to Real Property	471	65
Tools and Equipment	475	62
Company Building Renovations – Stephenville	351	67
Standby and Emergency Power	205	69
Generation	**3,317**	
Facility Rehabilitation	1,607	2
Facility Rehabilitation Thermal	234	9
TCV Plant Refurbishment	1,476	6
Information Systems	**4,285**	
Network Infrastructure	388	88
Personal Computer Infrastructure	485	83
Shared Server Infrastructure	661	86
System Upgrades	1,676	81
Geographic Information System Improvements	200	92
Outage Management System	875	90

Normal Capital (continued)		**Page**
Substations	**15,584**	
Additions Due to Load Growth	2,574	17
Substations Refurbishment & Modernization	8,875	12
Substation Feeder Termination	284	22
Replacement Due to In-Service Failures	3,851	15
Telecommunications	**98**	
Replace/Upgrade Communications Equipment	98	76
Transmission	**6,711**	
Transmission Line Rebuild	6,711	25
Transportation	**3,456**	
Purchase Vehicles and Aerial Devices	3,456	72

Justifiable	**$1,003**	**Page**
Information Systems	**1,003**	
Application Enhancements	1,003	79

Mandatory	**$1,671**	**Page**
Generation	**662**	
Public Safety Around Dams	662	4
Substations	**1,009**	
PCB Bushing Phase-out	1,009	19

Summary of
2017 Capital Projects by Materiality
(000's)

Large – Greater than $500	**$86,011**	**Page**
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	95
Distribution	**46,825**	
Distribution Feeder Automation	568	55
Distribution Reliability Initiative	1,415	53
Extensions	11,834	29
Feeder Additions for Growth	1,430	51
Meters	4,391	31
Rebuild Distribution Lines	4,023	44
Reconstruction	4,908	42
Relocate/Replace Distribution Lines for Third Parties	2,266	47
Services	3,564	34
Street Lighting	2,049	37
St. John's Main Underground Refurbishment	2,440	57
Transformers	6,103	40
Trunk Feeders	1,834	49
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	97
Generation	**3,745**	
Facility Rehabilitation	1,607	2
Tors Cove Plant Refurbishment	1,476	6
Public Safety Around Dams	662	4
Information Systems	**4,215**	
Application Enhancements	1,003	79
Shared Server Infrastructure	661	86
System Upgrades	1,676	81
Outage Management System	875	90
Substations	**16,309**	
Additions Due to Load Growth	2,574	17
Substations Refurbishment & Modernization	8,875	12
Replacement Due to In-Service Failures	3,851	15
PCB Bushing Phase-out	1,009	19
Transmission	**6,711**	
Transmission Line Rebuild	6,711	25
Transportation	**3,456**	
Purchase Vehicles and Aerial Devices	3,456	72

Medium – Between $200 and $500	**$3,302**	**Page**
Distribution	**209**	
AFUDC	209	59
General Property	**1,502**	
Additions to Real Property	471	65
Tools and Equipment	475	62
Company Building Renovations – Stephenville	351	67
Standby and Emergency Power	205	69
Generation	**234**	
Facility Rehabilitation Thermal	234	9
Information Systems	**1,073**	
Geographic Information System Improvements	200	92
Network Infrastructure	388	88
Personal Computer Infrastructure	485	83
Substations	**284**	
Substation Feeder Termination	284	22

Small – Under $200	**$98**	**Page**
Telecommunications	**98**	
Replace/Upgrade Communications Equipment	98	76

GENERATION - HYDRO

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

Project Cost: **$1,607,000**

Project Description

This Generation Hydro project is necessary to improve the efficiency and reliability of various hydro plants or to replace plant components 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 2017 project includes the following items:

- Refurbishment of Frozen Ocean Outlet and Spillway ($412,000);
- Refurbishment of West Brook Forebay Dam and Spillway ($314,000);
- Refurbishment of Three Arm Pond Dam ($329,000); and
- Equipment replacements due to in-service failures. ($552,000)

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 2017 proposed expenditures are included in ***1.1** 2017 Facility Rehabilitation*.

Justification

The Company's 23 hydroelectric plants range in age from 17 to 116 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 438.6 GWh. Replacing the energy produced by these facilities by increasing production at Newfoundland and Labrador Hydro's Holyrood thermal generation facility would require approximately 696,000 barrels of fuel annually. At an oil price of $54.60 per barrel, this translates into approximately $38 million in annual fuel savings.[1]

[1] The price forecast per barrel of oil used at Holyrood as per Rate Stabilization Plan Adjustment - Revised Application dated June 3, 2016.

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 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	1,148	-	-	-
Labour – Internal	157	-	-	-
Labour – Contract	-	-	-	-
Engineering	173	-	-	-
Other	129	-	-	-
Total	**$1,607**	**$1,512**	**$4,666**	**$7,785**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2012	2013	2014	2015	2016F
Total	$1,616	$1,449	$1,825	$1,545	$1,342

The budget estimate for this project is based on 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: **Public Safety Around Dams (Pooled)**

Project Cost: **$662,000**

Project Description

This project is necessary for the Company to address public safety improvements for dams throughout its various hydroelectric developments over the period from 2015 to 2017. Newfoundland Power has over 150 dam structures throughout its 23 hydroelectric facilities.

In 2011, the Canadian Dam Association ("CDA") published their *Guidelines for Public Safety Around Dams*.[2] These guidelines address the risk of accidents or incidents in which a member of the public is exposed to a hazard created by a hydroelectric development. It is estimated that expenditures of approximately $2.0 million are necessary to implement public safety improvements at the Company's hydroelectric developments over this period.

The Company has completed detailed public safety assessments consistent with the *Guidelines for Public Safety Around Dams* on developments associated with all 23 hydroelectric plants.[3] Included in this 2017 capital project are expenditures associated with the safety improvements identified for 9 hydroelectric plants. Expenditures in 2017 are based upon detailed public safety assessments for the remaining 9 hydroelectric plants.

Details on the proposed expenditures are included in ***1.2** Public Safety Around Dams.*

Justification

The Public Safety Around Dams project is justified on the basis of making reasonable effort to eliminate hazards and minimize risk that have the potential to threaten the health and safety of employees, contractors and the general public.

Although the Company's dam portfolio consists of small dams, it is recognized that all dams pose a risk to public safety, regardless of size or impoundment. Low head and small dams may be equally or more hazardous than high dams as the hazards may not be as apparent and they may not command the same respect as high dams from the general public.

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[2] These guidelines are in addition to the *CDA Dam Safety Guidelines 2007*. Copies of these guidelines can be ordered online from www.cda.ca.

[3] In 2015, public safety improvements were completed at 4 of the 23 hydroelectric plants. In 2016, public safety improvements are being completed at 10 of the 23 hydroelectric plants.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 1

Projected Expenditures (000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$497	-	-	-
Labour – Internal	33	-	-	-
Labour – Contract	-	-	-	-
Engineering	99	-	-	-
Other	33	-	-	-
Total	**$662**	**$0**	**$0**	**$662**

Costing Methodology

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

Future Commitments

This is not a multi-year project.

Project Title: **Tors Cove Plant Refurbishment (Pooled)**

Project Cost: **$1,476,000**

Project Description

This Generation Hydro project involves a major refurbishment of electrical and mechanical systems on generating unit G3 at Tors Cove Plant. Also, the main inlet valve on unit G1 requires replacement.[4] The components requiring replacement or refurbishment on unit G3 include turbine runner, wicket gates, main inlet valve and generator rotor.[5]

Details on the proposed expenditures for the refurbishment of the electrical and mechanical systems are included in ***1.3*** *Tors Cove Hydro Plant Refurbishment*.

Justification

The Tors Cove Plant, located on the Avalon Peninsula near the community of Tors Cove, was commissioned in 1941 with a capacity of 6.5 MW. The normal annual production at Tors Cove is 25.9 GWh or 6% of the total hydroelectric production of Newfoundland Power.

Engineering assessments of unit G3's electrical and mechanical systems have revealed these systems have reached the end of their useful lives and require replacement.

A present worth feasibility analysis of projected capital and operating expenditures for the Tors Cove Plant has determined the levelized cost of energy from the plant over the next 50 years to be 3.54¢ per kWh, which is less than the cost of replacement energy from other sources such as additional Holyrood thermal generation or the estimated marginal cost of production post completion of the Muskrat Falls Project.[6]

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4 A more comprehensive refurbishment for unit G1 is planned for 2018. Replacement of the G1 main inlet valve in 2017 will allow the 2018 refurbishment work to be completed without de-watering the penstock.

5 The refurbishment of unit G3 is similar to the work completed on unit G2 in 2015 as approved under Order No. P.U. 40 (2014).

6 The avoided cost of No. 6 fuel at the Holyrood Thermal Generating Station is estimated at 8.7¢ per kWh for 2016. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $54.60 per barrel for 2016, as per Newfoundland and Labrador Hydro's Rate Stabilization Plan Adjustment - Revised Application dated June 3, 2016. The avoided cost of fuel for the Holyrood 100 MW combustion turbine is 29.0 ¢/kWh as per Hydro's response to Request for Information GT-NP-NLH-006. Also, an estimate of the marginal cost of production post completion of the Muskrat Falls Project is 5.0 ¢/kWh for energy plus $103/kW for demand starting in 2018, as per Hydro's response to Request for Information CA-NLH-033 (Revision 1, December 9, 2014) in Hydro's 2013 Generation Rate Application. This marginal cost increases into the future.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 1
Multi-year Projected Expenditures
(000s)

Cost Category	**2017**	**2018**	**2019 - 2021**	**Total**
Material	$1,050	-	-	-
Labour – Internal	203	-	-	-
Labour – Contract	-	-	-	-
Engineering	124	-	-	-
Other	99	-	-	-
Total	**$1,476**	**$3,650**	-	**$5,126**

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. Expenditures for projects in future years will be presented in future Capital Budget Applications.

GENERATION - THERMAL

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

Project Cost: **$234,000**

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 2017 project consists of the refurbishment or replacement of thermal plant structures and equipment due to damage, deterioration, corrosion and in-service failure. This equipment is critical to the safe and reliable operation of thermal generating facilities and must be replaced in a timely manner. Based upon historical information, $234,000 is estimated to be the cost of refurbishment or replacement of thermal plant structures in 2017.

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 41.5 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 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$42	-	-	-
Labour – Internal	22	-	-	-
Labour – Contract	-	-	-	-
Engineering	149	-	-	-
Other	21	-	-	-
Total	**$234**	**$239**	**$747**	**$1,220**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2012	2013	2014	2015	2016F
Total	$117	$201	$331	$228	$238

The budget requirement for rehabilitation of thermal generating facilities is based on a historical average, and is adjusted for anticipated expenditure requirements for extraordinary items.

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

Future Commitments

This is not a multi-year project.

SUBSTATIONS

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

Project Cost: **$8,875,000**

Project Description

This Substations 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 that plan. An update to the *Substation Strategic Plan* is included in ***2.1*** *2017 Substation Refurbishment and Modernization*.

The Company has 130 substations ranging in age from 14 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, support structures, equipment foundations, switches and fencing. Infrastructure to be replaced is identified as a result of inspections, engineering assessments and operating experience.

In 2017, this project will refurbish and modernize the following substations:

- Catalina Substation
- Chamberlains Substation
- Salt Pond Substation

In addition to the substations listed above, the 2017 project includes the upgrading of automation equipment in substations, including the automation of distribution feeder breakers and reclosers.[7]

The Chamberlains Substation refurbishment and modernization item is clustered with the installation of a new substation transformer which is included in the *Additions Due To Load Growth* project (Schedule B, page 17 of 97).

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.

[7] At the end of 2015, approximately 80% of distribution feeder breakers and reclosers located in Company substations were automated through the SCADA system. By the end of 2016, there will be 249 distribution feeders automated, representing approximately 83% of all distribution feeders. By the end of 2017, there will be 266 distribution feeders automated, representing approximately 89% of all distribution feeders.

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 2017 and a projection of expenditures through 2021. Appendix A of ***2.1*** *2017 Substation Refurbishment and Modernization* details the work planned for each year.

Table 1

Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$7,006	-	-	-
Labour – Internal	198	-	-	-
Labour – Contract	-	-	-	-
Engineering	1,480	-	-	-
Other	191	-	-	-
Total	**$8,875**	**$9,875**	**$28,558**	**$47,308**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2012	2013	2014	2015	2016F
Total	$2,279	$3,570	$6,411	$10,938	$7,571

The budget for this project is based on 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: **$3,851,000**

Project Description

This Substations 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 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$2,675	-	-	-
Labour – Internal	777	-	-	-
Labour – Contract	-	-	-	-
Engineering	302	-	-	-
Other	97	-	-	-
Total	**$3,851**	**$3,931**	**$12,290**	**$20,072**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2012	2013	2014	2015	2016F
Total	$3,327	$3,485	$4,797	$3,116	$3,371

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

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 that the loss of a particular apparatus would have on the electrical system.

The budget for this project is based on engineering assessment of historical expenditures and inventory 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: **Additions Due To Load Growth (Clustered)**

Project Cost: **$2,574,000**

Project Description

This Substations project involves the replacement of the existing 66/25 kV 25.0 MVA substation transformer CHA-T1 at Chamberlains Substation ("CHA") with a new 66/25 kV 50 MVA substation transformer. This Substations project is necessary to address the growth in customer load in the Conception Bay South and Paradise areas.

Details on the proposed expenditures are contained in ***2.2*** *2017 Additions Due to Load Growth*.

The *Additions Due To Load Growth* project is clustered with the refurbishment and modernization of Chamberlains substation which is included in the *Substation Refurbishment and Modernization* project (Schedule B, page 12 of 97).

The individual requirements for additions to substations due to load growth 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.

Justification

A 20-year load forecast has projected increased electrical demand for the Conception Bay South and Paradise areas. In the winter of 2017, the substation transformers at CHA are expected to experience a total peak load of 53.1 MVA. The current parallel capacity of CHA-T1 and CHA-T2 is 49.3 MVA.[8] As a result, the load forecast indicates that both CHA-T1 and CHA-T2 will be overloaded in 2017.

The development and analysis of alternatives has established a recommended expansion plan to meet that demand. The least cost alternative that meets all of the technical criteria requires the installation of a new 50 MVA substation transformer at CHA to replace 1 of the existing 25 MVA substation transformers.

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.

[8] The total substation capacity is not necessarily equal to the sum of the individual transformer nameplate capacities. The electrical characteristics of each transformer, more specifically the transformer's per unit impedance, determines how load is split between transformers that operate in parallel.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$2,421	-	-	-
Labour – Internal	18	-	-	-
Labour – Contract	-	-	-	-
Engineering	90	-	-	-
Other	45	-	-	-
Total	**$2,574**	**$0**	**$7,750**	**$10,324**

Costing Methodology

The budget estimate for this project is based on 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: PCB Bushing Phase-out (Pooled)

Project Cost: $1,009,000

Project Description

This Substations project is proposed to facilitate the phase-out of polychlorinated biphenyls ("PCB") from breaker and substation transformer bushings with concentrations of greater than 50 parts-per-million ("ppm").

In September 2008, regulations made under the *Environment Protection Act (Canada)* were amended by the Government of Canada. The new *PCB Regulations* accelerated the schedule that Canadian utilities previously were operating under in addressing the phase-out of PCBs contained in substation equipment. The new *PCB Regulations* required that by the end of 2014, substation transformer bushings, breakers and instrument transformers with PCB concentrations of greater than 500 ppm were to be removed from service.[9] Over the period from 2011 to 2014, Newfoundland Power identified 68 power transformers and 28 bulk oil circuit breakers with bushings having PCB concentrations greater than 500 ppm which were removed from service.[10]

Beyond the end-of-life extension date of December 31, 2014, expenditures are now required to address the phase-out of PCBs in equipment with concentrations greater than 50 ppm and less than 500 ppm. Government regulations require equipment with PCB concentrations in that range to be removed from service by 2025.

By the end of 2014, the bushings on all 167 substation transformers were tested with bushings on 68 substation transformers being replaced.[11] The inspections identified a further 24 substation transformers with PCB concentrations greater than 50 ppm and less than 500 ppm. The bushings on these substation transformers will be replaced by 2025 to ensure compliance with government regulations regarding the phase out of PCBs in substation equipment.

By the end of 2014, bushings on all 185 bulk oil circuit breakers were tested with 28 breakers being replaced.[12] The inspections identified a further 42 bulk oil circuit breakers with PCB concentrations greater than 50 ppm and less than 500 ppm. These circuit breakers will be

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9 The 2014 deadline was subsequently extended to 2025.

10 Expenditures related to the 2011 to 2014 program to address the Company's substation equipment with PCB concentrations greater than 500 ppm were approximately $8.7 million. Details on the PCB Bushing Phase-out project were included in the 2011 Capital Budget Application in *2.3 2011 PCB Removal Strategy*, and in the 2012 Capital Budget Application in *2.3 2012 PCB Removal Strategy*.

11 The remediation strategy for substation transformer bushings was to replace bushings that (i) test at 500 ppm or more or (ii) that cannot be tested. To minimize costs and customer outages, in situations where one or more of a transformer's bushings test at 500 ppm or more, all bushings that test at 50 ppm or more were replaced at the same time.

12 Whenever the bushings on a bulk oil circuit breaker test at 500 ppm or more, the complete breaker was replaced.

replaced by 2025 to ensure compliance with government regulations regarding the phase out of PCBs in substation equipment.

By the end of 2014, PCB testing was completed on the Company's potential and current transformers, metering tanks, and station service transformers. All required replacements of units with PCB concentrations of 50 ppm or more were completed before the end of 2014.

In 2017, the Company will replace 5 bulk oil circuit breakers and replace bushings on 3 substation transformers.

Justification

The project is justified on the requirement to meet the Government of Canada's *PCB Regulations*. Newfoundland Power has completed the work required under the end-of-life date extension of December 31, 2014 for PCB concentrations greater than 500 ppm in accordance with subsection 17(2) of the *PCB Regulations*. Substation equipment with PCB concentrations greater than 50 ppm must now be addressed by 2025 as per the *PCB Regulations*.

Projected Expenditures

Table 3 provides a breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 3
Projected Cost
(000s)

Cost Category	**2017**	**2018**	**2019 - 2021**	**Total**
Material	$582	-	-	-
Labour – Internal	100	-	-	-
Labour – Contract	-	-	-	-
Engineering	299	-	-	-
Other	28	-	-	-
Total	**$1,009**	**$811**	**$3,271**	**$5,091**

Costing Methodology

The budget for this project is based on 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: **Substation Feeder Termination (Clustered)**

Project Cost: **$284,000**

Project Description

This Substations project is required to provide substation equipment necessary for the addition of a new distribution feeder at Chamberlains Substation ("CHA"). The project involves the termination of a new 25 kV feeder CHA-04 at CHA.

The feeder termination at CHA is clustered with the *Feeder Additions for Growth* Distribution project to install a new 25 kV feeder at CHA (Schedule B, page 51 of 97).

Justification

The project is justified on the basis of accommodating customer load growth and the obligation to provide safe, least cost reliable service. Actual peak load conditions and customer growth indicate that this project is warranted in order to maintain the reliability of the electrical system.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$272	-	-	-
Labour – Internal	3	-	-	-
Labour – Contract	-	-	-	-
Engineering	7	-	-	-
Other	2	-	-	-
Total	**$284**	**$290**	**$1,497**	**$2,071**

Costing Methodology

The budget estimate for this project is based on 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.

TRANSMISSION

Project Title: **Transmission Line Rebuild (Clustered, Multi-year)**

Project Cost: **$6,711,000**

Project Description

This Transmission project is necessary to replace deteriorated transmission line infrastructure. The 2017 project involves:

1. The rebuilding of the Company's oldest, most deteriorated transmission lines in accordance with the program outlined in the report ***3.1** Transmission Line Rebuild Strategy* that was filed with the 2006 Capital Budget Application.

   Proposed 2017 transmission line rebuild work will take place on transmission lines 32L, 41L and 57L. Transmission line 32L operates between Ridge Road Substation and Oxen Pond Substation in St. John's. Transmission line 41L operates between Carbonear Substation and Heart's Content Substation on the Avalon Peninsula. Transmission line 57L operates between Bay Roberts Substation and Harbour Grace Substation in Conception Bay North.[13] ($4,611,000)

   Details on the proposed 2017 rebuilds are included in ***3.1** 2017 Transmission Line Rebuild*.

2. The replacement of poles, crossarms, conductors, insulators and hardware due to deficiencies identified during inspections and engineering reviews, or due to in-service and imminent failures. ($2,100,000)

For 2017, a portion of the Transmission Line Rebuild project proposed for the St. John's area is clustered with the *Trunk Feeders* Distribution project. (Schedule B, page 49 of 97) This is because relocation of the under-built trunk feeders is dependent upon the completion of the transmission line rebuilds for transmission line 32L.

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

Approximately 30% of the Company's 103 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.

[13] The 57L transmission line rebuild project is a multi-year project approved in Order No. P.U. 28 (2015). Details on the multi-year expenditures are provided in the Future Commitments section on page 27 of 97.

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 2017 and a projection of expenditures through 2021. Appendix A of ***3.1** 2017 Transmission Line Rebuild* details the transmission line rebuilds planned for each year.

Table 1

Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$2,265	-	-	-
Labour – Internal	283	-	-	-
Labour – Contract	3,157	-	-	-
Engineering	237	-	-	-
Other	769	-	-	-
Total	**$6,711**	**$7,535**	**$32,632**	**$46,878**

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, the distance covered and the construction standard used in the design.

Table 2

Expenditure History
(000s)

Year	2012	2013	2014	2015	2016F
Total	$4,694	$5,081	$4,664	$6,391	$6,067

The budget estimates for rebuilding and upgrade projects are based on engineering cost estimates. The budget estimates for replacements 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

The rebuilding of transmission line 57L is a multi-year project approved in Order No. P.U. 28 (2015). Table 3 details the 2016 and 2017 project expenditures for this multi-year project.

Table 3
57L Multi-Year Projected Expenditures
(000s)

Cost Category	2016F	2017B	Total
Material	$521	$525	$1,046
Labour – Internal	66	60	126
Labour – Contract	721	840	1,561
Engineering	40	57	97
Other	173	235	408
Total	**$1,521**	**$1,717**	**$3,238**

DISTRIBUTION

Project Title: **Extensions (Pooled)**

Project Cost: **$11,834,000**

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 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$3,607	-	-	-
Labour – Internal	3,489	-	-	-
Labour – Contract	2,776	-	-	-
Engineering	1,568	-	-	-
Other	394	-	-	-
Total	**$11,834**	**$11,456**	**$34,004**	**$57,294**

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 2017.

Table 2
Expenditure History and Unit Cost Projection

Year	2012	2013	2014	2015	2016F	2017B
Total (000s)	$ 11,321	$ 13,434	$ 15,467	$ 15,423	$ 10,689	$ 11,834
Adjusted Costs (000s)[1]	$ 12,673	$ 14,591	$ 14,547	$13,175	11,189[2]	-
New Customers	5,286	5,280	4,308	3,786	3,394	3,417
Unit Costs ($/customer)[1]	$ 2,397	$ 2,763	$ 3,377	$ 3,480	$ 3,297	$ 3,463

1 2016 dollars

2 Adjusted to meet joint use agreement 60/40 ownership ratio.

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 Costs”). 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 Costs”). The average of these Unit Costs, with unusually high and low data excluded, is inflated 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: **$4,391,000**

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 2017.

Table 1
2017 Proposed Meter Acquisition

Program	Number of Meters
Energy Only Domestic Meters	40,210
Other Energy Only and Demand Meters	5,306

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

The 2013 Capital Budget Application included the *2013 Metering Strategy*. In 2016, the Company completed another review of the meter reading function and prepared an update to the 2013 strategy. The 2016 Capital Budget Application included an updated metering strategy in the report ***4.4** 2016 Metering Strategy*. The *2016 Metering Strategy* will:

- Continue with the objectives outlined in the *2013 Metering Strategy* with respect to accuracy & timeliness, cost management, worker safety and ratemaking;
- Continue with the transition strategy to comply with changes to Measurement Canada regulations;
- Maintain focus on route optimization in order to achieve productivity improvements and reduced costs through use of AMR meters; and
- Accelerate the installation of AMR meters in order to achieve 100% penetration by the end of 2017.

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 by both safety and economics. The additional cost associated with accelerating expenditures on AMR meters is justified by a positive net present value of $1.1 million.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 2
Projected Expenditures (000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$3,126	-	-	-
Labour – Internal	1,157	-	-	-
Labour – Contract	108	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$4,391**	**$539**	**$1,822**	**$6,752**

Costing Methodology

Table 3 shows the annual expenditures for the most recent five-year period, as well as a projection for 2017.

Table 3
Expenditure History and Unit Cost Projection

Year	2012	2013	2014	2015	2016F	Avg	2017B
Meter Requirements							
New Connections	5,286	5,280	4,308	4,001	3,394		3,670
GROs/CSOs	15,257	18,805	20,009	18,856	3,670		7,326
Other	7,130	6,218	8,825	12,679	41,154		34,520
Total	27,673	30,303	33,142	35,536	48,218		45,516
Meter Costs							
Actual (000s)	$2,557	$3,109	$3,003	$3,108	$4,582		$4,391
Adjusted[1] (000s)	$2,742	$3,273	$3,094	$3,129			
Unit Costs[1]	$ 99	$ 108	$ 93	$ 88	$ 95	$ 97	$ 96

[1] 2016 dollars

The project cost for meters is calculated on the basis of the accelerated strategy and 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"). The Adjusted Meter Costs are divided by the total meter requirements in each year to derive the annual meter cost in current-year dollars ("Unit Costs"). The average of the Unit Costs, with unusually high and low data excluded, is inflated 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 based on historic data and the transition strategy outlined in the *2013 Metering Strategy* to comply with changes to compliance sampling regulations for electricity meters, and the *2016 Metering Strategy* plan to accelerate the replacement of non-AMR meters. 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: **$3,564,000**

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 Company'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 services 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 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$1,101	-	-	-
Labour – Internal	1,843	-	-	-
Labour – Contract	206	-	-	-
Engineering	353	-	-	-
Other	61	-	-	-
Total	**$3,564**	**$3,493**	**$10,511**	**$17,568**

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 2017.

Table 2

**Expenditure History and Unit Cost Projection
New Services**

Year	2012	2013	2014	2015	2016F	2017B
Total (000s)	$3,351	$3,608	$3,300	$3,183	$3,174	$2,837
Adjusted Costs (000s)[1]	$3,762	$3,927	$3,479	$3,248	-	-
New Customers	5,286	5,280	4,308	3,786	3,394	3,417
Unit Costs ($/customer)[1]	$ 712	$ 744	$ 808	$ 858	$ 935	$ 817

[1] 2016 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 Costs”). 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 Costs”). The average of the Unit Costs, with unusually high and low data excluded, is inflated 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 2017.

Table 3

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

Year	2012	2013	2014	2015	2016F	2017B
Total	$1,157	$672	$544	$544	$610	$727
Adjusted Costs[1]	$1,075[2]	$731	$573	$555	-	-

[1] 2016 dollars
[2] Amount adjusted for a large numbers of services replaced following tropical storm Leslie.

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 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: **$2,049,000**

Project Description

This Distribution project involves the installation of new street 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 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$1,110	-	-	-
Labour – Internal	730	-	-	-
Labour – Contract	158	-	-	-
Engineering	30	-	-	-
Other	21	-	-	-
Total	**$2,049**	**$2,020**	**$6,107**	**$10,176**

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 2017.

Table 2

Expenditure History and Unit Cost Projection
New Street Lights

Year	2012	2013	2014	2015	2016F	2017B
Total (000s)	$1,588	$1,889	$2,265	$1,906	$1,479	$1,335
Adjusted Costs (000s)[1]	$1,739	$2,019	$1,681[2]	$1,533[3]	-	-
New Customers	5,286	5,280	4,308	3,786	3,394	3,417
Unit Costs ($/customer)[1]	$ 329	$ 382	$ 390	$ 405	$ 436	$ 391

[1] 2016 dollars
[2] Amount adjusted for the timing of a large number of street light poles installed in 2014.
[3] Amount adjusted to remove third party survey costs and one time extraordinary duct bank costs.

The project cost for street lights 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 Costs"). 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 Costs"). The average of the Unit Costs, with unusually high and low data excluded, is inflated 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 cost for 2017.

Table 3

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

Year	2012	2013	2014	2015	2016F	2017B
Total	$776	$703	$482	$623	$766	$714
Adjusted Costs[1]	$847	$751	$502	$631	-	-

[1] 2016 dollars

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

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

Future Commitments

This is not a multi-year project.

Project Title: **Transformers (Pooled)**

Project Cost: **$6,103,000**

Project Description

This Distribution project includes the cost of purchasing transformers to serve 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 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$6,103	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$6,103**	**$5,978**	**$17,934**	**$30,015**

Costing Methodology

Table 2 shows the annual expenditures for the most recent five-year period, as well as an estimate for 2017.

Table 2

Expenditure History and Budget Estimate (000s)

Year	**2012**	**2013**	**2014**	**2015**	**2016F**	**2017B**
Total	$6,565	$6,710	$7,106	$7,462	$5,759	$6,103
Adjusted Costs[1]	$6,872	$ 6,940	$7,234	$7,462	-	-

[1] 2016 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 Costs"). 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 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: **$4,908,000**

Project Description

This Distribution project involves the replacement of deteriorated or damaged distribution structures and electrical equipment. This project comprises 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 wait 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 2017 and a projection of expenditures through 2021.

Table 1

Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$1,161	-	-	-
Labour – Internal	1,976	-	-	-
Labour – Contract	1,107	-	-	-
Engineering	497	-	-	-
Other	167	-	-	-
Total	**$4,908**	**$5,020**	**$15,764**	**$25,692**

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 2017.

Table 2

Expenditure History and Budget Estimate (000s)

Year	**2012**	**2013**	**2014**	**2015**	**2016F**	**2017B**
Total	\$3,463	\$4,643	\$5,041	\$5,059	\$4,599	\$4,908
Adjusted Costs[1]	\$3,877	\$5,043	\$5,306	\$5,158		

[1] 2016 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 Costs”). 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 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: **$4,023,000**

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.

Based on a 7-year inspection cycle for distribution feeders, the work for 2017 will be performed on the following 47 of the Company's 305 feeders:

ABC-02	GBY-02	HUM-07	PUL-04	SCV-01	WAL-06
BCV-01	GDL-02	KBR-02	RBK-01	SCV-02	WES-02
BCV-04	GDL-03	KBR-11	RRD-02	SJM-04	
BLK-02	GIL-02	KEL-01	RRD-03	SJM-13	
BUC-02	GRH-01	KEL-02	RRD-04	SJM-14	
COB-03	HBS-01	KEL-03	RRD-07	SMV-01	
DLK-01	HBS-02	MSY-04	RRD-08	SPF-01	
FRN-01	HUM-01	PAB-03	RRD-10	TRN-01	
GAL-01	HUM-04	PUL-01	RVH-02	TRN-02	

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 10,000 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 2017 and a projection of expenditures through 2021.

Table 1

Projected Expenditures (000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$1,619	-	-	-
Labour – Internal	1,908	-	-	-
Labour – Contract	249	-	-	-
Engineering	41	-	-	-
Other	206	-	-	-
Total	**$4,023**	**$4,111**	**$12,882**	**$21,016**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2012	2013	2014	2015	2016F
Actual	$3,723	$2,958	$4,338	$4,137	$3,694
Adjusted[1]	$4,093	$3,170	$4,525	$4,195	

[1] 2016 dollars

Distribution feeders are inspected in accordance with Newfoundland Power's distribution inspection standards to identify 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. This includes primary components such as poles, crossarms and conductor; and
b) Specific line components targeted for replacement based on engineering reviews, including lightning arrestors, CP8080 and 2-piece insulators, current limiting fuses, automatic sleeves, porcelain cutouts and transformers.

The report ***4.4** Rebuild Distribution Lines Update* included with the 2013 Capital Budget Application described the Company's current preventative maintenance program, distribution inspection standards and targeted replacement programs. Proposed expenditures under this Distribution project are consistent with that report.

Inspections for the lines upon which work is to take place in 2017 are ongoing throughout 2016. Complete inspection data will not be available until late 2016. Therefore, the 2017 budget estimate is based on average historical expenditures over the previous 5 years.

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

Project Cost: **$2,266,000**

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 Bell Aliant, Eastlink and Rogers Cable, or (3) requests from customers.[14]

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. Relocation or replacement of facilities by customers may be governed by the Company's policy respecting contributions in aid of construction.

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 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$815	-	-	-
Labour – Internal	743	-	-	-
Labour – Contract	429	-	-	-
Engineering	238	-	-	-
Other	41	-	-	-
Total	**$2,266**	**$2,316**	**$7,259**	**$11,841**

[14] Also included is distribution work associated with the installation and relocation of communications cables used by the Company's various protection and control systems.

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	**2012**	**2013**	**2014**	**2015**	**2016F**
Total	$2,195	$2,586	$2,077	$2,118	$2,329
Adjusted Costs[1]	$2,420	$2,778	$2,170	$2,150	

[1] 2016 dollars

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 Costs"). 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.

Estimated contributions from customers and requesting parties associated with this project are included in the estimated contributions in aid of construction 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: **Trunk Feeders (Clustered)**

Project Cost: **$1,834,000**

Project Description

This Distribution project includes:

1. The replacement of distribution plant from pole line infrastructure shared with transmission line 32L. Transmission line 32L is a 66 kV line running between Oxen Pond Substation and Ridge Road Substation in St. John's.[15] The distribution plant sharing the poles with transmission line 32L will be replaced at the same time as the pole line infrastructure is replaced on transmission line 32L. ($102,000)

2. The upgrade of the 4.16 kV distribution system from King's Bridge Substation to 12.5 kV is a least cost way of addressing reliability concerns with the aging distribution infrastructure. Details on the proposed expenditures are included in 2016 Capital Budget Application report ***4.6*** *KBR Substation Distribution Feeder Refurbishment.* ($1,220,000)

3. The refurbishment and modernization of 3 vaults in the St. John's underground distribution system. These vaults contain high voltage equipment supplying customers utilizing special underground arrangements. Details on the proposed expenditures are included in ***4.3*** *Vault Refurbishment and Modernization.* ($512,000)

For 2017, portions of the *Trunk Feeders* project are clustered with the *2017 Transmission Line Rebuild* Transmission project (Schedule B, page 25 of 97), since the relocation of the under-built distribution feeders is dependent upon the completion of the rebuild of transmission line 32L.

Justification

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

Inspections of transmission line 32L have identified deterioration due to decay and vehicular damage, splits and checks in the poles, substandard crossarms and other hardware deficiencies. Many of these components are in advanced stages of deterioration and require replacement. As this transmission line supports distribution line infrastructure, it is necessary to relocate and rebuild those distribution lines when the transmission line support structures are replaced.

The refurbishment and modernization of the underground vaults and the KBR distribution system will bring this infrastructure into compliance with current standards.

[15] A description of the project to rebuild transmission line 32L can be found in ***3.1*** *2017 Transmission Line Rebuild.*

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 1

Projected Expenditures
(000s)

Cost Category	**2017**	**2018**	**2019 - 2021**	**Total**
Material	$401	-	-	-
Labour – Internal	485	-	-	-
Labour – Contract	270	-	-	-
Engineering	244	-	-	-
Other	434	-	-	-
Total	**$1,834**	**$1,285**	**$3,170**	**$6,289**

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 (Clustered)**

Project Cost: **$1,430,000**

Project Description

This Distribution project consists of expenditures to address overload conditions and provide additional capacity to address growth in the number of customers and volume of energy deliveries. For 2017, the following proposed expenditures are required:

1. The upgrading of conductor on Rattling Brook Substation feeder RBK-01 in the Town of Norris Arm South to address overloaded conductor on a 6.6 km section of this distribution feeder. ($637,000)

2. The construction of a new feeder originating at Chamberlains Substation to accommodate growth in customers and load in the Conception Bay South and Paradise areas. The power transformers at Chamberlains Substation have reached their rated capacity and a 25 MVA transformer is being replaced with a 50 MVA transformer.[16] A new feeder CHA-04 will terminate at the substation and join with a section of the existing CHA-02 feeder. ($793,000)

Details on the proposed expenditures are included in ***4.2** Feeder Additions for Load Growth*.

A portion of the *Feeder Additions for Growth* Distribution project is clustered with the *Substation Feeder Terminations* substation project (Schedule B, page 22 of 97), since the installation of new distribution feeder at Chamberlains Substations is dependent upon the substation work necessary to terminate the new distribution feeders.

Justification

The project is justified based on the obligation to provide safe, least cost reliable service. Actual peak load conditions and customer growth indicate that this project is warranted in order to maintain the electrical system within recommended guidelines.

[16] Details on the transformer replacement can be found in *2.2 Additions Due to Load Growth*.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 1

Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$348	-	-	-
Labour – Internal	416	-	-	-
Labour – Contract	165	-	-	-
Engineering	197	-	-	-
Other	304	-	-	-
Total	**$1,430**	**$1,987**	**$5,583**	**$9,000**

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: **Distribution Reliability Initiative (Pooled, Multi-year)**

Project Cost: **$1,415,000**

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.[17] The nature of the upgrading work follows from a detailed assessment of past service problems, knowledge of local environmental conditions (such as salt contamination, wind and ice loading), and engineering knowledge to apply location-specific design and construction standards.

In the past, Newfoundland Power identified worst performing feeders on the basis of SAIDI, SAIFI and customer minutes.[18] These indices rank reliability performance based on the customer impact of the outages. In 2012, the Canadian Electricity Association began capturing and reporting on 2 additional indices; CIKM and CHIKM.[19] These indices rank reliability performance based on the length of line experiencing outages and tend to be more reflective of asset condition. The Company has incorporated CIKM and CHIKM into its reliability analysis.

The 2017 project involves work on feeders RVH-02, SUM-02 and TRP-01. Table 1 shows the number of customers affected and the average unscheduled interruption statistics by feeder for the 5-year period ending December 31, 2015. These statistics exclude planned power interruptions and interruptions due to all causes other than distribution system failure. An analysis of these feeders is contained in report ***4.1*** *Distribution Reliability Initiative*.

Table 1
Distribution Interruption Statistics
5-Years to December 31, 2015

Feeder	Customers	SAIFI	SAIDI	CHIKM	CIKM
RVH-02	153	4.20	6.24	29	5
SUM-02	615	2.97	10.93	84	8
TRP-01	611	2.42	4.81	291	2
Company Average		**1.39**	**1.74**	**45**	**35**

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[17] These feeders are sometimes referred to in the industry as *worst performing feeders*.

[18] System Average Interruption Frequency Index (SAIFI) is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area. 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.

[19] Customers Interrupted per Kilometer (CIKM) is calculated by dividing the number of customers that have experienced an outage by the kilometres of line. Customer Hours of Interruption per Kilometer (CHIKM) is calculated by dividing the number of customer-outage-hours by the kilometres of line.

Justification

This project is justified on the basis of the obligation to provide reliable electrical service. Individual feeder projects have been prioritized based on their historic interruption statistics. Customers supplied by these worst performing feeders experience power interruptions more often, or of longer duration, than the Company average or experience power interruptions caused by the deteriorated condition of the distribution infrastructure. The Distribution Reliability Initiative project has had a positive impact on the reliability performance of the feeders that have been upgraded.[20]

Projected Expenditures

Table 2 provides the breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 2
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$352	$371	-	-
Labour – Internal	358	388	-	-
Labour – Contract	156	152	-	-
Engineering	165	172	-	-
Other	384	348	-	-
Total	**$1,415**	**$1,431**	**$4,731**	**$7,577**

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 a multi-year project. The DRI projects proposed for distribution feeders SUM-02 and TRP-01 are planned to be completed over 2-years.

20 Chart 7 of the 2017 Capital Plan shows a 56% improvement in SAIDI and 49% improvement in SAIFI over the period from 2000 to 2015.

Project Title: **Distribution Feeder Automation (Pooled)**

Project Cost: **$568,000**

Project Description

This Distribution project is necessary to increase the level of automation in the Company's distribution system. The project consists of expenditures to address remote control limitations in the distribution system. Increasing the level of automation in the distribution system will improve the Company's capability to deal with cold load pickup and improve efficiency of restoration following both local and system wide outages.[21] Installing automated reclosers on distribution feeders allows for the isolation of the section of feeder closest to the fault from the remainder of the customers upstream of the fault location. This will isolate the outage to only those customers closest to the fault location, reducing the duration of the outage for customers upstream of the fault location.

Increasing automation of distribution feeders will involve the addition of new equipment to the distribution system or the replacement of some older generation equipment in service with modern communications capable equipment. The increase in automation will include the addition of technologies such as automated downline reclosers and sectionalizing switches, sensors for voltage and load flow, and fault indicators.

In 2017, the following distribution feeders have been identified for a downline automated recloser to be installed:

Avalon Peninsula	**Bonavista Peninsula**	**Grand Falls**[22]	**St. John's**
RVH-01	MIL-02	LEW-02-R2	HWD-01
		LEW-02-R3	MOB-01
		LEW-03-R2	VIR-02

[21] Increasing the level of automation in the distribution system is consistent with Recommendation 2.4 of Liberty's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power*.

[22] In all 3 locations an existing hydraulic recloser will be replaced. The new reclosers will be remotely monitored and controlled from the System Control Centre through SCADA.

Justification

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

Installing automated reclosers to sectionalize distribution feeders provides a greater degree of reliability in all operating conditions.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 1

Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$280	-	-	-
Labour – Internal	72	-	-	-
Labour – Contract	24	-	-	-
Engineering	96	-	-	-
Other	96	-	-	-
Total	**$568**	**$452**	**$2,040**	**$3,060**

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: **St. John's Main Underground Refurbishment (Other, Multi-year)**

Project Cost: **$2,440,000**

Project Description

This Distribution project consists of expenditures to address the refurbishment of underground distribution infrastructure originating from St. John's Main ("SJM") substation. The substation is located on Southside Road, just east of the Pitts Memorial Drive overpass. It supplies electricity to the area surrounding St. John's harbour, including the downtown core of the City of St. John's. This project was approved as a multi-year project in Order No. P.U. 28 (2015).

The distribution system supplied from the SJM substation includes both overhead distribution feeders and an underground system that consists of a series of ductbanks, manholes, switches and cables. In 2010, the Company completed a planning study on the underground system and has completed a series of upgrade projects in the years since.[23]

The underground system supplying the St. John's downtown core is approximately 40 years old, serving a dense population of large commercial customers. This underground system includes a major ductbank that exits the substation and runs under the Waterford River, containing the main trunks of 9 distribution feeders.

The Company has completed an engineering assessment for alternatives to replace the ductbank from SJM Substation to Hutchings Street. Details on the proposed expenditures were included in the 2016 Capital Budget Application in report ***4.5*** *St. John's Main Waterford River Ductbank Replacement*.

Justification

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

The assessment of the underground distribution infrastructure has identified deterioration due to decay and water. These ductbanks are approximately 40 years old and in advanced stages of deterioration. As these ductbanks supply distribution lines serving the St. John's downtown core and its dense population of large commercial customers, they must be replaced to maintain reliable service going forward.

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[23] The *St. John's Main Planning Study* was included as Attachment A to the report ***4.2*** *Feeder Additions for Load Growth* included in the 2011 Capital Budget Application.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2016 and 2017, along with a projection of expenditures through 2021.

Table 1

Projected Expenditures (000s)

Cost Category	2016	2017	2018 - 2021	Total
Material	$1,503	$1,163	-	$2,666
Labour – Internal	38	556	-	594
Labour – Contract	-	70	-	70
Engineering	338	270	-	608
Other	71	381	-	452
Total	**$1,950**	**$2,440**	-	**$4,390**

Costing Methodology

The budget estimate is based on a detailed engineering 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 a multi-year project to be completed in 2016 and 2017.

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

Project Cost: **$209,000**

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 AFUDC is the mainstream practice for 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 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	-	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering		-	-	-
Other	$209	-	-	-
Total	**$209**	**$211**	**$657**	**$1,077**

Costing Methodology

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

Table 2
Expenditure History and Budget Estimate
(000s)

Year	2012	2013	2014	2015	2016F
Total	$192	$196	$208	$214	$206

The budget estimate for AFUDC is based on an estimated $1.0 million monthly average of distribution work in progress and capital materials 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: **$475,000**

Project Description

This General Property project is necessary 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.

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

1. *Operations Tools and Equipment ($123,000)*: 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 working conditions.

2. *Engineering Tools and Equipment ($200,000)*: This item includes engineering test equipment and tools 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 ($127,000)*: This item includes 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. *Substation Grounding Sticks ($25,000)*: This item involves the purchase of grounding sticks for approximately 8 substations. Grounding sticks are required for the safe isolation of equipment to allow for maintenance, testing and troubleshooting. Multiple sets of grounding sticks are required at each substation.[24]

[24] A set of grounding sticks includes 3 individual grounding sticks, one for each of the 3 phases. Estimated cost per set is $3,000.

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.

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 2017 and a projection of expenditures through 2021.

Table 1

Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$475	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$475**	**$479**	**$1,495**	**$2,449**

Costing Methodology

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

Table 2 Expenditure History (000s)					
Year	**2012**	**2013**	**2014**	**2015**	**2016F**
Total	$449	$443	$440	$328	$497[1]

[1] Excludes cost of a load cell ($150,000) and tools for a new line truck ($35,000).

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.

The budget for this project is calculated on the basis of historical data respecting operations tools and equipment, engineering tools and equipment, and office furniture. The budget for the substation grounding sticks, tools for the new line truck and the load cell are based on an engineering estimate. 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: **Additions to Real Property (Pooled)**

Project Cost: **$471,000**

Project Description

This General Property project is necessary 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 2017 project consists of the upgrading, refurbishment or replacement of equipment and facilities due to organizational changes, damage, deterioration, corrosion and in-service failure. Based upon recent historical information, $371,000 is required for 2017. This project also includes corporate security upgrades to the Company's security infrastructure, including improvements in surveillance, fencing and lighting of Company facilities. Based upon an engineering estimate, $100,000 is required for corporate security upgrades in 2017. 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 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$365	-	-	-
Labour – Internal	35	-	-	-
Labour – Contract	-	-	-	-
Engineering	44	-	-	-
Other	27	-	-	-
Total	**$471**	**$475**	**$1,408**	**$2,354**

Costing Methodology

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

Table 2 **Expenditure History** **(000s)**					
Year	**2012**	**2013**	**2014**	**2015**	**2016F**
Total	\$300	\$401[1]	\$271[2]	\$307[3]	\$334[4]

1 Excludes cost of parking lot resurfacing (\$40,000) and Duffy Place truck bay doors replacement (\$47,000).
2 Excludes corporate security upgrades (\$96,000).
3 Excludes corporate security upgrades (\$106,000).
4 Excludes corporate security upgrades (\$100,000).

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: **Company Building Renovations – Stephenville (Pooled)**

Project Cost: **$351,000**

Project Description

This General Property project includes the replacement of the existing Heating Ventilation and Air Conditioning ("HVAC") system and associated architectural renovation of the Company's Stephenville area office building.[25] The renovations are required to replace deteriorated building components required to ensure the continued safe operation of the facility, workplaces and surrounding property.

The Stephenville building was originally constructed in 1958 as part of the Harmon Air Force Base in Stephenville. With the exception of roof refurbishment in 2003 and 2004, the last major renovation took place in 1988.

Details on the proposed expenditures can be found in the report ***5.1*** *Company Building Renovations–Stephenville*.

The individual budget items are not inter-dependent. However, they are related from a construction perspective and are therefore pooled for consideration as a single capital project.

Justification

The project is justified based on the age and the deterioration of the existing Company buildings. Justification for individual projects is based upon inspections completed by professional engineers or independent experts.

[25] The building houses employees and the equipment necessary to support operations throughout the Stephenville and Port aux Basques service territory. This includes line crews, line inspectors, technicians, meter reading and associated support and management staff. In addition, the facility houses customer service functions and warehouse.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 1
Multi-year Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$305	-	-	-
Labour – Internal	12	-	-	-
Labour – Contract	-	-	-	-
Engineering	26	-	-	-
Other	8	-	-	-
Total	**$351**	-	-	**$351**

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: **Standby and Emergency Power – Stephenville Office (Other)**

Project Cost: **$205,000**

Project Description

This General Property project consists of the installation of a new diesel generating unit to provide a back-up power supply to the Company's Stephenville area operations building.

The 2006 Capital Budget Application included the report *Standby Generation at Newfoundland Power Facilities*. This report identified the need for standby generation at the Company's area operations buildings across the province. The 2014 Capital Budget Application included the report ***5.1*** *Standby and Emergency Power – Gander Office* which includes a review of the progress with the 2006 initiative, including the Company's plan to undertake the installation of standby generation in the 3 remaining area operations buildings. In 2015, the Company installed a standby generator in the Carbonear office. The Stephenville area operations building is the final office requiring the installation of a standby generator.

For a major storm and power outage situation, full power restoration could take several days depending on the severity of the event. In such a situation, a response would involve teams working around the clock, that consists of field employees (involved in the physical restoration work) and support employees (involved in customer service, communications, information services, materials management, engineering, and operational support). Essentially, the Company has to provide essential services during such emergency situations.

During a major storm and power outage situation, restoration teams on the Port aux Port Peninsula and the Codroy Valley would require technology and communications infrastructure located in the Stephenville area operations building. The uninterruptible power supply ("UPS") system that is currently located at the Stephenville area operations building is only sufficient to sustain SCADA communications for a short duration (several hours). This limited UPS system would not support operating conditions required during a major outage event.

Justification

This project is necessary to ensure electrical service at the Company's Stephenville area operations building is not interrupted during a widespread power outage. This will permit the Company to facilitate the restoration of electrical service to customers during extended power outages as quickly as possible.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$175	-	-	-
Labour – Internal	10	-	-	-
Labour – Contract	-	-	-	-
Engineering	15	-	-	-
Other	5	-	-	-
Total	**$205**	**-**	**-**	**$205**

Costing Methodology

The budget estimate for this project is based on 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: **$3,456,000**

Project Description

This Transportation project involves the addition and 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 summarizes the units to be replaced in 2017.

Table 1
2017 Proposed Vehicle Replacements

Category	No. of Units
Heavy fleet vehicles	8
Passenger vehicles[1]	20
Off-road vehicles[2]	4
Total	**32**

1 The Passenger vehicles category includes the purchase of cars and light duty trucks.
2 The Off-road vehicles category includes snowmobiles, ATVs trailers and specialized mobile equipment.

In 2017, there are 8 heavy fleet vehicles that meet the age, mileage and condition parameters which indicate replacement is necessary. In 2017, the Company has identified 20 passenger vehicles for replacement.

The Company's replacement criteria for vehicles are described in the 2016 Capital Budget Application report ***5.1** Vehicle Replacement Criteria*. This report also compared these criteria to those used by other Canadian electrical utilities and shows the current approach of the Company is (i) consistent with current Canadian utility practice and (ii) consistent with the least cost delivery of service to customers.

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 2017 and a projection of expenditures through 2021.

Table 2
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$3,456	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$3,456**	**$3,556**	**$11,332**	**$18,344**

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

Table 3
Expenditure History
(000s)

Year	2012	2013	2014	2015	2016F
Total	$2,514	$3,220	$2,872	$3,080	$3,258

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 5 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 forecast that each unit proposed for replacement will reach the end of its useful life and require replacement in 2017.

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: **$98,000**

Project Description

This Telecommunications project is necessary to ensure the continued integrity of the Company's operational voice systems and the remote monitoring and control of field devices. This, in turn, allows the Company to provide acceptable levels of customer service and operational efficiency. The 2017 project involves the replacement and/or upgrade of communications equipment, including radio communication equipment associated with electrical system operations and data communications equipment providing remote monitoring and control capabilities associated with the SCADA system.

The Company has mobile radio, portable radio, base station radio and radio console equipment in service providing operational voice communications for field staff. The radio equipment is used for communications between (i) field staff working in multiple crews, (ii) field staff and operations centres, and (iii) field staff and the System Control Centre.

Data communications equipment is used to link the monitoring and control technologies on distribution lines, in substations and hydro plants to the SCADA system at the System Control Centre. A variety of different technologies are used to provide these data communications links depending upon local conditions and available service offerings from telecommunications companies. The technologies used include land line communications, fibre optic communications and wireless communications.

Over time this voice and data communications equipment fails in service, becomes obsolete or no longer supports the most cost effective service offering from telecommunications companies. As a result the equipment must be upgraded or replaced.

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 justified on the basis that reliable operational voice and data communications is necessary to provide reliable least cost service to customers.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2017**	**2018**	**2019 - 2021**	**Total**
Material	$61	-	-	-
Labour – Internal	9	-	-	-
Labour – Contract	-	-	-	-
Engineering	19	-	-	-
Other	9	-	-	-
Total	**$98**	**$100**	**$312**	**$510**

Costing Methodology

Table 2 shows the annual expenditures and costs in current dollars for the most recent five-year period.

Table 2 **Expenditure History** **(000s)**					
Year	**2012**	**2013**	**2014**	**2015**	**2016F**
Total	$100	$82	$97	$78	$105
Adjusted Cost[1]	$108	$87	$100	$79	

[1] 2016 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 Costs"). 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.

INFORMATION SYSTEMS

Project Title: Application Enhancements (Pooled)

Project Cost: $1,003,000

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 effective operation of the electrical system and compliance with regulatory and financial reporting requirements.

The application enhancements proposed in 2017 include enhancements to the Company's Customer Service System, and Customer Service Internet and energy conservation website enhancements.

The application enhancements proposed for 2017 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*** *2017 Application Enhancements*.

Justification

The proposed enhancements included in this project are justified on the basis of improving customer service and operational efficiencies.

Cost benefit analyses, where appropriate, are provided in ***6.1*** *2017 Application Enhancements*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$30	-	-	-
Labour – Internal	773	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	200	-	-	-
Total	**$1,003**	**$1,270**	**$4,044**	**$6,317**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2012	2013	2014	2015	2016F
Total	$1,102	$1,473	$1,382	$1,301	$1,143

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: **$1,676,000**

Project Description

This Information Systems project involves necessary upgrades to the computer software underlying the Company's business applications. Most upgrades are necessary to address known software issues, to facilitate infrastructure upgrades or to maintain vendor support.

For 2017, the project includes upgrades to the Company's business applications including the meter reading system, mobile maintenance inspection application, database management software, Dynamic Great Plains application and other software development tools.

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 the multi-year expenditure associated with the Microsoft Enterprise Agreement are included in *Schedule C* to this Application.

Details on proposed expenditures are included in ***6.2*** *2017 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 2017 and a projection of expenditures through 2021.

Table 1

Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$578	-	-	-
Labour – Internal	814	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	284	-	-	-
Total	**$1,676**	**$1,651**	**$5,212**	**$8,539**

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	2012	2013	2014	2015	2016F
Total	$1,363	$1,269	$1,066	$1,163	$1,718

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 in 2017 for the Microsoft Enterprise Agreement, which was approved as a multi-year project in Order No. P.U. 40 (2014). This is not otherwise a multi-year project.

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

Project Cost: **$485,000**

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 2017, a total of 165 PCs will be purchased, consisting of 70 desktop computers and 95 mobile computers. 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 2015 and 2016, as well as the proposed additions and retirements for 2017.

Table 1
PC Additions and Retirements
2015 – 2017B

	2015			**2016F**			**2017B**		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	50	62	441	122	164	399	70	76	393
Mobile	133	133	308	59	17	350	95	95	350
Total	**183**	**195**	**749**	**181**	**181**	**749**	**165**	**171**	**743**

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 2017 and a projection of expenditures through 2021.

Table 2
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$350	-	-	-
Labour – Internal	90	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	45	-	-	-
Total	**$485**	**$464**	**$1,475**	**$2,424**

Costing Methodology

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

Table 3
Expenditure History
(000s)

Year	2012	2013	2014	2015	2016F
Total	$401	$411	$455	$488	$465

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, mobile, 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: **$661,000**

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 2017, the project includes the replacement of technology infrastructure that has reached the end of their useful life, as well as infrastructure required to ensure the security of customer and corporate information.

Projects proposed for 2017 include:

1. The replacement of shared server infrastructure used to manage the Company's production computing environment;
2. The installation of new security management infrastructure, including software to protect the Company's email system from security threats, improve the Company's network access control capabilities and infrastructure to enforce policies to prevent users from visiting malicious places on the internet and to provide real-time internet activity information for Company computers and mobile devices; and
3. The replacement of workgroup printing infrastructure that has reached the end of its useful life.

The shared server infrastructure requirements for 2017 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** 2017 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 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$275	-	-	-
Labour – Internal	231	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	155	-	-	-
Total	**$661**	**$854**	**$2,718**	**$4,233**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2012	2013	2014	2015	2016F
Total	$687	$941	$832	$997	$916

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: **$388,000**

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, corporate and customer service data. The Company has increased its use of wireless communications technologies in recent years.

For 2017, this project includes the purchase and implementation of network equipment that has reached the end of useful life and to increase overall network availability and disaster recovery capabilities.

The individual network infrastructure requirements for 2017 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. This project will replace components of the network equipment that facilitate communication between all of the Company's shared servers and related applications. These components have reached the end of their useful lives.

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 2017 and a projection of expenditures through 2021.

Table 1

Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	$180	-	-	-
Labour – Internal	141	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	67	-	-	-
Total	**$388**	**$334**	**$1,063**	**$1,785**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2012	2013	2014	2015	2016F
Total	$429	$218	$345	$307	$294

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: **Outage Management System (Other, Multi-year)**

Project Cost: **$875,000**

Project Description

In 2016, the Company commenced a multiyear project to replace its existing outage management system ("OMS") with a commercially available system.[26] The OMS replacement will follow the installation of the Company's replacement SCADA system in 2016. The OMS will be integrated with both the SCADA and GIS systems. This integration will provide improved response capability, including customer response, to major system events.[27]

Newfoundland Power operates over 300 distribution feeders, with approximately 10,000 kilometres of distribution lines, serving approximately 263,000 customers. The Company's OMS was developed internally and has performed as expected since it was created in 2003. It is functionally obsolescent and at the end of its expected service life.

Details on the multiyear project to replace the OMS were included in the 2016 Capital Budget Application report ***6.4*** *Outage Management System Replacement.*

Justification

The replacement OMS is an important tool in improving customer service and overall efficiency in the Company's field operations. Providing accurate outage data will allow for efficient power restoration and improved customer service.

This project is justified on maintaining acceptable levels of customer service.

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26 The multiyear project to replace the OMS was approved in Order No. P.U. 28 (2015).
27 Conclusion 6.4 of Liberty's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power*, December 17, 2014 indicated that Newfoundland Power's "Outage Management System has served adequately, but the Company is appropriately moving to a commercially provided replacement."

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2016 and 2017, and a projection of expenditures through 2021.

Table 1

Projected Expenditures (000s)

Cost Category	2016	2017	2019 - 2021	Total
Material	$15	393	-	-
Labour – Internal	49	382	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	85	100	-	-
Total	**$149**	**$875**	**-**	**$1,024**

Costing Methodology

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.

Future Commitments

This is a multi-year project approved in Order No. P.U. 28 (2015) to be completed in 2016 and 2017.

Project Title: **Geographic Information System Improvements (Other)**

Project Cost: **$200,000**

Project Description

This Information Systems project involves expanding the GIS database to include information about customer location and electrical connectivity.[28]

Newfoundland Power operates approximately 300 distribution feeders, representing over 10,000 kilometres of distribution lines. It is important that accurate records of the current state of the electrical system be made available to field and technical employees at all times.

The Company's geographical information system ("GIS") provides a central database for storage of distribution asset information. This enables information to be updated and available in a more efficient and timely manner, and also reduces the inherent inefficiencies that exist with maintaining multiple systems.

Details on proposed expenditures were included in the 2015 Capital Budget Application in report ***6.5*** *Geographic Information System Improvements.*

Justification

This project is justified on the basis that GIS technology is an important tool in improving customer service and overall efficiency in the Company's field operations. Providing improved functionality to crews in the field, and integrating the GIS with other key systems such as the customer service system, will help improve data management, eliminate redundancies and enhance decision making abilities.

The proposed improvements included in this project are justified on the basis of improving customer service and operational efficiencies. Net Present Value analysis for the proposed improvements can be found in Appendix B of the 2015 Capital Budget Application report ***6.5*** *Geographical Information System Improvements*.

[28] The collection of customer premise information and tying the location into the distribution network was started in 2015. When completed, the GIS database will include customer locations relative to devices on the distribution network. This information will be used in the future by the replacement outage management system to identify customers impacted by distribution system outages.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2017 and a projection of expenditures through 2021.

Table 1
Projected Expenditures
(000s)

Cost Category	2017	2018	2019 - 2021	Total
Material	-	-	-	-
Labour – Internal	150	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	50	-	-	-
Total	**$200**	**-**	**-**	**$200**

Costing Methodology

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.

Future Commitments

This is not a multi-year project. Expenditures for projects in future years will be presented in future Capital Budget Applications.

UNFORESEEN ALLOWANCE

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

Project Cost: **$750,000**

Project Description

This Allowance for Unforeseen Items project is necessary to permit unforeseen capital expenditures which have not been budgeted elsewhere. The purpose of the account is to permit the Company to act expeditiously to respond to 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 in accordance with Section B Supplementary Capital Budget Expenditures of the *Capital Budget Application Guidelines*.

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. If the balance in the Allowance for Unforeseen Items is depleted in the year, the Company may be required to file an application for approval of an additional amount in accordance with the *Capital Budget Application Guidelines.*

Future Commitment

This is not a multi-year project.

GENERAL EXPENSES CAPITALIZED

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

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

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.
2017 Capital Budget
Multi-Year Projects Approved in Previous Years

Class	Project Description	CBA/ Board Order		Expenditure (000s) 2015	2016	2017	2018	Total
Information Systems	Outage Management System[1] Replacement	2016 CBA P.U. 28 (2015)	Approved		$149	$800		$949
			Forecast		$149	$875		$1,024
Information Systems	Microsoft Enterprise Agreement[2]	2015 CBA P.U. 40 (2014)	Approved	$195	$195	$195		$585
			Forecast	$195	$195	$195		$585
Distribution	SJM Waterford River Ductbank Replacement[3]	2016 CBA P.U. 28 (2015)	Approved		$1,950	$2,440		$4,390
			Forecast		$1,950	$2,440		$4,390
Transmission	Transmission Line Rebuild[4]	2016 CBA P.U. 28 (2015)	Approved		$1,521	$1,717		$3,238
			Forecast		$1,521	$1,717		$3,238

[1] A detailed project description can be found in the 2016 Capital Budget Application, Schedule B pages 93 and 94, and report ***6.4*** *Outage Management System Replacement.*
[2] A detailed project description can be found in the 2015 Capital Budget Application, Schedule B pages 81 and 82, and report ***6.2*** *2015 System Upgrades.*
[3] A detailed project description can be found in the 2016 Capital Budget Application, Schedule B pages 56 and 57, and report ***4.5*** *St. John's Main Waterford River Ductbank Replacement.*
[4] A detailed project description can be found in the 2016 Capital Budget Application, Schedule B pages 24 to 26, and report ***3.1*** *2016 Transmission Line Rebuild*.

Newfoundland Power Inc.
2017 Capital Budget
Multi-Year Projects Commencing in 2017

Class	Project Description	CBA/ Board Order		Expenditure (000s) 2015	2016	2017	2018	Total
Distribution	Distribution Reliability Initiative[5]	2017 CBA	Budget			$1,215	$1,431	$2,646

5 A detailed project description can be found in the 2017 Capital Budget Application, Schedule B pages 53 and 54 of 97, and report 4*.1 Distribution Reliability Initiative.*

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

	2015	2014
Net Plant Investment		
Plant Investment	1,665,762	1,592,616
Accumulated Amortization	(668,641)	(645,826)
Contributions in Aid of Construction	(34,238)	(33,701)
	962,883	913,089
Additions to Rate Base		
Deferred Pension Costs	98,829	103,939
Credit Facility Costs	56	72
Cost Recovery Deferral – Seasonal/TOD Rates	49	68
Cost Recovery Deferral – Hearing Costs	-	322
Cost Recovery Deferral – Regulatory Amortizations	-	1,107
Cost Recovery Deferral – 2012 Cost of Capital	-	588
Cost Recovery Deferral – 2013 Revenue Shortfall	-	1,126
Cost Recovery Deferral – Conservation	7,463	4,937
Customer Finance Programs	1,211	1,136
	107,608	113,295
Deductions from Rate Base		
Weather Normalization Reserve	(4,411)	1,640
Other Post-Employment Benefits	39,208	32,435
Customer Security Deposits	1,286	660
Accrued Pension Obligation	4,955	4,635
Accumulated Deferred Income Taxes	1,268	2,529
Excess Earnings	49	49
Demand Management Incentive Account	-	446
	42,355	42,394
Year End Rate Base	1,028,136	983,990
Average Rate Base Before Allowances	1,006,063	952,907
Rate Base Allowances		
Materials and Supplies Allowance	6,280	5,619
Cash Working Capital Allowance	6,739	6,404
Average Rate Base at Year End	1,019,082	964,930

2017 Capital Plan

July 2016

Table of Contents

1.0 Introduction

Newfoundland Power's *2017 Capital Plan* provides an overview of the Company's 2017 Capital Budget together with an outlook for capital expenditure through 2021.

Newfoundland Power's 2017 Capital Budget totals $89,411,000.

For the 5 years from 2017 through 2021, Newfoundland Power plans to make capital investments totaling approximately $481 million. This is $57 million, or about 11%, lower than the 5-year outlook presented in the Company's *2016 Capital Plan*.

Changes in customer requirements are a primary influence on the Company's lower capital planning forecast. For example, expenditures in Distribution capital are forecast to decline by approximately 11% over the 2017 to 2021 period due, in part, to lower projected growth in customer connections. In Newfoundland Power's *2012 Capital Plan*, forecast new customer connections were approximately 50% higher than those forecast in the *2017 Capital Plan*.

Similarly, forecast Substation capital expenditures for the 5 years from 2017 through 2021 are reduced. The *2017 Capital Plan* forecast for Substation capital expenditure is approximately 10% lower than the 5-year outlook presented in the Company's *2016 Capital Plan.* This reduction is also largely reflective of reduced forecast customer requirements.

Technological change also influences Newfoundland Power's capital planning forecast. For example, part of the reduction in the Distribution capital forecast over the 2017 to 2021 period reflects the forecast conclusion of the Company's *2016 Meter Strategy* in 2017. Expenditures for automated meters result in larger Distribution expenditures in 2017, but significantly reduced expenditures in subsequent years.

Stability and predictability in capital planning is conducive to rate stability for customers. Accordingly, to the extent that it can, Newfoundland Power continues to target stability and predictability in its annual capital budgeting. In addition, Newfoundland Power's *2017 Capital Plan* is consistent with the Company's obligation to provide least-cost reliable electrical service to its customers as required by the *Public Utilities Act* and the *Electrical Power Control Act, 1994*.

2.0 2017 Capital Budget

Newfoundland Power's 2017 capital budget is $89,411,000.

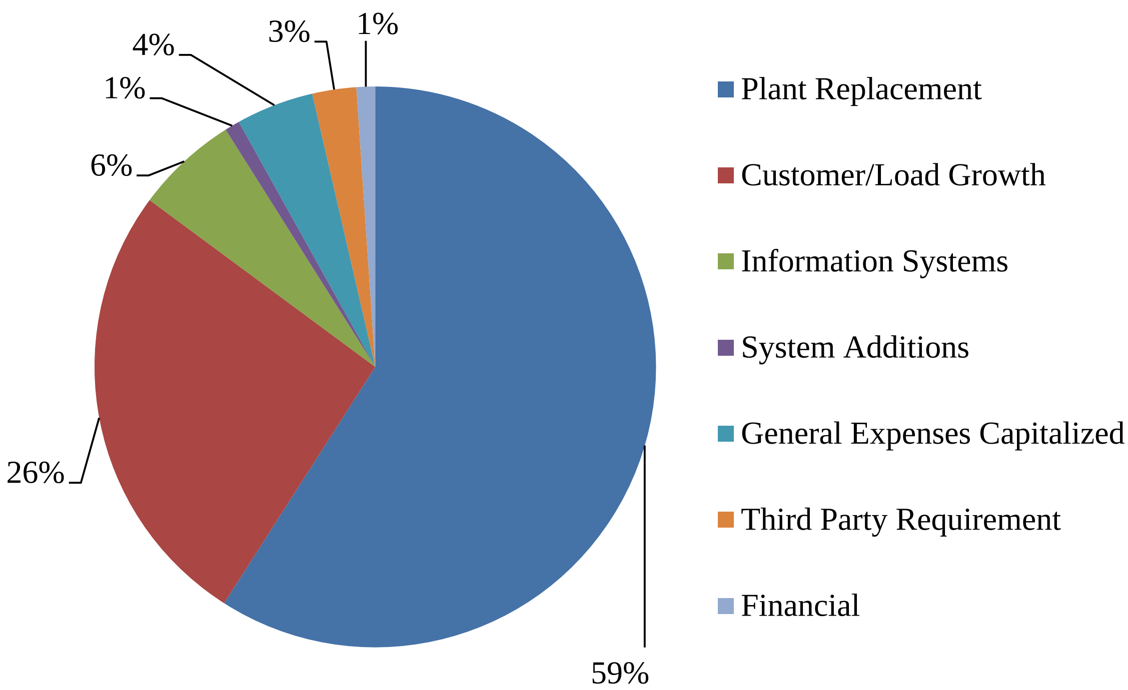
This section of the 2017 Capital Plan provides an overview of the 2017 capital budget by origin (root cause) and asset class. In addition, this section summarizes 2017 capital projects by the various categories set out in the Board's October 2007 Capital Budget Application Guidelines.

2.1 2017 Capital Budget Overview

Newfoundland Power's 2017 Capital Budget contains 39 projects totalling approximately $89.4 million.

Chart 1 shows the 2017 Capital Budget by origin, or root cause.

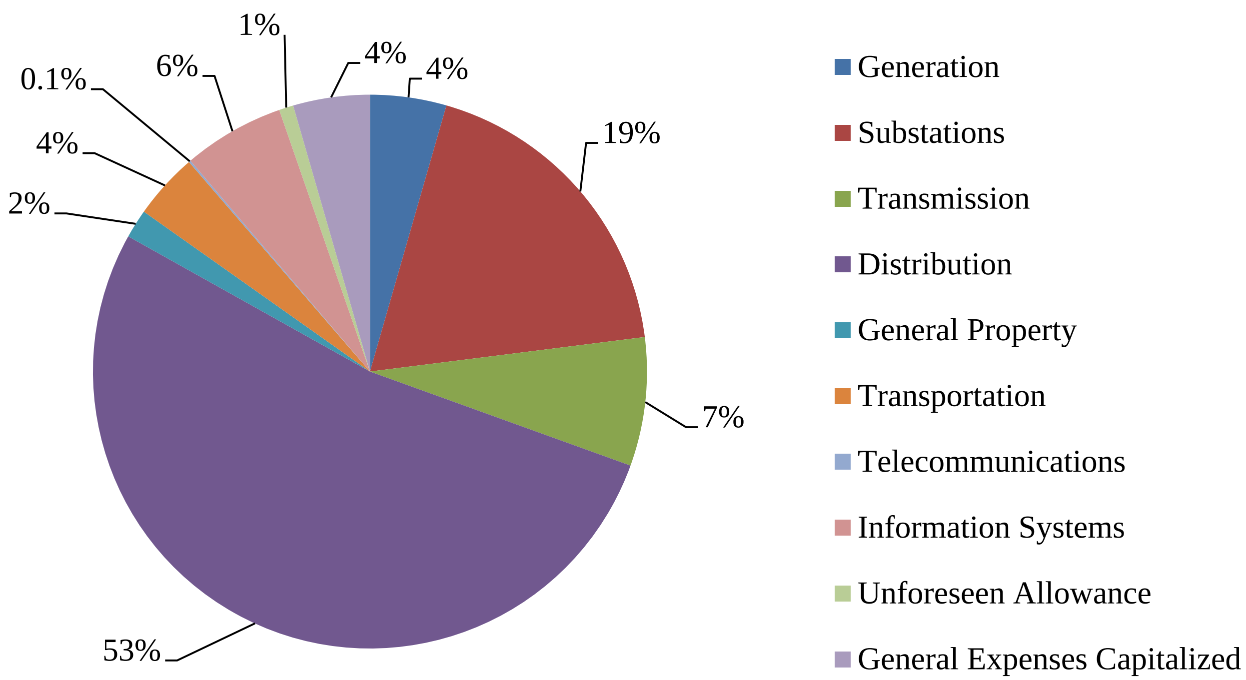
Chart 1
2017 Capital Expenditures by Origin



Approximately 59% of proposed 2017 capital expenditure is related to the replacement of plant. A further 26% of proposed 2017 capital expenditure is required to meet the Company's obligation to serve new customers and meet the requirement for increased system capacity. The 6% of proposed 2017 capital expenditure associated with Information Systems includes the project to replace the Company's Outage Management system. The remaining 9% of forecast capital expenditures for 2017 relates to general expenses capitalized, third party requirements and financial carrying costs (allowance for funds used during construction). The allocation of 2017 capital expenditures is broadly consistent with capital budgets for the past 5 years.

Chart 2 shows the 2017 capital budget by asset class.

Chart 2
2017 Capital Expenditures by Asset Class



As in past years, Distribution capital expenditure accounts for the greatest percentage of overall expenditure at $47.0 million, or 53% of the 2017 capital budget. Generation capital expenditure accounts for $4.0 million, or 4% of the 2017 capital budget. Substations capital expenditure accounts for $16.6 million, or 19% of the 2017 capital budget. Transmission capital expenditure accounts for $6.7 million, or 7% of the 2017 capital budget. Information Systems capital expenditure accounts for $5.3 million or 6% of the 2017 capital budget. Together, expenditure for these 5 asset classes comprises 89% of the Company's 2017 capital budget.

Distribution capital expenditure is primarily driven by customer requests for new connections to the electrical system and the rebuilding of aged and deteriorated infrastructure. In 2017, the Company will complete the upgrading of its metering infrastructure to 100% AMR. Otherwise, Distribution capital expenditures in 2018 and beyond are expected to reflect reduced new customer connections.

In 2017, the Company plans to install a new power transformer at Chamberlains Substation to serve customers in the Conception Bay South and Paradise areas. Also in 2017, the Company will construct a new distribution feeder originating from Chamberlains Substation. These projects are necessary to address growth in customer load in this area.

In 2017, the Company will continue with the rebuilding of the oldest, most deteriorated transmission lines in its system. Transmission line 32L operates between Ridge Road Substation and Oxen Pond Substation in the City of St. John's. Transmission line 41L operates between Carbonear Substation and Heart's Content Substation on the Avalon Peninsula. Also, in 2017 the Company will complete a 2-year project to rebuild transmission line 57L operating between Bay Roberts and Harbor Grace substations in the Conception Bay North area.

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 for definition and categorization of capital expenditures for which a public utility requires prior approval of the Board. Newfoundland Power's 2017 Capital Budget Application complies with the CBA Guidelines.

The 2017 Capital Budget Application includes 39 projects, as detailed in *Schedule A*. Included in *Schedule B* is a summary of these projects organized by definition, classification, and costing method.

The following section provides a summary of each of these views of the 2017 Capital Budget, along with a summary of costs segmented by materiality.

2017 Capital Projects by Definition

Table 1 summarizes Newfoundland Power's proposed 2017 capital projects by definition as set out in the CBA Guidelines.

Table 1
2017 Capital Projects
By Definition

Definition	**Number of Projects**	**Budget (000s)**
Pooled	27	$59,233
Clustered[1]	6	21,708
Other	6	8,470
Total	**39**	**$89,411**

There are a total of 33 *pooled* or *clustered* projects accounting for 90% of total expenditures.

[1] Projects that have some items that are defined as Clustered and some other items that are defined as either Pooled or Other are included as Clustered for the purpose of this table.

2017 Capital Projects by Classification

Table 2 summarizes Newfoundland Power's proposed 2017 capital projects by classification as set out in the CBA Guidelines.

Table 2
2017 Capital Projects
By Classification

Classification	**Number of Projects**	**Budget (000s)**
Normal	36	$86,737
Mandatory	2	1,671
Justifiable	1	1,003
Total	**39**	**$89,411**

There are 36 *normal* projects accounting for 97% of total expenditures.

2017 Capital Projects Costing

Table 3 summarizes Newfoundland Power's proposed 2017 capital projects by costing method (i.e., identified need vs. historical pattern) as set out in the CBA Guidelines.

Table 3
2017 Capital Projects
By Costing Method

Method	**Number of Projects**	**Budget (000s)**
Identified Need	23	$40,185
Historical Pattern	16	49,226
Total	**39**	**$89,411**

Projects with costing method based on *identified need* account for 45% of total expenditures, while those based on *historical pattern* account for 55% of total expenditures.

2016 Capital Projects Materiality

Table 4 segments Newfoundland Power's proposed 2017 capital projects by materiality as set out in the CBA Guidelines.

Table 4
2017 Capital Projects
Segmentation by Materiality

Segment	Number of Projects	Budget (000s)
Under $200,000	1	$98
$200,000 - $500,000	10	3,302
Over $500,000	28	86,011
Total	**39**	**$89,411**

There are 28 projects budgeted at over $500,000 accounting for 96% of total expenditures.

3.0 5-Year Outlook

Newfoundland Power's 5-year capital outlook for 2017 through 2021 includes forecast average annual capital expenditure of $96.1 million. Over the 5 year period 2012 through 2016, the average annual capital expenditure is expected to be $96.8 million.

The forecast annual capital expenditure reflects inflation and requirements for specific projects related to replacement of deteriorated facilities, meeting customer and load growth, replacing the Company's Customer Service System and a new portable generator. Annual expenditure through the forecast period is broadly consistent with that in the period 2012 through 2016.

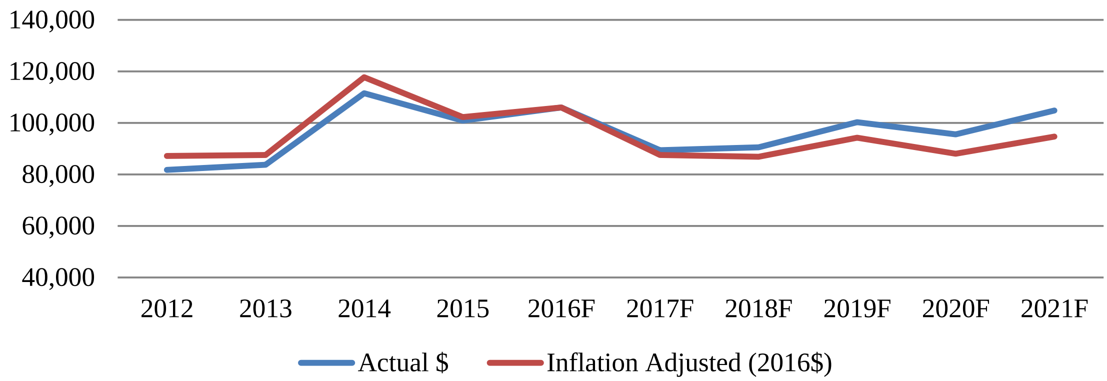
3.1 Capital Expenditures: 2012-2021

The Company plans to invest $481 million in plant and equipment during the 2017 through 2021 period. On an annual basis, capital expenditures are expected to average approximately $96.1 million and range from a low of $89.4 million in 2017, to a high of $104.8 million in 2021.[2]

[2] In 2021, the Company plans to refurbish the Mobile and Morris hydro plants at an estimated cost of $4 million and initiate the replacement of its Customer Service System at an estimated 2021 cost of $8 million.

Chart 3 shows actual capital expenditures for the period 2012 through 2015, and forecast capital expenditures for the period 2016 through 2021. For comparison purposes, the annual capital expenditures are also expressed in 2016 dollars to remove the effects of inflation.

Chart 3
Capital Expenditures
2012 to 2021F
($000s)



Overall planned capital expenditures for the 5-year period from 2017 through 2021 are expected to be similar to those in the 5-year period from 2012 through 2016.[3] Forecast requirements for the 5-year period from 2017 through 2021 include additional power transformers due to forecast load growth, new transmission lines on the northeast Avalon Peninsula, replacement of Topsail penstock, new mobile generation, gas turbine refurbishment and the replacement of important information technology such as Outage Management and Customer Service systems.

The replacement of plant has been, and will continue to be, the largest driver of Newfoundland Power's capital budget, accounting for 55% of total expenditure for the 10-year period from 2012 through 2021. Over the same 10-year period, capital expenditures to meet increased customer connections and electricity sales account for 27.5% of total expenditures.

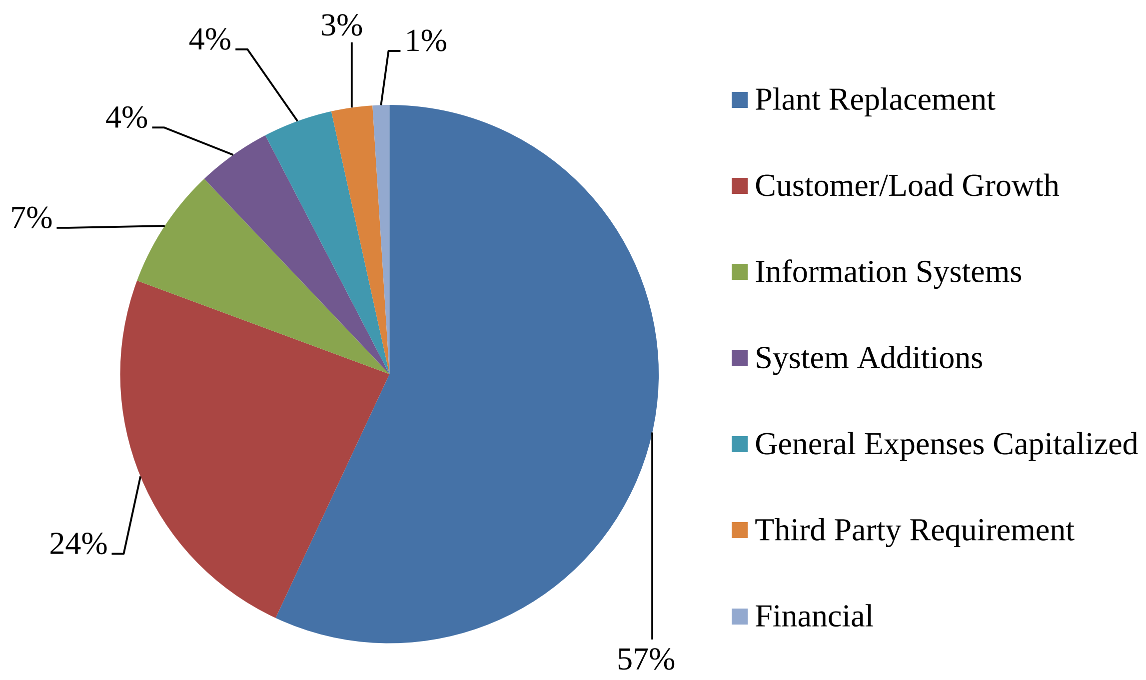
[3] In 2014 to 2016 there were a number of exceptional items that increased capital expenditures in those years. In 2014 supplemental capital expenditures for the Bell Island Submarine Cable Replacement and distribution feeder improvements and substation refurbishment application approved by Board Order Nos. P.U. 43 (2013) and P.U. 14 (2014) respectively were approximately $16 million. In 2015, capital expenditures for the Duffy Place building renovation and SCADA system replacement were approximately $5 million. In 2016, capital expenditures for the Pierre's Brook penstock replacement are approximately $14 million.

3.2 2017-2021 Capital Expenditures

3.2.1 Overview

Chart 4 shows aggregate forecast capital expenditures by origin for the period 2017 through 2021.

Chart 4
Capital Expenditures
by Origin
2017 to 2021

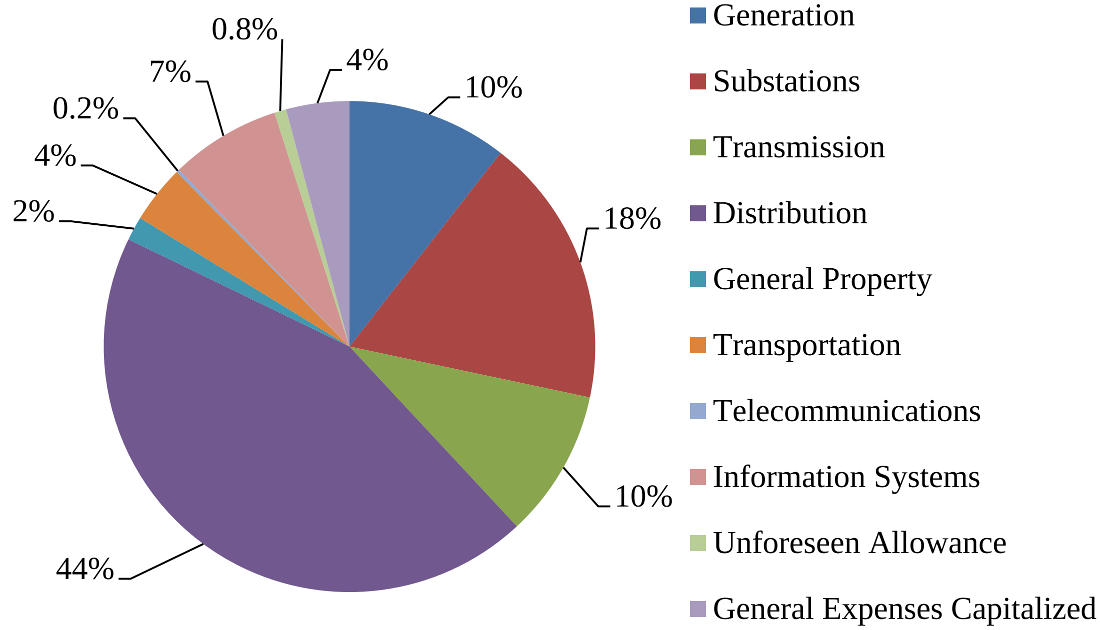


Plant replacement accounts for 57% of all planned expenditures over the 5-year period from 2017 through 2021. This is greater than the average of 53% in the previous 5-year period from 2012 through 2016. Capital expenditure related to customer and load growth accounts for 24% of planned expenditures over the 5-year period from 2017 through 2021. This is less than the average of 31% in the previous 5-year period from 2012 through 2016.

The remaining 19% of total capital expenditures for the 2017 through 2021 period relate to a variety of origins including information systems, system additions, general expenses capitalized, third party requirements and financial costs.

Chart 5 shows aggregate forecast capital expenditures for the period 2017 through 2021 by asset class.

Chart 5
Capital Expenditures
by Asset Class
2017 to 2021



The Distribution asset class accounts for 44% of all planned expenditures over the next 5 years, followed by Substations (18%), Generation (10%) and Transmission (10%). The remaining six asset classes account for 18% of total capital expenditures for the 2017 through 2021 period.

Overall, planned expenditures for the period 2017 through 2021 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, and the addition of portable generation over the forecast period. The Company has also included the replacement of its Customer Service System in the 5-year plan, which significantly increases Information Systems expenditures in 2020 and 2021.

A summary of planned capital expenditures by asset class and by project for 2017 to 2021 is provided in Appendix A.

3.2.2 Generation

Generation capital expenditures will average approximately $10.1 million per year from 2017 through 2021, which is greater than the annual average of $9.7 million from 2012 through 2016.[4]

Generation capital expenditures on the Company's 23 hydroelectric plants, 3 gas turbines and 2 diesel plants are primarily driven by:

- breakdown capital maintenance;
- preventive capital maintenance; and
- specific capital project initiatives, such as plant refurbishment.

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 5 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 2017, the Company plans to refurbish the generator rotor, turbines and wicket gates on generator G3 along with the replacement of 2 main valves at the 76 year old Tors Cove hydro plant at an estimated total cost of $1.4 million. In 2018, the Company plans to refurbish the generators, turbines and wicket gates on generator G1 along with the switchgear at Tors Cove hydro plant at an estimated total cost of $3.7 million.

- In 2018 and 2019, the Company plans to purchase a mobile generator at an estimated cost of $13.4 million. The mobile generator will be used for both emergency generation and to minimize customer outages during planned work.[5]

- In 2018 and 2019, the Company plans to replace the Topsail woodstave penstock at an estimated cost of $7.1 million.

- In 2019 and 2020, the Company plans to refurbish the Greenhill gas turbine facility at an estimated cost of $5.9 million.

- In 2020, the Company plans to replace the deteriorated runner at the Cape Broyle hydro plant. The new runner will increase hydro production by 0.9 GWh at an estimated cost of $1.2 million.

- In 2021, the Company plans to replace the turbine runner at the Rattling Brook hydro plant at an estimated cost of $1.0 million.

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4 This increase is attributable to the purchase of a new mobile generator, the refurbishment of the Greenhill gas turbine, upgrades to the Wesleyville gas turbine, and the replacement of the penstock at Topsail hydro plant.

5 The existing mobile gas turbine will be 44 years old in 2017.

- In 2021, the Company plans to upgrade the Wesleyville gas turbine facility. The Company will explore replacement options in advance of the 2021 project.

3.2.3 Transmission

Transmission capital expenditures are expected to average $9.4 million annually from 2017 through 2021 compared with $5.6 million annually from 2012 through 2016.[6]

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

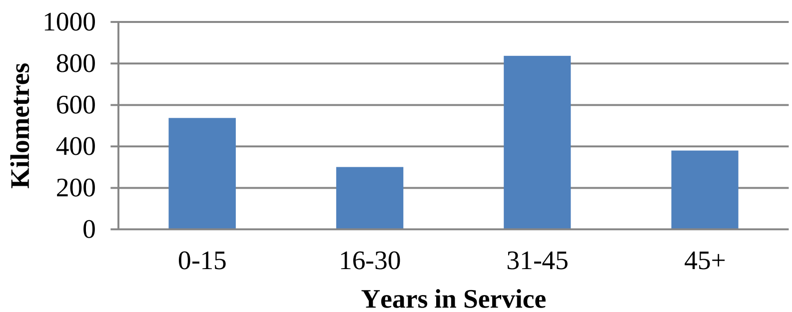
- rebuilding aging transmission lines;
- preventive capital maintenance; and
- third party requests.

The Company has a maintenance program in place for its transmission assets. The level of expenditure for capital maintenance, both breakdown and preventive, 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 the 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. An update of the strategic plan is included in the report ***3.1** 2017 Transmission Line Rebuild* included with the 2017 Capital Budget Application.

Chart 6 shows the age distribution of the Company's transmission lines.

Chart 6
Kilometres of Transmission Line By Age



As shown in the chart, a significant number of transmission lines were constructed in the 1970s. These transmission lines are approaching 50 years in service and will need to be rebuilt in the coming decade.

[6] The increase in transmission line capital expenditures over the 5-year plan is attributable to the construction of a new transmission line on the Northeast Avalon Peninsula and the rebuild of the 66 kV transmission system in Central Newfoundland.

In 2019, the Company anticipates that additional transmission capacity will be required to supply substations in the area from Torbay to Portugal Cove at an estimated cost of approximately $4.3 million over 2 years. In 2011, the Company installed a new 25 MVA transformer in Pulpit Rock substation and in 2019, the Company plans to install a new 25 MVA transformer in Broad Cove substation. Both transformers are required due to customer and load growth in the area. The transmission lines supplying these 2 substations are radial with no contingency for the loss of supply other than mobile generation. The construction of new transmission lines is required to provide redundancy of supply to this growing area.

Starting in 2020, and continuing beyond the 5-year plan, the Company plans to rebuild approximately 112 km of 66kV transmission line from Grand Falls to Gander at approximately $16 million based upon the deteriorated condition of the lines. It may be technically feasible to retire the 66 kV transmission systems between Grand Falls and Gander by expanding the existing 138 kV transmission system into substations at Notre Dame Junction and Rattling Brook. Prior to 2020, the Company will undertake a planning study to determine the least cost design for providing reliable service to substations in the Central Newfoundland region.

3.2.4 Substations

Substations capital expenditures are expected to average $17.1 million annually from 2017 through 2021, which is consistent with the average of $17.6 million annually from 2012 through 2016. This level of expenditure is driven by forecast additional system capacity and increased automation of transmission line breakers and distribution feeder breakers and reclosers.

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

- breakdown capital maintenance;
- preventive capital maintenance and modernization;
- Government regulations regarding the elimination of PCBs; and
- system load growth.

The Company has a preventive capital maintenance program in place for its substation assets. Preventive maintenance is expected to ensure that the overall reliability of substation assets remains stable.

In its 2007 Capital Budget Application, the Company submitted its 10-year substation strategy in a report titled *Substation Strategic Plan*. The 2007 plan addressed substation refurbishment and modernization work in 80% of the Company's substations in an orderly way over a multi-year planning horizon. This is consistent with the maintenance of reasonable year to year stability in the Company's annual capital budgets. Since 2007, work performed as part of the Substation Refurbishment and Modernization capital project has broadly reflected this approach. An update of the strategic plan is included in the report ***2.1** 2017 Substation Refurbishment and Modernization* filed with this 2017 Capital Budget Application.

The system events of January 2-8, 2014, particularly the lengthy customer outages and the successive rotating power outages, revealed control limitations on the Company's transmission and distribution systems.[7] At year-end 2017, SCADA control and monitoring will be implemented on approximately 92% of Newfoundland Power's transmission lines and approximately 89% of distribution feeders.[8] The 5-Year Capital Plan includes projects to complete the automation of the remaining distribution feeders by the end of 2019. The *2017 Substation Refurbishment and Modernization* project includes the automation of 17 distribution feeders.

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

Over the 2017 to 2021 forecast period, there is a requirement to install 4 substation transformers to accommodate load growth.[9] In 2017, as a result of customer and load growth experienced over the past decade, a new power transformer will be required at Chamberlains substations.[10] Commencing in 2019 and continuing through 2021, 3 additional substation transformers will be required for the Northeast Avalon Peninsula and Western Newfoundland areas.[11]

The Company has met the Government of Canada's regulatory requirement to remove from service all bushings and instrument transformer equipment containing oil at or above 500 mg/kg by December 31, 2014.[12] Equipment with PCB concentrations greater than 50 mg/kg and less than 500 mg/kg must be removed from service by 2025. Commencing in 2017, the 5-year capital plan includes expenditures of approximately $5.1 million to address PCB concentrations greater than 50 mg/kg and less than 500 mg/kg in advance of the 2025 deadline.

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7 The level of monitoring is dependent on the type of protection and communication equipment installed at the substation and ranges from monitoring equipment status to the ability to remotely control equipment and configure protection settings.

8 This is an increase from year end 2013 when SCADA control and monitoring had been implemented on approximately 91% of Newfoundland Power's transmission lines and approximately 60% of distribution feeders.

9 By comparison, in the period 2012 through 2016, Newfoundland Power has purchased 8 new power transformers and relocated 4 power transformers to serve increased customer load. The purchase of new transformers and the relocation of other transformers to serve customer load growth are in addition to the requirement to replace aged or deteriorated equipment.

10 The planning study for the Chamberlains service areas is included in the 2017 Capital Budget Application report ***2.2*** *2017 Additions Due To Load Growth*.

11 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.

12 Newfoundland Power was granted a permit extending the deadline to remove from service equipment containing oil at or above 500 mg/kg to December 31, 2014. Subsequent to this, the Government extended the deadline to 2025

3.2.5 Distribution

Distribution capital expenditures from 2017 through 2021 are expected to average approximately $42.4 million annually, compared to an average of $47.9 million annually from 2012 through 2016. This decrease is largely attributable to lower expenditures related to customer growth.

The Company operates approximately 10,000 km of distribution lines serving approximately 263,000 customers. Distribution capital expenditures are primarily driven by:

- new customers;
- third party requests;
- breakdown capital maintenance;
- preventive capital maintenance;
- system load growth; and
- specific capital project initiatives, such as trunk feeder rebuilds.

The number of new customer connections is forecast to decrease over the planning period when compared to the 2012 to 2016 period. Over the 5-year period from 2017 to 2021, the number of new customer connections is forecast to decrease by 18.9%. This decrease in capital expenditures is primarily due to the reduction in the number of forecast new customer connections. 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 5 years.

Table 5
New Customer Connections

	2017	**2018**	**2019**	**2020**	**2021**
New Customer Connections	3,714	3,234	3,099	3,064	3,013
Average Cost/Connection	$5,126	$5,709	$5,886	$5,980	$6,118
Capital Expenditure (000s)	$19,039	$18,464	$18,241	$18,324	$18,433

Over the period 2017 to 2021, the expenditure associated with new customer connections is forecast to be within the range of $18.2 million to $19.0 million, or approximately 19% of the annual capital expenditures.

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. Expenditures for feeder modifications and additions due to system load growth from 2017 through 2021 are expected to total approximately $9 million over the next 5 years.[13]

Distribution capital expenditures are required to relocate or replace distribution lines to meet third party requests from governments, telecommunications companies and individual customers. In 2017, the expenditures associated with third party requests are estimated at $2.3 million. Over the 5-year period from 2017 through 2021, these expenditures are forecast to remain stable and approximate an average of $2.4 million.

Capital expenditures associated with the replacement of meters are typically based upon historical expenditures. In 2016, the Company accelerated the replacement of all remaining non-AMR meters with AMR meters. A detailed description of the Company's strategy to deal with new regulations and improved efficiency in the metering function can be found in the 2016 Capital Budget Application report ***4.4** 2016 Meter Strategy*. Subsequent to the 2017 AMR installations, over the period from 2018 to 2021 distribution capital expenditures for meters will average $590,000 per year.

In the 2013 Capital Budget Application, the Company outlined its preventive capital maintenance program for Distribution assets in the report ***4.4** Rebuild Distribution Lines Update*. The expenditures associated with the preventive capital maintenance program are budgeted in the annual *Rebuild Distribution Lines* project. The Company plans to perform preventive capital maintenance on approximately 43 distribution feeders per year over the planning period.

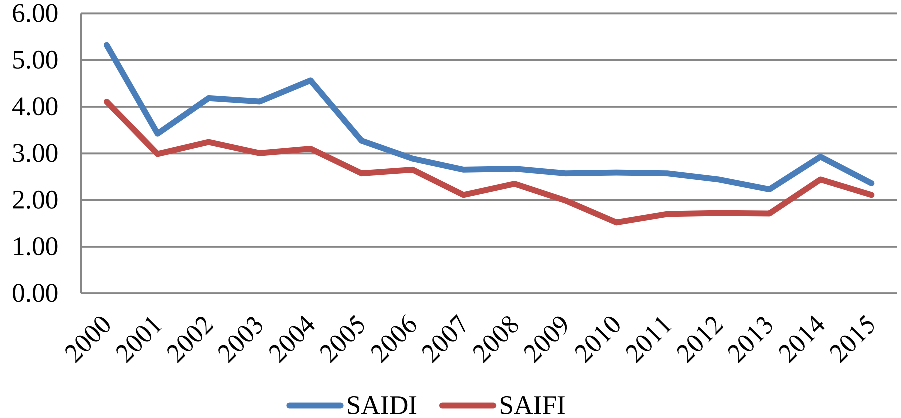
The Distribution *Reconstruction* project involves the replacement of deteriorated or damaged distribution structures and electrical equipment. The project is comprised of small unplanned projects and is estimated using the historical average of the most recent 5-year period.

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*.

[13] Capital expenditures for the *Feeder Additions for Load Growth* project for the 5-year period 2012 to 2016 were approximately $8.2 million.

Chart 7 shows SAIDI, or system average interruption duration index, and SAIFI, or system average interruption frequency index, for the years 2000 through 2015. Chart 7 has been adjusted to remove the effects of severe weather and system events.[14]

Chart 7
SAIDI and SAIFI
2000 - 2015



Newfoundland Power considers current levels of service reliability on a system wide basis to be satisfactory. The Company, through the *Distribution Feeder Automation* project, is increasing the number of downstream reclosers on the distribution system. Installing more of these reclosers over time, beginning with those worst performing feeders, is a cost effective way of further improving distribution reliability.[15]

In 2014, Newfoundland Power incorporated additional reliability indices, CIKM and CHIKM into its reliability analysis.[16] This has resulted in additional distribution feeders being identified for work under the *Distribution Reliability Initiative* project. In 2017, distribution feeders SUM-02 in Central Newfoundland, and RVH-02 and TRP-01 on the Avalon Peninsula, are

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14 Adjustments exclude the 2007 and 2010 Bonavista ice storms, Hurricane Igor in 2010, the December 2011 high wind event, Tropical Storm Leslie in September 2012, the January 11th 2013 system disturbance and the Central Newfoundland winter storm in November 2013. These exclusions are consistent with the Canadian Electricity Association approved definitions. If these severe weather events were included, 2007 SAIDI and SAIFI would be 5.94 and 2.46, respectively, 2010 SAIDI and SAIFI would be 13.82 and 2.69 respectively, 2011 SAIDI and SAIFI would be 4.03 and 1.95, respectively, 2012 SAIDI and SAIFI would be 5.85 and 2.12 respectively and 2013 SAIDI and SAIFI would be 3.04 and 1.82 respectively .

15 Recommendation 2.4 of Liberty's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power, December 17, 2014*, identified the potential for downline reclosers to positively impact reliability indices.

16 In 2012 the Canadian Electricity Association began capturing and reporting on 2 additional indices; customer hours of interruption per kilometer "CHIKM" and customers interrupted per kilometer "CIKM".

included for reliability rebuilds.[17] Details on the project expenditure can be found in the report ***4.1** Distribution Reliability Initiative*.

Newfoundland Power has equipment located in duct banks and manholes under Water Street in the St. John's downtown. The Water Street underground electrical distribution system was installed in the late 1960s and is approaching the end of its service life. A planning study for the St. John's downtown was included in the Company's 2011 Capital Budget Application that discussed the aging infrastructure and presented a plan to replace various sections of the underground system over a period of years. Included in the plan was the requirement to replace duct banks under the Waterford River and along Water Street. In 2016 and 2017, the Company plans to replace the duct banks on the Waterford River crossing.[18]

In March 2015, the City of St. John's issued terms of reference documents for engineering consulting services to design the replacement of its water and sewer infrastructure under Water Street from Waldegrave Street to Jobs Cove. In its 2016 Capital Budget Application, the 5-year plan included expenditures to allow the replacement of the underground electricity distribution system along Water Street to coincide with the work to be undertaken by the City of St. John's. In early 2016, the City announced that it was exploring other alternatives to replace its infrastructure that did not involve excavating Water Street. As a result, the Company has returned to its original plan that involves replacing 2 sections of existing duct bank in 2020 and 2021.[19]

The 2017 Capital Plan includes a distribution project titled *Distribution Feeder Automation* that increases the automation of the Company's distribution feeders. In 2017, the Company will install 8 additional automated reclosers on distribution feeders. Additional distribution feeder automation will improve the Company's capability to deal with cold load pickup and improve efficiency of restoration following both local and system wide outages. Downline reclosers on distribution feeders will also improve reliability indices when used to isolate faulted segments from undamaged sections of feeder upstream of the fault.

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;
- the refurbishment of Company buildings; and
- backup electricity generation at Company buildings.

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[17] It is anticipated that by using indices that consider customer interruptions and circuit length that the worst performing feeders will be found in urban settings where the Company has issues with older poles and associated infrastructure.

[18] In 2016, the Company will construct the civil infrastructure necessary for the Waterford River crossing. In 2017, the project will be completed with the installation and termination of the cables at the substation and Water Street ends.

[19] In the *St. John's Main Planning Study* included as Attachment A of the 2011 Capital Budget Application report *4.2 Feeder Additions for Laid Growth*, 2 sections of duct bank from Beck's Cove to Baird's Cove and from Telegram Lane to Prescott Street were identified for replacement.

General Property capital expenditures are expected to average $1.5 million annually from 2017 through 2021 which is less than the average of $2.3 million for the period from 2012 through 2016. General Property capital expenditures involve addressing deterioration associated with Company owned office, service and special purpose buildings throughout its service territory.

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 from 2017 through 2021 are expected to increase to an average of approximately $3.7 million annually, compared to an average of $3.0 million annually from 2012 through 2016. The Company operates 71 heavy fleet vehicles which have an anticipated service life of 10 years. On average, it would be expected that approximately 7 heavy fleet vehicles and 40 passenger vehicles would be replaced annually. The increase in transportation capital expenditures from 2017 through 2021 is principally reflective of inflation and the number of heavy fleet and passenger vehicles expected to meet the replacement parameters over the period.

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, substations, plants and offices.

Telecommunications capital expenditures are expected to average approximately $193,000 annually from 2017 through 2021, less than the annual average of $335,000 from 2012 through 2016.[20] Over the next 5-year period the Telecommunications capital expenditures are largely associated with the installation of new fibre optic cables in Corner Brook. The Company's fibre optic cables provide telecommunications for the Company's remote control and protective relaying technology.

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 from 2017 through 2021 are expected to increase to an average of approximately $7.0 million annually, compared to an average of $5.6 million annually

[20] In 2014, the Company replaced its mobile radio system at an approximate cost of $838,000.

from 2012 through 2016. The increase is largely driven by the replacement of corporate systems such as the Outage Management System ("OMS") and the Customer Service System ("CSS").[21]

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 exigent circumstances in advance of seeking approval of the Board.

The Unforeseen Allowance constitutes $750,000 in each year's capital budget from 2017 through 2021.

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 $4.0 million is reflected in each year's capital budget from 2017 through 2021.

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 2017 through 2021.

Newfoundland Power has an obligation to serve customers in its service territory. Should customer and load 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 load 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 losses of the Kenmount, Horse Chops, Pierre's Brook and Salt Pond power transformers will necessitate capital expenditures.[22]

Newfoundland Power's gas turbines range in age from 41 years to 47 years. These gas turbines had a significant increase in usage during the 2013/2014 winter season. Condition assessments

[21] A detailed report on the OMS replacement can be found in report ***6.4*** *Outage Management System Replacement* included with the 2016 Capital Budget Application.

[22] Replacement of the Horse Chops 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 and its refurbishment was approved in Board Order No. P.U. 29 (2009).

were completed following the 2013/2014 winter season identifying necessary refurbishment work to be completed prior to the 2014/2015 winter season. The 5-year capital plan has identified refurbishment work on the Greenhill gas turbine system and the future replacement of the Wesleyville gas turbine system. An in-service failure of either gas turbine system will necessitate a change to this plan.

New home construction on the Northeast Avalon Peninsula has weakened considerably compared with the previous 5-year period, and is expected to deteriorate over the forecast period. The current forecast for new customer connections indicates a decline throughout the Company's service territory. The extent of change in new customer connections required over the course of this 5-year capital plan can have a material impact on capital expenditures.

The Muskrat Falls development will have an impact upon Newfoundland Power's capital expenditures. The Company will be involved in supplying construction power to sites within its service territory and potential rerouting of existing transmission and distribution lines to accommodate the Nalcor DC transmission line. There may be other impacts associated with integrating the new DC infeed with the existing power system. This capital plan has not envisioned material capital expenditures resulting from the Muskrat Falls development.

The Company has taken steps to reduce the uncertainty regarding replacement of its CSS, which has been in service since 1991.[23] These steps have included upgrades of hardware and software components and removal of technology components that posed the highest risk. While the current versions of hardware, software and database should be supported throughout this capital plan period, commencing in 2020, the Company has included a project to replace CSS. Any changes to the availability of support to existing technology platforms could materially impact the capital plan.

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 March 5th and 6th, 2010, an ice storm in eastern Newfoundland caused widespread power outages on the Bonavista and Avalon Peninsulas. In September 2010, Hurricane Igor caused extensive damage to the Company's generation and distribution assets. In 2012, Tropical Storm Leslie caused damage to the distribution system. The occurrence and costs of severe storms are not predictable.

[23] The CSS originally cost in excess of $10 million.

Appendix A
2017-2021 Capital Plan

Newfoundland Power Inc.
2017-2021 Capital Plan
(000s)

Asset Class	**2017**	**2018**	**2019**	**2020**	**2021**
Generation	$3,979	$12,291	$17,412	$7,913	$9,041
Substations	$16,593	$14,907	$16,080	$18,055	$19,863
Transmission	$6,711	$7,535	$10,959	$10,864	$10,809
Distribution	$47,034	$40,299	$40,441	$42,582	$41,661
General Property	$1,502	$1,700	$1,337	$1,556	$1,476
Transportation	$3,456	$3,556	$3,666	$3,776	$3,890
Telecommunications	$98	$100	$199	$230	$337
Information Systems	$5,288	$5,419	$5,456	$5,837	$12,974
Unforeseen Allowance	$750	$750	$750	$750	$750
General Expenses Capitalized	$4,000	$4,000	$4,000	$4,000	$4,000
Total	**$89,411**	**$90,557**	**$100,300**	**$95,563**	**$104,801**

Newfoundland Power Inc.
2017-2021 Capital Plan
(000s)

GENERATION

Project	2017	2018	2019	2020	2021
Facility Rehabilitation – Hydro	$1,607	$1,512	$1,533	$1,556	$1,577
Facility Rehabilitation - Thermal	$234	$239	$244	$249	$254
Public Safety Around Dams	$662	$0	$0	$0	$0
Tors Cove Plant Refurbishment	$1,476	$3,650	$0	$0	$0
Rattling Brook Plant Refurbishment	$0	$0	$0	$0	$1,008
Cape Broyle Plant Refurbishment	$0	$0	$25	$1,170	$0
Topsail Plant Upgrades	$0	$300	$7,038	$0	$0
Petty Harbour Plant Refurbishment	$0	$0	$0	$0	$847
Lookout Brook Plant Refurbishment	$0	$0	$0	$623	$0
Mobile Plant Refurbishment	$0	$0	$0	$0	$3,145
Morris Plant Refurbishment	$0	$0	$0	$0	$510
Greenhill Plant Upgrades	$0	$0	$1,762	$4,115	$0
Purchase Portable Generation	$0	$6,590	$6,810	$0	$0
Wesleyville Plant Refurbishment	$0	$0	$0	$200	$1,700
Total - Generation	**$3,979**	**$12,291**	**$17,412**	**$7,913**	**$9,041**

Newfoundland Power Inc.
2017-2021 Capital Plan
(000s)

SUBSTATIONS

Project	**2017**	**2018**	**2019**	**2020**	**2021**
Substations Refurbishment & Modernization	$8,875	$9,875	$8,213	$9,741	$10,604
Replacements Due to In-Service Failure	$3,851	$3,931	$4,015	$4,098	$4,177
Additions Due to Load Growth	$2,574	$0	$2,750	$2,500	$2,500
Substation Feeder Terminations	$284	$290	$0	$596	$901
PCB Bushing Phase Out	$1,009	$811	$1,102	$1,120	$1,049
MOB Plant Upgrade	$0	$0	$0	$0	$632
Total – Substations	**$16,593**	**$14,907**	**$16,080**	**$18,055**	**$19,863**

Newfoundland Power Inc.
2017-2021 Capital Plan
(000s)

TRANSMISSION

Project	2017	2018	2019	2020	2021
Rebuild Transmission Lines	$4,611	$5,385	$7,397	$6,217	$8,809
Transmission Line Reconstruction	$2,100	$2,100	$2,000	$2,000	$2,000
Transmission Line Additions	$0	$50	$1,562	$2,647	$0
Total – Transmission	**$6,711**	**$7,535**	**$10,959**	**$10,864**	**$10,809**

Newfoundland Power Inc.
2017-2021 Capital Plan
(000s)

DISTRIBUTION

Project	2017	2018	2019	2020	2021
Extensions	$11,834	$11,456	$11,223	$11,361	$11,420
Meters	$4,391	$539	$559	$603	$660
Services	$3,564	$3,493	$3,460	$3,509	$3,542
Street Lighting	$2,049	$2,020	$2,010	$2,038	$2,059
Transformers	$6,103	$5,978	$6,160	$5,887	$5,887
Reconstruction	$4,908	$5,020	$5,137	$5,255	$5,372
Rebuild Distribution Lines	$4,023	$4,111	$4,203	$4,295	$4,384
Relocations For Third Parties	$2,266	$2,316	$2,368	$2,420	$2,471
Distribution Reliability Initiative	$1,415	$1,431	$1,731	$1,500	$1,500
Distribution Feeder Automation	568	452	560	760	720
Feeder Additions for Load Growth	$1,430	$1,987	$1,590	$1,808	$2,185
Trunk Feeders	$1,834	$1,285	$1,225	$1,595	$350
St. John’s Underground Refurbishment	$2,440	$0	$0	$1,332	$888
Allowance for Funds Used During Construction	$209	$211	$215	$219	$223
Total – Distribution	**$47,034**	**$40,299**	**$40,441**	**$42,582**	**$41,661**

Newfoundland Power Inc.
2017-2021 Capital Plan
(000s)

GENERAL PROPERTY

Project	2017	2018	2019	2020	2021
Tools and Equipment	$475	$479	$489	$496	$510
Additions to Real Property	$471	$475	$483	$459	$466
Renovations Company Buildings	$351	$746	$365	$601	$500
Standby Generators	$205	$0	$0	$0	$0
Total – General Property	**$1,502**	**$1,700**	**$1,337**	**$1,556**	**$1,476**

Newfoundland Power Inc.
2017-2021 Capital Plan
(000s)

TRANSPORTATION

Project	2017	2018	2019	2020	2021
Replace Vehicles and Aerial Devices	$3,456	$3,556	$3,666	$3,776	$3,890
Total – Transportation	**$3,456**	**$3,556**	**$3,666**	**$3,776**	**$3,890**

Newfoundland Power Inc.
2017-2021 Capital Plan
(000s)

TELECOMMUNICATIONS

Project	2017	2018	2019	2020	2021
Replace/Upgrade Communications Equipment	$98	$100	$102	$104	$106
Fibre Optic Cable	$0	$0	$97	$126	$231
Total – Telecommunications	**$98**	**$100**	**$199**	**$230**	**$337**

Newfoundland Power Inc.
2017-2021 Capital Plan
(000s)

INFORMATION SYSTEMS

Project	2017	2018	2019	2020	2021
Application Enhancements	$1,003	$1,270	$1,308	$1,348	$1,388
System Upgrades	$1,676	$1,651	$1,693	$1,737	$1,782
Personal Computer Infrastructure	$485	$464	$477	$492	$506
Shared Server Infrastructure	$661	$854	$879	$906	$933
Network Infrastructure	$388	$334	$344	$354	$365
GIS Improvement	$200	$0	$0	$0	$0
Outage Management System	$875	$0	$0	$0	$0
Customer Service System	$0	$0	$0	$1,000	$8,000
Human Resource System	$0	$346	$755	$0	$0
Call Centre Technology	$0	$500	$0	$0	$0
Total – Information Systems	**$5,288**	**$5,419**	**$5,456**	**$5,837**	**$12,974**

Newfoundland Power Inc.
2017-2021 Capital Plan
(000s)

UNFORESEEN ALLOWANCE

Project	2017	2018	2019	2020	2021
Allowance for Unforeseen Items	$750	$750	$750	$750	$750
Total - Unforeseen Allowance	**$750**	**$750**	**$750**	**$750**	**$750**

Newfoundland Power Inc.
2017-2021 Capital Plan
(000s)

GENERAL EXPENSES CAPITALIZED

Project	2017	2018	2019	2020	2021
General Expenses Capitalized	$4,000	$4,000	$4,000	$4,000	$4,000
Total - General Expenses Capitalized	**$4,000**	**$4,000**	**$4,000**	**$4,000**	**$4,000**

2016 Capital Expenditure Status Report

July 2016

NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

2016 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. 28 (2015).

Page 1 of the 2016 Capital Expenditure Status Report outlines the forecast variances from budget of the capital expenditures approved by the Board. The detailed tables on pages 2 to 13 provide additional detail on capital expenditures in 2016, which were approved in Order No. P.U. 28 (2015). The detailed tables also include information on those capital projects approved for 2012 and 2015 (and approved in Order No. P.U. 26 (2011) and Order No. P.U. 40 (2014)) that were not completed prior to 2016.

Variances of more than 10% of approved expenditure and $100,000 or greater are explained in the Notes contained in Appendix A, which immediately follows at the conclusion of the 2016 Capital Expenditure Status Report. These variance criteria are as outlined in the *Capital Budget Application Guidelines*.

Newfoundland Power Inc.

2016 Capital Budget Variances
(000s)

	Approved by Order No. P.U.28 (2015)	Forecast	Variance
Generation – Hydro	$17,357	$16,837	($520)
Generation - Thermal	1,738	1,738	-
Substations	17,940	16,940	(1,000)
Transmission	6,067	6,067	-
Distribution	45,055	45,055	-
General Property	1,840	1,840	-
Transportation	3,258	3,258	-
Telecommunications	514	419	(95)
Information Systems	8,009	8,009	-
Unforeseen Items	750	750	-
General Expenses Capitalized	4,500	4,200	(300)
Total	$107,028	$105,113	($1,915)
Projects carried forward from 2015		$2,917[1]	
Projects carried forward from 2012		$100[1]	

1 Forecast 2016 expenditures associated with projects carried forward from 2012 and 2015.

2016 Capital Expenditure Status Report
(000s)

	Capital Budget			Actual Expenditure			Forecast			
	2015	2016	Total	2015	2016	Total To Date	Remainder 2016	Total 2016	Overall Total	Variance
	A	B	C	D	E	F	G	H	I	J
2016 Projects	$ -	$ 107,028	$ 107,028	$ -	$ 22,180	$ 22,180	$ 82,933	$ 105,113	105,113	$ (1,915)
2015 Projects	28,170	-	28,170	24,251	1,010	25,261	2,007	$ 3,017	27,268	(902)
Grand Total	**$ 28,170**	**$ 107,028**	**$ 135,198**	**$ 24,251**	**$ 23,190**	**$ 47,441**	**$ 84,940**	**$ 108,130**	**$ 132,381**	**$ (2,817)**

Column A	Approved Capital Budget for 2015
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Column H	Total of Columns E and G
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2016 Capital Expenditure Status Report
(000s)

Category: Generation - Hydro

Project	Capital Budget 2015 (A)	Capital Budget 2016 (B)	Capital Budget Total (C)	Actual Expenditures 2015 (D)	Actual Expenditures 2016 (E)	Actual Expenditures Total To Date (F)	Forecast Remainder 2016 (G)	Forecast Total 2016 (H)	Forecast Overall Total (I)	Variance (J)	Notes*
2016 Projects											
Facility Rehabilitation	$ -	$ 1,462	$ 1,462	$ -	$ 234	$ 234	$ 1,108	$ 1,342	$ 1,342	$ (120)	
Public Safety Around Dams	-	883	883	-	107	107	776	883	883	-	
Pierre's Brook Plant Refurbishment	-	15,012	15,012	-	199	199	14,413	14,612	14,612	(400)	
Total - 2016 Generation Hydro	**-**	**$ 17,357**	**$ 17,357**	**-**	**$ 540**	**$ 540**	**$ 16,297**	**$ 16,837**	**$ 16,837**	**$ (520)**	
2015 Projects											
Facility Rehabilitation	$ 1,586	$ -	$ 1,586	$ 1,365	$ -	$ 1,365	$ 180	$ 180	$ 1,545	$ (41)	
Rattling Brook Fisheries Compensation **	5,000	-	5,000	3,026	-	3,026	100	100	3,126	(1,874)	1
Total - Generation Hydro	**$ 6,586**	**$ 17,357**	**$ 23,943**	**$ 4,391**	**$ 540**	**$ 4,931**	**$ 16,577**	**$ 17,117**	**$ 21,508**	**$ (2,435)**	

* See Appendix A for notes containing variance explanations.
** 2012 Project

Column A	Approved Capital Budget for 2015
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Column C	Total of Columns A and B
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Column E	Actual Capital Expenditures for 2016
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2016 Capital Expenditure Status Report
(000s)

Category: Generation - Thermal

Project	Capital Budget 2016	Capital Budget Total	Actual Expenditures 2016	Actual Expenditures Total To Date	Forecast Remainder 2016	Forecast Total 2016	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2016 Projects									
Facility Rehabilitation Thermal	$ 238	$ 238	$ 198	$ 198	$ 40	$ 238	$ 238	$ -	
Greenhill Gas Turbine Refurbishment	1,500	1,500	15	15	1,485	1,500	1,500	-	
Total - Generation Thermal	**$ 1,738**	**$ 1,738**	**$ 213**	**$ 213**	**$ 1,525**	**$ 1,738**	**$ 1,738**	**-**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2016
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2016
Column D	Total of Column C
Column E	Forecast for Remainder of 2016
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Column H	Column G less Column B

2016 Capital Expenditure Status Report
(000s)

Category: Substations

	Capital Budget			Actual Expenditures			Forecast				
Project	**2015**	**2016**	**Total**	**2015**	**2016**	**Total To Date**	**Remainder 2016**	**Total 2016**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	
2016 Projects											
Substation Refurbishment and Modernization	$ -	$ 7,871	$ 7,871	$ -	$ 1,116	$ 1,116	$ 6,455	$ 7,571	$ 7,571	$ (300)	
Replacements Due to In-Service Failures	-	3,771	3,771	-	456	456	2,915	$ 3,371	3,371	(400)	2
Additions Due to Load Growth	-	5,868	5,868	-	425	425	5,143	$ 5,568	5,568	(300)	
Substation Feeder Termination	-	430	430	-	3	3	427	$ 430	430	-	
	$ -	$ 17,940	$ 17,940	$ -	$ 2,000	$ 2,000	$ 14,940	$ 16,940	$ 16,940	$ (1,000)	
2015 Projects											
Substation Refurbishment and Modernization	$ 9,961	$ -	$ 9,961	$ 10,777	$ -	$ 10,777	$ 161	$ 161	$ 10,938	$ 977	
Total - Substations	**9,961**	**17,940**	**27,901**	**10,777**	**2,000**	**12,777**	**15,101**	**17,101**	**27,878**	**(23)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2015
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2016 Capital Expenditure Status Report
(000s)

Category: Transmission

Project	Capital Budget 2015	Capital Budget 2016	Capital Budget Total	Actual Expenditures 2015	Actual Expenditures 2016	Actual Expenditures Total To Date	Forecast Remainder 2016	Forecast Total 2016	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2016 Projects											
Rebuild Transmission Lines	$ -	$ 6,067	$ 6,067	$ -	$ 930	$ 930	$ 5,137	$ 6,067	$ 6,067	$ -	
	$ -	$ 6,067	$ 6,067	$ -	$ 930	$ 930	$ 5,137	$ 6,067	$ 6,067	$ -	
2015 Projects											
Rebuild Transmission Lines	$ 5,731	$ -	$ 5,731	$ 5,731	$ -	$ 5,731	$ -	$ -	$ 5,731	$ -	
Total - Transmission	**5,731**	**6,067**	**11,798**	**5,731**	**930**	**6,661**	**5,137**	**6,067**	**11,798**	**-**	

* See Appendix A for notes containing variance explanations.

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2016 Capital Expenditure Status Report
(000s)

Category: Distribution

Project	Capital Budget			Actual Expenditures			Forecast				
	2015	2016	Total	2015	2016	Total To Date	Remainder 2016	Total 2016	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2016 Projects											
Extensions	$ -	$ 10,439	$ 10,439	$ -	$ 4,036	$ 4,036	$ 6,653	$ 10,689	$ 10,689	$ 250	
Meters	-	4,582	4,582	-	2,104	2,104	2,478	4,582	4,582	-	
Services	-	3,784	3,784	-	1,104	1,104	2,680	3,784	3,784	-	
Street Lighting	-	2,245	2,245	-	628	628	1,617	2,245	2,245	-	
Transformers	-	5,759	5,759	-	2,226	2,226	3,533	5,759	5,759	-	
Reconstruction	-	4,599	4,599	-	1,797	1,797	2,802	4,599	4,599	-	
Rebuild Distribution Lines	-	3,694	3,694	-	1,001	1,001	2,693	3,694	3,694	-	
Relocate/Rebuild Distribution Lines for Third Parties	-	2,454	2,454	-	739	739	1,590	2,329	2,329	(125)	
Trunk Feeders	-	1,607	1,607	-	104	104	1,503	1,607	1,607	-	
Feeder Additions for Growth	-	1,708	1,708	-	61	61	1,647	1,708	1,708	-	
Distribution Reliability Initiative	-	1,463	1,463	-	18	18	1,320	1,338	1,338	(125)	
Distribution Feeder Automation	-	565	565	-	12	12	553	565	565	-	
St. John's Main Underground Refurbishment	-	1,950	1,950	-	67	67	1,883	1,950	1,950	-	
Allowance for Funds Used During Construction	-	206	206	-	73	73	133	206	206	-	
		-									
	$ -	$ 45,055	$ 45,055	$ -	$ 13,970	$ 13,970	$ 31,085	$ 45,055	$ 45,055	$ -	
2015 Projects											
Trunk Feeders	$ 991	$ -	$ 991	$ 683	$ -	$ 683	$ 308	308	$ 991	$ -	
Total - Substations	**991**	**45,055**	**46,046**	**683**	**13,970**	**14,653**	**31,393**	**45,363**	**46,046**	**-**	

* See Appendix A for notes containing variance explanations.

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2016 Capital Expenditure Status Report
(000s)

Category: General Property

Project	Capital Budget 2015	Capital Budget 2016	Capital Budget Total	Actual Expenditures 2015	Actual Expenditures 2016	Actual Expenditures Total To Date	Forecast Remainder 2016	Forecast Total 2016	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2016 Projects											
Tools and Equipment	$ -	$ 682	$ 682	$ -	$ 118	$ 118	$ 564	$ 682	$ 682	$ -	
Additions to Real Property	-	434	434	-	31	31	403	434	434	-	
Company Buildings Renovations	-	724	724	-	540	540	184	724	724	-	
	$ -	**$ 1,840**	**$ 1,840**	**$ -**	**$ 689**	**$ 689**	**$ 1,151**	**$ 1,840**	**$ 1,840**	**$ -**	
2015 Projects											
Company Buildings Renovations	$ 2,068	$ -	$ 2,068	$ 1,049	$ 1,010	$ 2,059	$ 8	$ 1,018	$ 2,067	$ (1)	
Total - General Property	**$ 2,068**	**$ 1,840**	**$ 3,908**	**$ 1,049**	**$ 1,699**	**$ 2,748**	**$ 1,159**	**$ 2,858**	**$ 3,907**	**$ (1)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2015
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2016 Capital Expenditure Status Report
(000s)

Category: Transportation

Project	Capital Budget 2016	Capital Budget Total	Actual Expenditures 2016	Actual Expenditures Total To Date	Forecast Remainder 2016	Forecast Total 2016	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2016 Projects									
Purchase Vehicles and Aerial Devices	$ 3,258	$ 3,258	$ 1,014	$ 1,014	$ 2,244	$ 3,258	$ 3,258	$ -	
Total - Transportation	**$ 3,258**	**$ 3,258**	**$ 1,014**	**$ 1,014**	**$ 2,244**	**$ 3,258**	**$ 3,258**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2016
Column B	Total of Column A
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Column H	Column G less Column B

2016 Capital Expenditure Status Report
(000s)

Category: Telecommunications

	Capital Budget		Actual Expenditures		Forecast				
Project	**2016**	**Total**	**2016**	**Total To Date**	**Remainder 2016**	**Total 2016**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2016 Projects									
Replace/Upgrade Communications Equipment	$ 105	$ 105	$ -	$ -	$ 105	$ 105	$ 105	$ -	
Fibre Optic Network	409	409	-	-	314	314	314	(95)	
Total - Telecommunications	**$ 514**	**$ 514**	**$ -**	**$ -**	**$ 419**	**$ 419**	**$ 419**	**$ (95)**	

* See Appendix A for notes containing variance explanations.

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Column E	Forecast for Remainder of 2016
Column F	Total of Columns C and E
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2016 Capital Expenditure Status Report
(000s)

Category: Information Systems

Project	Capital Budget 2015 A	Capital Budget 2016 B	Capital Budget Total C	Actual Expenditures 2015 D	Actual Expenditures 2016 E	Actual Expenditures Total To Date F	Forecast Remainder 2016 G	Forecast Total 2016 H	Forecast Overall Total I	Variance J	Notes*
2016 Projects											
Application Enhancements	$ -	$ 1,143	$ 1,143	$ -	$ 344	$ 344	$ 799	$ 1,143	$ 1,143	$ -	
System Upgrades	-	1,718	1,718	-	215	215	1,503	1,718	1,718	-	
Personal Computer Infrastructure	-	465	465	-	137	137	328	465	465	-	
Shared Server Infrastructure	-	916	916	-	280	280	636	916	916	-	
Network Infrastructure	-	294	294	-	143	143	151	294	294	-	
SCADA System Replacement	-	2,842	2,842	-	-	-	2,842	2,842	2,842	-	
Geographic Information System Improvement	-	482	482	-	143	143	339	482	482	-	
Outage Management System Replacement	-	149	149	-	17	17	132	149	149	-	
Total	**$ -**	**$ 8,009**	**$ 8,009**	**$ -**	**$ 1,279**	**$ 1,279**	**$ 6,730**	**$ 8,009**	**$ 8,009**	**$ -**	
2015 Projects											
SCADA System Replacement	$ 2,833	$ -	$ 2,833	$ 1,620	$ 1,206	$ 2,826	$ 1,250	$ 2,456	$ 4,076	$ 1,243	
Total - Information Systems	**$ 2,833**	**$ 8,009**	**$ 10,842**	**$ 1,620**	**$ 2,485**	**$ 4,105**	**$ 7,980**	**$ 10,465**	**$ 12,085**	**$ 1,243**	

* See Appendix A for notes containing variance explanations.

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2016 Capital Expenditure Status Report
(000s)

Category: Unforeseen Allowance

	Capital Budget		Actual Expenditures		Forecast				
Project	**2016**	**Total**	**2016**	**Total To Date**	**Remainder 2016**	**Total 2016**	**Overall Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2016 Projects									
Allowance for Unforeseen Items	$ 750	$ 750	$ -	$ -	$ 750	$ 750	$ 750	$ -	
Total - Unforeseen Items	**$ 750**	**$ 750**	**$ -**	**$ -**	**$ 750**	**$ 750**	**$ 750**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2016
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2016 Capital Expenditure Status Report
(000s)

Category: General Expenses Capitalized

	Capital Budget		Actual Expenditures		Forecast				
Project	**2016**	**Total**	**2016**	**Total To Date**	**Remainder 2016**	**Total 2016**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2016 Projects									
General Expenses Capitalized	$ 4,500	$ 4,500	$ 1,545	$ 1,545	$ 2,655	$ 4,200	$ 4,200	$ (300)	
Total - General Expenses Capitalized	**$ 4,500**	**$ 4,500**	**$ 1,545**	**$ 1,545**	**$ 2,655**	**$ 4,200**	**$ 4,200**	**$ (300)**	

* See Appendix A for notes containing variance explanations.

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Column A	Approved Capital Budget for 2016
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Generation - Hydro

1. *Rattling Brook Fisheries Compensation (2012 Project):*

Budget: $5,000 Forecast: $3,126 Variance: ($1,874)

In 2010, the Company received an order from Department of Fisheries and Oceans stating that, pursuant to section 20 of the Fisheries Act, fish passage must be in place on Rattling Brook to allow downstream migration of salmon kelts and smolts by May 1, 2013 and the upstream migration of grilse and adult salmon by June 2014.

The implementation plan as proposed in the 2012 Capital Budget Application involved completing all construction work in 2012. Subsequent to the project being approved, the Company engaged the necessary technical expertise to execute the project. As a result of this technical work, it was determined that the work should take place over a 5-year period from 2012 to 2016. The extended implementation period allows in-stream structures to be adapted to make them more suitable to migrating salmon. A decision will be made later in year as to where additional expenditure is required.

Substations

2. *Additions Due to In-Service Failures:*
Budget: $3,771 Forecast: $3,371 Variance: ($400)

The *Replacement Due to In-Service Failures* project involves expenditures needed to respond to individual in-service failure of substation equipment. The budget estimate is based on an assessment of historical expenditures. Year to date expenditures are below historical averages.

2017 Facility Rehabilitation

July 2016

Prepared by:

David Ball, P. Eng.

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21 JUNE 2016
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

The 2017 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.

Newfoundland Power (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 for 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 438.4 GWh.[1] The alternative to maintaining these facilities is to retire them.

The 2017 Facility Rehabilitation project totalling $1,607,000 is comprised of Hydro Dam and Spillway Rehabilitation and Generation Equipment Replacements Due to In-Service Failures.

2.0 Hydro Dam and Spillway Rehabilitation

Cost: $1,055,000

The Company has over 150 dam structures throughout its 23 hydroelectric facilities. Based on the age of structures in the Newfoundland Power system, deterioration of earth filled, timber crib 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.[2] The cost of the projects is justified based on the need to restore the structures to an appropriate safety level based on the current site 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.

Specific work to be completed in 2017 includes:

1. *Frozen Ocean Outlet and Spillway ($412,000)*
   The Frozen Ocean Outlet and Spillway were re-constructed in 1988 and are part of the Rattling Brook hydro development. Since that time, only minor upgrades have been completed to the structure. This project involves replacement of the timber

[1] Normal annual production was established as 438.4 GWh in Newfoundland Power's Normal Hydroelectric Production for 2016 in a letter dated February 26, 2016.

[2] The guidelines established by the Canadian Dam Association ("CDA") applicable to the Hydro Dam Rehabilitation projects are *CDA Dam Safety Guidelines 2007 (2013 Edition)*, *Dam Safety Guidelines 2007 Technical Bulletins* and *Guidelines for Public Safety Around Dams 2011*. Copies of these guidelines can be ordered online from www.cda.ca.

outlet structure and gate, refurbishment of the steel spillway core and localized refurbishment of the spillway riprap.[3]

The timber gate structure has deteriorated timbers, particularly near the waterline. The control gate is inoperable in winter as the current design is susceptible to icing. Employee safety improvements are required on the outlet structure to meet provincial occupational health and safety regulations. The existing safety railing was constructed without a toe board and does not fully extend along the structure's length as seen in Figure 1 and 2. Replacement of the outlet structure is required to guarantee the integrity and operability of the structure and improve employee safety.

As seen in Figures 3 and 4, the top of the 50m long steel spillway core is in poor condition and over time has shifted as it is now misaligned and no longer level. Refurbishment and reinforcement of the spillway core is required to ensure the long term stability of the structure. The riprap has migrated in places and requires localized refurbishment to maintain adequate erosion protection for the structure.

The refurbishment work will involve the removal of the existing riprap, realignment of the steel core, installation of a steel reinforcing cap and the reinstatement of the riprap covering.

Figure 1 – Outlet Structure (Upstream)

Figure 2 – Outlet Structure (Downstream)

[3] Riprap is a layer of rock placed on the face of an embankment dam to prevent erosion from currents or waves.

Figure 3 – Frozen Ocean Spillway

Figure 4 – Steel Spillway Core

2. *West Brook Forebay Dam and Spillway Refurbishment ($314,000)*
   The West Brook Forebay is the only storage reservoir in the West Brook Hydroelectric Development. The West Brook Forebay Spillway is approximately 79m long and is constructed from concrete topped with 2-150mm flashboards. The project involves refurbishment and extension of the Spillway.

   The stop logs on the spillway structure are deteriorated and the anchorages have begun to fail when subjected to the forces from significant water spill and ice flows. The displacement of the flashboards can be seen in Figures 5 and 6. The loss of any stop logs section or sections result in lower plant efficiency due to increased water spill, reduced storage capacity and lower forebay operating elevations. The underlying concrete is in good condition with the exception of the crest, which is exhibiting some deterioration. The deterioration can be observed in Figure 6 in the form of erosion. Replacement of the flashboards and refurbishment of the concrete spillway surface is required at this time.

   The spillway capacity is inadequate to prevent overtopping of the adjacent power canal embankment. A reconfiguration of the North spillway abutment will allow sufficient flow to prevent overtopping.[4] Employee safety improvements are also required on the structure to meet provincial occupational health and safety regulations.

[4] Extension of the spillway is more economical than raising the height of the 1.2km long power canal.

Figure 5 – Forebay Spillway

Figure 6 – Forebay Spillway Flash Boards

3. *Three Arm Pond Dam Refurbishment ($329,000)*
   Three Arm Pond Dam is a 51m long timber crib dam within the Topsail Hydro Electric Development. The structure includes a control gate and 12m long spillway. Figure 7 and Figure 8 provide a view of the general arrangement. This project involves replacement of the complete timber crib structure.

   Inspections have determined the timbers along the structure are deteriorated near the waterline from exposure to ice and water as seen in Figure 10. Operation of the gate is becoming increasingly difficult due to binding caused by settlement of the timber support structure. The timber gate is deteriorated and is no longer adequately sealed. The deteriorated lower portion of the gate is visible on Figure 9. Finally, hydraulic analysis indicates that the dam will overtop during the design conditions, which would result in erosion of the downstream ballast, impacting structural stability.

Due to the condition of the structure and the modifications required to adequately meet design guidelines, replacement of the entire structure is the required.

Figure 7 – Three Arm Pond Dam

Figure 8 – Spillway

Figure 9 – Deteriorated Gate

Figure 10 – Deteriorated Timbers

3.0 Generation Equipment Replacements Due to In-Service Failures

Cost: $552,000

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

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

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

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

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

Table 1 shows the expenditures for replacements due to in-service failures since 2012.

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

Year	**2012**	**2013**	**2014**	**2015**	**2016F**
Total	$523	$399	$590	$524	$539

Based upon this recent historical information and engineering judgement, $552,000 is estimated to be required in 2017 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 Concluding

This project, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable generating plant operations. A 2017 budget of $1,607,000 for Facility Rehabilitation is recommended as follows:

- $1,055,000 for Hydro Dam and Spillway Rehabilitation; and
- $552,000 for Generation Equipment Replacements Due to In-Service Failures;

Public Safety Around Dams

July 2016

Prepared by:

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June 28/2016
DATE
PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

In the 2015 Capital Budget Application, Newfoundland Power (the "Company") outlined plans to address public safety deficiencies throughout its various hydroelectric developments over a 3-year period from 2015-2017.[1] It was estimated that expenditures of approximately $2.0 million will be necessary to implement public safety improvements at the Company's hydroelectric developments over this period.

Continuing with year 3 of the 3-year plan, the Company has completed detailed public safety assessments, consistent with the Canadian Dam Association ("CDA") *Guidelines for Public Safety Around Dams 2011* (the "Guidelines") for the remaining 9 hydroelectric developments to be included in the 2017 Capital Budget.[2] The 2017 expenditures associated with the public safety improvements identified through the assessments total $662,000.

2.0 2017 Project Description

For 2017 the Company has identified 9 hydroelectric developments where public safety projects will take place. Assessments have been completed for Lawn, West Brook, Fall Pond, Lockston, Port Union, Rattling Brook, Sandy Brook, Lookout Brook and Rose Blanche hydroelectric developments.[3]

A number of safety hazards were found to exist at dams, intakes and other infrastructure located within the developments reviewed. Based on the level of activity and site particulars, varying levels of treatment have been recommended. The minimum treatment to be implemented involves signage with text viewable from outside of the hazardous area; additional treatments such as warning buoys, safety booms, railing and fencing are also required.

The assessments identified approximately 84 small items requiring attention with many of these items relating to deficiencies in signage. The types of projects by development are identified in the subsequent sections. The projects to be completed in 2017 include:

(i) Warning buoys at 10 sites
(ii) Fencing additions and modifications at 17 sites
(iii) Signage improvements at all sites
(iv) Audible alarms at tailraces frequented by the public

[1] The first 2 years of the program consisted of 14 assessments and associated public safety improvements that were approved in Order No. P.U. 40(2014) and Order No. P.U. 28 (2015)

[2] These guidelines are in addition to the *CDA Dam Safety Guidelines 2007*. Copies of these guidelines can be ordered online from www.cda.ca.

[3] Developments to be assessed in 2017 were grouped geographically for efficiency in both assessment and construction.

2.1 Lawn Development

Lawn Development is located on the southern part of the Burin Peninsula near the community of Lawn. The development was constructed in 1927 and has a capacity of 625 kW under a net head of about 20 m. The development consists of one generating unit in a wood frame construction powerhouse supplied by a wood stave penstock extending from the forebay dam. A concrete storage dam and spillway are located at the forebay which is the only reservoir in this development.

Figure 1 shows the locations of the dam and control structures that form the Lawn development.

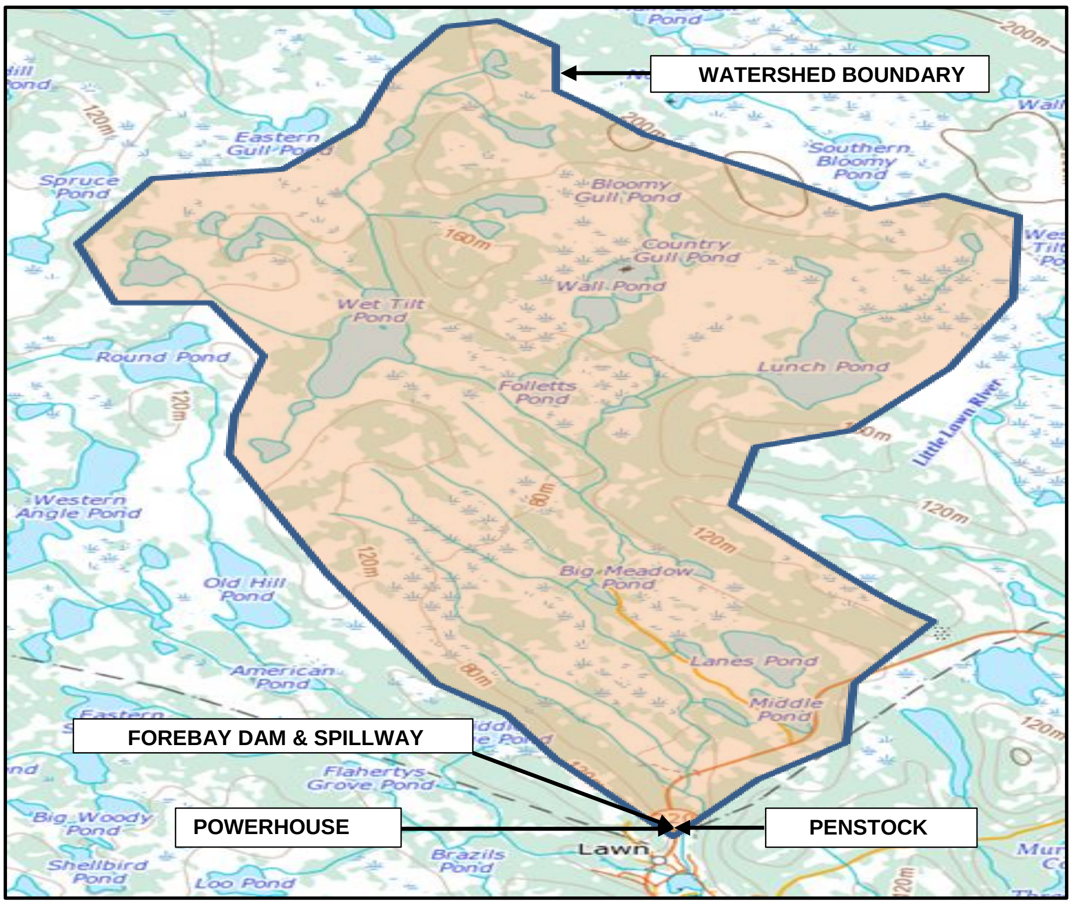

Figure 1 – Lawn Hydroelectric Development

Lawn Plant and Associated Infrastructure

The powerhouse is 19.5 m x 6.3 m x 3.6 m high and consists of reinforced concrete foundation with wood frame wall and roof construction and metal exterior cladding. The generator is supplied from the intake by a 300 m long wood stave penstock. There is a 15 m tailrace that runs into St. Lawrence harbour.

Lawn Forebay Dam & Spillway
The forebay dam was originally constructed using rock fill, but in 1937 it was given a concrete base and concrete was placed along the sides, upstream and downstream, encasing the rockfill compartments. In 1948, The dam was refaced with concrete on the downstream surface and in 1983 an application of mesh reinforced shotcrete was applied. Fencing was installed at the dam abutments in conjunction with dam repairs after tropical storm Igor in 2010. The dam has a crest length of 50 m and a maximum height of 9.0 m. It has a concrete intake and sluice gate. The spillway is a shallow concrete weir with a crest length of 53.0 m

Required Treatments
Fencing is required along the spillway channel, tailrace channel, forebay dam crest and to extend existing fencing at the dam abutments. Marker buoys are required at the intake. Improvements are required for the wooden bridge crossing the penstock. Signage conforming to the Guidelines is required at all sites within the Lawn Development.

Public safety treatments identified for the Lawn Development are listed in Table 1 below.

Table 1
Public Safety Treatments
Lawn Development

Site	Signage	Buoys[4]	Fencing[5]	Other[6]
Lawn Tailrace	×		×	×
Lawn Forebay	×	×	×	
Lawn Penstock				×

2.2 West Brook Development

West Brook Development is located on the southern part of the Burin Peninsula near the community of St. Lawrence. The development was constructed in 1942 and has a capacity of 700 kW under a net head of 47 m. The development consists of one generating unit in a reinforced concrete powerhouse supplied by a buried fiberglass penstock extending from an intake located at the east end of the power canal. A concrete storage dam and spillway are located at the canal inlet.

4 Buoys include treatments involving marker buoys and larger booms to restrict access by recreational boaters and swimmers to hazardous areas.
5 Fencing includes treatments involving new and refurbishment of existing fences, gates and other barriers to restrict access by pedestrians to hazardous areas.
6 Railing improvements include penstock bridge and adding toe boards to existing railing.

Figure 2 shows the locations of the dam and control structures that form the West Brook development.

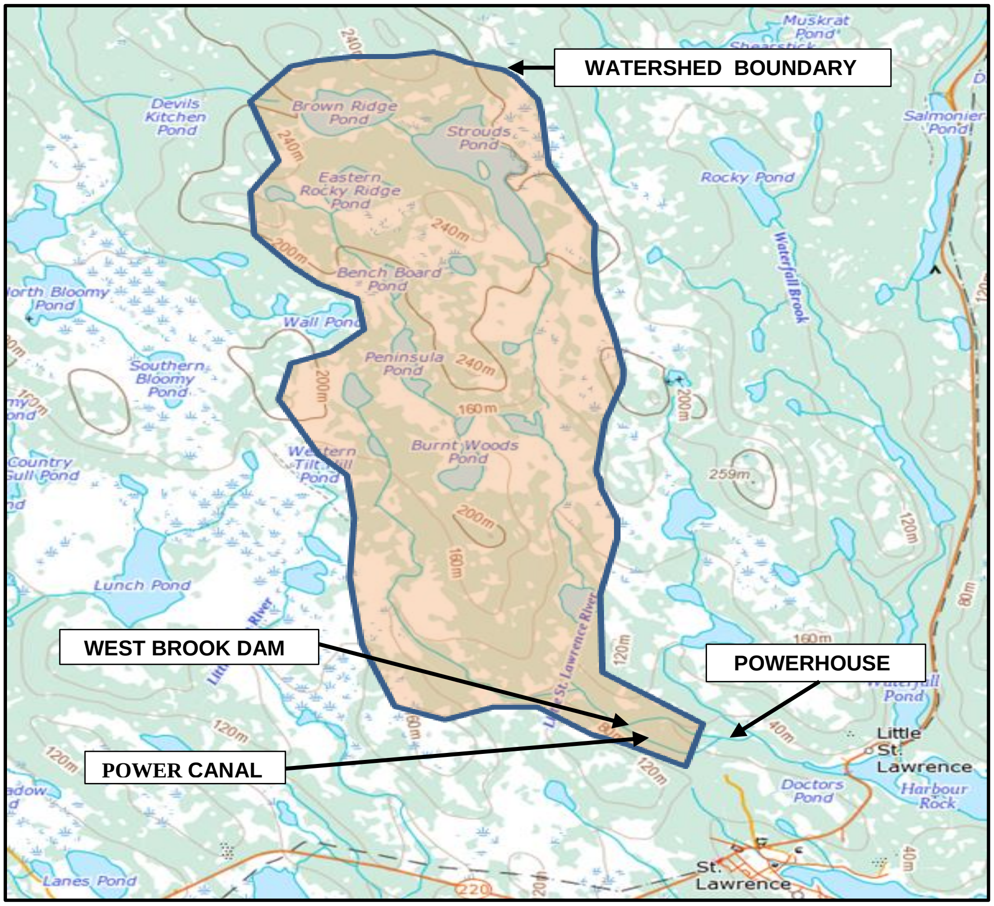

Figure 2 – West Brook Hydroelectric Development

West Brook Plant and Associated Infrastructure
The powerhouse is 8.2 m x 6.5 m x 4.0 m high and constructed using reinforced concrete with a wood frame roof. The generator is supplied from the intake by a buried 536 m long fiberglass penstock. The plant has a tailrace channel 45 m long which extends from the powerhouse to the St. Lawrence River.

West Brook Forebay Dam, Spillway and Power Canal
The forebay dam is a 25.7 m long reinforced concrete arch dam with a maximum height of 6.8m. There is a 4.9 m long auxiliary spillway integrated into the forebay dam. The main spillway is adjacent to the forebay dam and is made of reinforced concrete construction with a crest length of 79.3 m and a maximum height of 6.0 m.

A concrete intake canal forms the transition from the forebay to an earth embankment canal which meanders 1250 m to a reinforced concrete intake structure. The intake structure consists of a small concrete overflow spillway, concrete intake with wing walls and a wooden gate house.

Required Treatments
Fencing is required at the forebay spillway abutment, intake structure and tailrace. Railing improvements are required at the forebay dam and spillway. Signage conforming to the Guidelines is required at all sites.

Public safety treatments identified for the West Brook Development are listed in Table 2 below.

Table 2
Public Safety Treatments
West Brook Development

Site	Signage	Buoys	Fencing[7]	Other[8]
West Brook Plant	×		×	
West Brook Canal	×		×	
West Brook Forebay	×		×	×

2.3 Fall Pond Development

Fall Pond Development is located on the southern part of the Burin Peninsula in the community of Little St. Lawrence. The development was commissioned in the 1920's and has a capacity of 350 kW under a net head of 15 m. The development consists of one generating unit in a wood frame construction powerhouse supplied by a short steel penstock extending from the forebay dam. A concrete storage dam and spillway is located at the forebay which is the only reservoir in this development.

7 Fencing includes treatments involving new and refurbishment of existing fences, gates and other barriers to restrict access by pedestrians to hazardous areas.
8 Railing Improvements include penstock bridge and adding toe boards to existing railing.

Figure 3 shows the locations of the dam and control structures that form the Fall Pond development.

Figure 3 – Fall Pond Hydroelectric Development

Fall Pond Plant and Associated Infrastructure
The powerhouse is 10.0 m x 8.0 m x 4.0 m high and consists of reinforced concrete construction and wood frame roof. The generator is supplied from the intake by 13.0 m long steel penstock. There is a 30 m tailrace that runs into Little St. Lawrence harbour.

Fall Pond Forebay Dam & Spillway
The forebay structure is a reinforced concrete buttress Ambersen dam built in 1942 with a crest length of 54.7 m and a maximum height of 10.8 m. The dam incorporates a reinforced concrete intake structure and a spillway with a crest length of 32.6 m with a maximum height of 9.0 m at the left abutment. There is also a sluice gate located at the left abutment.

Required Treatments
Fencing improvements are required at the dam, spillway, tailrace and plant steps. Marker buoys are required at the intake and spillway. Signage conforming to the Guidelines is required at all sites.

Public safety treatments identified for the Fall Pond Development are listed in Table 3 below.

Table 3
Public Safety Treatments
Fall Pond Development

Site	Signage	Buoys[9]	Fencing[10]	Other[11]
Fall Pond Plant Steps	×		×	×
Fall Pond Forebay	×	×	×	×
Fall Pond Tailrace	×		×	

2.4 Lockston Development

Lockston Development is located on the Bonavista Peninsula along Route 230 approximately 60 km northeast of Clarenville. It was commissioned in 1956 and has a capacity of 3000 kW with a net head of 79 m. The powerhouse is of concrete construction with a steel frame extension added in 2012. The generating unit is supplied by a steel penstock extending from the intake located at the south end of the power canal. The system consists of two reservoirs; Rattling Pond and Trinity Pond. Rattling Pond serves as the headpond and Trinity Pond is the primary reservoir and controls inflows to Rattling Pond. A power canal, cut into rock with low level concrete walls, extends 564 m from Rattling Pond to a concrete intake structure.

[9] Buoys include treatments involving marker buoys and larger booms to restrict access by recreational boaters and swimmers to hazardous areas.
[10] Fencing includes treatments involving new and refurbishment of existing fences, gates and other barriers to restrict access by pedestrians to hazardous areas.
[11] Other includes railing treatments involving new installation and adding toe boards to existing railing.

Figure 4 shows the locations of the various dams and control structures that form the Lockston development.

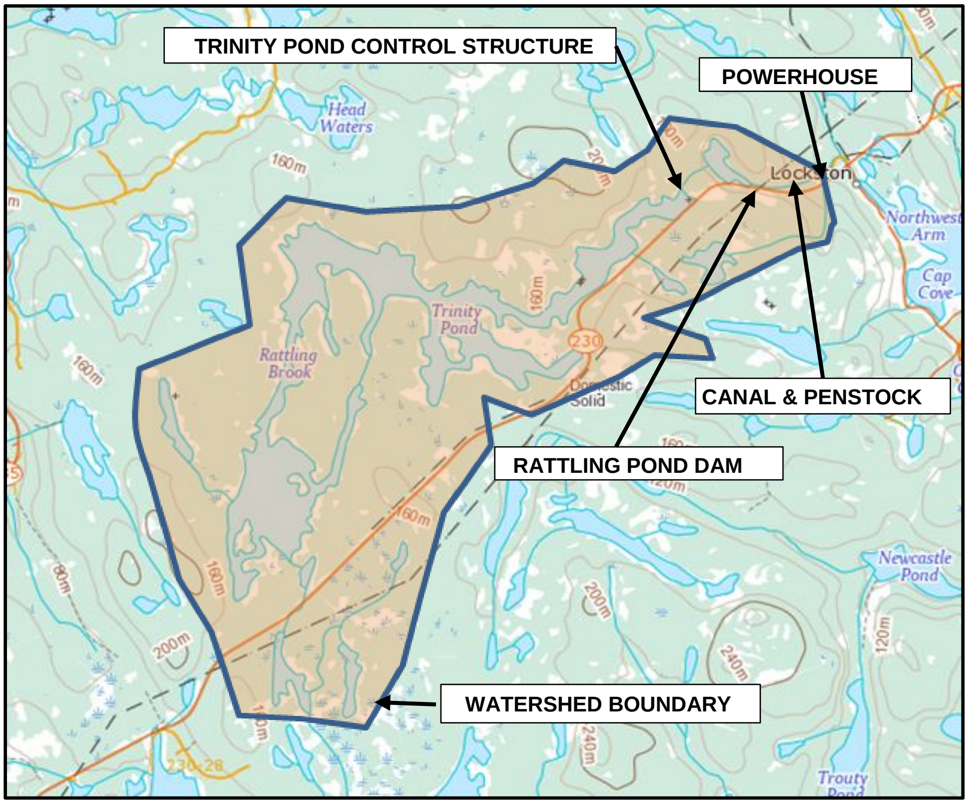

Figure 4 – Lockston Hydroelectric Development

Lockston Plant and Associated Infrastructure
Lockston Plant is fed from a 608 m long steel penstock extending from the intake which is located at the east end of a 560 m long, 4.0 m high embankment canal flowing from Rattling Pond. The plant has a 420 m tailrace channel extending to an existing waterbody.

Rattling Pond and Associated Infrastructure
Rattling Pond has several structures. The Forebay Dam is a 23.4 m long, 2.6 m high concrete structure with a 15.1 m long, 1.0 m high concrete gravity spillway remote from the dam. The power canal inlet, adjacent to the dam, is a 7.5 m long, 4.2 m high concrete structure with a screw stem gate. The power canal extends 564 m from Rattling Pond to a concrete intake structure.

Trinity Pond
A concrete buttress control structure is located in a narrow rock cut on Trinity Pond. The structure is 6.8 m long and 11 m high with a wood frame gatehouse and motorized screw stem gate.

Copley's Pond
The dam is an earthfill dam with riprap along the upstream slope. It is the original railway track bed with a culvert that was plugged to form the dam. This is a very low dam with a head differential of less than 1 m.

Required Treatments
Railing improvements are required at the Trinity Pond outlet and Rattling Pond forebay and fencing is required at the tailrace, power canal and forebay. Signage conforming to the Guidelines is required at all sites except Copley's Pond.

Public safety treatments identified for the Lockston Development are listed in Table 4 below:

Table 4
Public Safety Treatments
Lockston Development

Site	Signage	Buoys	Fencing[12]	Other[13]
Lockston Tailrace	×		×	
Power Canal	×		×	
Rattling Pond (Forebay)	×		×	×
Trinity Pond	×			×
Copley's Pond	×			

2.5 Port Union Development

Port Union development is located on the Bonavista Peninsula near the community of Port Union. It was commissioned in 1917 and has a capacity of 500 kW under a net head of 21.3 m. The Powerhouse is of wood frame construction with a concrete foundation housing two generating units supplied by a 118 m long wood stave penstock, which is 1.8 m in diameter and extends from the embankment canal intake structure. The development has a forebay reservoir at Second Storage Pond that flows to the embankment canal and concrete intake structure. There are larger controlled reservoirs up stream at Whirl Pond and Long Pond.

12 Fencing includes treatments involving new and refurbishment of existing fences, gates and other barriers to restrict access by pedestrians to hazardous areas.
13 Other includes railing treatments involving new installation and adding toe boards to existing railing.

Figure 5 shows the locations of the various dams and control structures that form the Port Union development.

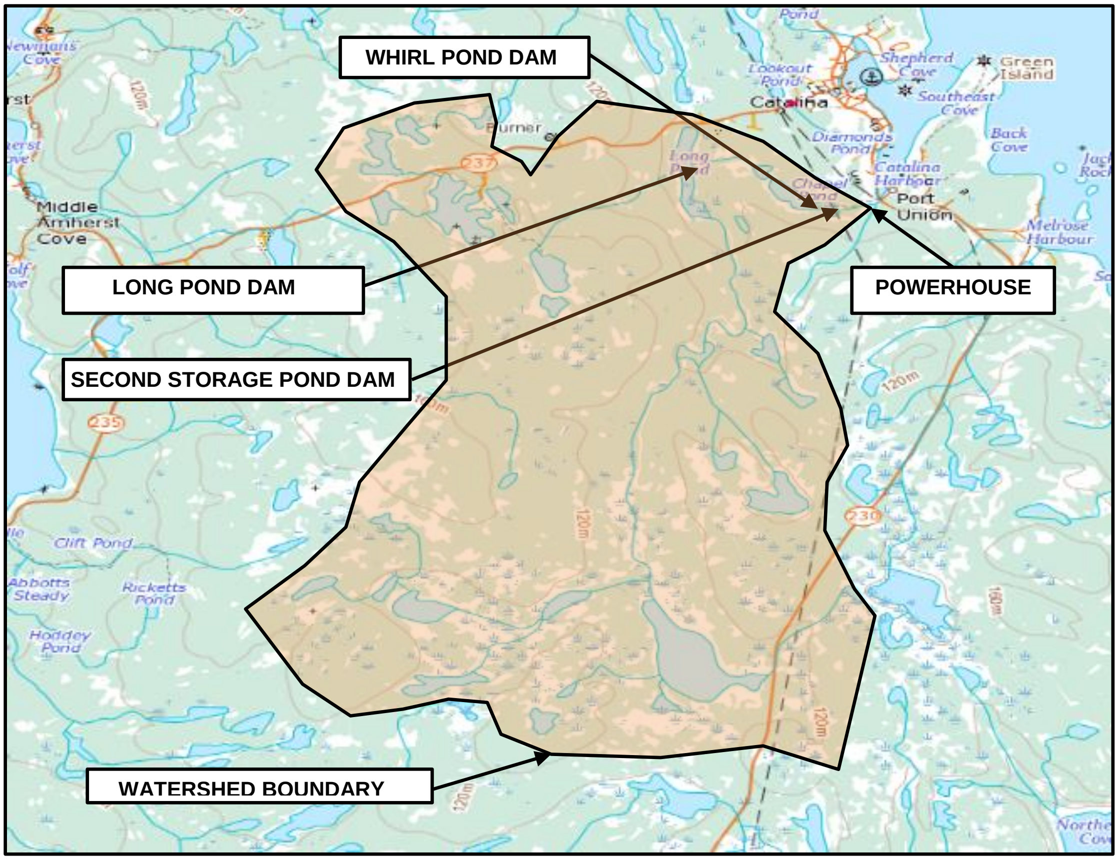

Figure 5 – Port Union Hydroelectric Development

Port Union Plant and Associated Infrastructure

Port Union Plant is fed from a 118 m long wood stave penstock extending from the intake which is located at the east end of a 560 m long, 4.0 m high embankment canal flowing from Second Storage Pond. The plant has an 8.0 m tailrace channel extending to the spillway channel.

Second Storage Pond (forebay) Dam and Spillway

The Dam and Spillway is a rock fill dam 43.5 m long and less than 3.0 m high with a wooden upstream slope and wooden deck along the crest. There is a remnant sluice embedded in the dam that has been plugged and has no discharge capacity.

Whirl Pond

Whirl Pond Dam, 65 m long and 4 m high, was reconstructed in 2008 and consists of an embankment dam with a steel core and reinforced concrete outlet structure with screw lift stem gate. The dam crest was raised during repairs after tropical storm Igor in 2010. A separate concrete gravity spillway structure, which incorporates fish passage, is 70 m long and less than 2 m high. There were three freeboard embankment dykes constructed in 2000 which are 100 m in combined length. The dyke crests were raised during repairs after tropical storm Igor.

Long Pond

The dam and spillway structure is of reinforced concrete construction consisting of two dam sections 20 m in total length and 6.0 m high with a control structure at the left abutment. A spillway 17.0 m long and 4.0 m high extends between the outlet and right abutment.

Required Treatments

Fencing is required along the Long Pond spill channel and dam abutment,Whirl Pond outlet, power canal at the intake and Second Storage Pond Dam abutments. Signage conforming to the Guidelines is required at all sites.

Public safety treatments identified for the Port Union Development are listed in Table 5 below:

Table 5
Public Safety Treatments
Port Union Development

Site	Signage	Buoys	Fencing[14]	Other
Port Union Plant	×			
Embankment Canal	×		×	
Second Storage Pond (forebay)	×		×	
Whirl Pond	×		×	
Dykes 1-3	×			
Long Pond	×		×	

2.6 Rattling Brook Development

Rattling Brook development is located in central Newfoundland near the community of Norris Arm. It was constructed in 1958 and has a capacity of 15 MW under a net head of 100 m. The Powerhouse has two generating turbines supplied by a 1,995 m long steel penstock 2.9 m in diameter. The building is of steel frame construction with a concrete foundation. The development has a forebay reservoir at Rattling Brook with larger controlled reservoirs upstream at Rattling Lake, Amy's Lake and Frozen Ocean Lake.

[14] Fencing includes treatments involving new and refurbishment of existing fences, gates and other barriers to restrict access by pedestrians to hazardous areas.

Figure 6 shows the locations of the various dams and control structures that form the Rattling Brook development.

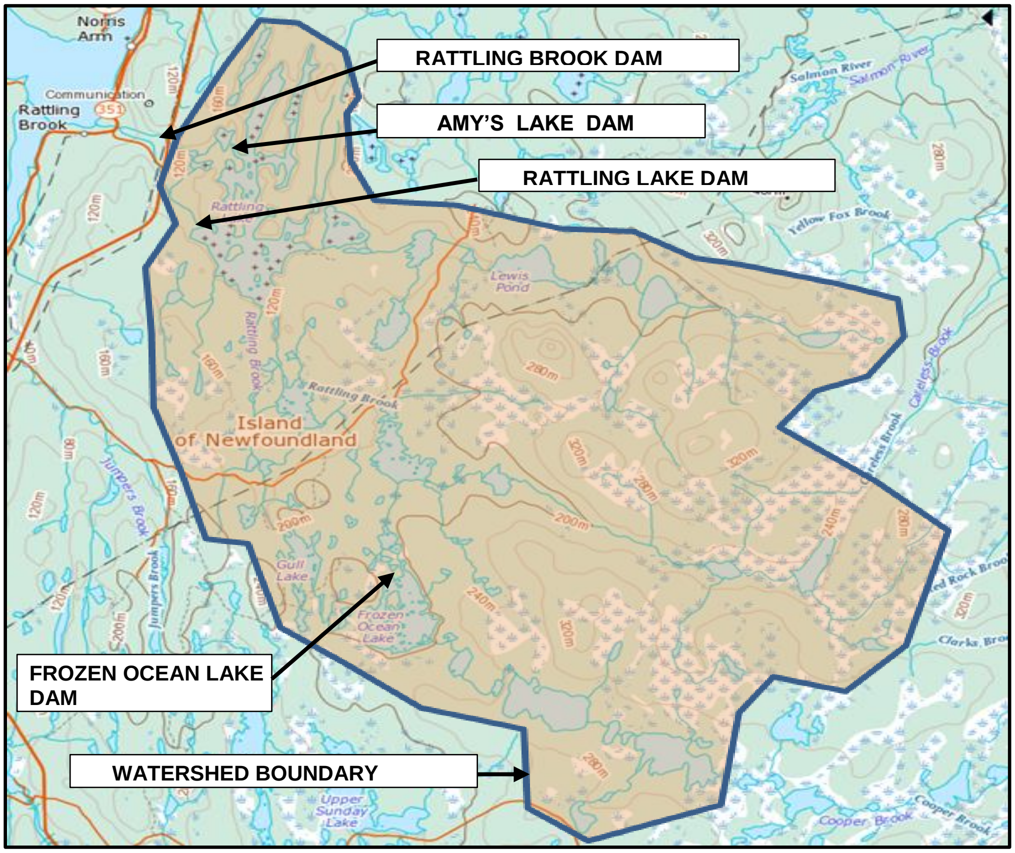

Figure 6 – Rattling Brook Hydroelectric Development

Rattling Brook Plant and Associated Infrastructure
The Rattling Brook Powerhouse is supplied from the intake at Rattling Brook by a 1,995 m long steel penstock with a 94.0 m high steel surge tank located 300 m upstream from the powerhouse. A 850 m tailrace runs from the plant to the shoreline of Norris Arm.

Rattling Brook (forebay)
The structures at the forebay consist of the Rattling Brook Dam and Spillway. The dam is a 122 m long, 10.7 m high earthfill structure with a concrete intake and wood frame gatehouse. The spillway is a 38.55 m long, rockfill overflow structure with sheet metal core. There is a concrete fish by-pass structure located in the reservoir 100 m up stream of the spillway with the outlet located at the toe of the spillway.

Rattling Lake
The structures at Rattling Lake consist of the Rattling Lake Dam and Spillway. The dam consists of three embankment dams in series with relatively steep downstream slopes and riprap along the upstream face. Each dam is approximately 200-300 m in length and 10.7 m high. The spillway, which is 105 m long and 3.0 m high, consists of a reinforced concrete piano key weir structure on a reinforced concrete slab and reinforced concrete wing walls at the abutments.

Amy's Lake
The structures at Amy's Lake consist of a control dam, outlet structure, fish by-pass structure and 3 freeboard dykes. The Amy's control dam is an earthfill structure, approximately 200 m long and 10.7 m high, with relatively steep downstream slope and riprap along the upstream face. The outlet structure regulates flows to the outlet channel through a reinforced concrete box culvert with a submerged, vertical lift screw stem type gate. The fish by-pass is a reinforced concrete structure with wood frame building which houses water flow & fish monitoring equipment and is located next to the control structure. Flows are discharged into the outlet channel through two plastic culverts and regulated using removeable upstream aluminum stop logs. The freeboard dykes are embankment type structures with riprap along the upstream slope. Each freeboard dyke is 25-75 m in length and 2.5-3.5 m high.

Frozen Ocean Pond
The structures at Frozen Ocean Pond consist of the Frozen Ocean Pond Dam, Spillway and outlet. The dam is an embankment structure 450 m long and 3.0 m high. It has a timber crib outlet structure with a vertical lift screw stem timber gate located at center. The spillway is a rockfill, overflow structure 50.0 m long and 2.4 m high with a steel core.

Required Treatments
Fencing is required at Amy's intake and fish by-pass and Frozen Ocean Lake outlet structure. A buoy is required at the Rattling Brook forebay intake structure and Amy's Lake intake structure. An audible alarm will be installed at Rattling Brook Plant to warn the public that the plant is about to start. Signage conforming to the Guidelines is required at all sites.

Public safety treatments identified for the Rattling Brook Development are listed in Table 6 below.

Table 6
Public Safety Treatments
Rattling Brook Development

Site	Signage	Buoys[15]	Fencing[16]	Other[17]
Rattling Brook Plant	×			×
Rattling Brook (forebay)	×	×		
Rattling Lake	×			
Amy's Lake	×	×	×	
Frozen Ocean Lake	×		×	

[15] Buoys include treatments involving marker buoys and larger booms to restrict access by recreational boaters and swimmers to hazardous areas.
[16] Fencing includes treatments involving new and refurbishment of existing fences, gates and other barriers to restrict access by pedestrians to hazardous areas.
[17] An audible alarm is planned for Rattling Brook tailrace.

2.7 Sandy Brook Development

Sandy Brook development is located in central Newfoundland near the community of Grand Falls. It was constructed in 1963 and has a capacity of 7.0 MW under a net head of 30 m. The Powerhouse has a single generating unit supplied by a 260 m long steel penstock 2.8 m in diameter extending from the forebay and a steel surge tank 20 m high. The building is steel frame construction with a concrete foundation. The development has a forebay reservoir at Sandy Brook with larger controlled reservoirs upstream at West Lake, and Sandy Lake Flow from the reservoir at Island Pond is uncontrolled.

Figure 7 shows the locations of the various dams and control structures that form the Sandy Brook development.

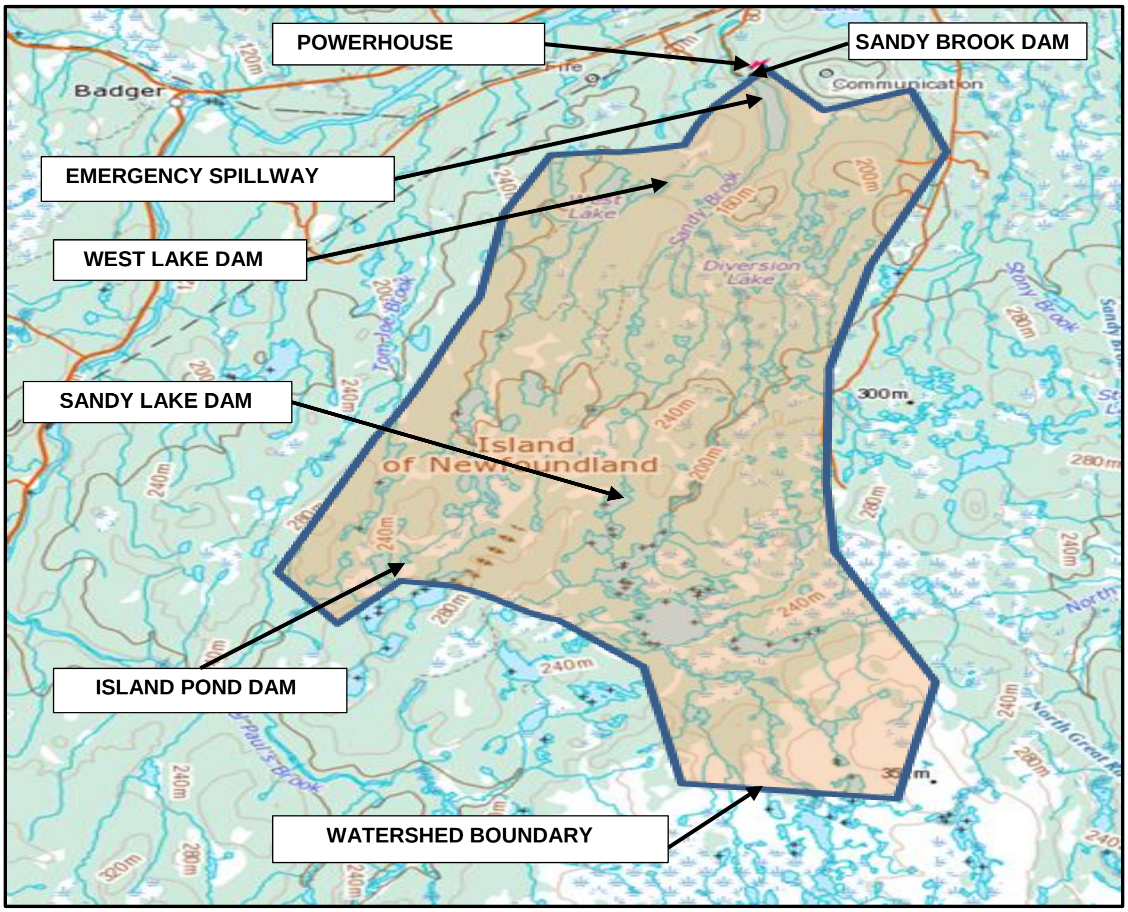

Figure 7 – Sandy Brook Hydroelectric Development

Sandy Brook Plant and Associated Infrastructure
Sandy Brook Plant is supplied from the intake by a 260 m long, 2.8 m diameter wood stave penstock with a steel surge tank on a reinforced concrete foundation located approximately 75 m upstream of the Powerhouse. A 65 m long, 6.0 m wide tailrace extends from the plant to the confluence of the spillway channel and Sandy Brook.

Sandy Brook (Forebay)
The structures at the forebay consist of Sandy Brook Dam, Spillway and Emergency Spillway. The forebay dam is an embankment dam in two sections separated by a central spillway. The total length of the two sections is 250 m with a height of 10.7 m. The reinforced concrete spillway, approximately 150 m long, contains six vertical lift gates. Each gate consists of two concrete half sections that can be raised individually or as a single unit by an overhead monorail hoist. The emergency spillway is a rockfill overflow structure with a timber core and is located 620 m southwest of the forebay dam. The structure is approximately 150 m long with a height of about 1.0 m.

West Lake
The structures consist of an embankment dam in two sections separated by a central spillway. The total length of the two sections is 150 m with a height of 3.6 m. The spillway is a rockfill overflow structure 75 m long and 2.6 m high with a sheet steel core. There is a reinforced concrete outlet structure with a vertical lift screw stem gate centrally located in the spillway and accessed by a walkway from the left abutment.

Island Pond
The structure at Island Pond is an embankment diversion dam 128 m long and 2.4 m high with riprap along the upstream slope. Flows are uncontrolled through a 4.9 m long bridge opening to a diversion ditch. The bridge earthfill embankments function as freeboard dykes.

Sandy Lake
The Sandy Lake structure consists of two earthfill embankment sections separated by a central spillway and an outlet structure. The total length of the two embankment sections is 40.0 m with a height of 3.5 m. In 2011 the original 111.5 m long and 1.5 m high rockfill overflow spillway with sheet steel core and concrete outlet structure was rehabilitated. The spillway was extended by 15.5 m and raised by 1.0 m. The outlet structure is a reinforced concrete culvert with a vertical lift screw stem gate located in the left abutment.

Required Treatments
Fencing is required at the Sandy Brook forebay, tailrace, Sandy Lake outlet and West Lake outlet. Buoys are required at the Sandy Brook forebay and Sandy Lake outlet. The wooden bridge along the Sandy Lake access road requires improvements. Signage conforming to the Guidelines is required at all sites.

Public safety treatments identified for the Sandy Brook Development are listed in Table 7 below.

Table 7
Public Safety Treatments
Sandy Brook Development

Site	Signage	Buoys[18]	Fencing[19]	Other[20]
Sandy Brook Tailrace	×		×	
Sandy Brook Forebay	×	×	×	
West Lake	×		×	
Island Pond	×			
Sandy Lake Outlet	×	×	×	×

2.8 Lookout Brook Development

Lookout Brook is located on the West Coast of Newfoundland near the community of St. George's. The plant was commissioned in 1945 and has a capacity of 6.15 MW under a net head of 154.6 m. The powerhouse is of reinforced concrete construction with a steel frame extension added in 2010. It has two generating units supplied by a penstock extending 1,365.0 m from the forebay. The penstock consists of a buried fiberglass section and an above ground steel section. The development has a small forebay reservoir with larger controlled reservoirs up stream at Joe Dennis Pond and Cross Pond.

[18] Buoys include treatments involving marker buoys and larger booms to restrict access by recreational boaters and swimmers to hazardous areas.
[19] Fencing includes treatments involving new and refurbishment of existing fences, gates and other barriers to restrict access by pedestrians to hazardous areas.
[20] Wooden access road bridge improvements required at Sandy Lake.

Figure 8 shows the locations of the various dams and control structures that form the Lookout Brook development.

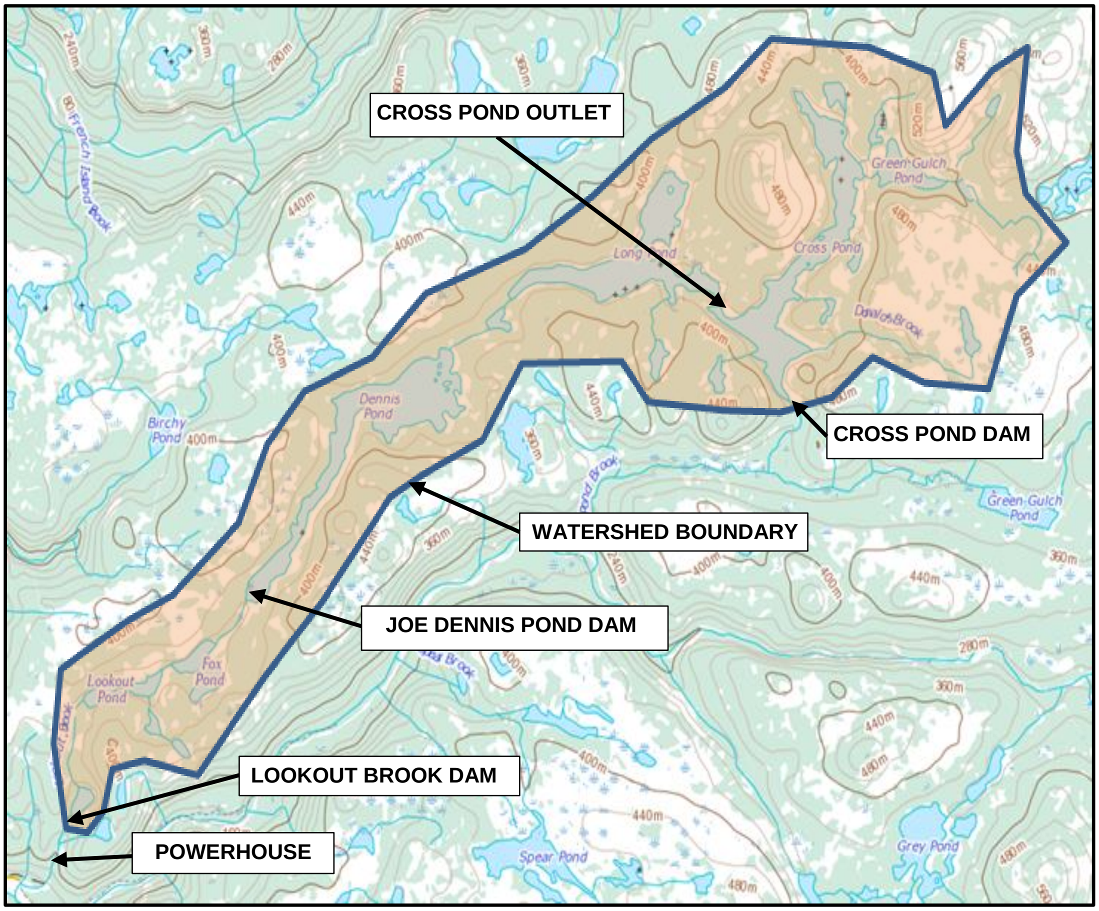

Figure 8 – Lookout Brook Hydroelectric Development

Lookout Brook Plant and Associated Infrastructure
Lookout Brook Plant is supplied from the intake by a 1,365 m long penstock consisting of a 1.5 m diameter buried fiberglass section that transitions to two above ground steel sections 0.9 m in diameter. A reinforced concrete tailrace channel extends from the plant to the confluence of the spillway channel.

Lookout Brook Forebay
Structures at the forebay consist of Lookout Brook Dam, Spillway, sluice gate and intake. The dam is a concrete faced rockfill structure 66.0 m long and 5.4 m high with a reinforced concrete gravity spillway and sluice gate located on the right. The spillway, 16.0 m long and 5.4 m high, was reconstructed in 1992 and incorporates a stop log structure along the crest. The reinforced concrete sluice has a wooden gate operated by a vertical screw stem lift. The reinforced concrete intake structure, located at the left, has a wood frame superstructure housing two cast iron gates, each operated by a vertical screw stem lift.

Joe Dennis Pond
Joe Dennis Pond Dam, rebuilt in 1992, consists of two embankment dams with central spillway and outlet structure. The two dams have a total length of 375 m with a height of about 6.0 m. The spillway is a rockfill overflow structure 30.5 m long and 5.0 m high with a steel sheet core. The reinforced concrete outlet structure, located near the left abutment, has a vertical lift screw stem gate and discharges into a steel culvert.

Cross Pond
Cross Pond dam, rebuilt in 1984, is a rock fill structure 76 m in length with steel sheet pile core. The outlet channel is 65 m long, excavated through rock, with an outlet structure consisting of concrete abutments with a manually operated wooden gate which is accessed by a wooden walkway.

Required Treatments
Fencing is required at the Lookout Brook forebay, Joe Dennis Pond and Cross Pond outlet. Buoys are required at the Lookout Brook forebay and Joe Dennis Pond. Signage conforming to the Guidelines is required at all sites within the area.

Public safety treatments identified for the Lookout Brook Development are listed in Table 8 below.

Table 8
Public Safety Treatments
Lookout Brook Development

Site	Signage	Buoys[21]	Fencing[22]	Other[23]
Lookout Brook Tailrace	×		×	
Lookout Brook Forebay	×	×	×	×
Joe Dennis Pond	×	×	×	
Cross Pond	×		×	×

2.9 Rose Blanche Brook Development

Rose Blanche Brook is located on the Southwest Coast of Newfoundland approximately 45 km east of Channel-Port Aux Basques. The plant was commissioned in 1998 and has a capacity of 6.1 MW under a net head of 114.0 m. The powerhouse is of steel frame construction and houses two generating units supplied by an above ground steel penstock extending 1,300 m from the forebay. The system consists of one reservoir with a dam and separate spillway located about 500 m west of the dam.

[21] Buoys include treatments involving marker buoys and larger booms to restrict access by recreational boaters and swimmers to hazardous areas.
[22] Fencing includes treatments involving new and refurbishment of existing fences, gates and other barriers to restrict access by pedestrians to hazardous areas.
[23] Other includes railing treatments involving new installation and adding toe boards to existing railing.

Figure 8 shows the locations of the various dams and control structures that form the Lookout Brook development.

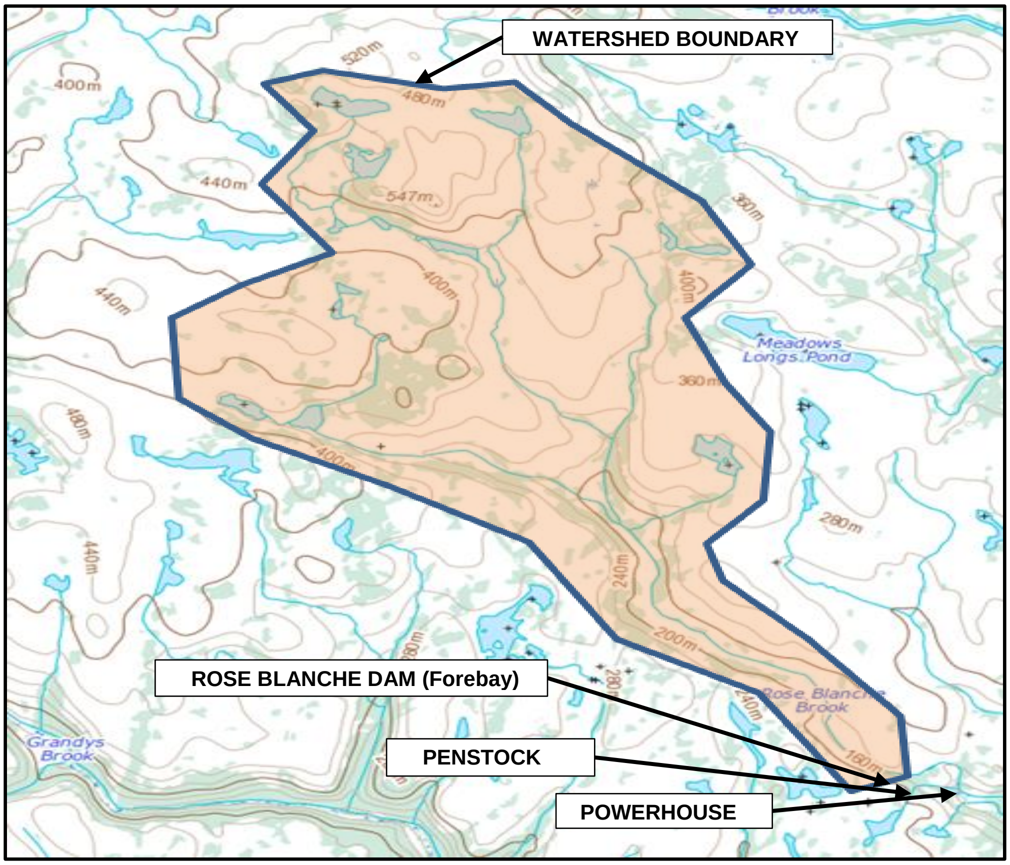

Figure 8 – Rose Blanche Brook Hydroelectric Development

Rose Blanche Brook Plant and Associated Infrastructure
Rose Blanche Plant is supplied from the intake by a 1,300 m long above ground steel penstock 1.5 m in diameter. A reinforced concrete tailrace channel extends 15 m from the plant to an excavated channel extending 95 m to the confluence of Rose Blanche Brook.

Rose Blanche Brook Forebay
Structures at the forebay consist of the dam, spillway, and intake. The dam is a rockfill concrete faced structure 52.0 m long and 27.0 m high incorporating a reinforced concrete intake structure with a wood frame super structure housing the intake gate lift mechanism. The spillway is a separate reinforced concrete gravity structure 40.0 m long and 2.0 m high located 500 m west of the dam.

Fisheries Dykes 1 & 2
Two embankment dykes with riprap along the upstream slopes are located downstream of the powerhouse. These structures are designed to direct flow away from the fish compensation channel and do not impound water. There is a small reinforced concrete intake at dyke No. 1 to regulate flow to the fish compensation channel.

Fish Passages 1 & 2
There are two reinforced concrete fish passages with steel grating along the top constructed in rock channels located along Rose Blanche Brook approximately 3.2 km downstream of the powerhouse.

Required Treatments
Fencing is required at the forebay, spillway and tailrace. Buoys are required at the spillway and forebay. Signage conforming to the Guidelines is required at all sites within the area.

Public safety treatments identified for the Rose Blanche Brook Development are listed in Table 9 below.

Table 9
Public Safety Treatments
Rose Blanche Brook Development

Site	Signage	Buoys[24]	Fencing[25]	Other
Rose Blanche Brook Tailrace	×		×	
Rose Blanche Brook Forebay	×	×	×	
Rose Blanche Brook Spillway	×	×	×	
Fisheries Dyke No.1 (North)	×			
Fisheries Dyke No.2 (South)	×			

24 Buoys include treatments involving marker buoys and larger booms to restrict access by recreational boaters and swimmers to hazardous areas.
25 Fencing includes treatments involving new and refurbishment of existing fences, gates and other barriers to restrict access by pedestrians to hazardous areas.

3.0 2017 Project Cost

Table 10 provides a breakdown of the proposed expenditures for 2017.

Table 10
2017 Projected Expenditures
($000s)

Cost Category	**Cost**
Material	$497
Labour – Internal	33
Labour – Contract	0
Engineering	99
Other	33
Total	**$662**

Tors Cove Hydro Plant Refurbishment

July 2016

Prepared by:

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NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Background

1.1 General

Newfoundland Power's ("the Company") Tors Cove hydroelectric generating plant ("the Plant") is located on the Avalon Peninsula, near the community of Tors Cove, approximately 40 km south of the City of St. John's. The development went into service in 1941 and has provided 75 years of reliable energy production. The normal annual plant production is approximately 25.9 GWh of energy, or about 6% of Newfoundland Power's total hydroelectric production.[1]

The Plant was originally commissioned with two 2,350 kVA English Electric generators (G1 and G2) each with a 2,850 hp Francis turbine under a rated net head of 52.7 m. A third English Electric 2,780 kVA generator (G3) and 3,550 hp Francis turbine were installed in 1951. The 3 generating units combined have a nameplate capacity of 6.5 MW.[2]

In 2015, the G2 original turbine runner and main inlet valve were replaced. The original generator rotor on G2 was also rewound at that time.[3]

In 2017, the refurbishment of G3 will take place, including the replacement of the turbine runner, replacement of the wicket gates, rewinding the rotor, replacement of the power cables and replacement of the main inlet valve. During the Plant outage the main inlet valve of G1 will also be replaced. The Company plans to refurbish G1 in a future capital budget application.[4]

This report provides a summary of the engineering assessment of the Plant and the refurbishment proposed for 2017.

1.2 Previous Upgrades

There have been a number of major upgrades to the original plant and equipment since commissioning in 1941.

---

1 In 2014 the normal annual plant production was 25.4 GWh of energy. The G2 turbine runner and wicket gates were replaced in 2015 with a more efficient design that will provide approximately 0.5 GWh of additional energy annually.

2 The 2 original generators are rated at 2,350 kVA at 85% power factor, which equates to a 2,000 kW load rating and the unit installed in 1951 is rated at 2,780 kVA at 90% power factor which equates to a 2,500 kW load rating.

3 The 2015 refurbishment of Tors Cove Plant was included in the 2015 Capital Budget Application approved in Board Order No. P.U. 40 (2014).

4 The design of the penstock and main valves is such that undertaking the refurbishment of the 2 turbines over multiple years can occur without incurring additional lost production as each individual generator can be isolated from the others. This capability requires that the main inlet valves are sealing correctly, thereby allowing the individual turbines to be isolated from the penstock. Therefore both the G1 and G3 main inlet valves will be replaced during the G3 Plant outage.

The following is a list of the major upgrades that have been completed in the past 30 years:

1989 – Controls upgraded G2 and G3
1990 – G2 stator rewind
1999 – Cooling water system upgraded (coils, meters, etc.)
2000 – Surge tank and foundations replaced
2003 – Electric governors with digital controls installed on G2 and G3
2003 – Unit control and protection upgraded on G2 and G3 (PLC replaced)
2003 – Ventilation louvers replaced
2003 – Fiber optic forebay communications cable installed
2007 – Stainless steel heat exchanger installed on G2
2008 – Stainless steel heat exchanger installed on G3
2015 – G2 turbine runner, wicket gates, and main inlet valve
2015 – G2 rotor rewind
2015 – Overhead crane refurbishment
2015 – Penstock trestle replaced

2.0 Engineering Assessment

2.1 Turbine ($798,000)

The G3 turbine runner was originally installed by English Electric in 1941. A recent inspection of the turbine runner showed cavitation on the low and high pressure side of the turbine blades. The runner band has significant material loss, particularly along the blade welds to the runner band hub, as shown in Figure 1. There is also significant material loss on the inside of the runner band hub in numerous locations.

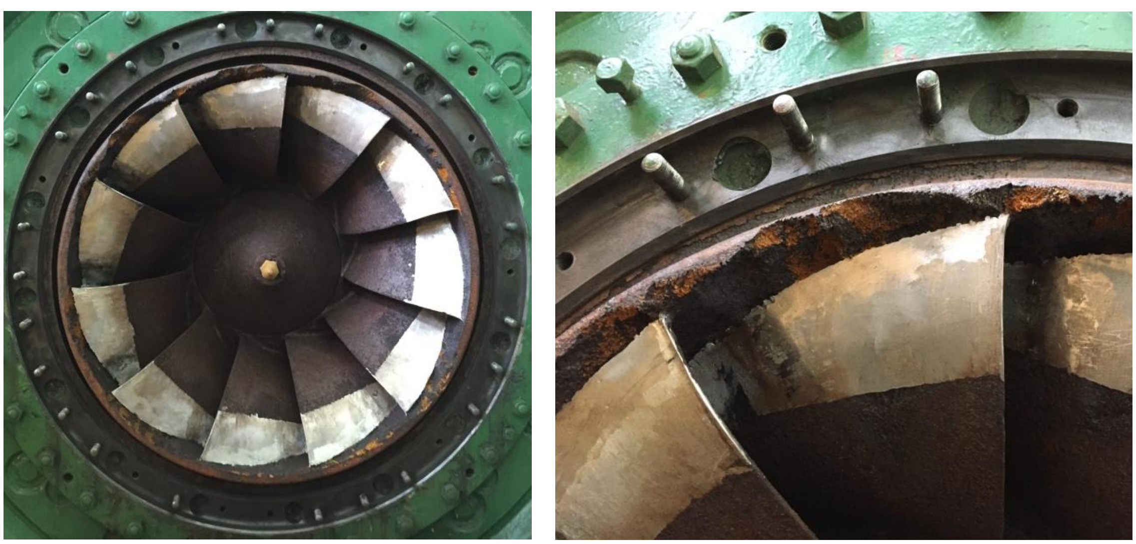

Figure 1 – G3 Turbine Runner Showing the Low Pressure Side and Typical Band Hub Material Loss Respectively

Index testing, performed by ACRES in 2001, determined the peak efficiency of G3 was 90%. The balance of load positions yielded between 74% and 80% efficiency which are considered low compared to that expected of a modern turbine runner design. To improve efficiency and minimize the operating cost associated with maintaining the existing runner, it will be replaced with a higher efficiency stainless steel unit. A replacement runner is expected to result in a peak efficiency of over 90% with the balance of typical operating load positions between 88% and 90%.[5] The new runner will yield an estimated additional 0.5 GWh of energy annually.

The turbine stay vanes in the scroll case were found to be in good condition. The original wicket gates were found to have considerable erosion on the toe and heal of the gates and do not provide a tight seal to isolate water from the turbine runner (see Figure 2). Leakage was also observed between some gate stems and the gland followers. Stainless steel wicket gates and new breaking links will be installed to minimize leakage and ensure continued reliability. Self-lubricating bushings, which require no maintenance and have less environmental risk, will be installed with the new wicket gates.

Figure 2 - G3 Scroll Case and Wicket Gates

[5] Modern runner designs proposed by turbine suppliers in 2015 for the G2 replacement guaranteed over a 90% turbine BEP with between 88% and 90% efficiency for loads between 75% and 100% wicket gate positions.

2.2 Main Inlet Valves ($438,000)

The G3 main inlet valve is a 42-inch electrically actuated butterfly valve which replaced the original manual operated butterfly valve in 1985.[6] It is evident from the constant flow of water when the valve is in the closed position that it is not sealing properly. Furthermore there are recorded instances where the rubber seal has separated from the disc allowing a large quantity of water to flow through. Replacing the rubber seal following one of these incidents requires that the valve be removed from the pipe requiring a plant outage.

The G1 main inlet valve is a 42-inch manually operated butterfly valve which is original to the plant. It is also evident from the constant flow of water when the valve is in the closed position that it is not sealing properly. The valve cannot be used safely as an isolation point to allow for inspections due to the excessive leakage.

Due to the excessive amount of leakage that currently exists, the main inlet valves on generators G1 and G3 cannot be used safely as a point of isolation to allow for turbine inspections. After 76 and 32 years of service respectively, both valves will be replaced in 2017 with modern butterfly valves.[7] In addition, dismantling joints and rearrangement of the bypass valves will be incorporated into the new design to increase maintainability of the new main inlet valves.

Figure 3 – G1 Valve Exterior Setup and G3 Valve Seal Separation

[6] When replaced in 1985 the original inlet valve had been in service for 34 years. In 2017, the replacement valve will have been in service for 32 years.

[7] Replacing the main inlet valve on G1 in 2017 will allow the future refurbishment of the G1 turbine and generator without a complete Plant outage. A fully functioning main inlet valve will be able to provide the necessary isolation that allows work to proceed safely on G1.

2.3 Generator ($190,000)

G3 was manufactured in 1941 by English Electric Co. Ltd. The rotor windings are original to the 75 year old generator. The stator was rewound in 1983.

Electrical insulation of the rotor is subjected to thermal and mechanical stresses due to normal operation of the generator. The variation of operating temperature caused by load changes and the start/stop cycling of the generator creates thermal cycling in the rotor. Thermal cycling causes expansion and contraction of the copper windings relative to the insulating material creating an abrasive effect on the insulation. Visual inspection has confirmed that thermal stress on the G3 rotor has resulted in degradation of the insulating material.

Mechanical stresses experienced by rotor poles are high due to centrifugal forces present during normal operation. Also, during an emergency shutdown the speed of the rotor accelerates dramatically increasing the magnitude of the centrifugal force exerted on the rotor poles. As the generator ages, the loss of insulating material causes pole movement when the rotor experiences centrifugal forces during operation. Over time thermal and mechanical stresses have weakened the G3 rotor poles.

The condition and age of the rotor insulation necessitates the rewinding in 2017.

The power cables between the exciter and the rotor are original to the 1941 installation. Visual inspection has identified degradation due to thermal stresses and cycling. The condition and age of the cables require that they be replaced.

3.0 Project Proposal

3.1 Cost Breakdown

The total project cost for the refurbishment of the Plant in 2017 is estimated at $1,476,000. Table 1 below provides the cost breakdown.

Table 1
Project Cost
($000s)

Cost Category	Cost
Material	1,050
Labour - Internal	203
Labour - Contract	-
Engineering	124
Other	99
Total	**$1,476**

3.2 Feasibility Analysis

Appendix A provides an economic feasibility analysis for the continued operation of the Plant. The results of the analysis show that the continued operation of the Plant is economical over the long term. Investing in the life extension of the Plant ensures the availability of 26.4 GWh of energy to the Island Interconnected System.

The feasibility analysis includes estimates for work to be completed within the next 25 years including expenditures in 2018. The major items included in the 2018 estimate include a turbine and generator overhaul for G1, switch gear, and substation reconfiguration. The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $11.8 million over the next 25 years, is 3.54¢ per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation.[8]

4.0 Conclusion

An engineering assessment completed on the Tors Cove Hydro Plant has determined that it is in generally good condition. The primary systems requiring refurbishment at this time for the life extension of the Plant are the G3 generator including the rotor and power cables, the G3 turbine and the G1 and G3 main inlet valves. Completing all of the Plant refurbishment work during the same outage will minimize the cost of disassembly and reassembly and reduce Plant downtime reducing potential spill.

The feasibility analysis included in Appendix A verifies the financial viability of completing this project. The 26.4 GWh of energy that will be available from Tors Cove Plant each year will provide affordable energy to the customers of Newfoundland Power. The planned schedule for project execution ensures the minimum amount of lost production due to spill. Based upon these considerations, and others outlined in this report and attached analysis, the project is recommended to proceed in 2017.

[8] The avoided cost of No. 6 fuel at the Holyrood Thermal Generating Station is estimated at 8.7¢ per kWh for 2016. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $54.60 per barrel for 2016, as per Newfoundland and Labrador Hydro's Rate Stabilization Plan Adjustment – Revised Application dated June 3, 2016. The avoided cost of fuel for the Holyrood 100 MW combustion turbine is 29.0 ¢/kWh as per Hydro's response to Request for Information GT-NP-NLH-006. Also, an estimate of the marginal cost of production post completion of the Muskrat Falls Project is 5.0 ¢/kWh for energy plus $103/kW for demand starting in 2018, as per Hydro's response to Request for Information CA-NLH-033 (Revision 1, Hydro's 2013 Generation Rate Application, December 9, 2014). This marginal cost increases into the future.

Appendix A
Tors Cove Hydro Plant
Feasibility Analysis

Table of Contents

1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Tors Cove hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2017.

With investment required in 2017 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
Tors Cove Hydroelectric Plant
Capital Expenditures

Year	**($000s)**
2017	$1,476
2018	4,794
2024	20
2029	8
2033	5,275
2039	20
2040	275
Total	**$11,868**

The estimated capital expenditure for the Plant listed above is $11.9 million. 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 $170,718 per year.[1] 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.

[1] 2016 dollars

The annual operating cost also includes a water power rental rate of $2.50 per MWh[2]. This fee is paid annually to the Provincial Department of Environment and Conservation based on yearly hydro plant generation/output. This charge is reflected in the historical annual operating costs for the Plant.

4.0 Benefits

The maximum output from the Plant is 7,340 kW. The Plant normally operates at an efficient load of 6,360 kW to maximize the energy from the water.

The estimated long-term normal production of the Plant under present operating conditions is 26.4 GWh per year.

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 3.54¢ per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Tors Cove 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, or other sources such as combustion turbines and marginal cost of supply in the post Muskrat Falls era.[3]

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.

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2 The water power rental rate increased from $0.80/MWh in 2015 to $2.50/MWh in 2016. The additional cost is added to the annual operating cost.

3 The avoided cost of No. 6 fuel at the Holyrood Thermal Generating Station is estimated at 8.7¢ per kWh for 2016. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $54.60 per barrel for 2016, as per Newfoundland and Labrador Hydro's Rate Stabilization Plan Adjustment – Revised Application dated June 3, 2016. The avoided cost of fuel for the Holyrood 100 MW combustion turbine is 29.0 ¢/kWh as per Hydro's response to Request for Information GT-NP-NLH-006. Also, an estimate of the marginal cost of production post completion of the Muskrat Falls Project is 5.0 ¢/kWh for energy plus $103/kW for demand starting in 2018, as per Hydro's response to Request for Information CA-NLH-033 (Revision 1, Hydro's 2013 Generation Rate Application, December 9, 2014). This marginal cost increases into the future.

6.0 Conclusion

The results indicate that continued operation of the Plant is economically viable. Investing in the current upgrades of the facilities at the Plant guarantees the availability of low cost energy to the Province. Otherwise, the projected annual production of 26.4 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.

Attachment A
Summary of Capital Costs

Tors Cove Feasibility Analysis
Summary of Capital Costs
($000s)

Description	2017	2018	2024	2029	2033	2039	2040
Civil							
Dam, Spillways and Gates							
Penstock & Intake					5,000		
Powerhouse							
Overhead Crane							
Mechanical							
Turbine & Wicket Gates	848	1,215					
Main Inlet Valve	438						
Governor							
Cooling Water							
Heat and Ventilation							
Electrical							
Generator Rewind	190	530			275		275
P&C and Gov. Controls		620					
Switchgear		1,285					
AC & DC Systems							
Battery Bank/Charger			20	8		20	
Substation Reconfig		1,144					
Annual Totals ($2016)	**$1,476**	**$4,794**	**$20**	**$8**	**$5,275**	**$20**	**$275**

Attachment B
Summary of Operating Costs

Tors Cove Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs ($2016)

Year	Amount
2011	$133,352
2012	$ 95,889
2013	$151,902
2014	$153,216
2015	$ 94,829
Average	**$125,838**

2016 Water Power Rental Increase	$44,880[1]
5 -Year Average Operating Cost	**$170,718**[2]

1 Calculated using difference between the current ($2.50/MWh) and the previous ($0.80/MWh) water power rental rates multiplied by the estimated annual output of the plant.
2 2016 dollars

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Present Worth Analysis

Weighted Average Incremental Cost of Capital	6.39%
Escalation Rate	See following worksheet
PW Year	2017

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net benefit	Present Worth Benefit +ve	Cumulative Present Value Benefit +ve	Present Worth of Sunk Costs	Total Present Worth Benefit +ve	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2017	1,476,000	0	132,275	170,718	0	-302,993	-302,993	-302,993	-10,013,236	-10,316,229	1.169856	3.5378
2018	4,889,253	0	581,982	174,110	0	-756,093	-710,680	-1,013,673	-9,466,209	-10,479,882	2.919276	3.5378
2019	0	0	615,941	177,386	0	-793,327	-700,891	-1,714,564	-8,922,036	-10,636,599	3.063038	3.5378
2020	0	0	597,631	180,459	0	-778,090	-646,142	-2,360,705	-8,425,751	-10,786,456	3.00421	3.5378
2021	0	0	580,209	183,486	0	-763,696	-596,097	-2,956,803	-7,972,873	-10,929,675	2.948632	3.5378
2022	0	0	563,604	186,595	0	-750,199	-550,393	-3,507,195	-7,559,378	-11,066,573	2.896522	3.5378
2023	0	0	547,750	189,781	0	-737,532	-508,599	-4,015,794	-7,181,651	-11,197,445	2.847613	3.5378
2024	22,617	0	534,615	193,058	0	-727,673	-471,661	-4,487,456	-6,835,126	-11,322,581	2.809547	3.5378
2025	0	0	520,265	196,418	0	-716,683	-436,637	-4,924,093	-6,518,156	-11,442,248	2.767114	3.5378
2026	0	0	506,257	199,847	0	-706,105	-404,354	-5,328,447	-6,228,245	-11,556,692	2.726272	3.5378
2027	0	0	492,791	203,349	0	-696,140	-374,704	-5,703,151	-5,962,995	-11,666,146	2.6878	3.5378
2028	0	0	479,823	206,917	0	-686,741	-347,443	-6,050,594	-5,720,238	-11,770,832	2.651509	3.5378
2029	10	0	467,315	210,541	0	-677,856	-322,350	-6,372,944	-5,498,010	-11,870,954	2.617203	3.5378
2030	0	0	455,227	214,214	0	-669,441	-299,228	-6,672,172	-5,294,532	-11,966,703	2.584715	3.5378
2031	0	0	443,527	217,937	0	-661,463	-277,904	-6,950,076	-5,108,191	-12,058,266	2.553913	3.5378
2032	0	0	432,183	221,741	0	-653,925	-258,235	-7,208,311	-4,937,521	-12,145,832	2.524807	3.5378
2033	6,970,219	0	1,045,818	225,581	0	-1,271,400	-471,921	-7,680,232	-4,549,332	-12,229,564	4.908879	3.5378
2034	0	0	1,089,639	229,491	0	-1,319,129	-460,229	-8,140,461	-4,169,170	-12,309,630	5.093164	3.5378
2035	0	0	1,058,925	233,480	0	-1,292,405	-423,823	-8,564,283	-3,821,913	-12,386,196	4.989981	3.5378
2036	0	0	1,029,456	237,537	0	-1,266,993	-390,534	-8,954,817	-3,504,597	-12,459,414	4.891865	3.5378
2037	0	0	1,001,135	241,663	0	-1,242,798	-360,068	-9,314,885	-3,214,545	-12,529,430	4.798447	3.5378
2038	0	0	973,867	245,862	0	-1,219,729	-332,159	-9,647,044	-2,949,339	-12,596,383	4.709378	3.5378
2039	29,304	0	950,196	250,133	0	-1,200,329	-307,243	-9,954,288	-2,706,121	-12,660,409	4.634477	3.5378
2040	409,925	0	961,758	254,478	0	-1,216,236	-292,617	-10,246,905	-2,474,730	-12,721,634	4.695892	3.5378
2041	0	0	940,297	258,899	0	-1,199,196	-271,188	-10,518,093	-2,262,089	-12,780,182	4.630101	3.5378
2042	0	0	915,195	263,397	0	-1,178,593	-250,521	-10,768,613	-2,067,556	-12,836,170	4.550551	3.5378
2043	0	0	890,851	267,973	0	-1,158,825	-231,524	-11,000,138	-1,889,571	-12,889,709	4.474226	3.5378
2044	0	0	867,204	272,629	0	-1,139,833	-214,052	-11,214,190	-1,726,717	-12,940,906	4.400898	3.5378
2045	243,704	0	866,038	277,365	0	-1,143,402	-201,826	-11,416,015	-1,573,849	-12,989,865	4.414681	3.5378
2046	0	0	845,527	282,183	0	-1,127,711	-187,100	-11,603,116	-1,433,567	-13,036,682	4.354096	3.5378
2047	0	0	822,944	287,086	0	-1,110,030	-173,105	-11,776,221	-1,305,231	-13,081,452	4.285828	3.5378
2048	0	0	800,894	292,073	0	-1,092,967	-160,207	-11,936,428	-1,187,836	-13,124,264	4.219951	3.5378
2049	13,925	0	780,583	297,147	0	-1,077,730	-148,486	-12,084,914	-1,080,291	-13,165,204	4.161121	3.5378
2050	0	0	759,585	302,309	0	-1,061,894	-137,516	-12,222,430	-981,923	-13,204,354	4.099978	3.5378
2051	0	0	738,853	307,561	0	-1,046,414	-127,373	-12,349,803	-891,988	-13,241,791	4.04021	3.5378
2052	0	0	718,505	312,904	0	-1,031,410	-118,006	-12,467,808	-809,782	-13,277,591	3.982277	3.5378
2053	0	0	698,511	318,340	0	-1,016,851	-109,352	-12,577,161	-734,664	-13,311,825	3.926067	3.5378
2054	37,942	0	682,242	323,871	0	-1,006,113	-101,699	-12,678,860	-665,703	-13,344,562	3.884607	3.5378
2055	0	0	663,170	329,497	0	-992,667	-94,313	-12,773,173	-602,695	-13,375,868	3.832691	3.5378
2056	0	0	643,965	335,222	0	-979,186	-87,445	-12,860,618	-545,187	-13,405,804	3.780642	3.5378
2057	0	0	625,019	341,045	0	-966,064	-81,091	-12,941,709	-492,723	-13,434,432	3.729977	3.5378
2058	0	0	606,311	346,970	0	-953,281	-75,212	-13,016,921	-444,886	-13,461,807	3.680621	3.5378
2059	0	0	587,821	352,998	0	-940,819	-69,771	-13,086,692	-401,293	-13,487,985	3.632507	3.5378
2060	0	0	569,534	359,130	0	-928,664	-64,733	-13,151,424	-361,594	-13,513,018	3.585576	3.5378
2061	0	0	551,431	365,369	0	-916,801	-60,067	-13,211,492	-325,465	-13,536,957	3.539772	3.5378
2062	0	0	533,499	371,717	0	-905,216	-55,746	-13,267,238	-292,610	-13,559,848	3.495044	3.5378
2063	0	0	515,724	378,175	0	-893,899	-51,743	-13,318,981	-262,758	-13,581,739	3.451348	3.5378
2064	0	0	498,094	384,745	0	-882,838	-48,033	-13,367,015	-235,658	-13,602,672	3.408641	3.5378
2065	0	0	480,596	391,429	0	-872,024	-44,595	-13,411,610	-211,080	-13,622,690	3.366889	3.5378
2066	0	0	463,220	398,229	0	-861,448	-41,409	-13,453,018	-188,814	-13,641,832	3.326056	3.5378

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 30%.

Operating Costs: Operating costs were assumed to be in 2016 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	4.660%	2.56%
Common Equity	45.00%	8.500%	3.83%
Total	**100.00%**		**6.39%**

CCA Rates:

Class	Rate	Details
47	8.00%	All generating, transmission, substation and distribution equipment not otherwise noted.
17.1	8.00%	Expenditures related primarily to new generation or additions/alterations that increase the capacity of generating facilities.

Escalation Factors: Conference Board of Canada GDP deflator, February 4, 2016, and November 3, 2015.

2017 Substation Refurbishment and Modernization

July 2016

Prepared by:

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J. W. Pardy, P. Eng.

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1.0 Substation Refurbishment and Modernization Strategy

Newfoundland Power (the "Company") has 130 substations located throughout its operating territory. Distribution substations connect the low voltage distribution system to the high voltage transmission system. Transmission substations connect transmission lines of different voltages. Generation substations connect generating plants to the electrical system. Substations are critical to reliability; an unplanned substation outage can affect thousands of customers. The Company's substation maintenance program and the Substation Refurbishment and Modernization project ensure 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.[1] Where practical the substation plan is coordinated with the maintenance cycle for major substation equipment. Such coordination minimizes customer service interruptions and ensures optimum use of resources. This approach is consistent with the least cost delivery of reliable service.

Substation refurbishment and modernization is reviewed annually. When updating the substation refurbishment and modernization plan, assessments are made based upon (i) the condition of the infrastructure and equipment, (ii) the need to upgrade and modernize protection and control systems, and (iii) other relevant work. In 2015, an initiative to accelerate substation feeder automation was incorporated into the Substation Refurbishment and Modernization Project. This initiative was identified to accelerate the automation of all distribution feeders by the end of 2019.[2] This will enhance the Company's ability to ensure system reliability.

Substation refurbishment and modernization typically requires power transformers to be removed from service. Therefore, the timing of the work is restricted to the availability of a portable substation if customer outages are to be avoided. Due to capacity limitations of portable substations, this often requires the work to be completed in the late spring through early fall when substation load is reduced.

The current 5-year forecast for the Substation Refurbishment and Modernization Plan is shown in Appendix A.

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[1] The Company's Substation Refurbishment and Modernization Project is the result of the Substation Strategic Plan filed with the 2007 Capital Budget Application.

[2] By the end of 2017 there will be 266 distribution feeders automated representing approximately 89% of all distribution feeders. In its *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power, December 17th, 2014,* (the "Liberty Report"), the Board's consultants; the Liberty Consulting Group, observed in Conclusion 2.9 that executing the 5-year plan to automate all distribution feeders by 2019 will bring "Newfoundland Power into conformity with good utility practices".

2.0 Substation Refurbishment and Modernization 2017 Projects

The 2017 Substation Refurbishment and Modernization project includes planned refurbishment and modernization of 3 substations. This substation work is estimated to cost a total of $7,548,000 which comprises approximately 85% of the total 2017 project cost. The remaining project cost includes $1,157,000 for Substation Feeder Automation to automate 11 distribution feeders and $170,000 associated with Substation Monitoring and Operations to upgrade substation communication systems.

Table 1 identifies the 2017 Substation Refurbishment and Modernization Project expenditures.

Table 1
2017 Substation Refurbishment and Modernization Projects
(000s)

Project	**Budget**
Salt Pond (SPO) Substation	$3,339
Catalina (CAT) Substation	$2,845
Chamberlains (CHA) Substation	$1,364
Substation Feeder Automation	$1,157
Substation Monitoring and Operations	$170
Total	**$8,875**

The location of the 3 substations undergoing refurbishment and modernization projects in 2017 is shown on the map below.

Figure 1: 2017 Substation Refurbishment and Modernization Projects

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

2.1 2017 Substation Projects ($7,548,000)

Salt Pond Substation ($3,339,000)

Salt Pond ("SPO") Substation was built in 1967 as both a transmission and distribution substation. The transmission portion of the substation contains two 138 kV transmission lines and two 66 kV transmission lines.[3] The 66 kV bus and associated transformers are in a nearby yard separate from the 138 kV and 12.5 kV bus and associated transformers. Two 138 kV to 66 kV, 41.6 MVA power transformers (SPO-T4 and SPO-T5) connect the 138 kV and 66 kV buses. Due to the different winding configurations of the two transformers, they cannot be operated in parallel. There is a single 66kV to 12.5 kV, 15 MVA power transformer (SPO-T1) which provides distribution voltage to the 12.5 kV structure. There are three 12.5 kV distribution feeders (SPO-01, SPO-02, and SPO-03) directly serving approximately 1,912 customers in the Burin area.

Engineering assessments determined that the 138 kV and 12.5 kV steel structures, buses and insulators are in good condition. The 66 kV wood pole structures are in a deteriorated condition and are splitting as shown in Figure 2. The wood pole structures will be replaced by steel structures. The 66 kV concrete foundations are also in a deteriorated condition as indicated in Figure 3. New concrete foundations will be required for the steel structures and associated equipment.

Figure 2: Deteriorated Wood Poles

[3] The two 138 kV transmission lines are 308L to Marystown Substation and TL-219 to Sunnyside Substation. The two 66kV transmission lines are 301L to Garnish Substation and 302L to Laurentian Substation.

Figure 3: Deteriorated Foundation

The 66 kV bus structure will be reconstructed. All of the switches on the 138kV, 66kV and 12.5 kV bus structures in excess of 30 years in service will be replaced due to their mechanical condition and age.[4] This includes 6 side break switches, 1 tie break switch, 2 transformer air break switches and the feeder hook stick switches. The air break switches will be replaced with motorized air break switches complete with ground switches.[5]

The 3 distribution feeders shown below are protected and controlled using hydraulic reclosers that range in age from 23 to 35 years old.[6] The hydraulic reclosers are not capable of automation through the SCADA system. New reclosers with intelligent controllers will be installed to replace the hydraulic reclosers providing automation for monitoring and control from the System Control Centre through the SCADA System. This will allow for automated restoration of service which will improve customer service. With feeder automation, the 3 SPO Substation distribution feeders will be added to the provincial under-frequency load shedding scheme.

4 The Company's strategy for switches is to operate and maintain switches whenever opportunities and substation work permit, and to replace switches when they are more than 30 years old. Over the life of the switches there is mechanical wear and tear experienced by items such as hinge bushings, Teflon bushing liners and springs used to assist movement. The result is typically misalignment of switch blades and contact surfaces.

5 The motorized air break switches in conjunction with the upgraded protection relays will improve equipment protection.

6 The 3 hydraulic reclosers are associated with distribution feeders SPO-01, SPO-02, and SPO-03.

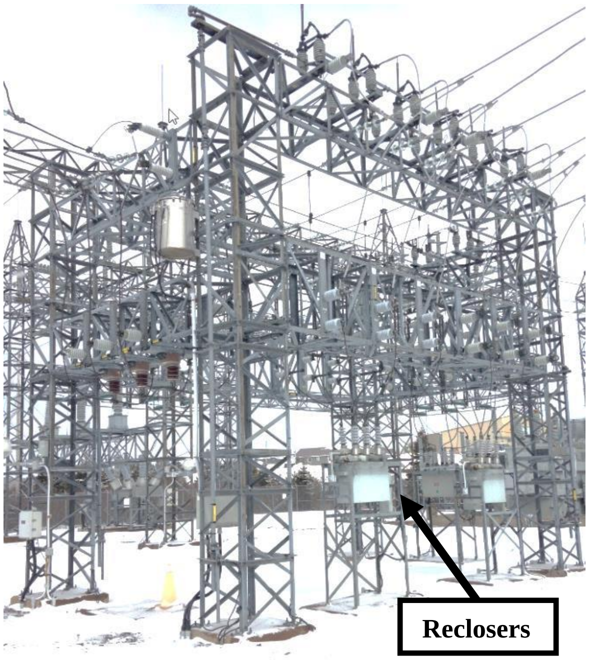

Figure 4: Hydraulic Reclosers

A spill containment foundation will be constructed for transformers SPO-T1 and SPO-T4 to protect against environmental damage in the event of an oil spill from the units. SPO-T4 is shown in Figure 5.

Figure 5: Existing SPO-T4

Power transformer SPO-T5 was installed in 2003 and will not require refurbishment. Power transformers SPO-T1 installed in 1966 and SPO-T4 installed in 1973, will be refurbished and upgrades made to the transformers' auxiliary protection. The existing 40 year old auxiliary protection and control devices used to monitor and protect the power transformers will be upgraded to ensure continued protection and safe operation of the power transformer.

As shown below, the relays for the bus and transformer protection are vintage electromechanical type and were installed in 1990 and 1982 respectively. Electromechanical relays operate by using torque-producing coils, energized by current and voltage inputs, which open or close contacts based upon mechanically calibrated thresholds. At present, there are 10 electromechanical relays installed in 2 individual protection panels inside the substation control building. These relays, used for the protection of 1 transformer (SPO-T4) and 1 bus (138 kV) structure range in age from approximately 26 to 34 years old. Electromechanical relays contain moving parts that can fail as they age, wear, and accumulate dirt and dust. The age of these relays dictate they are to be replaced.[7]

Figure 6: Existing Control Building with Electromechanical Relays

The protection and control of substation assets will be modernized by replacing these obsolete devices with microprocessor based digital relays, reducing the total protective relay device count

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[7] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electromechanical relays contain moving parts that can fail as they age, wear and accumulate dirt and dust. The Liberty Report examined Newfoundland Power's practice of replacing multiple obsolete electromechanical relays with a single modern microprocessor controlled relay.

from 10 electromechanical relays to 2 digital relays. The protection upgrade will also involve replacing all of the existing protection panels. This approach minimizes the number of active devices needed to provide protection to substation assets, consolidates the control and automation architecture, and reduces ongoing maintenance.

The existing 34 year old control building at SPO Substation cannot accommodate the new relay and communication panels required to complete the protection upgrades. The existing building does not meet current space and access requirements.[8] A new control building will be constructed adjacent to the existing building. The new control building will permit installation of the new protection and communications panels with minimum disruption to the existing protection scheme and the integrity of the electrical system during construction.

Figure 7: Inadequate Building Space

All low voltage equipment will have standard varmint protection installed.[9]

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[10]

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8 Overcrowding of the panels inside the building limits access to the rear of the panels where the wiring is terminated.

9 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application verified that these barriers can be effective in preventing damage to equipment and customer outages caused by small animals and birds. The Liberty Report's Conclusion 2.10 states that "The use of insulated coverings, guards and insulated leads have been effective in preventing animal-caused damage and outages."

10 Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2000 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practice for designing substation ground grids.

Catalina Substation ($2,845,000)

Catalina ("CAT") Substation was built in 1976 as both a transmission and distribution substation. The transmission portion of the substation contains two 138 kV transmission lines and one 66kV transmission line.[11] A 138kV to 66 kV, 16.6 MVA power transformer (CAT-T1) connects the 138 kV and 66 kV buses. There is a single 138 kV to 12.5 kV, 20 MVA power transformer (CAT-T2) which provides distribution voltage to the 12.5 kV bus structure. There are three 12.5 kV distribution feeders (CAT-01, CAT-02, and CAT-03), serving approximately 1,053 customers in the Catalina area.

Engineering assessments determined that the 138kV, 66 kV and 12.5 kV steel structures, buses, and insulators are all in good condition. The concrete foundations generally are in good condition with the exception of 9 pier foundations and breaker foundations that need to be refurbished. An example of a foundation that requires refurbishment is shown in Figure 8.

Figure 8: A Pier Foundation that Requires Refurbishment

Most of the switches on the 138 kV, 66 kV, and 12.5 bus structures are in excess of 35 years in service and will be replaced due to their mechanical condition and age.[12] This includes 6 side break switches, and two transformer air break switches (CAT-T1-A and CAT-T2-A). The transformer air break switches will be upgraded with motorized air break switches complete with ground switches.[13]

[11] The two 138kV transmission lines are 117L to Bonavista Substation and 123L to Princeton Pond Substation. The 66kV transmission line is 111L to Lockston Substation.

[12] The Company's strategy for switches is to operate and maintain switches whenever opportunities and substation work permit, and to replace switches when they are more than 30 years old. Over the life of the switches there is mechanical wear and tear experienced by items such as hinge bushings, Teflon bushing liners and springs used to assist movement. The result is typically misalignment of switch blades and contact surfaces.

[13] The motorized air break switches in conjunction with the upgraded protection relays will improve equipment protection.

The 3 distribution feeders are protected and controlled using hydraulic reclosers that range in age from 30 to 46 years old.[14] The hydraulic reclosers are not capable of automation through the SCADA system. New reclosers with intelligent controllers will be installed to replace the hydraulic reclosers providing automation for monitoring and control from the System Control Centre through the SCADA System. This will allow for automated restoration of service which will improve customer service. With feeder automation, the 3 CAT Substation distribution feeders will be added to the provincial under-frequency load shedding scheme.

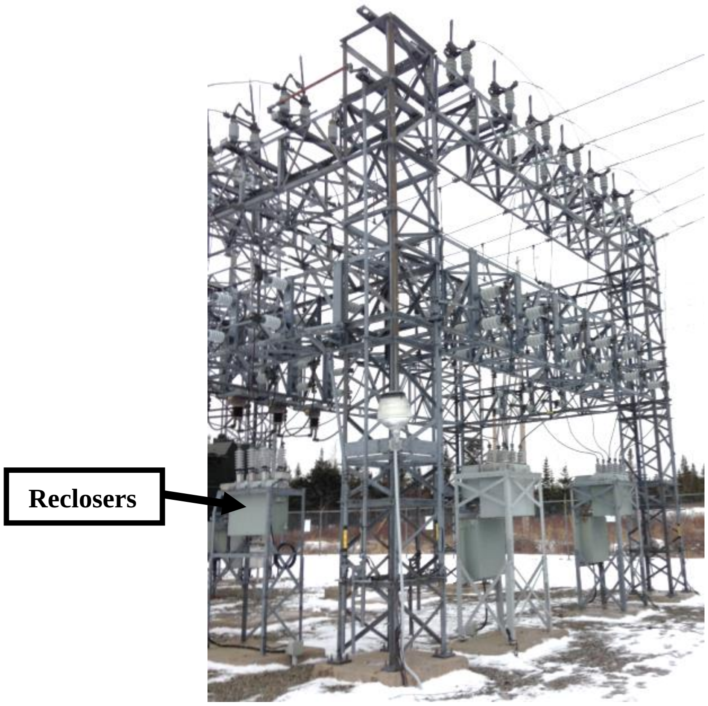

Figure 9: Hydraulic Reclosers

Power transformers CAT-T1 installed in 1972 and CAT-T2 installed in 1977, will be refurbished and upgrades made to the transformers' auxiliary protection. The existing 35 year old auxiliary protection and control devices used to monitor and protect the power transformers will be upgraded to ensure continued protection and safe operation of the power transformer.

Two spill containment foundations will be constructed for transformer CAT-T1 and CAT-T2 to protect against environmental damage in the event of an oil spill from the units. CAT-T1 is shown in Figure 10.

[14] The 3 hydraulic reclosers are associated with distribution feeders CAT-01, CAT-02, and CAT-03.

Figure 10: CAT-T1

The installation of one 138 kV breaker for transmission line 123L with the associated protective relaying to achieve operation flexibility is required for the 138 kV transmission system and for the protection of transformers CAT-T1 and CAT-T2. This will allow for the removal of the two high speed ground switches presently being utilized.

An incoming circuit breaker will be installed between transformer CAT-T2 and the 12.5 kV bus as part of the improved protection scheme. This will minimize the potential for disturbances on the distribution system and power transformers from disrupting the 138 kV transmission system supplying customers in the adjacent substations of Bonavista and Princeton Pond.

As shown in Figure 11, the relays for the line and transformer protection are vintage electromechanical type and were installed between 1978 and 1992. Electromechanical relays operate by using torque-producing coils, energized by current and voltage inputs, which open or close contacts based upon mechanically calibrated thresholds. At present, there are 14 electromechanical relays installed in 3 individual protection panels inside the substation control building. These relays, used for the protection of 2 transformers (CAT-T1 and CAT-T2) and 1 transmission line, range in age from approximately 24 to 38 years old. Electromechanical relays contain moving parts that can fail as they age, wear, and accumulate dirt and dust. The age of these relays dictate they are to be replaced.[15]

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15 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electromechanical relays contain moving parts that can fail as they age, wear and accumulate dirt and dust. The Liberty Report examined Newfoundland Power's practice of replacing multiple obsolete electromechanical relays with a single modern microprocessor controlled relay.

Figure 11: Existing Control Building with Electromechanical Relays

The protection and control of substation assets will be modernized by replacing these obsolete devices with microprocessor based digital relays, reducing the total protection relay device count from 14 electromechanical relays to 3 digital relays. The protection upgrade will also involve replacing all of the existing protection panels. This approach minimizes the number of active devices used to provide protection to substation assets, consolidates the control and automation architecture, and reduces ongoing maintenance.

A complete communications package including a gateway will be installed to facilitate SCADA system remote control and monitoring of the power system protection equipment. The gateway will integrate the digital devices providing monitoring and control of the transmission lines, distribution feeders and substation transformers into the SCADA system.

All low voltage equipment will have standard varmint protection installed.[16]

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[17]

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[16] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application verified that these barriers can be effective in preventing damage to equipment and customer outages caused by small animals and birds. The Liberty Report's Conclusion 2.10 states that "The use of insulated coverings, guards and insulated leads have been effective in preventing animal-caused damage and outages."

[17] Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2000 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practice for designing substation ground grids.

Chamberlains Substation ($1,364,000)

The refurbishment and modernization of Chamberlains ("CHA") Substation will be undertaken in 2017 at the same time as the replacement of an existing power transformer.[18]

CHA Substation was built in 1975 as both a transmission and distribution substation. The transmission portion of the substation contains three 66 kV transmission lines.[19] Two 66 kV to 25 kV, 25 MVA power transformers (CHA-T1 and CHA-T2) provide distribution voltage to the 25 kV bus structure. There are three 25 kV distribution feeders (CHA-01, CHA-02, and CHA-03) serving approximately 8,265 customers in the Conception Bay South Area.

Engineering assessments determined that the 66 kV and 25 kV steel structures, foundations, buses, and insulators are all in good condition. Transformer T2 is in good condition.

The T1 transformer switch, transmission line 51L, 79L switches, and the CHA-01 and CHA-03 feeder switches are all in excess of 30 years in service and will be replaced due to their mechanical condition and age.[20] This includes 4 side break switches, two feeder air break switches and 4 feeder hook stick operated switches. The transformer air break switches will be replaced with a motorized air break switch complete with ground switch.[21]

As shown in Figure 12, the relays for the transformer and bus protection are vintage electromechanical type and are original to the 1985 building construction. Electromechanical relays operate by using torque-producing coils, energized by current and voltage inputs, which open or close contacts based upon mechanically calibrated thresholds. At present, there are 11 electromechanical relays installed in 2 individual protection panels inside the substation control building. These relays, used for the protection of 1 transformer (CHA-T1) and the 66kV bus are approximately 40 years old. Electromechanical relays contain moving parts that can fail as they age, wear, and accumulate dirt and dust. The age of these relays dictate they are to be replaced.[22]

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[18] The Substations project *2017 Additions Due to Load Growth* includes the replacement of an existing 25 MVA transformer with a new 50 MVA substation transformer required for CHA.

[19] The 66 kV transmission lines are 49L and 79L paralleled to Hardwoods Substation and 51L to Kelligrews Substation.

[20] The Company's strategy for switches is to operate and maintain switches whenever opportunities and substation work permit, and to replace switches when they are more than 30 years old. Over the life of the switches there is mechanical wear and tear experienced by items such as hinge bushings, Teflon bushing liners and springs used to assist movement. The result is typically misalignment of switch blades and contact surfaces.

[21] The motorized air break switches in conjunction with the upgraded protection relays will improve equipment protection.

[22] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electromechanical relays contain moving parts that can fail as they age, wear and accumulate dirt and dust. The Liberty Report examined Newfoundland Power's practice of replacing multiple obsolete electromechanical relays with a single modern microprocessor controlled relay.

Figure 12: Existing CHA Control Building with Electromechanical Relays

The protection and control of substation assets will be modernized by replacing these obsolete devices with microprocessor based digital relays, reducing the total protection relay device count from 11electromechanical relays to 2 digital relays.

All low voltage equipment will have standard varmint protection installed.[23]

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[24]

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[23] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application verified that these barriers can be effective in preventing damage to equipment and customer outages caused by small animals and birds. The Liberty Report's Conclusion 2.10 states that "The use of insulated coverings, guards and insulated leads have been effective in preventing animal-caused damage and outages."

[24] Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2000 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practice for designing substation ground grids.

2.2 Substation Feeder Automation ($1,157,000)

At the end of 2016, approximately 83% of distribution feeders will be automated at the substation breaker or recloser. Under the current plan, this percentage will increase to 89% by the end of 2017. Automation of distribution feeders at the substation breaker or recloser improves restoration from local and system wide outages. In addition to the opening and closing of the devices under remote control, automation also allows for the adjusting of operational parameters such as automatic reclosing, protection settings and temporary adjustment of trip settings to allow for cold load pickup and other system events.

In 2017, the Company plans to automate an additional 17 distribution feeders. The refurbishment and modernization of Catalina (3) and Salt Pond (3) substations will automate an additional 6 distribution feeders. Eleven distribution feeders not associated with either of the 2 remaining substations undergoing refurbishment and modernization in 2017 will also be automated.[25] These feeders are located in Islington, Summerford, Northwest Brook, Gillams, Grand Bay, and Seal Cove Road substations.

2.3 Substation Monitoring and Operations ($170,000)

Over the past decade, there has been a substantial increase 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 2017, upgrades are planned to the communications gateways that connect multiple electronic devices in substations to the SCADA system. Effective management of increased volumes of electrical system data requires the upgrading of the hardware and software which comprise these gateways.

In 2017, the required work will incorporate manufacturers' upgrades to gateways and other computer-based equipment located in Company substations. These upgrades typically increase functionality of the equipment and software and remedy known deficiencies.

[25] The Company plans to automate *all* distribution feeders by 2019. The plan will be executed in 2018 and 2019 through the refurbishment and modernization of 3 substations with the remaining 24 distribution feeders being automated through this Substation Feeder Automation item. These projects will be justified in future capital budget applications.

Appendix A
Substation Refurbishment and Modernization Plan
Five-Year Forecast 2017 to 2021

Substation Refurbishment and Modernization Plan Five-Year Forecast 2017 to 2021 ($000s)									
2017		**2018**		**2019**		**2020**		**2021**	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
CAT	$2,845	BVA	$1,892	BCV	$1,057	ABC	$ 851	GAL	$ 950
CHA	$1,364	BVS	$2,478	HWD	$ 540	BLA	$ 1,491	GAM	$1,012
SPO	$3,339	HGR	$3,138	NCH	$1,656	DUN	$ 599	GOU	$2,000
SFA	$1,157	TCV	$1,144	PEP	$1,419	GBS	$1,597	HUM	$2,266
SMU	$ 170	SFA	$1,048	SLA	$1,282	GBY	$1,240	HAR	$1,508
		SMU	$ 175	SUN	$1,008	HCP	$ 593	MOL	$2,115
				SFA	$1,071	MSY	$2,765	PUL	$ 563
				SMU	$ 180	WAL	$ 420	SMU	$ 190
						SMU	$ 185		
	$8,875		**$9,875**		**$8,213**		**$9,741**		**$10,604**

Note: SUB: Substation - Refer to the Electrical System handbook included with the 2006 Capital Budget Application for three letter substation designations.

2017 Additions Due to Load Growth

July 2016

Prepared by:

Robert Cahill, Eng. L.

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1.0 Introduction

As load increases on an electrical system, individual components can become overloaded. The focus of Newfoundland Power's system planning is to avoid or minimize component overloading through cost effective upgrades to the system. In the case of substation transformers, an engineering study is completed to identify and evaluate technical alternatives in advance of the overloads.[1] These technical alternatives are fully examined, cost estimates are prepared, and an economic analysis is performed to identify the least cost alternative.

In general, the alternatives for addressing an overload condition on a substation transformer involve the following:

(i) Transferring the customer load from one existing substation transformer to another. The other substation transformer may or may not be in the same substation.

(ii) Paralleling substation transformers together. In substations that have more than one substation transformer, the substation transformers may be able to be connected in parallel so that they can share the load between them.

(iii) Replacing an existing substation transformer with a substation transformer of a higher capacity rating.

(iv) Installing an additional substation transformer to allow the transferring of customer load from the overloaded substation transformer(s) onto the additional substation transformer.

The system load forecast completed for the 2017 Capital Budget planning cycle has identified Chamberlains ("CHA") substation, which includes substation transformers CHA-T1 and CHA-T2, to become overloaded if no capital improvements are undertaken. To address this substation overload, it is proposed that the transformer capacity of CHA substation be increased.

This report provides details on the proposal to address the CHA substation overload including the justification for the items to be included in the *2017 Additions Due to Load Growth* project.

2.0 Chamberlains Substation ($2,574,000)

An engineering study has been completed on the distribution system upgrades to meet the electrical demands of the customers supplied by CHA substation. This study is presented in Attachment A to this report.

The study examined the 4 alternatives described in Section 1.0 to determine the least cost alternative to address the forecasted overload condition on the CHA substation. This study

[1] A substation transformer converts electricity from transmission level voltages (typically between 66 kV and 138 kV) to distribution level voltages (typically between 4 kV and 25 kV).

determined that only 3 of the 4 alternatives were viable options to address the overload condition.[2] These alternatives were evaluated using economic and sensitivity analyses to determine the least cost alternative to address the overload condition of the CHA substation over a 20 year load forecast period.

The least cost alternative involves installing a new 50 MVA substation transformer to replace an existing 25 MVA substation transformer, CHA-T1, at CHA substation.

3.0 Project Cost

Table 1 shows the total 2017 project capital costs for the project.

Table 1
2017 Project Costs
($000's)

Cost Category	**Chamberlains Substation Transformer Replacement**
Material	2,421
Labour – Internal	18
Engineering	90
Other	45
Total	**2,574**[3]

4.0 Conclusion

The Company continues to experience load growth in the CHA substation service area. As a result, the available CHA substation transformer capacity has diminished and equipment overloads are forecast to occur.

The recommended project to address the capacity issue in the CHA substation service area is the replacement of the existing 25 MVA CHA-T1 transformer with a new 50 MVA transformer.

[2] Substation transformers CHA-T1 and CHA-T2 currently operate in parallel. Therefore, alternative (ii) will not assist in addressing the overload condition that exists for CHA substation.

[3] The cost of $2,574,000 is for the associated replacement costs of CHA-T1 transformer only. The total cost associated with this project is $5,015,000 which includes the costs for both the construction and substation termination of a new CHA-04 distribution feeder as well as the refurbishment and modernization of other CHA substation equipment. These additional cost components are included in 3 other 2017 Capital Budget Application projects, *Substation Feeder Termination ($284,000), Feeder Additions for Growth ($793,000), and 2017 Substation Refurbishment and Modernization ($1,364,000).*

Based on the attached study and an analysis of alternatives, this option is the least cost alternative.

This project is estimated to cost $2,574,000 in 2017.

Attachment A
Chamberlains Substation Study

Table of Contents

1.0 Introduction

The purpose of this study is to determine the distribution system alternative that best meets the electrical demands of the Chamberlains ("CHA") Substation.

In the winter of 2017, the substation transformers at CHA are expected to experience a total peak load of 53.1 MVA. The current parallel capacity of CHA-T1 and CHA-T2 is 49.3 MVA.[1] As a result, the load forecast indicates that both CHA-T1 and CHA-T2 will be overloaded in 2017.

Load growth on these transformers is primarily the result of residential subdivision development in Adam's Pond, Grand Meadows, Southvalley Estates, and Vista Crest subdivisions.

This report identifies the capital project required to avoid the 2017 forecasted overload by determining the least cost expansion plan required to meet a 20 year load forecast.

2.0 Description of Existing System

CHA substation is located along Fowler's Road in the town of Conception Bay South. There are 2 substation transformers located in the substation: CHA-T1 and CHA-T2. CHA-T1 and CHA-T2 are both 25.0 MVA, 66/25 kV transformers. The parallel combination of these two transformers is used to convert a transmission level voltage of 66 kV to a distribution level voltage of 25 kV to supply power to customers through 3 CHA distribution feeders.

There are a total of 3 distribution feeders originating from the CHA substation:

1) CHA-01 is a 25 kV feeder serving approximately 3,083 customers. The main trunk portion of this feeder consists of approximately 1.2 km of 477 ASC conductor heading west, parallel to Neil's Line and 5.1 km of 477 ASC conductor that runs along the Conception Bay Highway between the areas of Topsail Beach and Long Pond. It can be paralleled with CHA-02 near Topsail Beach or CHA-03 near either the intersection of Swansea Street and Cambridge Crescent or the intersection of the Conception Bay Highway and Bishop's Road.

2) CHA-02 is a 25 kV feeder serving approximately 2,443 customers. The main trunk portion of this feeder consists of approximately 0.8 km of 477 ASC conductor that runs northeast along Buckingham Drive, approximately 0.7 km of 477 ASC conductor that runs through a wooded area between Buckingham Drive and Miller's Road, approximately 0.7 km of 477 ASC conductor that runs northeast along Frog Pond Road, approximately 1.7 km of 477 ASC conductor that runs southeast along Topsail Road, and approximately 2.2 km of 1/0 AASC conductor that runs north along St. Thomas Line. It can be paralleled with CHA-01 near Topsail Beach, HWD-07 near the intersection of

[1] The total substation capacity is not necessarily equal to the sum of the individual transformer nameplate capacities. The electrical characteristics of each transformer, more specifically the transformer's per unit impedance, determines how load is split between transformers that operate in parallel.

St. Thomas Line and Paradise Road, or HWD-09 near the intersection of Carberry Place and Topsail Road.[2]

3) CHA-03 is a 25 kV feeder serving approximately 2,679 customers. The main trunk portion of this feeder consists of approximately 1.5 km of 477 ASC conductor that runs southeast along Fowler's Road, approximately 0.4 km of 477 ASC conductor that runs southwest along Windemere Place, approximately 3.5 km of 477 ASC conductor that runs west along the Conception Bay South Bypass Highway, approximately 2.2 km of 477 ASC conductor that runs northwest along Minerals Road, and approximately 1.4 km of 477 ASC conductor that runs northeast along the Conception Bay Highway. It can be paralleled with CHA-01 near the intersection of the Conception Bay Highway and Bishop's Road.

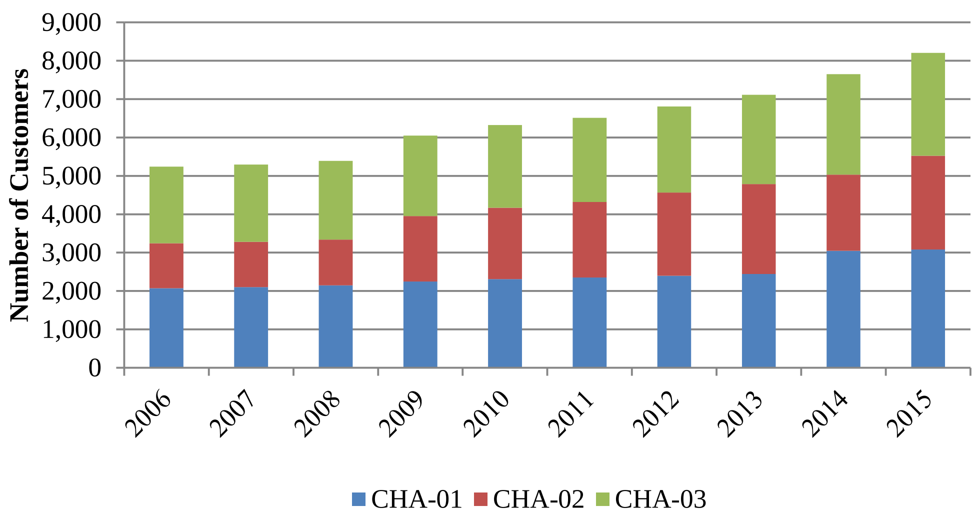
A map of the CHA substation service area is shown in Appendix A.

3.0 Load Forecast

From 2006 to 2015, the number of customers served from the CHA substation has increased by 57% from 5,242 customers to 8,205 customers. In addition, the electrical load on the CHA substation has increased at a levelized rate of 6.9% per year since 2006. These increases are due to the residential development that is occurring throughout the CHA substation service area. The forecast indicates that the load on CHA substation will reach 53.1 MVA in 2017.

Graph 1 shows the customer growth on CHA substation between 2006 and 2015.

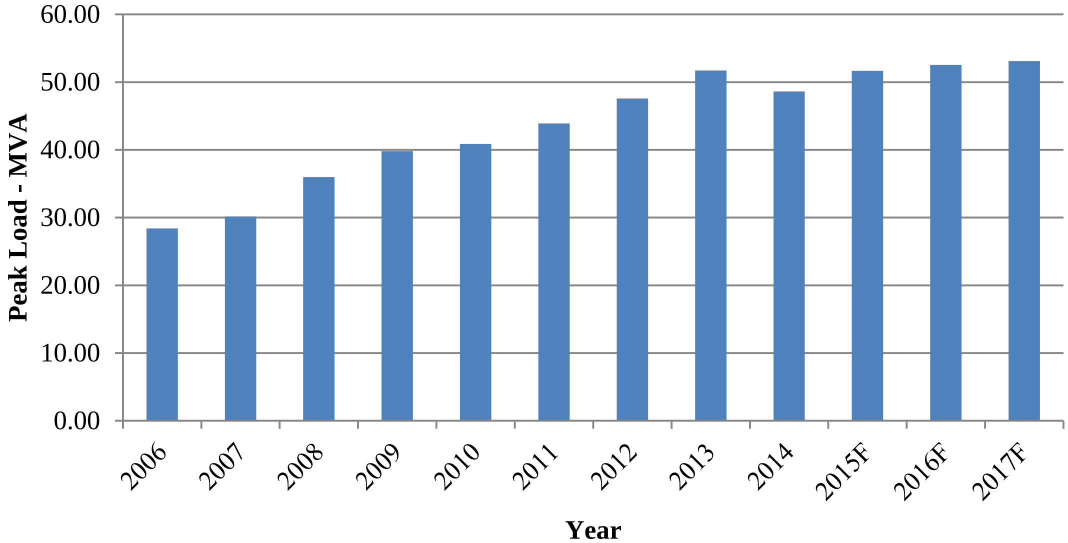
Graph 1
CHA Substation Customer Growth



[2] Hardwoods substation is represented by the acronym "HWD" throughout this report.

Graph 2 shows the historical load growth on CHA substation between 2006 and 2014, as well as the forecasted 2015, 2016, and 2017 loads.[3]

Graph 2
CHA Substation Load Growth



Both CHA-T1 and CHA-T2 transformers are rated for 25 MVA, with a combined parallel capacity of 49.3 MVA. The following is the forecasted peak substation load that is expected for CHA-T1 and CHA-T2 in the winter of 2017.

- CHA-T1 is rated for 25.0 MVA. The peak load on CHA-T1 is forecasted to be 27.0 MVA.
- CHA-T2 is rated for 25.0 MVA. The peak load on CHA-T2 is forecasted to be 26.2 MVA.

This study uses a 20 year load forecast for each substation transformer. The base case 20 year substation forecast for CHA-T1, CHA-T2, and HWD-T3 is located in Appendix B. High and low load growth forecasts have also been created for each alternative for use in a sensitivity analysis. With the exception of the first year forecast, the sensitivities are 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.

3 The reduction in peak load for CHA Substation in 2014 was the result of adjustments made to peak load data to account for cold load pickup during the January 2014 outages.

4.0 Development of Alternatives

Three alternatives have been developed to address the forecasted overload conditions using a set of defined technical criteria.[4] These alternatives will provide sufficient capacity to meet the forecasted loads over the next 20 years.

Each alternative contains estimates for all of the costs involved, including new substation transformers and feeders. The results of a net present value ("NPV") calculation are provided for each alternative.

4.1 Alternative 1

- In 2017, replace the existing 25 MVA, 66/25 kV CHA-T1 transformer with a new 50 MVA, 66/25 kV transformer. This new transformer would operate in parallel with the existing 25 MVA, 66/25 kV CHA-T2 transformer. This would increase the total substation 25 kV transformer capacity from 49.3 MVA to 74.4 MVA.[5] The old CHA-T1 will become a system spare.
- In 2017, construct a new 25 kV distribution feeder (CHA-04). This involves installing a new feeder termination at CHA, including a breaker and associated switches, as well as constructing approximately 0.35 km of new 477 ASC trunk feeder and upgrading 3.00 km of existing distribution line to 3-phase, 477 ASC conductor.[6] This new feeder will supply residential customers along Buckingham Drive, Topsail Pond Road, and Topsail Road as well as provide sufficient feeder capacity for future load growth in the area.

Table 1 shows the capital costs estimated for Alternative 1.

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[4] The following technical criteria were applied:
- The steady state substation 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 feeder normal peak loading should be sufficient to permit cold load pickup.

[5] New transformers are being purchased with a per unit impedance of 7% on the transformer base. As a result, the load split between new and existing transformers may not be evenly or proportionately divided so as to use 100% of each paralleled transformer's nameplate capacity. Therefore, the substation capacity is not necessarily equal to the sum of the paralleled transformer's capacities.

[6] The 3.00 km of existing distribution line that will be upgraded to 3-phase consists of two separate sections:
i) 1.55 km of 1-phase distribution line.
ii) 1.45 km of 2-phase distribution line.

Table 1
Alternative 1 Capital Costs

Year	Item	Cost
2017	Purchase and install a new 50 MVA transformer at CHA to replace the existing CHA-T1 and parallel it with the existing CHA-T2.	$2,574,000
2017	Distribution portion of the construction of a new 25 kV distribution feeder (CHA-04).	$793,000
2017	Substation portion of the construction of a new 25 kV distribution feeder (CHA-04).	$284,000
	Total	**$3,651,000**

The resultant peak load forecasts for CHA-T1, CHA-T2, and HWD-T3 under Alternative 1 are shown in Appendix C.

4.2 Alternative 2

- In 2017, add a new 25 MVA, 66/25 kV transformer (CHA-T3) to CHA Substation. The additional transformer would be configured to operate in parallel with the 25 MVA, 66/25 kV CHA-T1 transformer and the 25 MVA, 66/25 kV CHA-T2 transformer. This transformer addition would increase the total substation 25 kV transformer capacity from 49.3 MVA to 74.2 MVA.
- In 2017, construct a new 25 kV distribution feeder (CHA-04). This involves installing a new feeder termination at CHA, including a breaker and associated switches, as well as constructing approximately 0.35 km of new 477 ASC trunk feeder and upgrading 3.00 km of existing distribution line to 3-phase, 477 ASC. This new feeder will supply residential customers along Buckingham Drive, Topsail Pond Road, and Topsail Road as well as provide sufficient feeder capacity for future load growth in the area.

Table 2 shows the capital costs estimated for Alternative 2.

Table 2
Alternative 2 Capital Costs

Year	Item	Cost
2017	Purchase and install a new 25 MVA transformer (CHA-T3) at CHA and parallel it with the existing CHA-T1 and CHA-T2.	$2,670,000
2017	Distribution portion of the construction of a new 25 kV distribution feeder (CHA-04).	$793,000
2017	Substation portion of the construction of a new 25 kV distribution feeder (CHA-04).	$284,000
	Total	**$3,747,000**

The resultant peak load forecasts for CHA-T1, CHA-T2, CHA-T3, and HWD-T3 under Alternative 2 are shown in Appendix D.

4.3 Alternative 3

- In 2017, construct a new distribution feeder (HWD-10) between HWD and CHA to permit a load transfer of 10.0 MVA from CHA-02 feeder to HWD-10 feeder.[7] This involves installing a new feeder termination at HWD, including a breaker and associated switches, as well as constructing approximately 2.00 km of new 477 ASC trunk feeder and upgrading 2.90 km of existing distribution line to a double circuit configuration to create the necessary distribution connection to complete the load transfer.
- In 2019, add a new 25 MVA, 66/25 kV transformer (HWD-T4) to HWD Substation. The additional transformer would be configured to operate in parallel with the 50 MVA, 66/25 kV HWD-T3 transformer. This transformer addition would increase the total substation 25 kV transformer capacity from 50.0 MVA to 74.7 MVA.
- In 2031, replace the existing 25 MVA, 66/25 kV CHA-T1 transformer with a new 50 MVA, 66/25 kV transformer. This new transformer would operate in parallel with the existing 25 MVA, 66/25 kV CHA-T2 transformer. This would increase the total substation 25 kV transformer capacity from 49.3 MVA to 74.4 MVA. The old CHA-T1 will become a system spare.

[7] The transfer of load from CHA-02 to HWD-10 is practically fixed to 10.0 MVA due to the physical arrangement of the 2.25 km of 3-phase trunk distribution line heading north along St. Thomas Line from Topsail Road. To modify the transfer of load amount would require completing additional upgrades to existing distribution lines and would reduce the level of reliability currently provided through existing ties between CHA-02 and other HWD distribution feeders.

Table 3 shows the capital costs estimated for Alternative 3.

Table 3
Alternative 3 Capital Costs

Year	Item	Cost
2017	Distribution portion of the construction of a new 25 kV distribution feeder (HWD-10).	$1,344,000
2017	Substation portion of the construction of a new 25 kV distribution feeder (HWD-10).	$284,000
2019	Purchase and install a new 25 MVA transformer (HWD-T4) at HWD and parallel it with the existing HWD-T3.	$2,361,000
2031	Purchase and install a new 50 MVA transformer at CHA to replace the existing CHA-T1 and parallel it with the existing CHA-T2.	$2,574,000
	Total	**$6,563,000**

The resultant peak load forecasts for CHA-T1, CHA-T2, HWD-T3, and HWD-T4 under Alternative 3 are shown in Appendix E.

5.0 Evaluation of Alternatives

5.1 Economic Analysis

In order to compare the economic impact of the alternatives, a NPV calculation of customer revenue requirement was completed for each alternative. Capital costs from 2017 to 2034 were converted to the customer revenue requirement and the resulting customer revenue requirement was reduced to a NPV using the Company's weighted average incremental cost of capital.[8] Capital costs beyond the 20 year forecast period that are required to balance the installed transformer capacity across all 3 alternatives are also included in the NPV calculation and are known simply as end effect capital costs. The NPV analysis also accounts for the salvage value of assets removed from service.

[8] This analysis captures the customer revenue requirement for the life of a new transformer asset.

Table 4 shows the NPV of customer revenue requirement for each alternative under the base case load forecast.

Table 4
Net Present Value Analysis
($000)

Alternative	NPV
1	4,173
2	4,840
3	5,804

Alternative 1 has the lowest NPV of customer revenue requirement. As a result, Alternative 1 is recommended as the most appropriate expansion plan.

5.2 Sensitivity Analysis

To assess the sensitivity to load forecast variability of each alternative, high and low load growth forecasts were developed. The peak load forecasts for the sensitivity analysis are shown in Appendix C, D, and E for Alternatives 1, 2, and 3 respectively.

In general, the low load growth forecast results in delaying the required construction projects. Similarly, with a higher load growth forecast the timing of the required construction projects is advanced. Using these revised dates, the NPV of the customer revenue requirement was recalculated.

Table 5 shows the NPV of customer revenue requirement for each alternative under the high and low load forecasts.

Table 5
Sensitivity Analysis
($000)

Alternative	High Load Forecast NPV	Low Load Forecast NPV
1	4,729	3,668
2	5,396	4,335
3	6,290	4,211

Under all 3 scenarios, the base case, high and low growth forecasts, Alternative 1 is the least cost. This indicates that Alternative 1 is a suitable alternative under varying load growth scenarios. As a result, the recommendation to implement Alternative 1 is still appropriate given the results of the sensitivity analysis.

6.0 Project Costs

Table 6 shows the estimated project costs for the chosen alternative.

Table 6
Project Capital Costs

Year	Item	Cost
2017	Purchase and install a new 50 MVA transformer at CHA to replace the existing CHA-T1 and parallel it with the existing CHA-T2.	$2,574,000
2017	Distribution portion of the construction of a new 25 kV distribution feeder (CHA-04).	$793,000
2017	Substation portion of the construction of a new 25 kV distribution feeder (CHA-04).	$284,000
	Total	**$3,651,000**

7.0 Conclusion and Recommendation

A 20 year load forecast has projected the electrical demands for CHA substation. The development and analysis of distribution system alternatives has established a preferred expansion plan to meet the forecasted needs of the area.

The economic analysis performed in Section 5.1 of this study indicates that Alternative 1 is the least cost alternative that meets all of the required technical criteria. The sensitivity analysis performed in Section 5.2 indicates that Alternative 1 is the least cost alternative under both the high load growth forecast and the low load growth forecast. The sensitivity analysis is performed to ensure that the least cost alternative indicated by the economic analysis is a suitable alternative for varying levels of load growth. As a result, the Alternative 1 expansion plan has been selected as the most appropriate project.

The least cost expansion plan includes the following items in the 2017 Capital Budget:

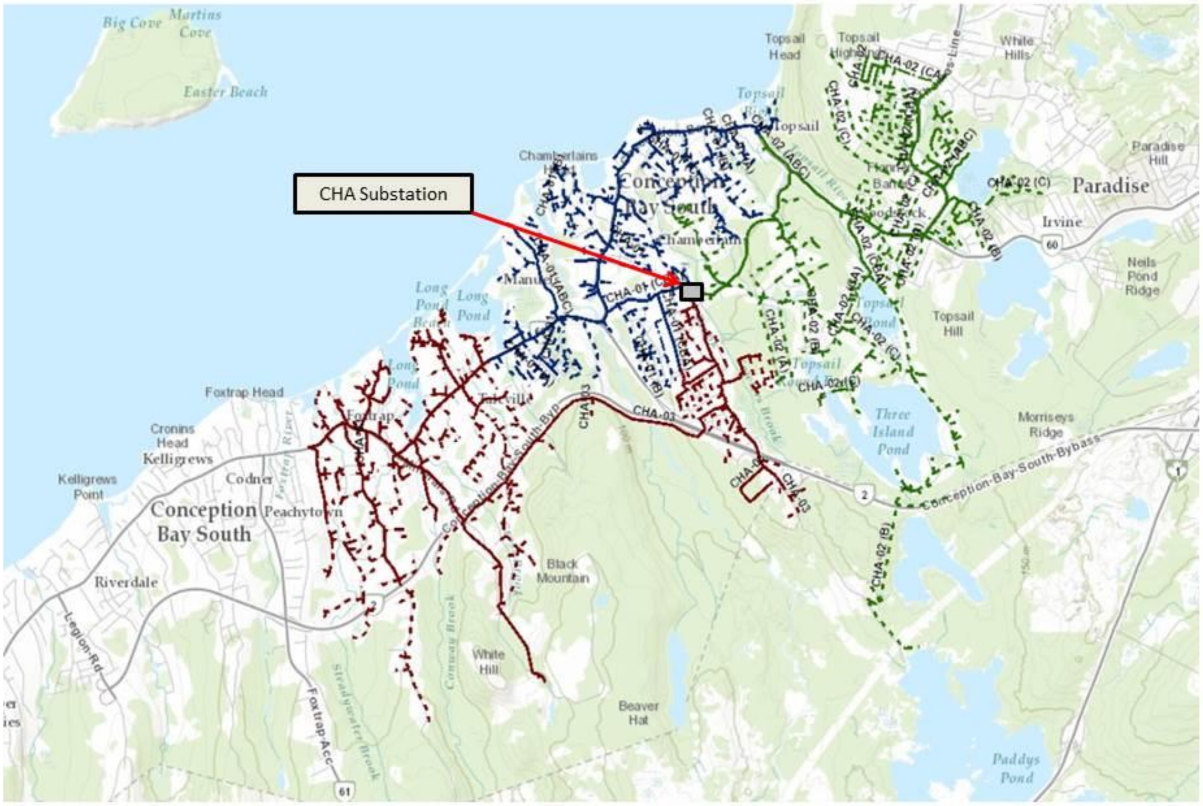
1) The purchase and installation of a new 50 MVA transformer at CHA to replace the existing CHA-T1 and parallel it with the existing CHA-T2.

2) The construction of a new 25 kV distribution feeder (CHA-04) for CHA, including the termination of the new feeder on the 25 kV substation bus.

The 2017 project is estimated to cost $3,651,000.

Appendix A
CHA Substation Service Area Map

CHA Substation Service Area Map



Appendix B
2015 Substation Load Forecast – Base Case

20 Year Substation Load Forecast – Base Case

Device	CHA-T1	CHA-T2	HWD-T3
Sec. Voltage (kV)	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	50.0
2014 Peak (MVA)	24.7	24.0	41.9
Year	**Forecasted Undiversified Peak (MVA)**		
2015	26.2	25.5	46.0
2016	26.7	25.9	38.8[1]
2017	27.0	26.2	39.2
2018	27.3	26.5	39.7
2019	27.6	26.7	40.1
2020	27.8	26.9	40.4
2021	28.0	27.1	40.7
2022	28.2	27.4	41.0
2023	28.4	27.6	41.3
2024	28.6	27.8	41.6
2025	28.8	28.0	41.9
2026	29.0	28.2	42.2
2027	29.3	28.4	42.5
2028	29.5	28.6	42.9
2029	29.7	28.8	43.2
2030	29.9	29.0	43.5
2031	30.1	29.3	43.8
2032	30.4	29.5	44.2
2033	30.6	29.7	44.5
2034	30.8	29.9	44.8

[1] A load transfer of 8.0 MVA from HWD-T3 to KEN-T1/T2 is scheduled to occur in 2016.

Appendix C
Alternative 1
20 Year Substation Load Forecasts

Alternative 1
20 Year Substation Load Forecast – Base Case

Device	**CHA-T1**	**CHA-T2**	**CHA-T1 (New)**	**HWD-T3**
Sec. Voltage (kV)	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	50.0	50.0
2014 Peak (MVA)	24.7	24.0	N/A	41.9
Year	**Forecasted Undiversified Peak (MVA)**			
2015	26.2	25.5	0.0	46.0
2016	26.7	25.9	0.0	38.8
2017	0.0	17.4	35.7	39.2
2018	0.0	17.6	36.1	39.7
2019	0.0	17.8	36.5	40.1
2020	0.0	17.9	36.8	40.4
2021	0.0	18.1	37.1	40.7
2022	0.0	18.2	37.3	41.0
2023	0.0	18.3	37.6	41.3
2024	0.0	18.5	37.9	41.6
2025	0.0	18.6	38.2	41.9
2026	0.0	18.8	38.5	42.2
2027	0.0	18.9	38.8	42.5
2028	0.0	19.0	39.1	42.9
2029	0.0	19.2	39.3	43.2
2030	0.0	19.3	39.6	43.5
2031	0.0	19.5	39.9	43.8
2032	0.0	19.6	40.2	44.2
2033	0.0	19.8	40.5	44.5
2034	0.0	19.9	40.8	44.8

Alternative 1
20 Year Substation Load Forecast – High Growth

Device	**CHA-T1**	**CHA-T2**	**CHA-T1 (New)**	**HWD-T3**
Sec. Voltage (kV)	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	50.0	50.0
2014 Peak (MVA)	24.7	24.0	N/A	41.9
Year	**Forecasted Undiversified Peak (MVA)**			
2015	26.2	25.5	0.0	46.0
2016	26.9	26.1	0.0	39.2
2017	0.0	17.6	36.2	39.9
2018	0.0	18.0	36.9	40.6
2019	0.0	18.2	37.4	41.2
2020	0.0	18.4	37.8	41.7
2021	0.0	18.7	38.3	42.1
2022	0.0	18.9	38.7	42.6
2023	0.0	19.1	39.1	43.1
2024	0.0	19.3	39.6	43.6
2025	0.0	19.5	40.0	44.1
2026	0.0	19.7	40.5	44.5
2027	0.0	19.9	40.9	45.0
2028	0.0	20.2	41.4	45.6
2029	0.0	20.4	41.9	46.1
2030	0.0	20.6	42.3	46.6
2031	0.0	20.9	42.8	47.1
2032	0.0	21.1	43.3	47.6
2033	0.0	21.3	43.8	48.2
2034	0.0	21.6	44.3	48.7

Alternative 1
20 Year Substation Load Forecast – Low Growth

Device	CHA-T1	CHA-T2	CHA-T1 (New)	HWD-T3
Sec. Voltage (kV)	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	50.0	50.0
2014 Peak (MVA)	24.7	24.0	N/A	41.9
Year	**Forecasted Undiversified Peak (MVA)**			
2015	26.2	25.5	0.0	46.0
2016	26.4	25.7	0.0	38.4
2017	0.0	17.2	35.2	38.6
2018	0.0	17.3	35.4	38.9
2019	0.0	17.4	35.6	39.1
2020	0.0	17.4	35.7	39.2
2021	0.0	17.5	35.9	39.4
2022	0.0	17.6	36.0	39.5
2023	0.0	17.6	36.2	39.6
2024	0.0	17.7	36.3	39.8
2025	0.0	17.8	36.4	39.9
2026	0.0	17.8	36.6	40.1
2027	0.0	17.9	36.7	40.2
2028	0.0	18.0	36.8	40.4
2029	0.0	18.0	37.0	40.5
2030	0.0	18.1	37.1	40.7
2031	0.0	18.2	37.3	40.9
2032	0.0	18.2	37.4	41.0
2033	0.0	18.3	37.5	41.2
2034	0.0	18.4	37.7	41.3

Appendix D
Alternative 2
20 Year Substation Load Forecasts

Alternative 2
20 Year Substation Load Forecast – Base Case

Device	**CHA-T1**	**CHA-T2**	**CHA-T3 (New)**	**HWD-T3**
Sec. Voltage (kV)	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	25.0	50.0
2014 Peak (MVA)	24.7	24.0	N/A	41.9
Year	**Forecasted Undiversified Peak (MVA)**			
2015	26.2	25.5	0.0	46.0
2016	26.7	25.9	0.0	38.8
2017	17.9	17.4	17.8	39.2
2018	18.1	17.6	18.0	39.7
2019	18.3	17.8	18.2	40.1
2020	18.4	17.9	18.4	40.4
2021	18.6	18.0	18.5	40.7
2022	18.7	18.2	18.6	41.0
2023	18.9	18.3	18.8	41.3
2024	19.0	18.4	18.9	41.6
2025	19.2	18.6	19.1	41.9
2026	19.3	18.7	19.2	42.2
2027	19.4	18.9	19.3	42.5
2028	19.6	19.0	19.5	42.9
2029	19.7	19.1	19.6	43.2
2030	19.9	19.3	19.8	43.5
2031	20.0	19.4	19.9	43.8
2032	20.2	19.6	20.1	44.2
2033	20.3	19.7	20.2	44.5
2034	20.5	19.9	20.4	44.8

Alternative 2
20 Year Substation Load Forecast – High Growth

Device	**CHA-T1**	**CHA-T2**	**CHA-T3 (New)**	**HWD-T3**
Sec. Voltage (kV)	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	25.0	50.0
2014 Peak (MVA)	24.7	24.0	N/A	41.9
Year	**Forecasted Undiversified Peak (MVA)**			
2015	26.2	25.5	0.0	46.0
2016	26.9	26.1	0.0	39.2
2017	18.2	17.6	18.1	39.9
2018	18.5	17.9	18.4	40.6
2019	18.8	18.2	18.7	41.2
2020	19.0	18.4	18.9	41.7
2021	19.2	18.6	19.1	42.1
2022	19.4	18.8	19.3	42.6
2023	19.6	19.0	19.5	43.1
2024	19.8	19.3	19.8	43.6
2025	20.1	19.5	20.0	44.1
2026	20.3	19.7	20.2	44.5
2027	20.5	19.9	20.4	45.0
2028	20.8	20.1	20.7	45.6
2029	21.0	20.4	20.9	46.1
2030	21.2	20.6	21.1	46.6
2031	21.5	20.8	21.4	47.1
2032	21.7	21.1	21.6	47.6
2033	22.0	21.3	21.8	48.2
2034	22.2	21.5	22.1	48.7

Alternative 2
20 Year Substation Load Forecast – Low Growth

Device	CHA-T1	CHA-T2	CHA-T3 (New)	HWD-T3
Sec. Voltage (kV)	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	25.0	50.0
2014 Peak (MVA)	24.7	24.0	N/A	41.9
Year	**Forecasted Undiversified Peak (MVA)**			
2015	26.2	25.5	0.0	46.0
2016	26.4	25.7	0.0	38.4
2017	17.7	17.1	17.6	38.6
2018	17.8	17.2	17.7	38.9
2019	17.9	17.3	17.8	39.1
2020	17.9	17.4	17.8	39.2
2021	18.0	17.5	17.9	39.4
2022	18.1	17.5	18.0	39.5
2023	18.1	17.6	18.0	39.6
2024	18.2	17.7	18.1	39.8
2025	18.3	17.7	18.2	39.9
2026	18.3	17.8	18.3	40.1
2027	18.4	17.9	18.3	40.2
2028	18.5	17.9	18.4	40.4
2029	18.5	18.0	18.5	40.5
2030	18.6	18.1	18.5	40.7
2031	18.7	18.1	18.6	40.9
2032	18.8	18.2	18.7	41.0
2033	18.8	18.3	18.7	41.2
2034	18.9	18.3	18.8	41.3

Appendix E
Alternative 3
20 Year Substation Load Forecasts

Alternative 3
20 Year Substation Load Forecast – Base Case

Device	CHA-T1	CHA-T2	CHA-T1 (New)	HWD-T3	HWD-T4 (New)
Sec. Voltage (kV)	25.0	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	50.0	50.0	25.0
2014 Peak (MVA)	24.7	24.0	N/A	41.9	N/A
Year	**Forecasted Undiversified Peak (MVA)**				
2015	26.2	25.5	0.0	46.0	0.0
2016	26.7	25.9	0.0	38.8	0.0
2017	21.9	21.2	0.0	49.2	0.0
2018	22.2	21.6	0.0	49.7	0.0
2019	22.5	21.8	0.0	33.5	16.6
2020	22.7	22.0	0.0	33.7	16.6
2021	22.9	22.2	0.0	33.9	16.7
2022	23.1	22.4	0.0	34.1	16.9
2023	23.3	22.6	0.0	34.3	17.0
2024	23.5	22.8	0.0	34.5	17.1
2025	23.7	23.0	0.0	34.8	17.2
2026	24.0	23.3	0.0	35.0	17.3
2027	24.2	23.5	0.0	35.2	17.4
2028	24.4	23.7	0.0	35.4	17.5
2029	24.6	23.9	0.0	35.6	17.6
2030	24.8	24.1	0.0	35.8	17.7
2031	0.0	16.2	33.2	36.0	17.8
2032	0.0	16.3	33.5	36.3	17.9
2033	0.0	16.5	33.8	36.5	18.0
2034	0.0	16.6	34.1	36.7	18.1

Alternative 3
20 Year Substation Load Forecast – High Growth

Device	CHA-T1	CHA-T2	CHA-T1 (New)	HWD-T3	HWD-T4 (New)
Sec. Voltage (kV)	25.0	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	50.0	50.0	50.0
2014 Peak (MVA)	24.7	24.0	N/A	41.9	N/A
Year	**Forecasted Undiversified Peak (MVA)**				
2015	26.2	25.5	0.0	46.0	0.0
2016	26.9	26.1	0.0	39.2	0.0
2017	22.3	21.6	0.0	49.9	0.0
2018	22.8	22.1	0.0	33.9	16.7
2019	23.2	22.5	0.0	34.3	16.9
2020	23.5	22.8	0.0	34.6	17.1
2021	23.8	23.1	0.0	34.9	17.2
2022	24.1	23.4	0.0	35.2	17.4
2023	24.5	23.7	0.0	35.5	17.5
2024	24.8	24.1	0.0	35.9	17.7
2025	0.0	16.2	33.3	36.2	17.9
2026	0.0	16.4	33.7	36.5	18.0
2027	0.0	16.7	34.2	36.9	18.2
2028	0.0	16.9	34.7	37.2	18.4
2029	0.0	17.1	35.1	37.5	18.5
2030	0.0	17.4	35.6	37.9	18.7
2031	0.0	17.6	36.1	38.2	18.9
2032	0.0	17.8	36.6	38.6	19.0
2033	0.0	18.1	37.0	38.9	19.2
2034	0.0	18.3	37.5	39.3	19.4

Alternative 3
20 Year Substation Load Forecast – Low Growth

Device	**CHA-T1**	**CHA-T2**	**HWD-T3**	**HWD-T4 (New)**
Sec. Voltage (kV)	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	50.0	25.0
2014 Peak (MVA)	24.7	24.0	41.9	N/A
Year	**Forecasted Undiversified Peak (MVA)**			
2015	26.2	25.5	46.0	0.0
2016	26.4	25.7	38.4	0.0
2017	21.5	20.9	48.6	0.0
2018	21.7	21.0	48.9	0.0
2019	21.8	21.2	49.1	0.0
2020	21.9	21.3	49.2	0.0
2021	22.0	21.4	49.4	0.0
2022	22.1	21.5	49.5	0.0
2023	22.2	21.6	49.6	0.0
2024	22.3	21.7	49.8	0.0
2025	22.4	21.8	49.9	0.0
2026	22.5	21.9	33.5	16.6
2027	22.6	22.0	33.6	16.6
2028	22.7	22.1	33.7	16.7
2029	22.8	22.2	33.8	16.7
2030	22.9	22.3	33.9	16.8
2031	23.0	22.4	34.0	16.8
2032	23.2	22.5	34.1	16.9
2033	23.3	22.6	34.3	16.9
2034	23.4	22.7	34.4	17.0

2017 Transmission Line Rebuild

July 2016

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1.0 Transmission Line Rebuild Strategy

Newfoundland Power's transmission lines are the bulk transmitter of electricity providing service to customers. The Company's transmission lines operate at 66 kV or 138 kV and are often located across country, away from road right of ways.

In 2006, Newfoundland Power (the "Company") submitted its *Transmission Line Rebuild Strategy* outlining a long term plan to rebuild aging transmission lines. This plan laid out 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 it reflects the latest reliability data, inspection information, and condition assessments.

Appendix A contains the updated Transmission Line Rebuild Strategy Schedule.

2.0 2017 Transmission Line Rebuild Projects

In 2017, the Company proposes to rebuild sections of 3 transmission lines totalling 24.3 km with an average age of 58 years.[1] Appendix B contains maps of each of the lines to be rebuilt. Appendix C contains photographs of the existing lines.

The transmission lines sections to be rebuilt in 2017 are included in Table 1.

Table 1
2017 Transmission Line Rebuilds

Transmission Line	Distance to be Rebuilt	Year Constructed
32L	1.4 km	1963
41L	13.6 km	1958
57L	9.3 km	1958

All of these sections of transmission line have deteriorated 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.

Upgrading of these sections of line will improve the overall reliability of the transmission system that serves customers in these areas.

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1 This 24.3 km represents approximately 1% of the total 2,000 km of transmission lines owned and maintained by Newfoundland Power.

2.1 Transmission Line 32L ($384,000)

Transmission line 32L is a 66 kV single pole line running between Ridge Road Substation ("RRD") and Oxen Pond Substation ("OXP") in St. John's.

The 3.2 km transmission line was originally constructed in 1963. Sections of the line have been rebuilt over the years, with 1.4 km of original vintage line remaining. This section consists of 35 single pole structures, some of which have under built distribution circuitry. The route taken by the transmission line, as shown by Figure 1 of Appendix B, is through Pippy Park and along Ridge Road, a residential and institutional area of the City of St. John's.

Inspections have identified deterioration due to decay, splits and checks in the poles and crossarms. Many of these wooden components are in advanced stages of deterioration and require replacement.[2] The majority of the wooden poles are original vintage and have surpassed their normal life expectancy. The line sustained wind damage during Hurricane Igor in 2010 with some severely damaged poles being replaced at that time. However severe checking of the poles that remained in service has exposed interior wood to the environment and has resulted in deterioration of the core.

Transmission line 32L also contains insulators manufactured by Canadian Ohio Brass. These insulators are identified as deficiencies due to a history of premature failure caused by cement growth. As the cement in these insulators expands, cracks in the porcelain insulator discs occur making the insulators more susceptible to flashovers.

This line was built to weather loading criteria that are less than the standards currently used to construct new lines in this area. Due to the age and condition of the line it is susceptible to damage should it become exposed to severe wind, ice or snow loading.

The transmission line has reached a point where continued maintenance is no longer feasible and it has to be rebuilt to continue its safe, reliable operation.

Based on the overall deteriorated condition and weather loadings experienced on the line, it is recommended the line be rebuilt to current design standards in 2017 at an estimated cost of $384,000.

2.2 Transmission Line 41L ($2,510,000)

Transmission line 41L is a 66 kV line running between Carbonear Substation ("CAR") and Heart's Content Substation ("HCT"). The line was originally constructed in 1958, with the exception of a 2.0 km section extending into CAR substation which was constructed in 1974, and a 5.3 km section that was rebuilt after the March 2010 ice storm. Approximately 13.6 km of original vintage line, consisting of 55 two-pole and three-pole H-Frame structures and 3 single

[2] Figures 1 through 5 in Appendix C show examples of deterioration such as pole top checks, broken crossarms, vandalism, splits and shell separation.

pole structures, remain in service. The conductor on this line is 4/0 ACSR, which is non-standard. The route taken by the transmission line is shown in Figure 2 of Appendix B.

Inspections have identified significant deterioration of the line due to decay, splits and checks in the poles and crossarms, cracks in insulators and other hardware deficiencies. Many of these components are in advanced stages of deterioration and require replacement.[3]

The design standards in place during construction of 41L did not include the requirement for crossbraces on the H-Frame structures.[4] Some of the structure types used on the line have since been identified as failure points when subjected to extreme weather loads and have thus been removed from the Company's design standards.

This line was built to weather loading criteria that are less than the standards currently used to construct new lines in this area. Due to the age and condition of the line it is susceptible to damage should it become exposed to severe wind, ice or snow loading.

The transmission line has reached a point where continued maintenance is no longer feasible and it has to be rebuilt to continue its safe, reliable operation.

Based on the age, deteriorated condition and weather loadings experienced on this section of line it is recommended that the section be rebuilt to current design standards in 2017 at an estimated cost of $2,510,000.

2.3 Transmission Line 57L ($1,521,000 in 2016 and $1,717,000 in 2017)

Transmission line 57L is a 66 kV line running between Bay Roberts Substation ("BRB") and Harbour Grace Substation ("HGR"). The line was originally constructed in 1958, with the exception of an 8 km section extending into Island Cove Substation ("ILC") which was constructed in 1989. Approximately 17.8 km of original vintage line, consisting of 186 two-pole and three-pole H-Frame structures, remain in service. The conductor on this line is 4/0 ACSR, which is non-standard. The route taken by the transmission line is shown in Figure 3 of Appendix B.

Inspections have identified significant deterioration of the line due to decay, splits and checks in the poles and crossarms, cracks in insulators and other hardware deficiencies. Many of these components are in advanced stages of deterioration and require replacement.[5]

The design standards in place during construction of 57L did not include crossbraces on the H-Frame structures. Some of the structure types used on the line have since been identified as failure points when subjected to extreme weather loads and have thus been removed from the Company's design standards.

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3 Figures 6 through 11 in Appendix C show examples of deterioration such as pole top checks, broken crossarms, vandalism, splits and shell separation.

4 Figure 9 in Appendix C shows an example of a two-pole H-Frame structure without cross bracing.

5 Figures 12 through 18 in Appendix C show examples of deterioration such as pole top checks, broken crossarms, vandalism, splits and shell separation.

This line was built to weather loading criteria that are less than the standards currently used to construct new lines in this area. Due to the age and condition of the line it is susceptible to damage should it become exposed to severe wind, ice or snow loading.

The transmission line has reached a point where continued maintenance is no longer feasible and it has to be rebuilt to continue its safe, reliable operation.

In Order No. P.U. 028 (2015) the Board approved a multiyear project to rebuild transmission line 57L. In 2016 work is ongoing to rebuild 8.5 km of 57L at an estimated cost of $1,521,000.

In 2017, the remaining 9.3 km of line will be rebuilt. The 2017 section will be completed at an estimated cost of $1,717,000.[6]

3.0 Concluding

In 2017, the Company will rebuild sections of 32L, 41L and 57L. Each of these transmission lines has structures experiencing deterioration of the poles, crossarms, hardware, and conductor. Recent inspections and engineering assessment have determined the transmission lines have reached a point where continued maintenance is no longer feasible and they have to be rebuilt to continue providing safe, reliable electrical service.

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

[6] Figure 3 in Appendix B shows the route taken by 57L and identifies the sections to be completed in 2016 and 2017.

Appendix A
Transmission Line Rebuild Strategy Schedule

Transmission Line Rebuilds 2017 – 2021 ($000s)						
Line	**Year**	**2017**	**2018**	**2019**	**2020**	**2021**
057L BRB-HGR	1958	1,717				
032L OXP-RRD	1959	384				
041L CAR-HCT	1958	2,510				
302L SPO-LAU	1959		2,500	2,612		
363L BVJ-SCR	1963		2,885	4,785	4,985	
102L GAN-RBK	1958				1,232	3,325
101L GFS-RBK	1957					4,504
055L BLK - CLK	1971					980
	Total	**4,611**	**5,385**	**7,397**	**6,217**	**8,809**

Appendix B
Maps of Transmission Lines
32L, 41L and 57L

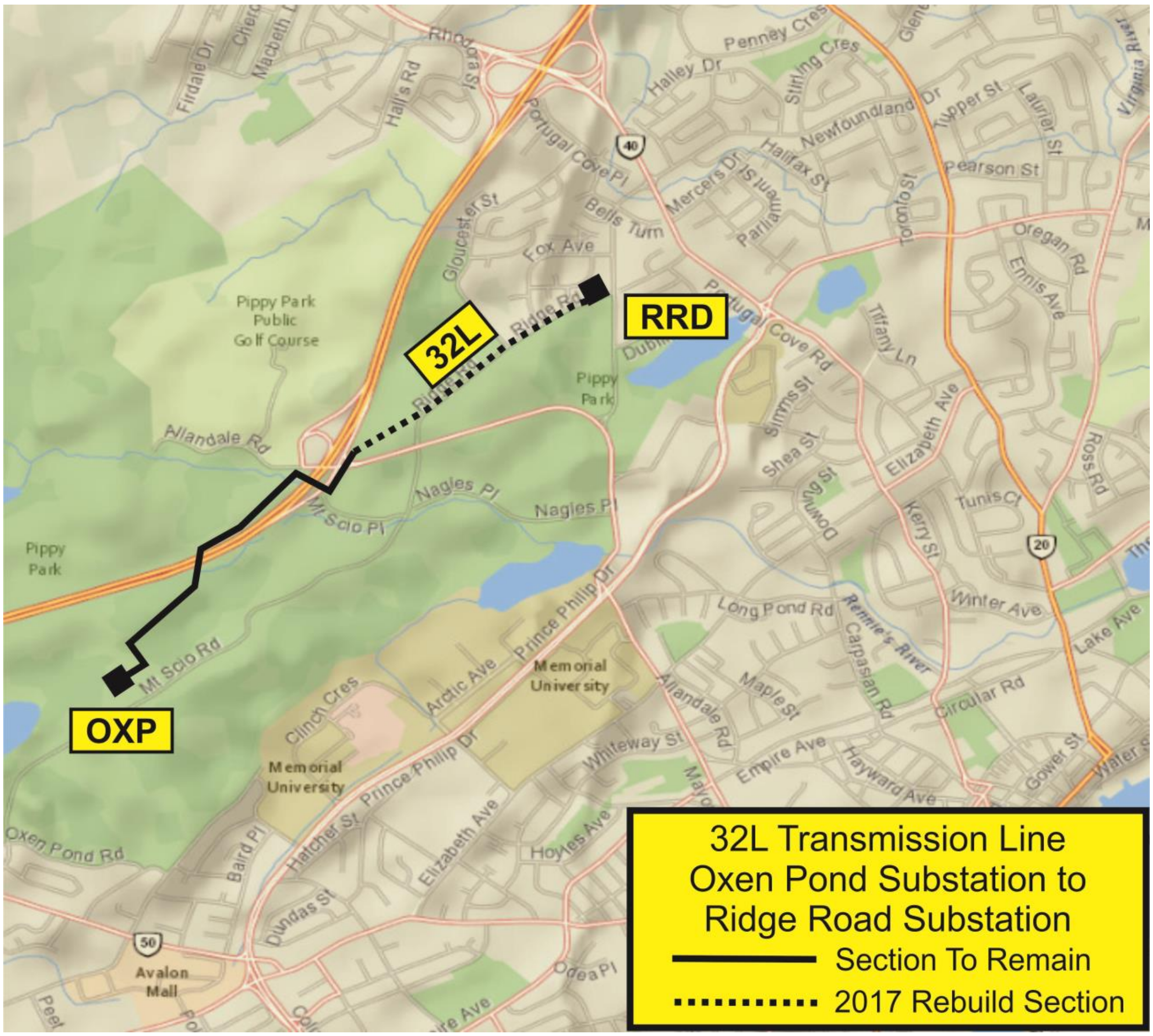

Figure 1 – Map of 32L Route

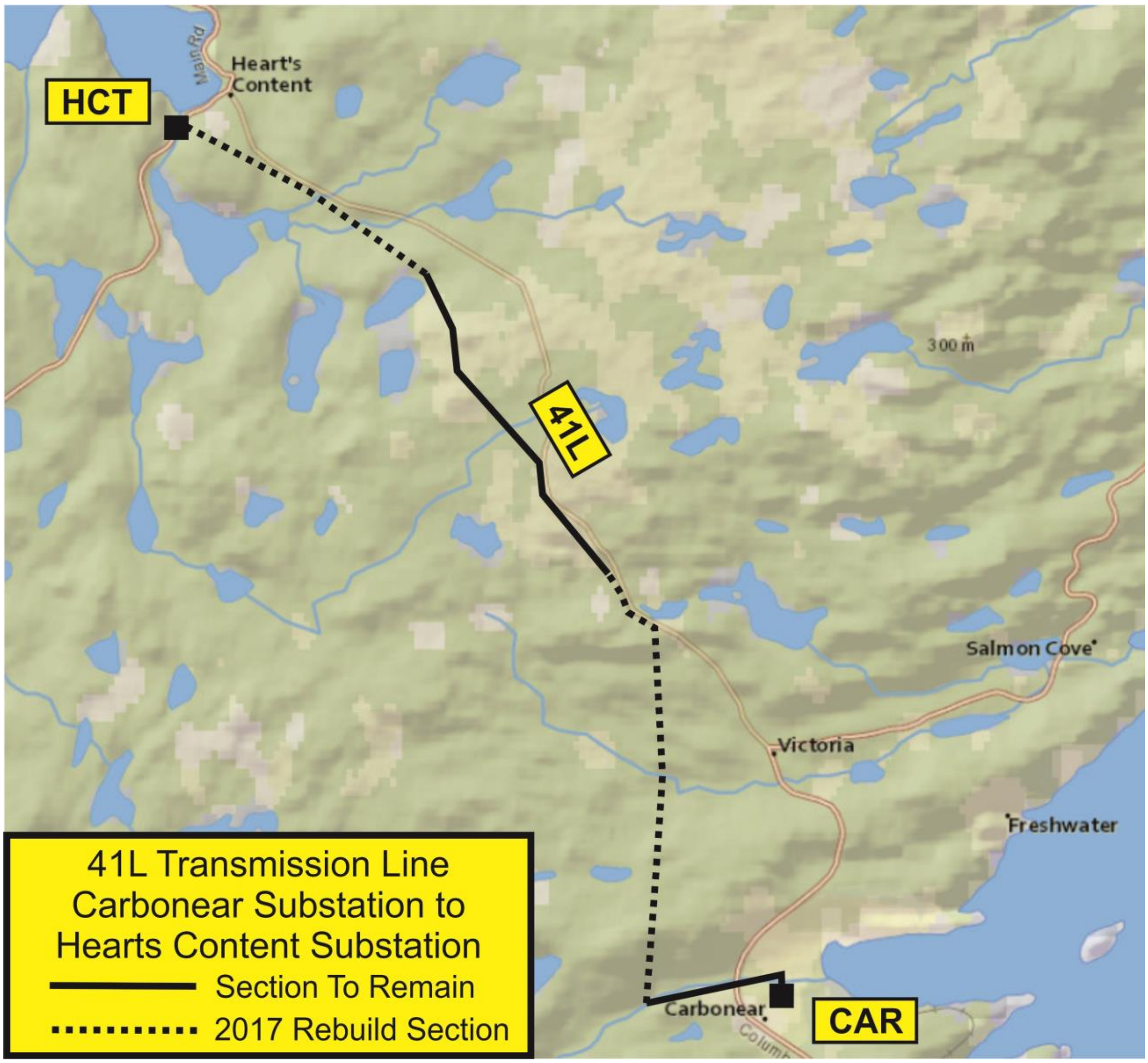

Figure 2 – Map of 41L Route

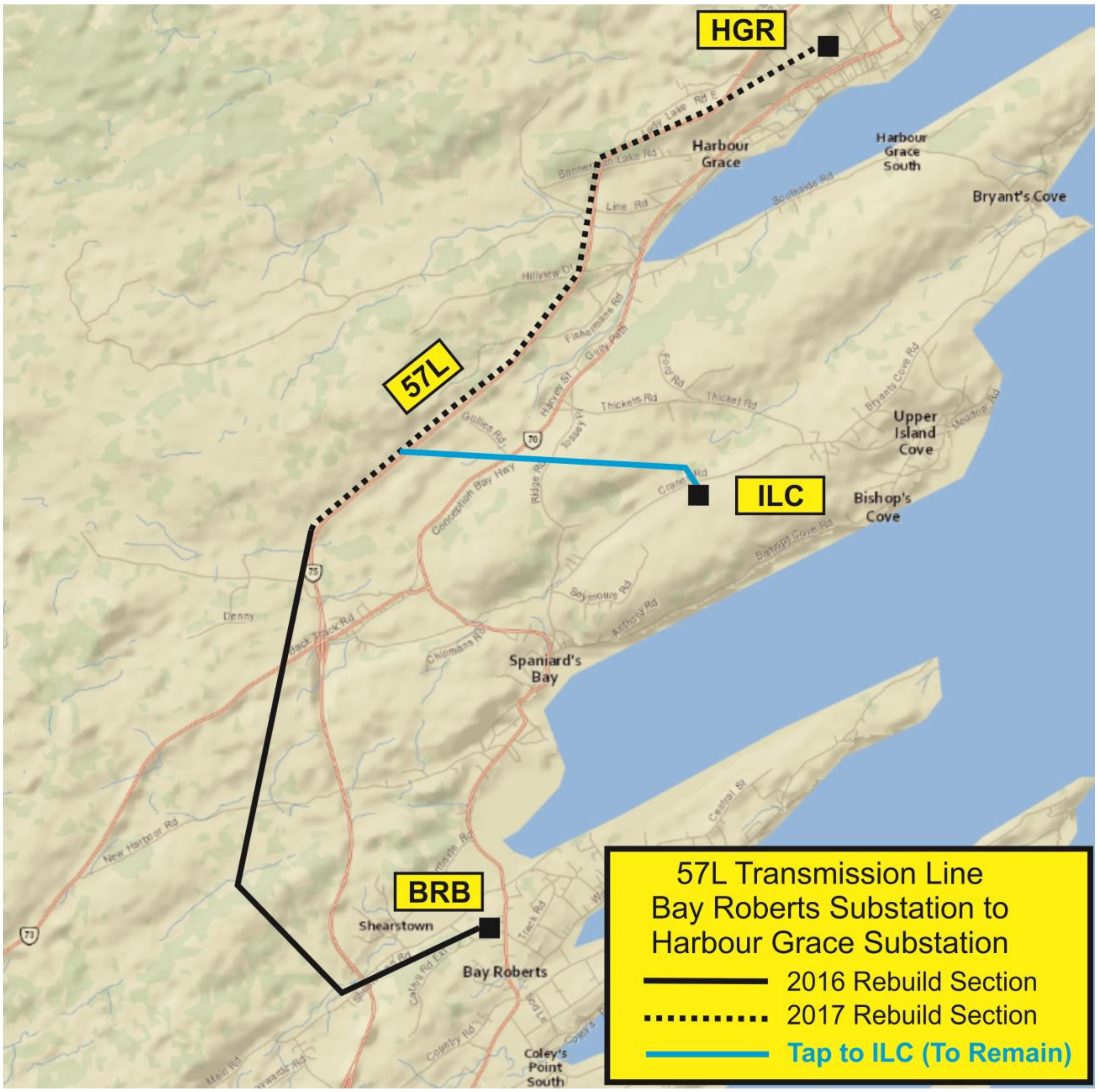

Figure 3 – Map of 57L Route

Appendix C
Photographs of Transmission Lines
32L, 41L and 57L

Transmission Line 32L

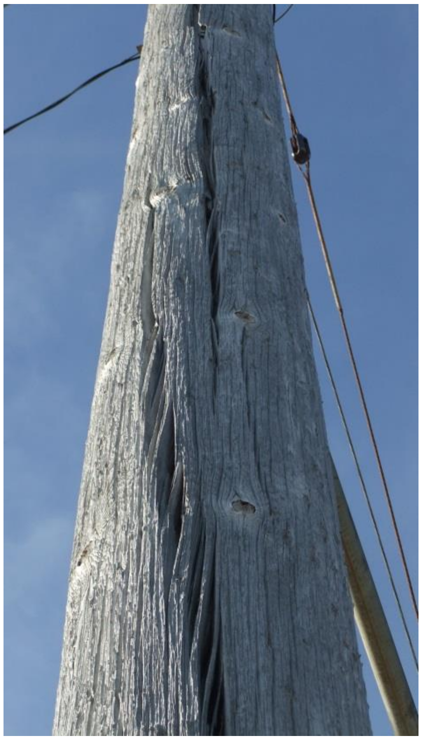

Figure 1 – Pole Checking

Figure 2 – Pole Shell Layer Separation

Figure 3 – Split Crossarm

Figure 4 – Split Crossarms with Temporary Bracing

Figure 5 – Bolts Provide Temporary Repairs to Damaged Pole

Transmission Line 41L

Figure 6 – Deteriorated Pole

Figure 7 – Woodpecker Holes in Pole

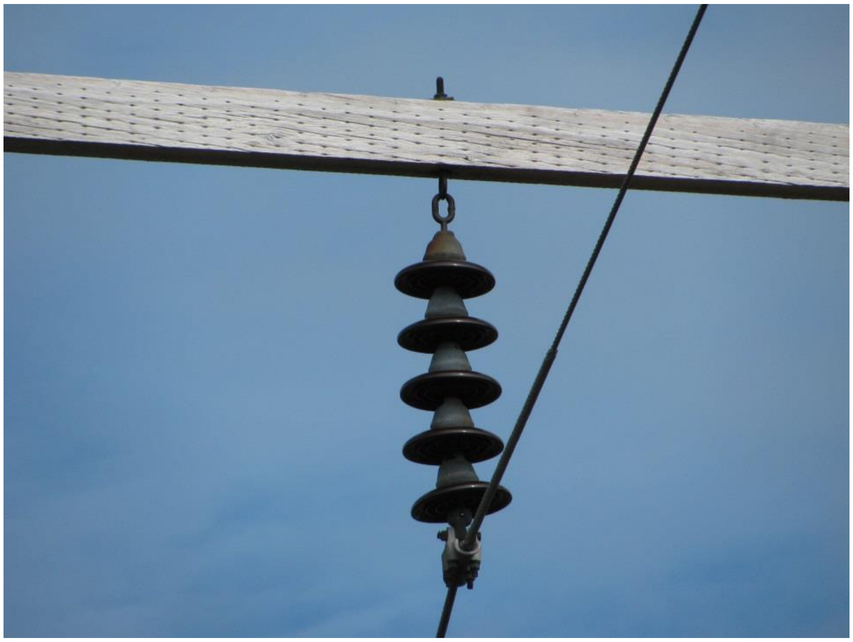

Figure 8 – Original Vintage COB Porcelain Insulators

Figure 9 – Original Structure Without Crossbracing

Figure 10 – Worn Ball Link Eye Bolts

Figure 11 – Worn Ball Link Eye Bolt Recently Removed

<u>Transmission Line 57L</u>

Figure 12 – Severe Check in Pole Top

Figure 13 – Damage Resulting from Rotten Crossarm

Figure 14 – Vandalism - Pole Damage

Figure 15 – Woodpecker Hole Damage

Figure 16 – Split Crossarm

Figure 17 – Outer Shell Layer Separation

Figure 18 – Twisted Structure

Distribution Reliability Initiative

June 2016

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1.0 Introduction

The Distribution Reliability Initiative is a capital project focusing 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.

The process used by Newfoundland Power to identify which distribution feeders will benefit from targeted capital investment involves (i) calculating reliability performance indices for all feeders, (ii) analysing the reliability data for the worst performing feeders to identify the cause of the poor reliability performance and (iii) where appropriate complete engineering assessments for those feeders where poor reliability performance cannot be directly related to isolated events that have already been addressed. The decision to make capital investment to improve the reliability performance of the worst performing feeders is based upon the engineering assessments completed as part of the process.

2.0 Background

Previously Newfoundland Power identified its worst performing feeders exclusively on the basis of System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI") and customer minutes of outage.[1] These are the indices most commonly used in Canada and are reflective of the overall system condition.

SAIDI and SAIFI are used to rank the reliability performance of distribution feeders on the impact outages have on individual customers. However, it is recognized that relying solely on these indices to identify worst performing feeders can lead to overlooking smaller feeders with chronic issues.[2]

In 2012, the Canadian Electricity Association began reporting on 2 additional indices; Customer Hours of Interruption per Kilometer ("CHIKM") and Customers Interrupted per Kilometer ("CIKM").[3] CHIKM and CIKM are used to rank the reliability performance of distribution feeders on the length of line exposed to the outage. These indices tend to be more reflective of

---

1 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. System Average Interruption Frequency Index (SAIFI) is 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 Smaller feeders will have fewer customers than larger feeders and as a result outages of similar duration will involve less customer minutes of outage.

3 Customers Interrupted per Kilometer (CIKM) is calculated by dividing the number of customers that have experienced an outage by the kilometres of line. Customer Hours of Interruption per Kilometer (CHIKM) is calculated by dividing the number of customer-outage-hours by the kilometres of line.

infrastructure condition and better identify issues associated with shorter feeders. Similar to SAIDI and SAIFI, CHIKM and CIKM are used to rank worst performing feeders that require further analysis of reliability data, and where appropriate, complete engineering assessments to determine if targeted capital investment is warranted to improve service reliability.

Newfoundland Power has incorporated CIKM and CHIKM into its reliability analysis in this report.[4] Appendix A contains the 5-year average distribution reliability data, excluding significant events, for the 15 worst performing feeders based on data for 2011 to 2015, utilizing SAIDI, SAIFI, customer minutes, CIKM and CHIKM.

Appendix B contains a summary of the assessment carried out on each of the feeders listed in Appendix A.

3.0 Project Description

The examination of the worst performing feeders, as listed in Appendix A and Appendix B, has resulted in *Distribution Reliability Initiative* work being proposed on 3 distribution feeders, SUM-02, TRP-01 and RVH-02.

A detailed engineering assessment of these distribution feeders is included in Appendix C, Appendix D, and Appendix E to this report.

Table 1 summarizes the reliability data for each of the 3 distribution feeders identified and compares those data to Company averages.

Table 1
Distribution Interruption Statistics
5 Years to December 31, 2015

Feeder	Customers	SAIFI	SAIDI	CHIKM	CIKM
SUM-02	615	2.97	10.93	84	8
TRP-01	611	2.42	4.81	26	2
RVH-02	153	4.20	6.24	29	5
Company Average	**839**	**1.39**	**1.74**	**45**	**35**

Table 1 shows that distribution feeders RVH-02, SUM-02 and TRP-01 are outliers from the Company average for SAIFI and SAIDI.[5] An analysis of the outage data reveals that equipment failure has been the cause of most of the outages experienced.

[4] Newfoundland Power started using the CIKM and CHIKM in its analysis of worst performing feeders in 2015. It is anticipated that by using indices that consider customer interruptions and circuit length that the worst performing feeders will be found in urban settings where the Company has older poles and associated infrastructure.

[5] The SAIFI for these 3 feeders is between 2.0 to 3.0 times the Company average while SAIDI is between 2.5 and 6.3 times the Company average.

4.0 Project Cost

The Company proposes to complete the *Distribution Reliability Initiative* work over 2 years for distribution feeders SUM-02 and TRP-01. The *Distribution Reliability Initiative* work on distribution feeder RVH-01 will be completed in 2017.

The estimate to complete the 2017 work associated with the *2017 Distribution Reliability Initiative* project is $1,415,000. Table 2 provides a detailed breakdown of the 2017 project cost by distribution feeder.

Table 2
2017 Project Cost

Description	SUM-02	TRP-01	RVH-02	Total
Engineering	$ 97,000	$49,000	$19,000	$165,000
Labour - Contract	54,000	83,000	19,000	156,000
Labour - Internal	241,000	81,000	36,000	358,000
Material	208,000	106,000	38,000	352,000
Other	191,000	105,000	88,000	384,000
Total	**$791,000**	**$424,000**	**$200,000**	**$1,415,000**

The estimate to complete the 2018 work associated with the *2017 Distribution Reliability Initiative* project is $1,431,000. Table 3 provides a detailed breakdown of the 2018 project cost by distribution feeder.

Table 3
2018 Project Cost

Description	SUM-02	TRP-01	Total
Engineering	$123,000	$49,000	$172,000
Labour - Contract	69,000	83,000	152,000
Labour - Internal	307,000	81,000	388,000
Material	265,000	106,000	371,000
Other	243,000	105,000	348,000
Total	**$1,007,000**	**$424,000**	**$1,431,000**

Appendix A
Distribution Reliability Data:
Worst Performing Feeders

Unscheduled Distribution Related Outages Five-Year Average 2011-2015 Sorted By Customer Minutes of Interruption				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
SCV-01	1,539	504,135	0.92	5.01
DUN-01	2,976	484,925	2.90	7.88
SUM-01	6,209	480,872	3.45	4.45
SUM-02	1,826	403,361	2.97	10.93
DLK-03	2,307	392,313	1.72	4.88
BOT-01	3,209	384,883	1.90	3.79
SLA-09	3,149	382,001	3.14	6.35
HWD-07	5,003	349,292	1.90	2.21
DOY-01	2,882	345,387	1.69	3.37
LAU-01	1,897	343,374	2.68	8.08
BLK-01	4,070	340,799	2.36	3.29
RRD-09	3,567	334,563	2.01	3.14
MOL-04	2,596	326,939	1.62	3.41
GBY-03	3,311	308,677	4.33	6.72
SJM-11	5,564	307,594	3.81	3.51
Company Average	**2,217**	**84,744**	**1.39**	**1.74**

Unscheduled Distribution Related Outages Five-Year Average 2011-2015 Sorted By Distribution SAIFI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
BHD-01	6,171	226,304	6.54	4.00
SCT-02	1,533	61,248	5.99	3.99
TWG-03	1,434	53,965	5.16	3.24
SCT-01	3,476	103,858	4.97	2.47
TWG-01	3,512	129,322	4.81	2.95
TWG-02	3,210	111,897	4.53	2.63
ABC-02	4,613	150,572	4.48	2.44
GBY-03	3,311	308,677	4.33	6.72
MOB-01	6,913	223,511	4.30	2.32
RVH-02	643	57,280	4.20	6.24
ABC-01	3,039	144,916	3.86	3.07
SJM-11	5,564	307,594	3.81	3.51
KBR-06	587	17,620	3.76	1.88
FER-01	2,341	177,966	3.61	4.58
SUM-01	6,209	480,872	3.45	4.45
Company Average	**2,217**	**84,744**	**1.39**	**1.74**

Unscheduled Distribution Related Outages Five-Year Average 2011-2015 Sorted By Distribution SAIDI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
SUM-02	1,826	403,361	2.97	10.93
LAU-01	1,897	343,374	2.68	8.08
DUN-01	2,976	484,925	2.90	7.88
GBY-03	3,311	308,677	4.33	6.72
SLA-09	3,149	382,001	3.14	6.35
RVH-02	643	57,280	4.20	6.24
LGL-01	583	129,020	1.65	6.07
GBY-01	2,005	214,414	3.20	5.70
LGL-02	1,171	198,754	1.88	5.32
GBS-02	868	141,679	1.88	5.11
SCV-01	1,539	504,135	0.92	5.01
SCR-01	1,505	288,118	1.54	4.92
DLK-03	2,307	392,313	1.72	4.88
TRP-01	1,476	176,397	2.42	4.81
FER-01	2,341	177,966	3.61	4.58
Company Average	**2,217**	**84,774**	**1.39**	**1.74**

Unscheduled Distribution Related Outages Five-Year Average 2011-2015 Sorted By Distribution CHIKM	
Feeder	**Annual Distribution CHIKM**
MOL-04	415
GFS-02	412
SLA-09	363
KBR-10	346
TRP-01	291
SLA-13	290
SJM-13	273
MOL-09	231
HWD-07	219
SPR-02	209
KBR-01	207
SJM-06	206
KBR-11	193
MOL-02	191
KEN-03	188
Company Average	**45**

Unscheduled Distribution Related Outages Five-Year Average 2011-2015 Sorted By Distribution CIKM	
Feeder	**Annual Distribution CIKM**
SLA-10	201
MOL-09	179
KBR-02	150
KBR-01	150
KBR-11	148
SLA-07	147
KEN-01	146
SJM-04	144
GFS-02	141
SJM-09	140
KEN-04	135
SJM-06	134
SLA-02	134
KBR-10	133
SLA-06	126
Company Average	**35**

Appendix B
Worst Performing Feeders:
Summary of Data Analysis

Worst Performing Feeders **Summary of Data Analysis**	
Feeder	**Comments**
ABC-01	Reliability statistics were driven by a sleet related incident in 2011, and broken conductor outage in 2014. No work is required at this time.
ABC-02	Reliability historically has been good. There were several insulator failures in 2015. These are being addressed through *Rebuild Distribution Lines* project. No work required at this time.
BHD-01	Reliability historically has been good. The 2015 reliability statistics were driven by 2 winds related incidents. No work is required at this time.
BLK-01	Poor reliability statistics were driven by a broken insulator in 2014 and several high wind events in 2015. No work is required at this time.
BOT-01	In 2013, 2014 and 2015 trees falling across the line during wind storms contributed to poor reliability statistics. No work is required at this time.
DLK-03	Poor reliability statistics were driven by weather related events in 2011 and 2014, along with several incidents of trees contacting the line in 2013. No work is required at this time.
DOY-01	Overall reliability statistics on this feeder have been impacted by feeder unbalance caused by a number of long single-phase taps. The poor reliability statistics are also driven by weather related events in 2012. Work was completed under the *2014 Feeder Additions for Load Growth* project to address the single-phase taps issue. No further work is required at this time.
DUN-01	Poor reliability statistics in 2012 were due to vegetation issues. In 2014, high winds and a faulty lightning arrestor also caused problems. A downline automated recloser is being added to the feeder in 2016 as part of the *Distribution Feeder Automation* project. Otherwise no further work is required at this time.
FER-01	Poor reliability statistics were driven by broken conductor in 2014 and 2015. No work is required at this time.
GBS-02	Wind and sleet caused several reliability issues in 2014 and 2015. Some work is being done in 2016 under the *Rebuild Distribution Lines* program. No work is required at this time
GBY-01	GBY-01 has had good reliability over the years. A lightning related event resulted in poor overall reliability statistics in each of 2012 and 2015. In addition a tree contacted the line in late 2013. No work is required at this time.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
GBY–03	This feeder had significant upgrades as part of the *2011 Rebuild Distribution Lines* project. Poor reliability statistics were driven by isolated weather related events in each of 2011 and 2013. A bird caused an outage in 2014 and lightning caused an outage in 2015. No work is required at this time.
GFS-02	Poor reliability statistics were driven by storm damage in November 2013. Broken conductor caused a long duration outage in 2014. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. This feeder has been included in the *2016 Distribution Reliability Initiative* project.
HWD-07	Poor reliability statistics were principally due to a wind related incident in 2013. No work is required at this time. This feeder has been included in the *2016 Distribution Reliability Initiative* project.
KBR-01	This feeder will be eliminated by upgrading the distribution line from 4.16 kV to 12.5 kV and transferring the customers to a new 12.5 kV feeder as part of the *2016 Trunk Feeders* project.
KBR-02	This feeder was eliminated by upgrading the distribution line from 4.16 kV to 12.5 kV and transferring the customers to a new 12.5 kV feeder as part of the *2015 Distribution Reliability Initiative* project.
KBR-06	Poor reliability statistics were caused by damage caused by a 3rd party and some conductor related issues. This feeder will be eliminated by upgrading the distribution line from 4.16 kV to 12.5 kV and transferring the customers to a new 12.5 kV feeder as part of the *2017 Trunk Feeder* project.
KBR-10	Over the period 2009 to 2013 this feeder has had 6 feeder level outages due to equipment failure. The condition of the aerial cable along Kings Bridge Road was of particular concern. This has now been replaced. The rebuilding of sections of this feeder was included in the *2015 Distribution Reliability Initiative* project to address poor reliability.
KBR-11	Reliability has generally been good. A broken insulator in 2015 contributed to reduced reliability in that year. No work is required at this time.
KEN-01	Reliability has generally been good. A broken insulator in 2015 contributed to reduced reliability in that year. No work is required at this time.
KEN-03	Reliability has generally been good. A broken insulator in 2012 and issues with a new pole installation in 2013 led to poor reliability statistics. No work is required at this time.

Worst Performing Feeders **Summary of Data Analysis**	
Feeder	**Comments**
KEN-04	Reliability has generally been good. Two events, a pole hit by a vehicle and a lightning strike, resulted in poor overall reliability statistics in 2012. A downline automated recloser is being added to the feeder in 2016 as part of the *Distribution Feeder Automation* project. Otherwise no work is required at this time.
LAU-01	Reliability has generally been good. A rodent related incident in 2015 contributed to reduced reliability in that year. No work is required at this time.
LGL-01	Weather related outages including damage from wind in 2013 and 2014 resulted in poor reliability statistics.
LGL-02	Poor reliability statistics were driven by salt spray and a broken conductor in 2013 and sleet in 2015. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. This feeder will continue to be monitored to determine if it should be considered for rebuilding in a future capital budget.
MOB-01	Reliability has generally been good. Broken conductor in 2011 and a broken pole and crossarm as a result of a vehicle accident in 2013 were the primary reasons for the poor reliability statistics experienced in recent years. Approximately 5 kilometers of the feeder was upgraded as part of the *2015 Feeder Additions for Growth* project. Otherwise no work is required at this time.
MOL-02	Reliability has generally been good. Wind and a broken crossarm contributed to poor reliability statistics in 2014. No work is required at this time.
MOL-04	MOL-04 has had good reliability over the years. Several weather events resulted in poor overall reliability in 2012. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. This feeder will continue to be monitored to determine if it should be considered for rebuilding in a future capital budget.
MOL-09	Over the period 2011 to 2013 this feeder has had 6 feeder level outages due to equipment failure. The feeder also had multiple outages on long taps due to equipment failure. This feeder was included in the *2015 Distribution Reliability Initiative* project to address poor reliability statistics. No work is required at this time.
RRD-09	Poor reliability statistics were due to broken conductor in 2011. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. This feeder will continue to be monitored to determine if it should be considered for rebuilding in a future capital budget.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
RVH-02	Poor reliability statistics were due to a blizzard and a broken crossarm in 2011 and several equipment failures in 2015. This feeder is one of the Company's worst performing from a SAIDI and SAIFI perspective. Work is required on this feeder in 2017.
SCR-01	Poor reliability statistics were driven by a wind related event in November 2011 and a tree contacting the line in 2013. No work is required at this time.
SCT-01	Poor reliability statistics were driven by wind and tree related events in 2012 and 2013. No work is required at this time.
SCT-02	Poor reliability statistics were driven by wind and tree related events in 2012, 2013 and 2014. No work is required at this time.
SCV-01	Poor reliability statistics were driven by a wind related event in 2015. No work is required at this time.
SJM-04	Reliability has generally been good. A protective relay issue contributed to poor reliability statistics in 2015. No work is required at this time.
SJM-06	Reliability has generally been good. A broken conductor and damages by a 3rd party contributed to poor reliability statistics in 2013. A protective relay issue contributed to poor reliability statistics in 2015. No work is required at this time.
SJM-09	Reliability has generally been good. There was a wind related incident that contributed to poor reliability statistics in 2015. No work is required at this time.
SJM-11	Reliability has generally been good. Damages by a 3rd party contributed to poor reliability statistics in 2012 and 2014. No work is required at this time.
SJM-13	Conductor failure during high winds in 2013 and 2014 contributed to continued worsening reliability. Feeder needs to be monitored but no work is required on this feeder in 2017.
SLA-02	Poor reliability statistics were caused by an underground cable fault and conductor failures in 2013. No work is required at this time.
SLA-06	Reliability has generally been good. A broken conductor contributed to poor reliability statistics in 2011. No work is required at this time.
SLA-07	Reliability has generally been good. A broken conductor contributed to poor reliability statistics in 2011. No work is required at this time.
SLA-09	Poor reliability statistics are due to an underground cable fault in 2011. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. Work is being carried out under the *2016 Distribution Reliability Initiative* project.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
SLA-10	Poor reliability statistics were due to two incidents, a broken conductor in 2011 and a downed tree in 2014. No work is required at this time,
SLA-13	Reliability has generally been good. However, a broken insulator and 2 wind related incidents in 2015 contributed to poor reliability statistics. No work is required at this time.
SPR-02	Poor reliability statistics were caused by tree issues in 2012 and 2013 and a snow storm in 2013. No work is required at this time.
SUM-01	Poor reliability statistics were caused by 3 events in 2012 and 2015, one involving salt spray and the others involving broken conductor. In 2013 an issue occurred with a broken insulator. No work is required at this time.
SUM-02	Poor reliability statistics were driven by 2 tree related events in 2011 and a weather event in 2012. There were several broken conductor issues in 2014 and 2015. Work is required on this feeder in 2017.
TRP-01	This feeder has experienced continuing worsening reliability over the past 5 years. The location of the feeder subjects it to extreme sleet and wind loading conditions. These have resulted in broken poles and numerous incidents of insulator and conductor failure over the past 5 years. Work is required on this feeder in 2017.
TRP-02	Feeder has good reliability. Statistics are swayed by a single wind related event in 2012. No work is required at this time.
TWG-01	Feeder has good reliability. Statistics are swayed by a single lightning related event in 2013. No work is required at this time.
TWG-02	Feeder has good reliability. Statistics are swayed by a single broken conductor incident in 2012. No work is required at this time.
TWG-03	Feeder has good reliability. Statistics are swayed by a single wind related event in 2013. No work is required at this time.

Appendix C
Summerford SUM-02 Feeder Study

July 2016

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Page

1.0 General

The *Distribution Reliability Initiative* is a project that 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 feeders. Distribution feeders are identified for evaluation based on an analysis of reliability statistics over the past 5 years. Once identified, a detailed engineering assessment of the feeder is carried out to determine if any upgrade work is required. The assessment looks at the physical condition of plant, the risk of failure and the potential impact to customers in the event of a failure.

The *2017 Distribution Reliability Initiative* identified the SUM-02 feeder as one of the *worst performing feeders* on Newfoundland Power's distribution system. An engineering evaluation of the feeder was carried out in early 2016. This report summarizes the findings of that evaluation and presents a plan to improve reliability on the feeder.

2.0 SUM-02 Feeder

The SUM-02 feeder is one of 2 distribution feeders originating from the Summerford ("SUM") Substation. The feeder has a tie to GBY-01 feeder which allows for both permanent and temporary load transfers between these feeders and substations during unplanned or planned outages. GBY-01 feeder originates from Gander Bay ("GBY") Substation.

SUM-02 is a 25 kV distribution feeder that was originally constructed in the mid-1960s. It currently serves 615 customers. The feeder extends from the substation located at the intersection of Routes 340 and 344 in Summerford and heads south along Route 340 to the community of Boyd's Cove. The feeder then heads east to the community of Rodgers Cove. Both SUM-02 and GBY-01 feeders terminate at Rodgers Cove providing a tie-point for both these feeders. SUM-02 feeder is comprised mainly of the 3-phase trunk but it does have some single-phase taps branching off to the communities of Boyd's Cove, Stoneville and Horwood.

The main 3-phase trunk portion of SUM-02 runs from the substation along the exterior of the community of Summerford, across the Dildo Run causeway and along the ocean shoreline to the end of the feeder at Rodgers Cove. The pole line infrastructure on the main trunk is original to the 1960's construction. This main trunk is comprised of all #2/0 Aluminum Conductor Steel Re-enforced (ACSR) conductor.[1]

[1] ACSR conductor has been noted to have poor operating characteristics in a salt spray environment. Over time, the outer aluminum strands break, leaving the steel core to carry the load. Eventually the steel core breaks causing an outage to customers.

3.0 Engineering Assessment

Inspections have identified significant deterioration due to corrosion of conductor and armour rods, and decay, splits, and checks in the poles and cross-arms, as well as deficiencies with guys, anchors, hardware and insulators on the feeder. Many of the insulators on this line are in excess of 40 years old and are deteriorated. Component failure during high winds has been an issue over the past couple of years. Due to the age and condition of the support structures and conductor, the feeder is becoming more susceptible to damage when exposed to severe wind, ice and snow loading.[2]

The steel core of the existing #2/0 ACSR conductor shows evidence of corrosion. Deterioration of the steel core reduces the strength of the conductor. In addition, there are numerous locations where the existing conductor has been sleeved to extend the distribution line to adjacent structures.[3] It is estimated that SUM-02 feeder contains over 100 sleeves. The physical condition of the overhead conductors make it highly likely that there will be further failures.

The entire SUM-02 feeder is built in a highly corrosive coastal environment. The main effect of corrosion is conductor bird caging.[4] Bird caging has been identified at many locations on SUM-02 feeder in areas were conductors are sleeved and also at most armor rod locations where conductor is attached to insulators.[5] It has been found that corrosion on armor rods has led to further corrosion of the conductor and steel core at bird caging locations. A thermal scan of the SUM-02 feeder has shown many hot spots at sleeve and bird caging locations under normal loading.[6]

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[2] Sections of this distribution feeder were built to weather loading criteria that are less than the standard currently used for new construction.

[3] The use of compression sleeves to laterally join aerial conductor reduces the structural integrity and represents potential-points of failure. Where practical, conductor is terminated at support structures using dead-end insulators. An example of conductor sleeving is shown in Appendix C-2, Figure 3.

[4] Bird caging is a condition that usually occurs in conductors that contain different materials forming the conductor, such as ACSR. Changes in tensions in the different conductor material cause the outer layer of aluminum strands to protrude outward exposing the steel core, resembling a bird cage . The exposed steel core becomes vulnerable to the harsh environmental conditions resulting in accelerated corrosion.

[5] Armor rods are placed on overhead conductors to provide mechanical protection at insulator attachment locations on poles.

[6] Thermal scan or thermal imaging is a non-destructive imaging technology used to detect material temperature. Thermal radiation is emitted from all objects and thermal scan cameras can identify the amount of heat being emitted from different objects considering common ambient temperatures.

Table 1 summarizes the reliability data for SUM-02 distribution feeder for the most recent 5-year period.

Table 1
SUM-02 Distribution Interruption Statistics
5 Years to December 31, 2015

	Customers	SAIFI	SAIDI	CHIKM	CIKM
SUM-02	615	2.97	10.93	84	8
Company Average	**839**	**1.39**	**1.74**	**45**	**35**

Table 1 shows that distribution feeder SUM-02 is an outlier from the Company average for SAIDI and SAIFI.[7] An analysis of the outage data reveals that equipment failure has been the cause of most of the outages experienced. The main trunk of this distribution feeder has reached a point where continued maintenance is no longer feasible and the feeder has to be rebuilt to current construction standards for continued safe and reliable operation.

4.0 Recommendations

The SUM-02 feeder is a critical part of the Company's distribution system in the Summerford and Gander Bay areas. It provides a major link for load transfer between SUM and GBY substations. Over the past 5 years the majority of the reliability issues on this line have been due to conductor failure, aged infrastructure and heavy loading.

To improve the performance and reliability of this feeder, it is recommended that:

- (i) The existing 29 kms of 2/0 ACSR conductor be replaced with 4/0 AASC conductor;
- (ii) All deteriorated cross arms and insulators on the main trunk of SUM-02 be replaced with 25 kV clamp top insulators and V-brace cross arms, involving approximately 400 structures; and
- (iii) Replace 75 deteriorated poles

It is proposed to complete the required work over a 2 year period at a total project cost estimated at $1,798,000. The project proposal includes an estimated expenditure of $791,000 in 2017 and the remaining $1,007,000 in 2018.

[7] The SAIFI for the SUM-02 feeder is 2.1 times the Company average while SAIDI is 6.3 times the Company average.

Appendix C-1
Map Showing Areas Served by SUM-02

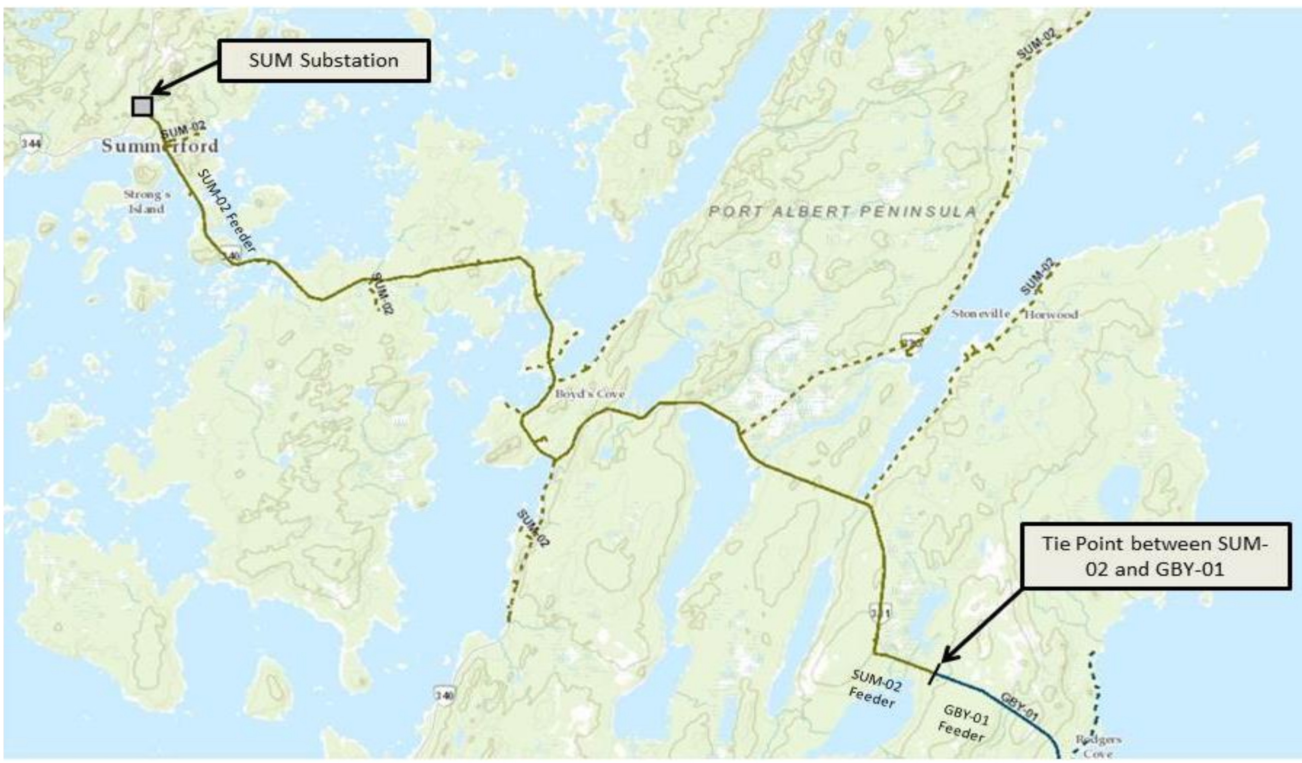

Figure 1 – Map of SUM-02

Appendix C-2
Photographs of SUM-02 Feeder

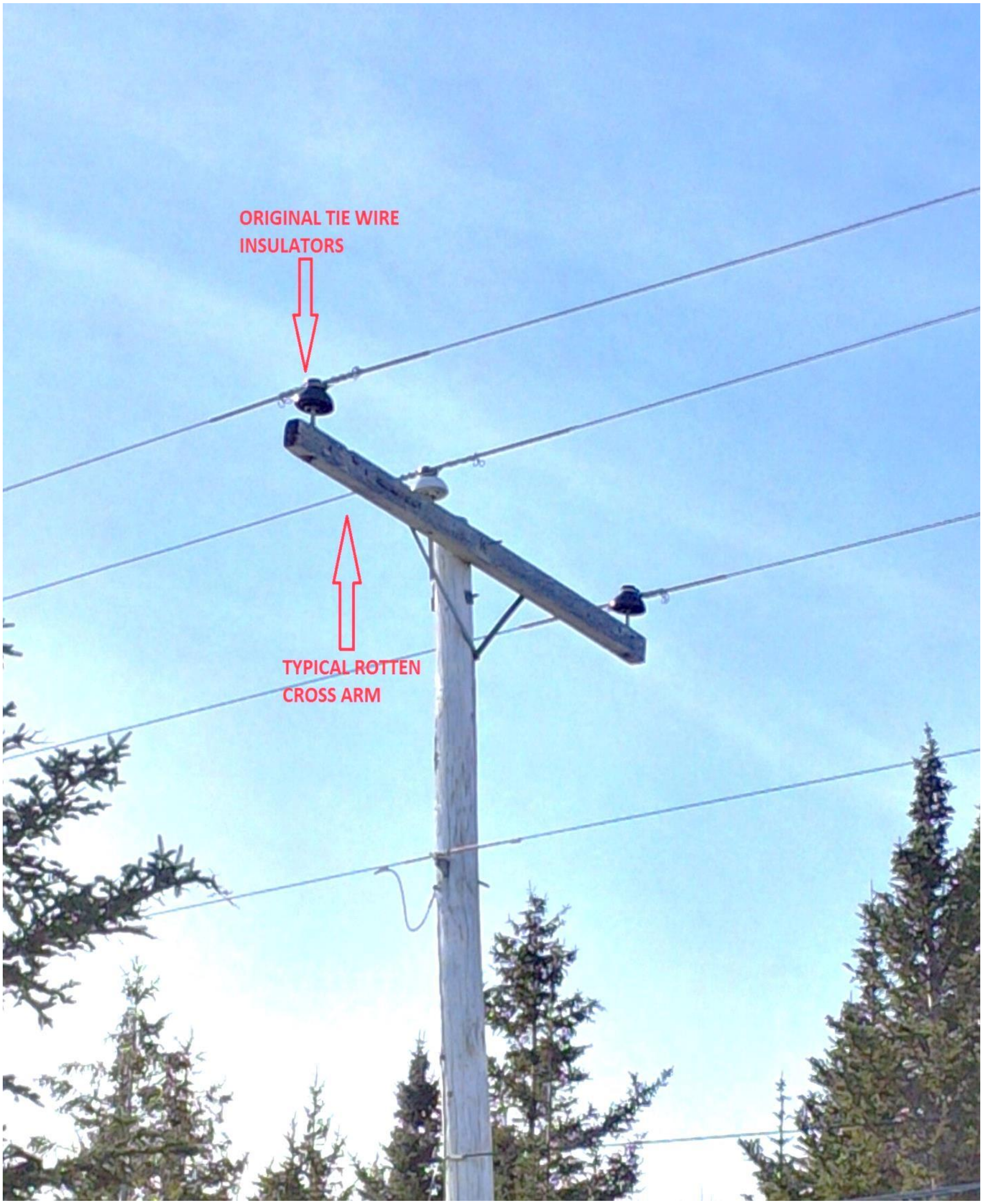

Figure 1 – Deteriorated Distribution Structure

Figure 2 – Bent Pole with Checks

Figure 3 – Pole with Woodpecker Hole

Figure 4 – Damaged Insulators

Figure 5 – Damaged Conductor/Pole and Crossarm Deterioration

Figure 6 – Span with Multiple Compression Sleeves

Figure 7 – #2/0 ACSR Conductor with Compression Sleeves and Bird Caging

Figure 8 – #2/0 ACSR Conductor Bird Caging

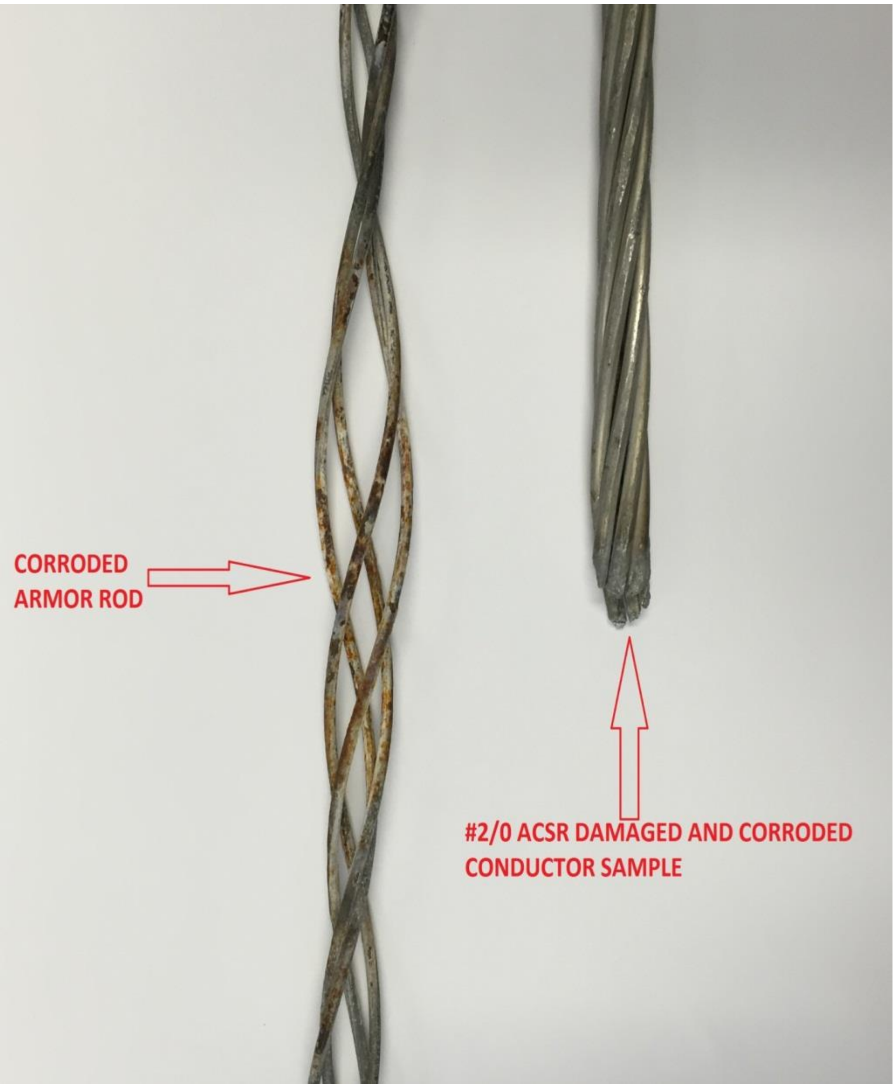

Figure 9 – #2/0 ACSR Conductor and Armor Rod

Appendix D
Trepassey TRP-01 Feeder Study

July 2016

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1.0 General

The *Distribution Reliability Initiative* is a project that 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 feeders. Distribution feeders are identified for evaluation based on an analysis of reliability statistics over the past 5 years. Once identified, a detailed engineering assessment of the feeder is carried out to determine if any upgrade work is required. The assessment looks at the physical condition of plant, the risk of failure and the potential impact to customers in the event of a failure.

The 2017 Distribution Reliability Initiative has identified the TRP-01 feeder as one of the *worst performing feeders* on Newfoundland Power's distribution system. An engineering evaluation of the feeder was carried out in early 2016. This report summarizes the findings of that evaluation and presents a plan to improve reliability on the feeder.

2.0 TRP-01 Feeder

The TRP-01 feeder is the only distribution feeder originating from Trepassey ("TRP") Substation. The feeder has no tie points to other feeders which eliminates the possibility for both permanent and temporary load transfers during unplanned or planned outages. Being the only feeder from the substation, TRP-01 feeder supplies all critical loads for the area.

TRP-01 is a 12.5 kV distribution feeder that was originally constructed in the late 1960's and currently serves approximately 611 customers. The feeder extends from the substation located on the north side of Low Point Road in the community of Trepassey and heads east along Route 10 through the community of Trepassey and on to Biscay Bay, Portugal Cove South and Cape Race. The feeder heads west from Trepassey into the community of St. Shott's. TRP-01 also has a 17 km 3-phase section that runs cross country from Trepassey to the NAV Canada facility located 8 km east of Portugal Cove south along Route 10.[1]

The main 3-phase trunk portion of TRP-01 runs from the substation east and west through the community of Trepassey. The 3-phase section that runs west from the substation is 4 km long and is constructed using #4/0 Aluminum Alloy Stranded Conductor ("AASC"). The main section that runs east through the community of Trepassey is 7 km long and is constructed using #477 Aluminum Stranded Conductor ("ASC") for the first 6 km with the remaining 1 km constructed using #1/0 AASC.

There are 2 long single-phase taps attached to the main trunk at either end of the community of Trepassey. The single-phase section that heads west from Trepassey runs along Route 10 for 7.5 km then south 14 km into St. Shott's. On the east side of Trepassey a single-phase line extends 30 km through Biscay Bay and Portugal Cove South as far as Cape Race. The 10 km section that runs between Trepassey and Portugal Cove South is located away from the road and is original to the 1960's construction.

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[1] Appendix D-1 includes a map showing the areas served by distribution feeder TRP-01.

3.0 Engineering Assessment

Inspections have identified the major contributing factors to outage duration and frequency to be deterioration due to decay, splits, and cracks in poles and cross-arms, as well as deficiencies with guys, anchors, hardware and insulators on the feeder. Many of the insulators are in excess of 40 years old and are deteriorated. Component failure during high winds has been an issue over the past number of years. Due to the age and condition of the support structures, they are becoming more susceptible to damage when exposed to severe wind, ice and snow loading.[2]

Analysis of the outage data reveals that equipment failure is the cause for most of the outages experienced. TRP-01 feeder is in an area of severe ice and wind loading and the age and condition of the infrastructure is resulting in steadily deteriorating outage statistics.

Inspections have identified that there are a number of poles along the main trunk that require upgrades to current construction standards. Also, installation of gang operated sectionalizing switches would improve restoration efforts during an outage.

The 10 km single phase section of TRP-01 from Trepassey to Portugal Cove South is over 55 years old. The existing poles in this section are at the end of life and do not meet current design standards. The rebuilding of this section of line is required to reduce outage frequency and provide safe, reliable service to the customers supplied by this section of distribution line.

Table 1 summarizes the reliability data for TRP-01 distribution feeder for the most recent 5-year period.

Table 1
TRP-01 Distribution Interruption Statistics
5 Years to December 31, 2015

	Customers	SAIFI	SAIDI	CHIKM	CIKM
TRP-01	611	2.42	4.81	291	2
Company Average	**839**	**1.39**	**1.74**	**45**	**35**

Table 1 shows that distribution feeder TRP-01 is an outlier from the Company average for SAIDI and SAIFI.[3] A review of the outage data reveals that equipment failure has been the cause for most of the outages experienced. The feeder has reached a point where continued maintenance is no longer feasible and the feeder has to be rebuilt to current construction standards for continued safe and reliable operation.

[2] Sections of this distribution feeder were built to weather loading criteria that are less than the standard currently used for new construction.

[3] The SAIDI for the TRP-01 feeder is 2.8 times the Company average while SAIFI is 1.7 times the Company average.

4.0 Recommendations

The TRP-01 feeder is a critical part of the Company's distribution system in the Trepassey area. Over the past 5 years the majority of the reliability issues on this line have been due to equipment failure, and aging and substandard infrastructure.

To improve the performance and reliability of this feeder, it is recommended to:

- Reframe 50 structures along the main trunk of the feeder with new cross-arms, insulators, and poles as required;
- Install 2 new sectionalizing switches; and
- Rebuild 10 km of 1-phase line from Trepassey to Portugal Cove South.

It is proposed to complete the required work over a two year period at a total project cost estimated at $848,000. The project proposal includes an estimated expenditure of $424,000 in 2017 and the remaining $424,000 in 2018.

Appendix D-1
Map Showing Areas Served by TRP-01

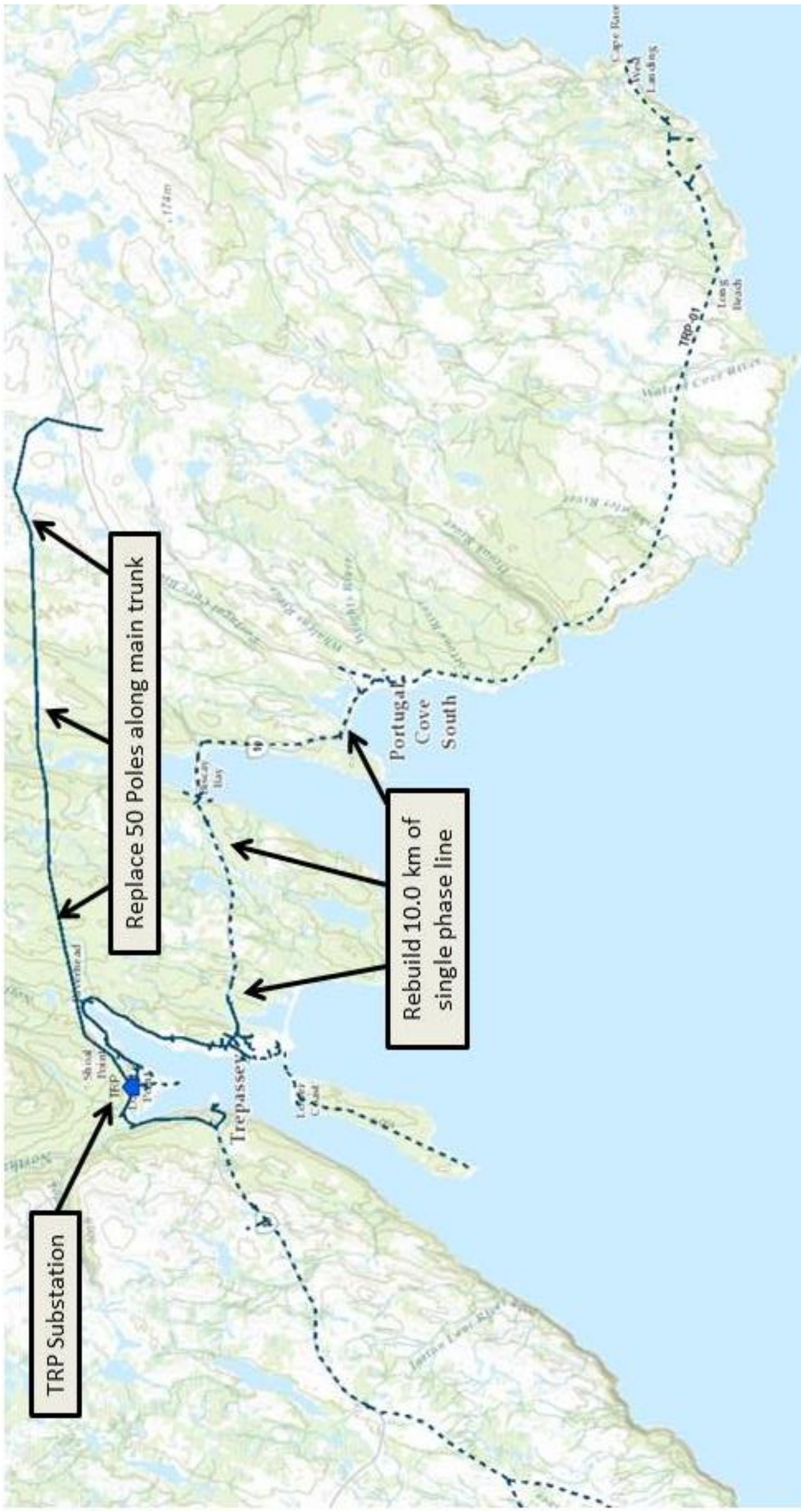

Figure 1 – Area Covered by TRP-01.

Appendix D-2
Photographs of TRP-01 Feeder

Figure 1 – 2 Piece Insulators with 1 Previous Failure

Figure 2 – Pole and Conductor Damage from 2 Piece Insulator Failure

Figure 3 – Non-Standard 1960's Vintage Construction on 30' Poles

Figure 4 – Deteriorated Crossarm

Figure 5 – Damaged Pole Due to Failed Insulator

Figure 6 – Damaged Crossarm Due to Failed Insulator

Figure 7 – Outage Cause by Deteriorated Crossarm

Appendix E
Riverhead RVH-02 Feeder Study

July 2016

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1.0 General

The *Distribution Reliability Initiative* is a project that 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 feeders. Distribution feeders are identified for evaluation based on an analysis of reliability statistics over the past 5 years. Once identified, a detailed engineering assessment of the feeder is carried out to determine if any upgrade work is required. The assessment looks at the physical condition of plant, the risk of failure and the potential impact to customers in the event of a failure.

The *2017 Distribution Reliability Initiative* identified the RVH-02 feeder as one of the *worst performing feeders* on Newfoundland Power's distribution system. An engineering evaluation of the feeder was carried out in early 2016. This report summarizes the findings of that evaluation and presents a plan to improve reliability on the feeder.

2.0 RVH-02 Feeder

The RVH-02 feeder is one of 2 distribution feeders originating from Riverhead ("RVH") Substation. The feeder has a tie point to RVH-01 feeder which allows for both permanent and temporary load transfers between these feeders during unplanned or planned outages.

RVH-02 is a 12.5 kV distribution feeder that was originally constructed in the late 1960's and currently serves approximately 153 customers. The feeder extends from the substation located on the south side of Route 90 through the community of Riverhead, then west to the communities of Mall Bay and Admiral's Beach.[1]

The main 3-phase trunk portion of RVH-02 runs from the substation through the communities of Riverhead and Mall Bay then across country 4.8 km to Admiral's Beach. At Admiral's Beach, the 3-phase trunk extends south through the community as far as the Marine Center. The total feeder length is 29.5 km. The conductor along the main trunk of the feeder is 4/0 Aluminum Alloy Stranded Conductor ("AASC") which extends to Admiral's Beach. There are two 3-phase taps and 3 single-phase taps along the feeder, all of which are comprised of #2 Aluminum Conductor Steel Re-Enforced ("ACSR") conductor.

[1] Appendix E-1 includes maps showing the areas served by distribution feeder RVH-02.

3.0 Engineering Assessment

Inspections have identified the major contributing factors to outage duration and frequency to be deterioration due to decay, splits, and cracks in the cross-arms, as well as deficiencies with guys, anchors, hardware and insulators on the feeder. Many of these deficiencies are located on the 4.8 km section of line that runs across country between the communities of Mall Bay and Admiral's Beach. Many of the insulators on this section of line are in excess of 40 years old and are deteriorated. Component failure during high winds has been an issue over the past number of years. Due to the age and condition of the support structures, they are becoming more susceptible to damage when exposed to severe wind, ice and snow loading.[2]

Analysis of the outage data reveals that equipment failure is the cause for most of the outages experienced. The feeder is in an area of severe ice and wind loading and the age and condition of the infrastructure is resulting in steadily deteriorating outage statistics.

Table 1 summarizes the reliability data for RVH-02 distribution feeder for the most recent 5-year period.

Table 1
RVH-02 Distribution Interruption Statistics
5 Years to December 31, 2015

	Customers	SAIFI	SAIDI	CHIKM	CIKM
RVH-02	153	4.20	6.24	29	5
Company Average	**839**	**1.39**	**1.74**	**45**	**35**

Table 1 shows that distribution feeder RVH-02 is an outlier from the Company average for SAIDI and SAIFI.[3] A review of the outage data reveals that failed insulators, conductor ties and cross-arms have been the cause for most of the outages experienced which is largely concentrated on the Mall Bay to Admiral's Beach section. The main trunk section of the feeder that runs across country from Mall Bay is the main contributor to long outage durations. Rebuilding this section will increase its reliability and therefore will reduce outage frequency and duration on RVH-02.

2 Sections of this distribution feeder were built to weather loading criteria that are less than the standard currently used for new construction.

3 The CHIKM and CIKM for the RVH-02 are both well below the Company average.

4.0 Recommendations

The RVH-02 feeder is a critical part of the Company's distribution system in the Riverhead - St. Mary's Bay area. Over the past 5 years the majority of the reliability issues on this line have been due to equipment failure, and aging and substandard infrastructure.

To improve the performance and reliability of this feeder, it is recommended to:

- Reframe 4.8 km of line between Mall Bay and Admirals Beach to current standards[4]; and
- Install all new anchors and guying, and replace poles as required on the line from Mall Bay to Admiral's Beach.

It is proposed to complete the required work in 2017 at an estimated cost of $200,000.

[4] The section of feeder to be rebuilt includes 60 structures each with deteriorated framing and insulators.

Appendix E-1
Map Showing Areas Served by RVH-02

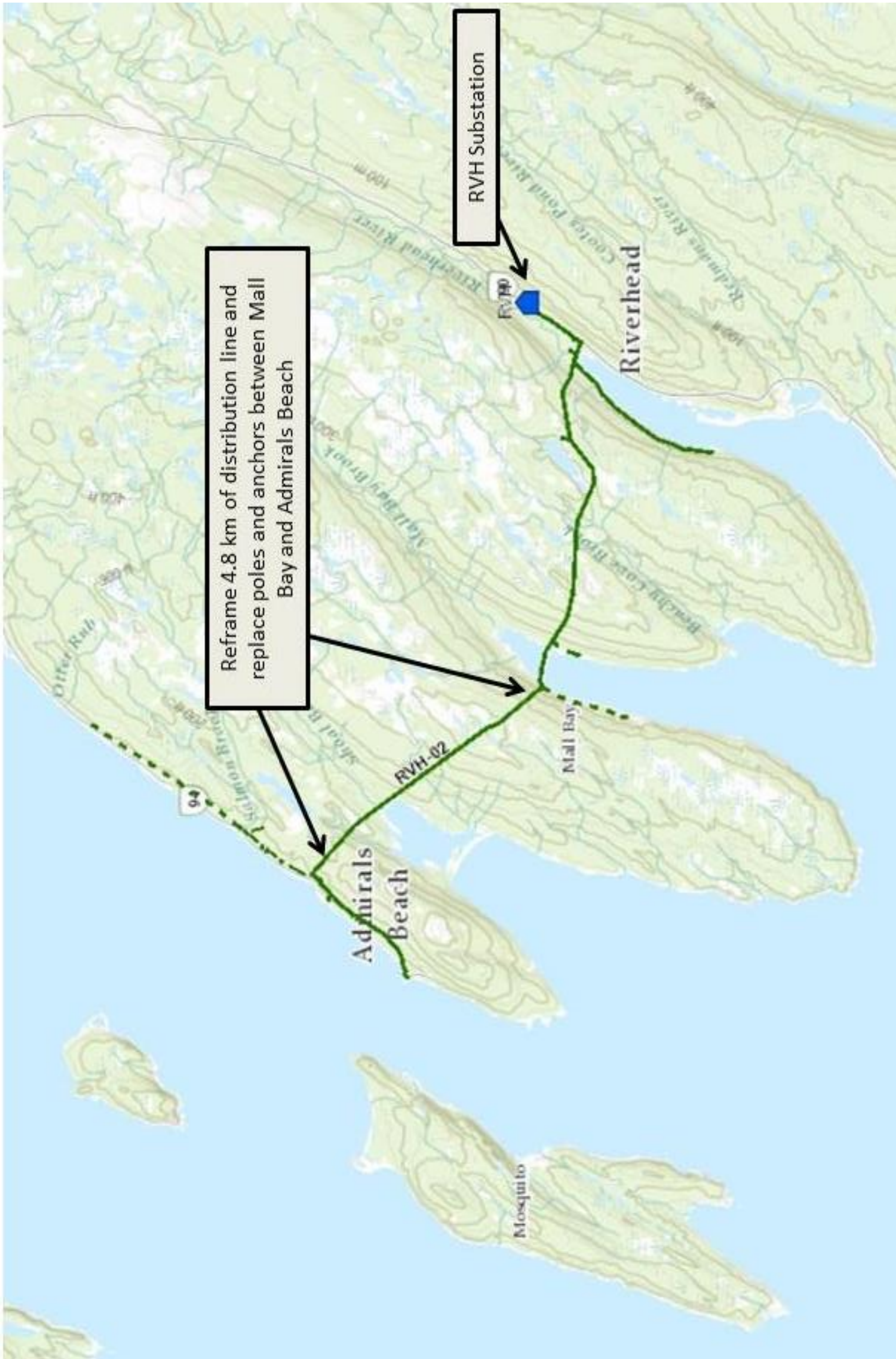

Figure 1 – Area Covered by RVH-02.

Appendix E-2
Photographs of RVH-02 Feeder

Figure 1 – Deteriorated Crossarm

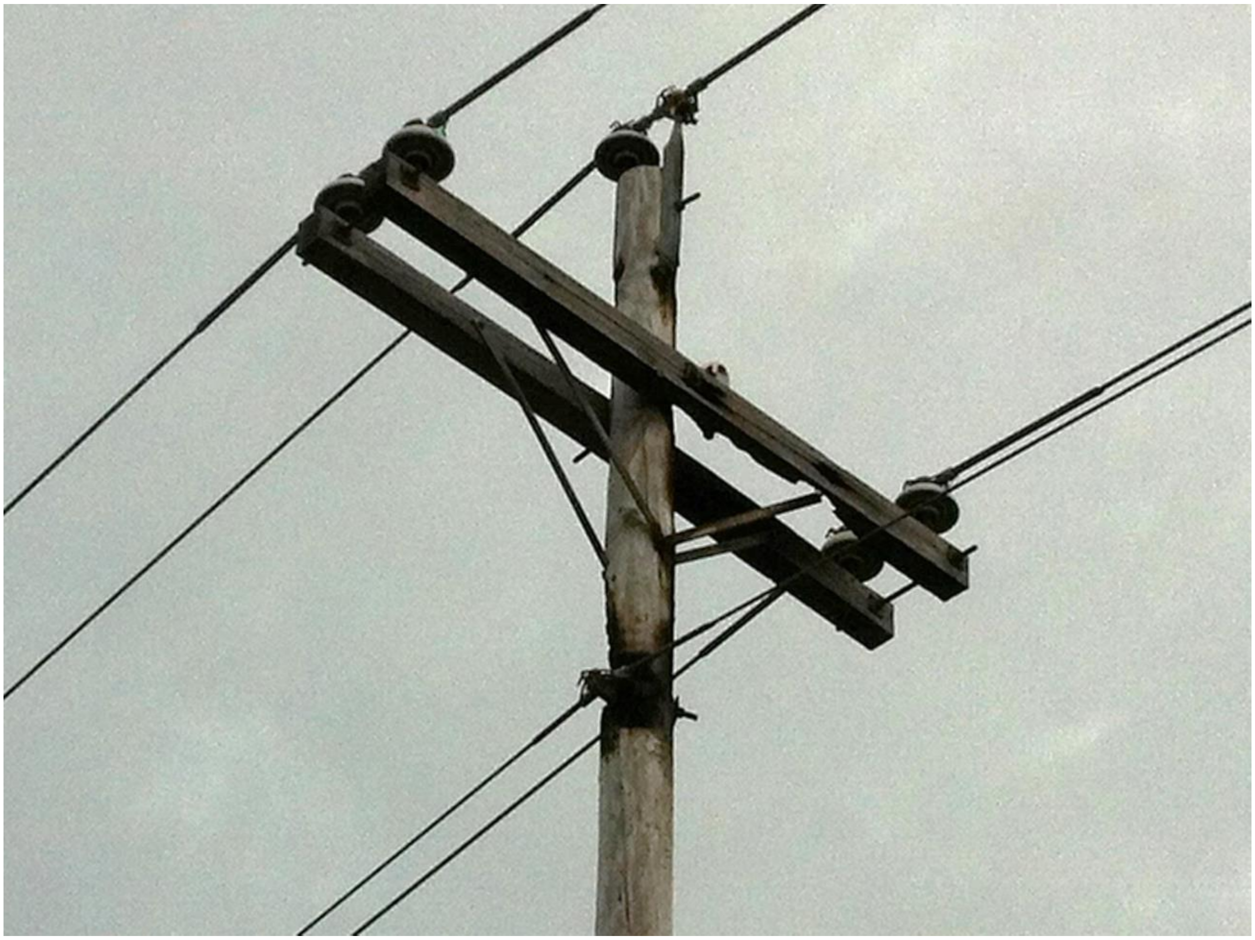

Figure 2 – Failed Insulator with Associated Pole and Crossarm Damage.

Figure 3 – Burn Damage on Pole due to Insulator Failure

Figure 4 – Deteriorated Crossarm

Figure 5 – Pole Top Deterioration

Feeder Additions for Load Growth

July 2016

Prepared by:

Dean Efford

Approved by:

Robert Cahill, Eng. L.

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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 occur at the substation level, on equipment such as transformers, breakers and reclosers, or on specific sections of the distribution system.

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.

The overload conditions described in this report can each be attributed to commercial and residential customer growth in Newfoundland Power's (the "Company") service territory.

2.0 Overloaded Conductors

2.1 General

An overloaded section of conductor on a distribution line is at risk of failure. Failures are caused by overheating of the conductor as the customer load exceeds the conductor's capacity ratings. As a result, the conductor will have excessive sag, which may result in the conductor coming into contact with other conductors or ultimately, the conductor breaking, causing a fault and subsequent power interruption.

The Company undertakes analysis of distribution feeders using a distribution feeder computer modelling application to identify sections of feeders that may be overloaded. Overload conditions that are identified using the computer modelling application are followed up with field visits to ensure the accuracy of information.[2]

2.2 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 on offloading strategies for surrounding feeders.

Alternative #1 – Feeder Balancing
In some cases, a conductor may be overloaded on only one phase of a 3-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. In some situations, overload conditions on individual phases can be alleviated by

---

[1] Feeder balancing involves transferring load from one phase to another on a 3-phase distribution feeder in order to balance the amount of load on each phase. Load transfers involve transferring load from one feeder to another adjacent feeder.

[2] Where necessary, load measurements are taken to verify the results of the computer modeling. The analysis uses conductor capacity ratings based on Newfoundland Power's Distribution Planning Guidelines. These ratings are shown in Appendix A.

extending the 3-phase trunk of the feeder. This is only applicable in situations where all 3 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 loading on the adjacent feeder to ensure a new overload condition is not created.

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 an adjacent feeder.

Alternative #4 – New Feeder
In cases where the feeder conductor leaving a substation is overloaded, and none of the above alternatives can be used to resolve the overload condition, then the addition of a new feeder from the substation is required to transfer a portion of load from the overloaded conductor.

2.3 Overloaded Feeders

RBK-01 Feeder Upgrade ($637,000)

Rattling Brook ("RBK") Substation is located on West Access Highway in the Town of Norris Arm South. There is one 12.5 kV distribution feeder terminated at RBK Substation serving approximately 775 customers in the Town of Norris Arm South.

The main trunk of this feeder is forecasted to overload in 2017. The forecasted overloaded section extends approximately 6.6 km from RBK substation to the intersection of Citizen's Drive and Gillingham Avenue in the Town of Norris Arm South. This section was evaluated using all 4 available alternatives identified in Section 2.2. The conductor on this section is #2 ACSR and is rated for 168 amps per phase. The 2017 balanced forecasted peak load on each of the phases in this section is 174 amps per phase.

This overload condition can be attributed to the expansion of the Central Waste Management Facility located east of the Town of Norris Arm South at the end of RBK-01 distribution feeder.[3] Continued growth is expected over the next 2 years as this new facility reaches full production.

Feeder balancing is not an option for this overload condition due to the fact that the combined forecasted peak currents exceed the total capacity of the 3 phase conductors. There are no adjacent feeders or tie points that would allow load to be transferred. Therefore, it is recommended that the 6.6 km section be upgraded to #4/0 AASC conductor, which has a rating of 356 amps per phase.[4]

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3 The contribution in aid of construction ("CIAC") amount of $162,660.42 to provide three-phase service to the Central Waste Management Facility was approved in Order No. P.U. 10 (2010).

4 Single line diagram for RBK-01 feeder is included in Appendix B.

3.0 CHA-04 New Feeder Construction ($793,000)

Chamberlains ("CHA") Substation serves customers in the Conception Bay South and Paradise areas. CHA Substation includes 2 power transformers, CHA-T1 and CHA-T2, that are used to convert transmission level voltage of 66 kV to a distribution voltage of 25 kV. CHA-T1 and CHA-T2 have a combined rated capacity of 50 MVA that supply approximately 8,200 customers through three 25 kV distribution feeders. An engineering study has been completed on the distribution system alternatives that best meet the electrical demands of the Conception Bay South and Paradise areas.[5]

The study examined alternatives to determine the least cost approach to dealing with the forecast overload conditions at CHA substation. Each alternative was evaluated using a 20 year load forecast. Based on net present value calculations, the least cost alternative was selected. The projects included in the least cost alternative include the replacement of a 25 MVA power transformer with a new 50 MVA power transformer and the construction of a 4th distribution feeder from CHA substation.[6]

The new distribution feeder will exit the substation and proceed eastward along Buckingham Drive for approximately 0.35 km to interconnect with the existing CHA-02 feeder at Topsail Pond Road. In addition, 3.00 km of the existing CHA-02 feeder along Buckingham Drive and Topsail Pond Road will be upgraded from a combination of single-phase and 2-phase lines to form the new 3-phase trunk of CHA-04 feeder[7]. This new distribution feeder will be used to offload a portion of CHA-02 feeder and provides the least cost alternative to distribute the existing load on the CHA feeders and provide capacity for the continued load growth forecasted for this area.

The new CHA-04 feeder item of the *Feeder Additions for Load Growth* project is clustered with the *Substation Feeder Termination* substation project and the *2017 Additions Due to Load Growth* substation project.

---

5 The study is included as Attachment A to the report *2.2 2017 Additions Due to Load Growth* filed with the 2017 Capital Budget Application.

6 The new feeder will be designated CHA-04.

7 The 3.00 km of existing distribution line that will be upgraded to 3-phase consists of two separate sections:
i) 1.55 km of 1-phase distribution line.
ii) 1.45 km of 2-phase distribution line.

4.0 Project Cost

Table 1 shows the estimated *2017 Feeder Additions for Load Growth* project costs.

Table 1
2016 Project Costs

Description	Cost Estimate
RBK-01 Feeder Upgrades	$637,000
CHA-04 Feeder Addition	$793,000
Total	**$1,430,000**

5.0 Concluding

The *Feeder Additions for Load Growth* project for 2017 includes distribution system upgrades to:

- Upgrade a 6.6 km section of RBK-01 distribution feeder, and
- Construct new CHA-04 distribution feeder at CHA substation.

The estimated cost to complete this work in 2017 is $1,430,000.

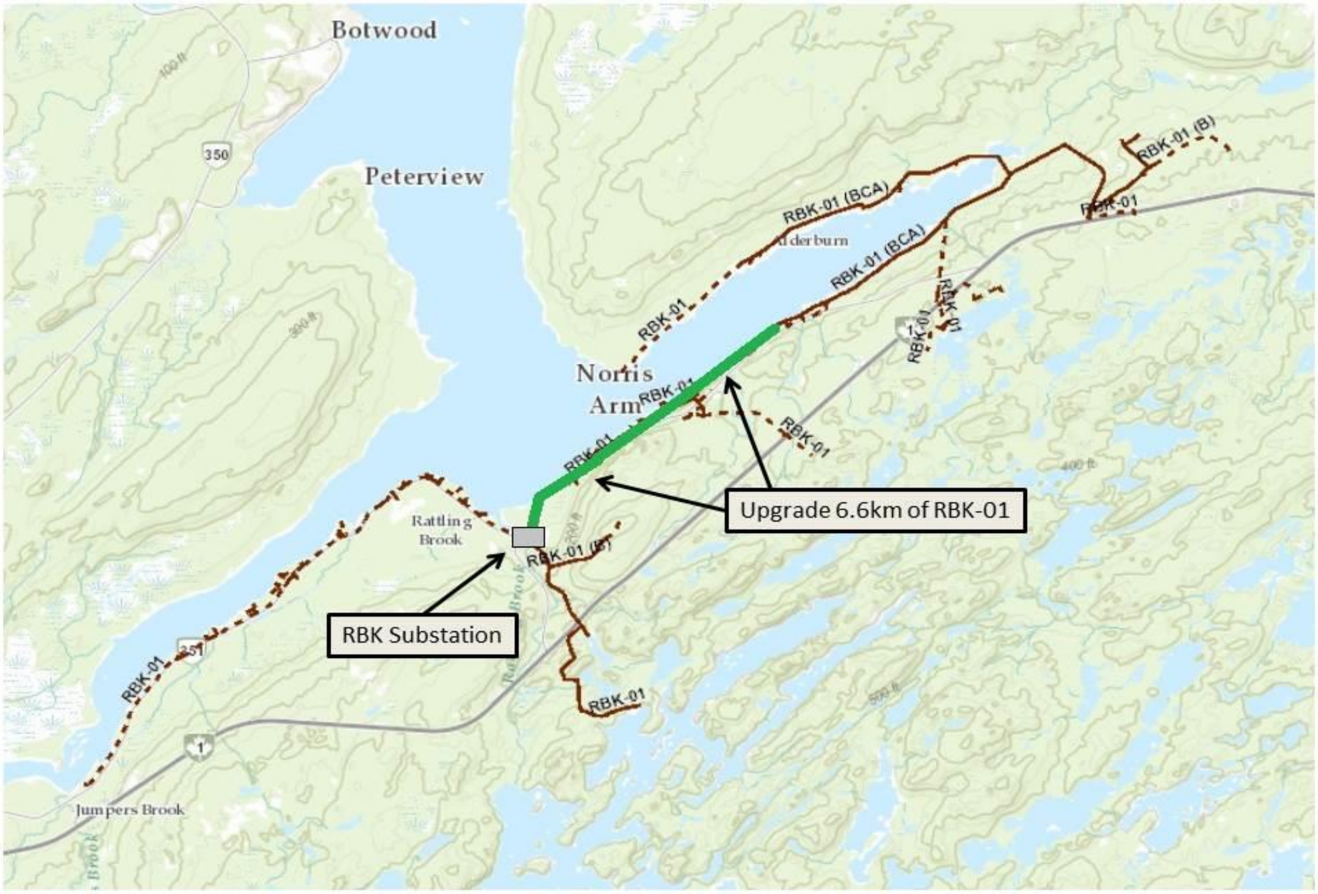
Appendix A
Distribution Planning Guidelines
Conductor Ampacity Ratings

Aerial Conductor Capacity Ratings						
Size and Type	Continuous Winter Rating[1]	Continuous Summer Rating[2]	Planning Ratings[3] CLPU Factor[4] = 2.0 Sectionalizing Factor[5] = 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

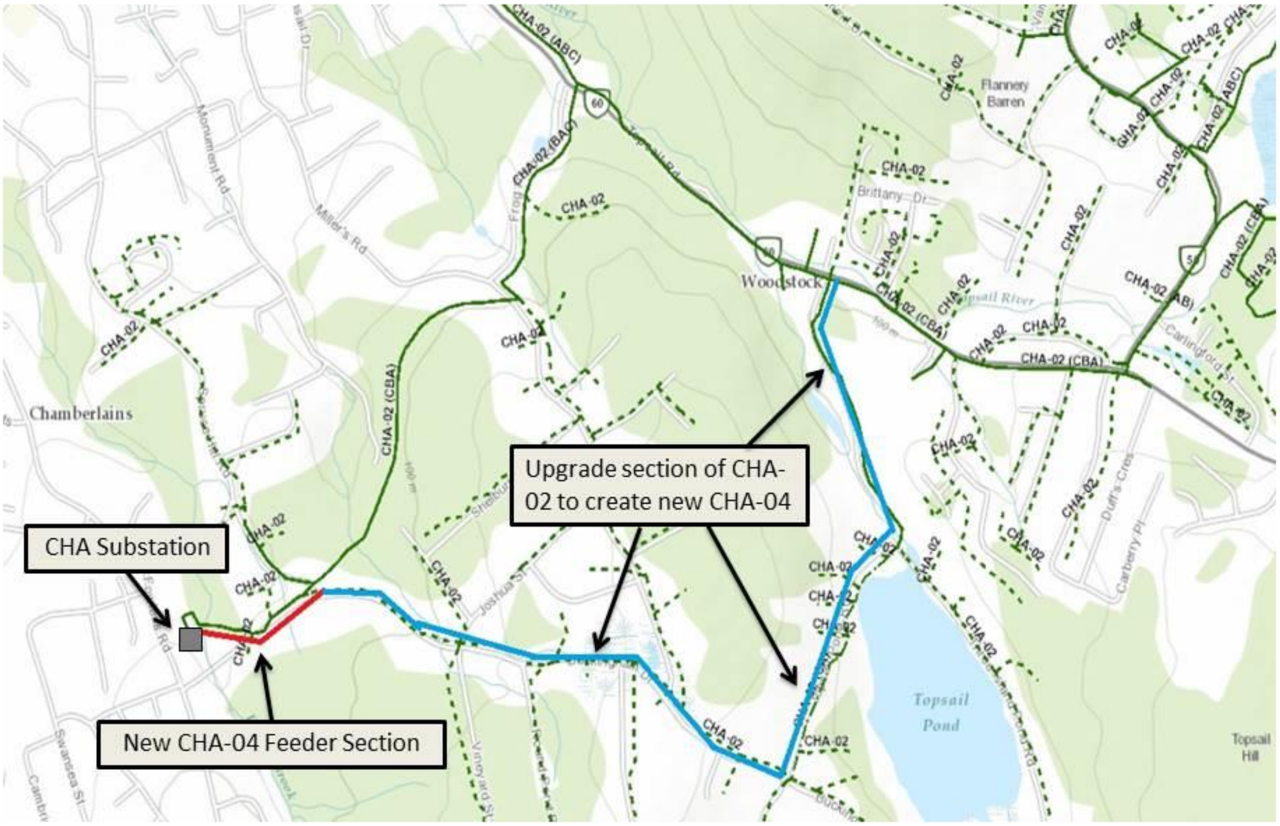
1 The winter rating is based on ambient conditions of 0ºC and 2ft/s wind speed.
2 The summer rating is based on ambient conditions of 25ºC and 2ft/s wind speed.
3 The planning rating is theoretically 75% of the winter conductor ampacity. In practice the actual percentage will be something less due to (i) the age and physical condition of the conductor, (ii) the number of customers on the feeder, (iii) the ability to transfer load to adjacent feeders and (iv) operational considerations including the geographic layout and the distribution of customers on the feeder.
4 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.
5 Sectionalizing factor: Two-stage sectionalizing is 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
Distribution Feeder Diagrams

RBK-01 Distribution Feeder Upgrade



CHA-04 New Distribution Feeder



Vault Refurbishment and Modernization

July 2016

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Jon O'Reilly

Approved by:

Robert Cahill, Eng. L.

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1.0 Vault Refurbishment and Modernization Plan

Newfoundland Power (the "Company") has a number of electrical distribution vaults within the City of St. John's.[1] These vaults are an essential part of the Company's electrical distribution system and are primarily located inside customer-owned buildings in the City of St. John's. These vaults are typically located in the basements of buildings and contain high voltage electrical equipment that converts primary voltages from the existing underground distribution system to secondary voltages. This electricity is then distributed to serve the building occupied by the vault, and in some cases, adjacent buildings in the area.

Most of the existing vaults are at least 40 years old and were initially constructed when underground electrical service was established in the buildings in which they are located. Throughout the years, as standards have changed, operational and safety issues associated with these vaults have required the Company to develop new procedures. In most cases, this requires that the electrical equipment in the vaults and associated buildings be de-energized prior to entry.

In the 2014 Capital Budget Application, the Company submitted a *Vault Refurbishment and Modernization* plan (the "Vault Plan") which identified the need to refurbish and modernize these vaults to comply with the current versions of: (i) the Canadian Standards Association Z462-08 Arc Flash Standard, (ii) the Canadian Electrical Code, (iii) the National Building Code of Canada and (iv) the Company's operational procedures.

The Company has selected 3 vaults to be upgraded in 2017.

2.0 2017 Vault Refurbishment and Modernization Projects

For 2017, the Company has identified 3 locations where refurbishment and modernization of existing vaults will take place. The vaults are located at Forest Hill Apartments on Larkhall Street; Terra Nova Tel ("TNT") Building on Water Street; and Churchill Square Apartments in Churchill Square.[2]

At each of these locations there is adequate space outdoors in the vicinity of the vault to eliminate the vault entirely. This can be achieved by replacing the exposed high voltage equipment in the vault with standard padmount equipment located outdoors.

---

[1] The Canadian Electrical Code (CSA C22.1-12) defines a vault as "an isolated enclosure, either above or below ground, with fire-resisting walls, ceilings, and floors for the purpose of housing transformers and other electrical equipment".

[2] The vaults are located on customer premises and are essential to the delivery of electricity to the customer and in some cases to customers in the same or adjacent buildings. The Company will work with the affected customers to plan and schedule the work to minimize the impacts on their businesses.

Table 1 identifies the 2017 Vault Refurbishment and Modernization estimated expenditures for 2017.

Table 1
2017 Vault Refurbishment and Modernization

Project	Budget
Forest Hill Apartments	$178,000
Terra Nova Tel ("TNT") Building	$192,000
Churchill Square Apartments	$142,000
Total	**$512,000**

2.1 Forest Hill Apartments ($178,000)

The electrical vault at Forest Hill Apartments is located within the building's bottom floor at 91 Larkhall Street.

Figure 1: Forest Hill Apartments Vault Location

The following is a list of electrical equipment within the vault:

- High voltage power cables,
- 4.16 kV to 120/208 volt pole mount distribution transformers,
- Pole mount cutouts, and
- Insulated secondary conductors.

All of the equipment within the vault is owned by Newfoundland Power.

Figure 2: Forest Hill Apartments Pole Mount Transformers

The 4.16 kV power cable supplies the vault from an underground termination pole located behind the Forest Hill Apartments building on Larkhall Street and enters the vault through an underground conduit. The power cables feed three 4.16 kV to 120/208 volt pole mount distribution transformers. The 120/208 volt secondary cable exits the room through a conduit system to the customer's electrical service.

A review of the vault has identified the following:

- Lack of proper spill containment for the pole mount transformers,
- Lack of adequate ventilation, and

- Exposed high voltage electrical equipment that could result in arc flash and electrical contact.

Due to electrical contact and arc flash hazards associated with the exposed high voltage equipment located in the vault, personnel must wear arc flash personal protective equipment and maintain a minimum approach distance of 30 inches from the exposed high voltage equipment while inside the vault.

Since there is adequate outdoor space in the vicinity of the vault, it is feasible to eliminate the vault by installing the electrical equipment outside.

The work required to complete this is as follows:

- Install a dual wound 4.16 kV/12.5 kV to 120/208 volt pad mount transformer,
- Install new 12.5 kV underground primary cable to new padmount transformer, and
- Install 120/208 volt cables to the customer-owned main disconnect switch in the building's electrical room.

2.2 Terra Nova Tel ("TNT") Building ($192,000)

The electrical vault at the TNT building is located within the building's bottom floor at 152 Water Street.

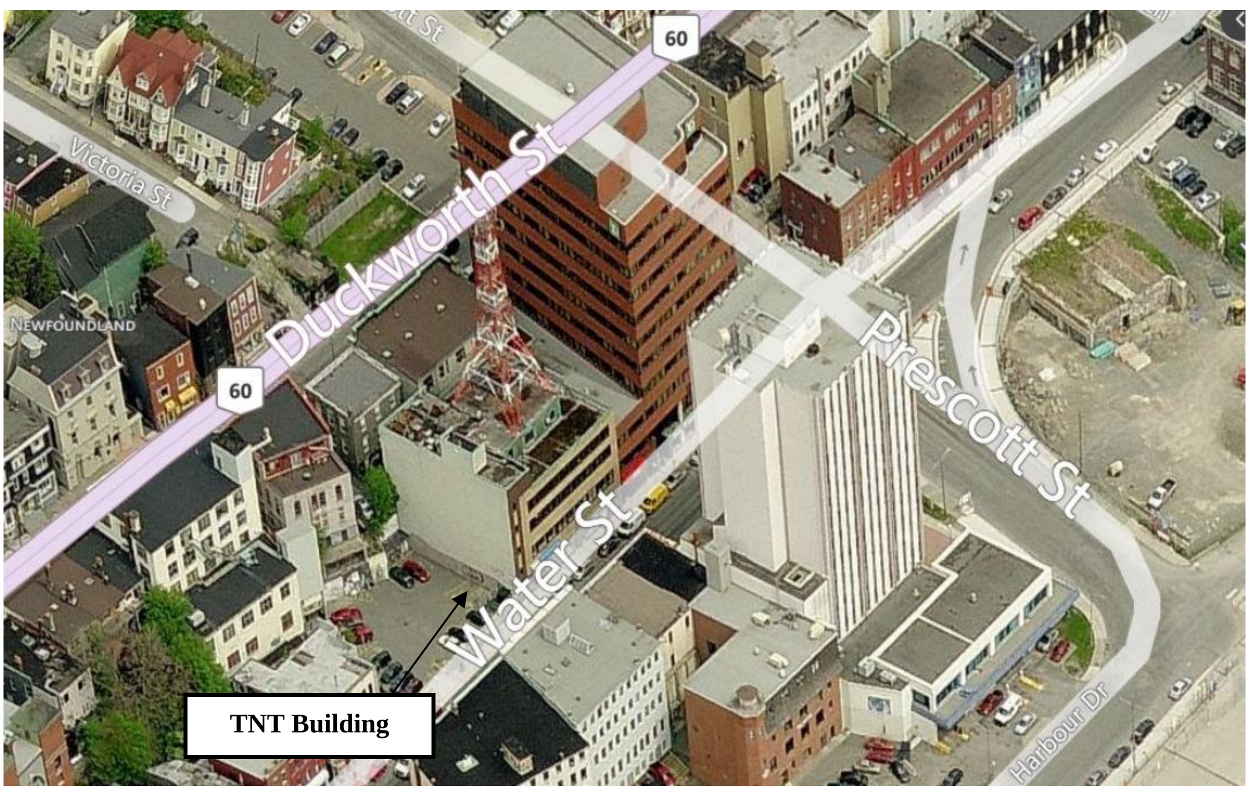

Figure 3: TNT Vault Location

The following is a list of electrical equipment within the vault:

- 12.5 kV 3 phase primary underground cable,
- 12.5 kV 3 phase primary breaker,
- 12.5 kV to 120/208 volt pole mount distribution transformers,
- Pole mount cutouts,
- Insulated secondary conductors, and
- Primary metering tank.

All of the equipment within the vault is owned by Newfoundland Power.

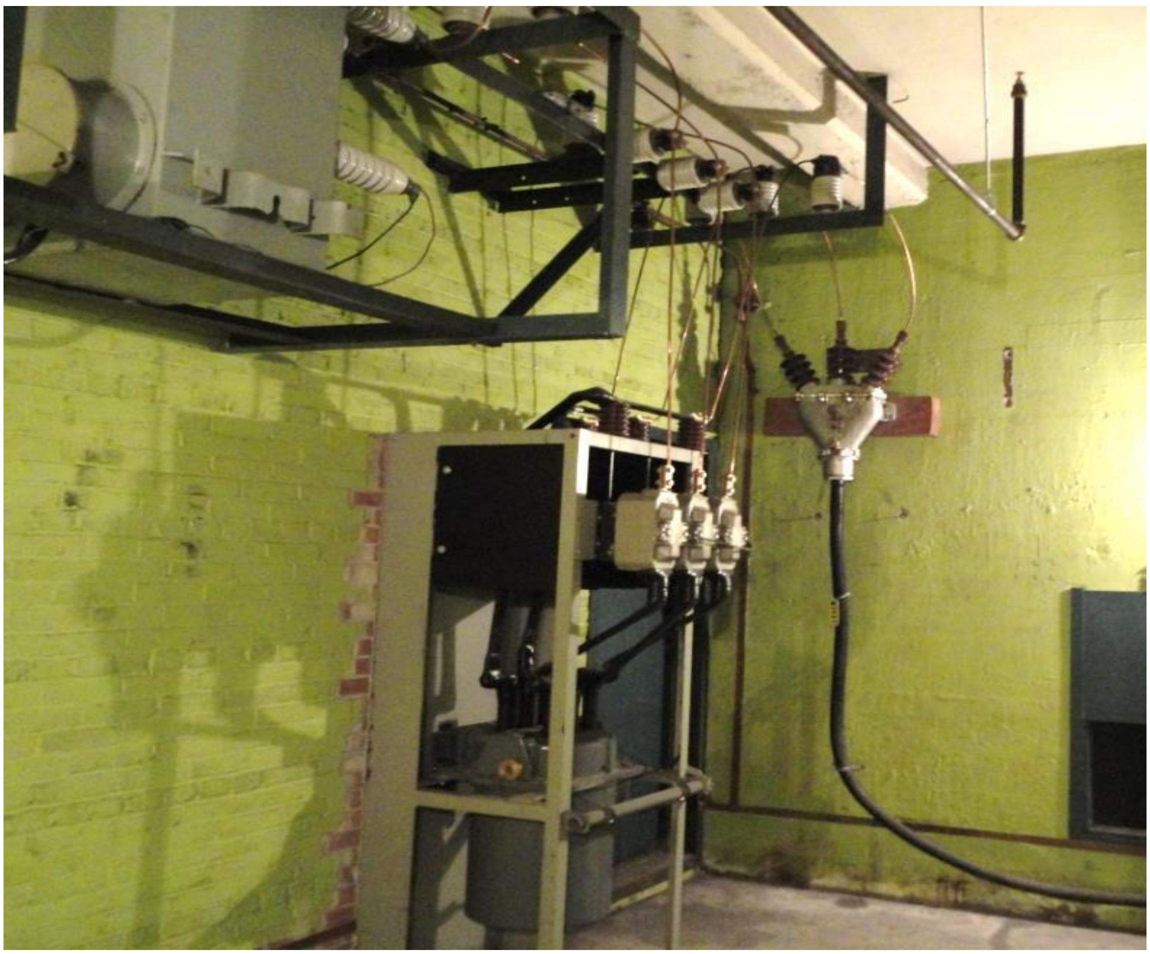

Figure 4: TNT Building Primary Cable and Breaker

The 12.5 kV power cable supplies the vault from a pad mount switch located adjacent to the building on Water Street and enters the vault through an underground conduit. The power cable feeds a 3 phase 12.5 kV breaker in the vault. A 12.5 kV power cable then leaves the breaker and feeds three 12.5 kV to 120/208 pole mount transformers.

A review of the vault has identified the following:

- Lack of proper spill containment for the pole mount transformers,
- Lack of adequate ventilation, and
- Exposed high voltage electrical equipment that could result in arc flash and electrical contact.

Figure 5: TNT Building Pole Mount Cutouts

Due to electrical contact and arc flash hazards associated with the exposed high voltage equipment located in the vault, personnel must wear arc flash personal protective equipment and maintain a minimum approach distance of 30 inches from the exposed high voltage equipment while inside the vault.

Since there is adequate outdoor space in the vicinity of the vault, it is feasible to eliminate the vault by installing the electrical equipment outside.

The work required to complete this is as follows:

- Install new 12.5 kV to 120/208 padmount transformer,
- Terminate 12.5 kV underground primary cable at new padmount transformer, and
- Install 120/208 volt cables from padmount to the customer-owned main disconnect switch in the building's electrical room.

2.3 Churchill Square Apartments ($142,000)

The electrical vault at Churchill Square Apartments is located within the building's bottom floor located in Churchill Square.

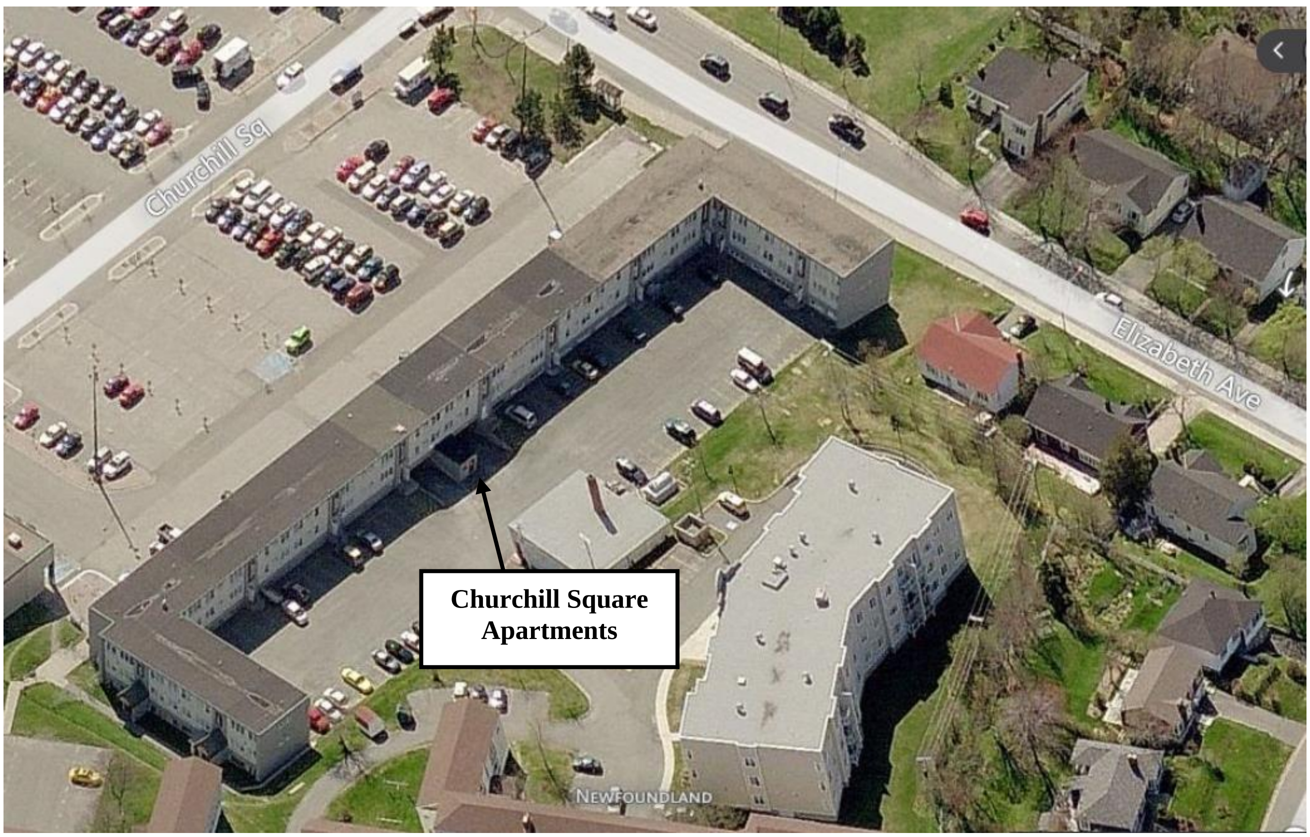

Figure 6: Churchill Square Apartments Vault Location

The following is a list of electrical equipment within the vault:

- High voltage power cable,
- High voltage primary bus,
- 4.16 kV to 120/240 volt pole mount distribution transformers, and
- Insulated secondary bus.

All of the equipment within the vault is owned by Newfoundland Power.

Figure 7: Churchill Square Apartments Pole Mount Transformers

The 4.16 kV power cable supplies the vault from a pole located behind the building and enters the vault through an underground conduit. The power cables feed four 4.16 kV to 120/240 volt pole mount distribution transformers. The 120/240 volt secondary cable exits the room through a conduit system to the customer's electrical service.

A review of the vault has identified the following:

- Lack of proper spill containment for the pole mount transformers,
- Exposed high voltage electrical equipment that could result in arc flash and electrical contact, and
- Lack of adequate ventilation.

Due to electrical contact and arc flash hazards associated with the exposed high voltage equipment located in the vault, personnel must wear arc flash personal protective equipment and maintain a minimum approach distance of 30 inches from the exposed high voltage equipment while inside the vault.

Since there is adequate outdoor space in the vicinity of the vault, it is feasible to eliminate the vault by installing the electrical equipment outside.

The work required to complete this is as follows:

- Install a dual wound 4.16/12.5 kV to 120/240 volt pad mounted transformer
- Install new 12.5 kV underground primary cable to new padmount transformer, and
- Install 120/240 volt secondary service conductors to the customer-owned main disconnect switch in the building's electrical room.

3.0 2017 Project Cost

Table 3 is a summary of the 2017 expenditures associated with the Vault Refurbishment and Modernization project.

Table 3
2017 Project Expenditures

Cost Category	Expenditure
Material	$120,000
Labour - Internal	$133,000
Labour - Contract	$105,000
Engineering	$33,000
Other	$121,000
Total	**$512,000**

4.0 Concluding

The Vault Refurbishment and Modernization work for 2017 includes the following:

- Replacement and relocation of vault equipment to outdoor location for the Forest Hill Apartments vault,
- Replacement and relocation of vault equipment to outdoor location for the TNT Building vault, and
- Replacement and relocation of vault equipment to outdoor location for the Churchill Square Apartments vault.

The estimated cost to complete this work in 2017 is $512,000.

Company Building Renovations
Stephenville Office Building HVAC Replacement

July 2016

Prepared by:

David Ball, P.Eng.

Brad Tooktoshina, P.Eng.

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1.0 Introduction

The Stephenville Office Building (the "Facility") is Newfoundland Power's (the "Company") primary operations facility for the Stephenville Area (the "Area").[1] The Area's service territory extends from Black Duck Siding, near Stephenville in the north to Rose Blanche in the South, including customers on the Port Aux Port Peninsula and in Port aux Basques. The Area serves approximately 17,000 customers, 7% of all customers served by the Company.[2]

The Facility houses employees and equipment necessary to support operations throughout the Area's service territory. This includes line crews, distribution design, electrical maintenance, maintenance planning, meter reading, stores and associated management staff. In addition, the Facility houses corporate functions such as regional emergency materials storage as well as area customer service agents.[3]

The Facility was originally constructed in 1958 as part of the Harmon Air Force Base in Stephenville. Newfoundland Power purchased the building in 1988. With the exception of a roof refurbishment in 2003 and 2004, the last major renovation took place in 1988. Many of the building's systems have reached an age where capital improvements are necessary to ensure it continues to provide safe and reliable service to employees and the public. The most immediate need is the replacement of the heating, ventilation and air conditioning ("HVAC") system. This project includes $351,000 in estimated capital expenditures associated with the replacement and refurbishment of the Facility's HVAC system.

2.0 Operating Experience

The HVAC system is 28 years old. The system consists of a packaged roof mounted heat pump with an integral heating coil and associated controls systems. The heat pump is supplemented by electric baseboard heaters in the office area and large electric space heaters in the warehouse area. A mini-split heat pump is used to provide air conditioning to a small area of the building that cannot adequately be served by the roof-mounted heat pump system.

The age of the HVAC system makes it increasingly difficult to source replacement parts and repair equipment failures. As a result, the system no longer performs optimally. For example, following the failure of the obsolete master controller on the rooftop unit, a replacement could not be sourced. Subsequently, a single thermostat was installed to control the rooftop unit resulting in unbalanced heating and cooling throughout the building. It is not uncommon for a room to be calling for cooling from the HVAC system while baseboard electric heaters are simultaneously heating the same room.

Sections of the building are cold during the heating season and hot during the cooling season. As a result, portable heaters are used as supplementary heat sources for some employee workspaces. Similarly, during the cooling season these same workspaces require portable fans for cooling.

[1] The building area is approximately 1,200 square metres. It includes a combination of office space, support space for operations and a stores warehouse.
[2] A district building in Port Aux Basques supports operations in the southern part of the Area.
[3] Area customer service agents provide both walk-up customer service and remote agent service in support of the larger customer service call center in St. John's.

Since December 2013, there have been 5 significant failures that required repairs to the rooftop unit. These included coolant leaks and blockages, a motor bearing failure and heat damaged wiring.

3.0 HVAC Condition Assessment

Due to the age, condition and operational issues associated with the HVAC system, Newfoundland Power retained Core Engineering Inc. ("Core") in 2015 to provide an overall HVAC system assessment and report.[4] The report is presented in Appendix A.

According to the Core report, the main deficiencies of the HVAC system are as follows:

(i) The system is in generally poor condition due to age and deterioration.
(ii) Airflows and zones cannot be optimized for the number of occupants and type of occupancy. The system has only one zone encompassing the open office, enclosed office and warehouse areas. As a result, comfort complaints are a constant problem during the heating and cooling seasons.
(iii) The system does not serve the entire building.
(iv) The control system is obsolete and should be replaced for efficiency, comfort and maintenance reasons.
(v) Current American Society of Heating, Refrigerating and Air Conditioning Engineers ("ASHRAE") fresh air standards are not currently being achieved.[5]
(vi) The washroom exhaust systems are 28 years old and do not have the efficiency of modern designs.
(vii) The cooling system uses R-22 refrigerant which is not environmentally friendly and is due to be phased out of commercial air conditioning equipment by 2020.[6]
(viii) Duct insulation is in poor condition.

Core's assessment concludes the system is at the end of its useful service life and requires replacement.

4.0 Project Description

Replacement of the existing HVAC system is planned for 2017. The Company will rectify the HVAC deficiencies noted by Core by replacing the roof mounted heat pump and upgrading the air distribution system with variable air volume boxes to supply the entire building. The warehouse section of the building will be upgraded with an air source heat pump to increase the efficiency of the building and add cooling during the summer months. All existing building exhaust fans will be replaced to improve efficiency and reduce maintenance cost. The existing building HVAC control system will be replaced with a digital controls system.

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[4] Core Engineering is an engineering consultant specializing in Electrical and Mechanical Building Systems.
[5] ASHRAE publish widely adopted standards for HVAC design.
[6] Hydrochlorofluorocarbons ("HCFC"), including R-22 are ozone-depleting refrigerants, and under the terms of the Montreal Protocol, will be 99.5% phased out by 2020. After 2020 R-22 refrigerant will no longer be imported or manufactured in Canada.

5.0 2017 Project Cost

Table 1 includes the estimate to complete the project in 2017

Table 1
Projected Expenditures
($000s)

Cost Category	**2016**
Material	305
Labour – Internal	12
Labour – Contract	-
Engineering	26
Other	8
Total	**351**

6.0 Concluding

The HVAC system in the Stephenville Office Building is at the end of its useful life. Attempting to extend the life of the system through further repairs to the HVAC equipment is not viable. Therefore, it is necessary to replace the existing HVAC system in 2017.

Appendix A
HVAC System Analysis
Stephenville

HVAC Systems Analysis

Newfoundland Power
Stephenville

Prepared by:

CORE ENGINEERING INC.

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HAROLD E. FOWLER
Harold Fowler
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May 11/16
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PROVINCE OF NEWFOUNDLAND

Client:

NEWFOUNDLAND POWER
A FORTIS COMPANY

Date: March 2015

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1.0 INTRODUCTION

Core Engineering Incorporated (Core) was retained by Newfoundland Power to evaluate the heating, ventilation and air-conditioning (HVAC) systems at the Stephenville site building. The scope of this report will include the existing equipment and systems, their condition, and provide recommendations.

Harold Fowler, P. Eng., from Core has visited this site and has reviewed drawings that were available. The report outlined below will provide the Owner with an update as to the operation of the various systems and their conditions.

The Stephenville office building was last renovated in the early to mid 80's as a single story structure, consisting of an office and warehouse section. The total building contains approximately 1160 square meters of space including the stores warehouse area. The area served by the roof mounted heat pump unit is the majority of the office section and the training room. There are offices to the left of the main entrance and lunch room that are not served by the heat pump system and are not ventilated. The washrooms are served by exhaust fans ducted to the exterior of the building to wall caps. There is also one A/C mini-split system installed in an office off the warehouse with the other offices in the warehouse section not having cooling/ventilation. The main heat pump system appears to have been installed approximately in 1986, putting it in operation for 28 years. The smaller A/C split system was installed at a later date.

2.0 DESCRIPTION

2.1 Stephenville Existing H.V.A.C. Systems

The heating/cooling system for the building is a combination of electric baseboard heat and the mechanical heat pump system. The heat pump system is designed as one zone which has the main thermostats in the main office area, while the baseboard heat control is provided in the individual offices. There are a few larger electric unit heaters in the warehouse section of the building as well.

The main equipment installed for this building appears, from the unit model number, to have been purchased in 1986. It consists of a packaged roof mounted heat pump with integral heating coil, and associated controls system. The system's heating is generated using a thermal expansion reversing valve in the heat pump which reverses refrigeration flow through the cooling coil which can be used for heating. The unit is complete with electric heating coil which tempers the fresh air and can be used to defrost the unit in heating mode when outdoor air condenses on the heating coil and causes frost build-up. The heating from the heat pump is also supplemented by baseboard heat.

The control system was designed as a variable volume and temperature (VVT) controls system. The building is served by one zone which is tempered to satisfy the desired temperature of the zone. Individual exterior offices with baseboard heaters have independent thermostats to control the baseboard heat if additional heat is required. The terminal heating coil is capable of modulating supply air temperature to the zone to meet the desired space temperature. When the main temperature controller in the system calls for either cooling or heating, depending on the control parameters, it will activate the unit in either heating or cooling mode.

As part of the ventilation system, the washrooms have exhaust fans which exhaust air to the exterior of the building. The time card room off the warehouse portion of the building also as a single zone A/C mini-split installed.

3.0 OPERATIONAL OBSERVATIONS

3.1 Stephenville Existing System

3.1.1 Existing H.V.A.C Systems

The system serving this space is approximately 28-year-old roof mounted heat pump as described earlier. Below are the main issues surrounding this system:

- The VVT zone distribution system installed at this site is not well suited for a combination of open office space and perimeter enclosed offices. Comfort issues are a problem.

- Controls system is in need of being updated to a newer modern system for efficiency, maintenance and comfort reasons. The existing VVT controls system is causing operational issues and has to be reset on a continual basis. This system is obsolete.

- The distribution of supply and return grilles, the zone airflows, and the number of zones are not optimized for the number of occupants and size of space being served. Also, it does not serve the entire building.

- Minimum fresh air standards of 8.5 l/s per person are not being achieved with this system. ASHRAE 62.1 2010 Standard "Ventilation for Acceptable Indoor Air Quality" requires that the minimum fresh air level of 8.5 l/s per person be maintained for an office type space.

- The washroom exhaust system is 28 years old and does not have the efficiency of newer modern systems. It also does not have the required airflows as indicated in the current ASHRAE 62.1, 2010 standard.

- Both the larger roof mounted heat pump and the mini-split A/C unit use Freon R-22 refrigerant which is not an environmentally friendly refrigerant agent. This refrigerant is due to be phased out of commercial air conditioning equipment by the year 2020. While this refrigerant is not used with new equipment, replacement refrigerant will remain available until 2020 before 99.5% phase-out. The manufacturing of R-22 will be eliminated by 2030.

- Duct insulation on the heat pump distribution mains is falling off. The insulation is in poor condition.

- This system is at the end of it's useful life and is generally in poor condition. It is expected that maintenance costs and reliability will cause further problems in the near future.

3.1.2 Miscellaneous fans

These systems are original to the buildings construction. All misc. fans with the exception of the range hood were found to be at the end of their useful life.

4.0 RECOMMENDATIONS

The existing systems as described are at the end of their useful lives and we would recommend replacement in the next couple of years with a new heat pump variable air volume system including controls.

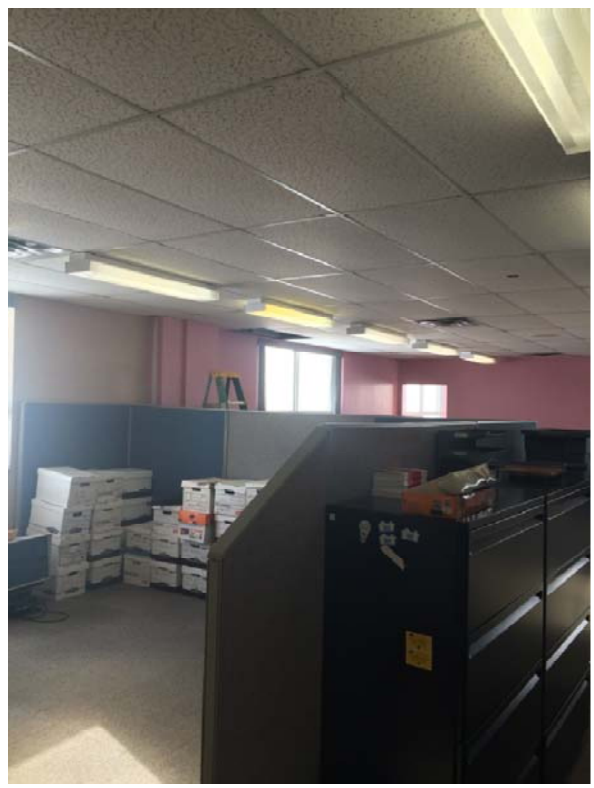
A summary of the recommendations are;

* Replace the roof mounted heat pump unit with a new packaged heat pump.
* Revamp the duct system with upgrading of the air distribution system and addition of Variable air Volume(VAV) boxes.
* Install new DDC controlled humidifier.
* Replace duct insulation.
* Replace all exhaust fans.
* Replace existing control system with a small DDC system.

Attachment A
Stephenville Existing Equipment

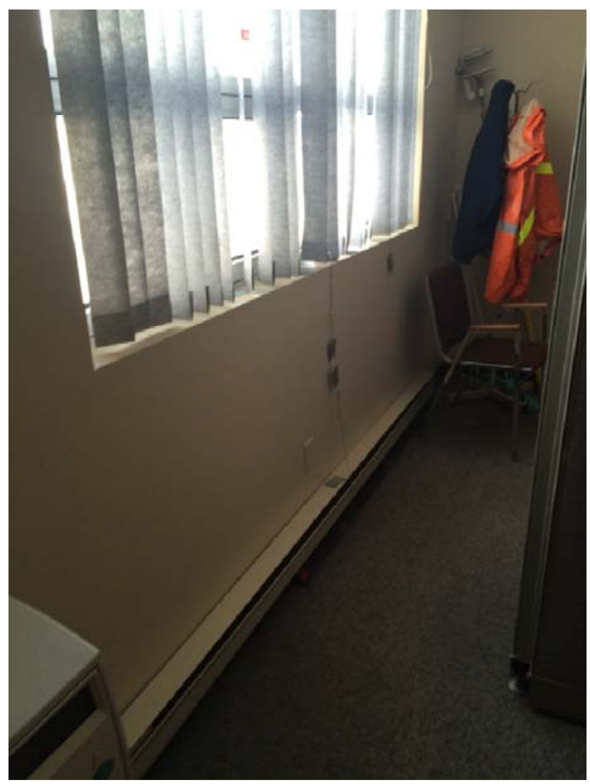
ROOF MOUNTED HEAT PUMP UNIT

MINI-SPLIT SYSTEM

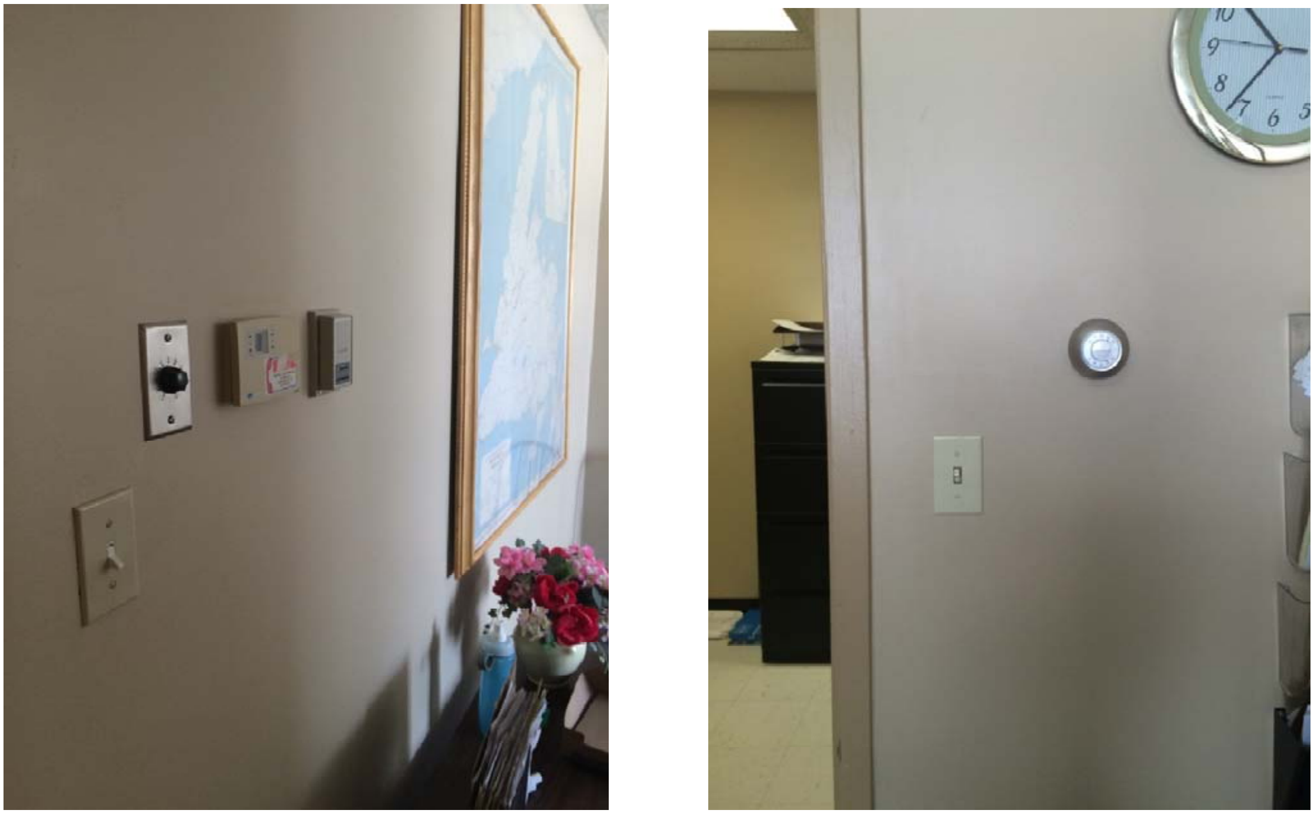


OFFICE

ROOF TOP HEAT PUMP RETURN/SUPPLY DISTRIBUTION



TYPICAL BASEBOARD HEATERS



HEAT PUMP AND BASEBOARD HEAT THERMOSTATS

DUCT INSULATION

WAREHOUSE

WASHROOM EXHAUST FAN

CARRIER VVT CONTOL BOXES

2017 Application Enhancements

July 2016

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1.0 Introduction

Newfoundland Power (the "Company") operates and supports over 60 computer applications. These include third party software products, such as the Microsoft Dynamics Great Plains ("Dynamics GP") financial system, the Click Software ("Click") work scheduling and dispatch system, as well as internally developed software, such as the Customer Service System ("CSS") and the Technical Work Request system ("TWR"). These applications help employees work more effectively and efficiently in their daily duties.

The Company's computer application enhancements can be considered in 4 broad categories: Business Support Systems, Operations and Engineering Systems, Customer Service Systems and Internet/Intranet Systems. In addition, the Company budgets for minor enhancements to respond to unforeseen requirements encountered during the course of each year.

Enhancing these applications, either through vendor supplied functionality or internal software development, enables the Company to meet its obligation to serve its customers at least cost.

The following report describes the application enhancements planned for 2017.

2.0 Customer Service System Enhancements

Customer Service System ("CSS") enhancements include application enhancements necessary to support customer service delivery, including the various forms of communications used by customers to receive service from the Company. For 2017, enhancements are proposed to improve safety of field service representatives and agent off-phone productivity.

Table 2 summarizes the estimated cost associated with this item.

Table 2
Customer Service Systems Enhancements
Project Expenditures
($000s)

Cost Category	2017 Estimate
Material	-
Labour – Internal	287
Labour – Contract	-
Engineering	-
Other	40
Total	**327**

2.1 Customer-Employee Interaction Management ($206,000)

Description

The purpose of this item is to ensure the safety of employees, customers and the general public when employees are faced with difficult and often unpredictable situations when dealing with some customers.

Enhancing the CSS to manage additional information related to the potential for an unpredictable customer situation will reduce the risk of employees being threatened, assaulted or injured. This information would include the level of risk associated with specific customer situations, the requirement for police escort and the presence of potentially dangerous animals.

This information would be made available to employees conducting Company business on customer premises such as meter reading, service connections or disconnections, and billing collections to help manage potential risk and prevent possible confrontations.

Operating Experience

Company employees working in the field are sometimes faced with situations involving aggressive people or animals. In some instances, similar behavior may have been displayed at the same location in the past. To alert staff and give them the ability to prepare for the customer visit, a coding system will be used to advise of potentially volatile or dangerous situations when in the field. This information is also useful to employees who serve customers in Company offices.

Field staff may be required to visit customer premises where there have been previous incidents of aggression. However, staff may not be aware that the previous incident has occurred. Tracking safety concerns in CSS will allow the information to be passed to the service order and visible on the customer account, giving the field representative advance warning. Supervisors will also be able to make necessary arrangements in cases where a police escort is required or it is recommended the Company representative not visit the customer premise alone.

Justification

This item is justified on the basis of employee, customer and general public safety. The enhancements will reduce the potential risk of employees dealing with unpredictable situations.

2.2 Contact Centre Enhancements ($121,000)

Description

The objective of this item is to reduce the manual effort associated with completing multiple off-phone tasks by agents in the Contact Centre. It will involve using automation to pre-assess security deposit requirements and to automate billing related tasks that are currently dealt with manually in the Contact Centre.

Operating Experience

The current process for security deposit assessment requires an agent to review, create, and bill security deposits for commercial accounts which have changed ownership or responsibility in CSS. For new commercial services, an agent must review the credit history of the customer, the type of business being operated, and retrieve a total connected load from a technologist to determine if a security deposit should be charged. Often, the agent will determine a customer account will not require a deposit based on the type of business or the customer's credit history.

Field service representatives receive a number of work tasks via a queue to determine which customer accounts require follow up. These accounts are reviewed when a prior CSS collection activity is not met. Tasks are often created in this work queue that upon further review, require no further collection activity. It is estimated 30% of these items should not require manual follow up and could be eliminated from this work queue by using an automated review process.

Justification

The proposed item would create efficiencies and is justified on FTE savings. It is estimated that once efficiencies are in place, savings of approximately 0.25 FTEs will be realized. This will also result in enhanced service for customers as it requires less wait time before determining if a deposit is required on the customer's account.

This item has a net present value of approximately $41,000 over an expected application life-cycle of 7 years.[1] The financial analysis is included in Appendix A.

3.0 Internet Enhancements

Internet Enhancements include enhancements to the Company's web-based applications, which provide customers with convenient, self-service options. These options give customers the ability to interact with the Company 24 hours a day. The applications in this category include the Company's customer service internet website, mobile website and the takeCHARGE website.[2]

For 2017, the customer service website will be enhanced to improve functionality and access for mobile devices.

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[1] The net present value calculation for this project can be found on page A-1 of Appendix A.

[2] The takeCHARGE website supports the joint Newfoundland and Labrador Hydro and Newfoundland Power customer energy conservation initiative.

Table 3 summarizes the estimated cost associated with this item.

Table 3
Internet Enhancements
Project Expenditures
($000s)

Cost Category	**2017 Estimate**
Material	30
Labour – Internal	221
Labour – Contract	-
Engineering	-
Other	120
Total	**371**

3.1 Customer Service Internet Enhancements ($286,000)

Description

For 2017, items proposed include adding payment arrangements to the Newfoundland Power mobile app, as well as expanding the SMS texting service to include additional self service capabilities, such as account balance inquires, reporting power outages and submitting a meter reading.

Operating Experience

The connected world of people and business are forcing customer service providers to rethink self-service strategies. The number of customers visiting the Newfoundland Power website, and using self-service tools to interact with the Company, especially in times of power disruptions, continues to increase.

Figure 1 shows the number of web site visits over the period from 2012 to 2015 by technology. It also indicates the percentage of mobile devices used by customers to contact the Company during power outages.

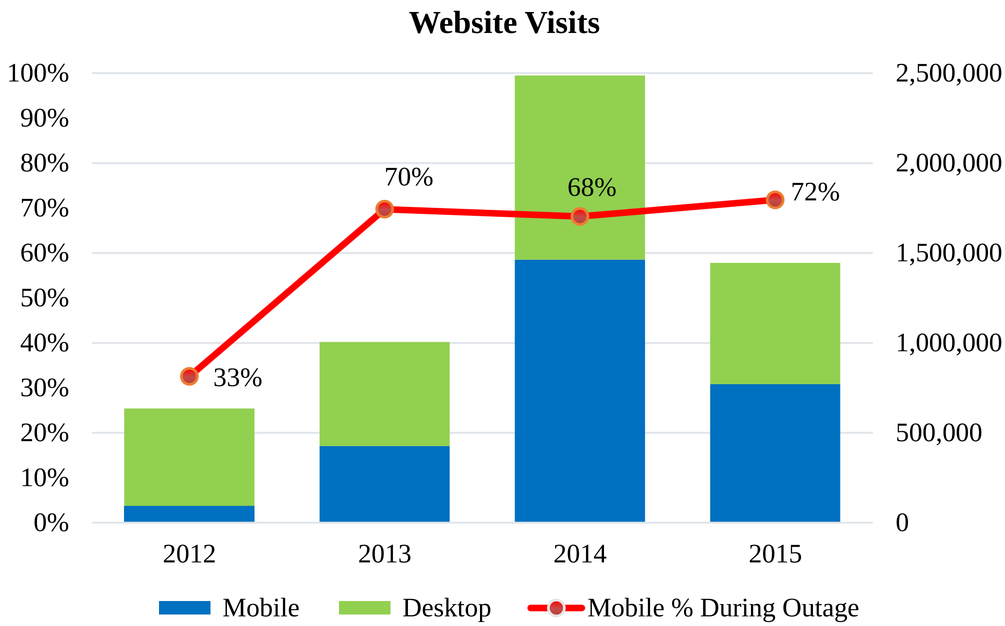

Figure 1

Newfoundland Power's analysis has shown that when customers experience service interruptions, mobile devices are the primary method used to access the Company website.[3]

In 2015, the number of customers interacting with the Company via self-service increased by 14% over the previous year. Similarly, the Company grew its electronic billing customer base by 23% in 2015. Given the customer acceptance of self-service and electronic interactions, the Company will continue to leverage technology investments to expand self-service options.

Self-service functionality offered via smart phone increases customer choice for conducting business with the Company and is a critical communication channel during power interruptions. This enhancement will continue to build on the platform Newfoundland Power has invested in, and which has been demonstrated to be preferred by customers.

Justification

This item is justified primarily on customer service improvements, providing convenience to customers through self-service functionality, while also improving employee productivity. By targeting selected service offerings that accounted for over 75,000 agent assisted service requests in 2015, Newfoundland Power will expand self-service capabilities to enable customers to complete the request themselves; thereby reducing agent assisted service requests.

[3] The increase in website visits in 2014 is largely attributable to the January 2014 outages.

3.2 Energy Conservation Website Enhancements ($85,000)

Description

The purpose of this item is to enhance the Internet based functionality which supports the Company's energy conservation initiatives under takeCHARGE.

In 2017, the takeCHARGE website enhancements are required to support the changes to customer energy conservation programs arising from the *5-Year Energy Conservation Plan: 2015-2019*. Specific enhancements include expansion of customer self-service rebate applications, tools and calculators, and additional energy efficient technology options within the Business Efficiency Program. Enhancements are also required in the Company's management of paper based and electronic files regarding customer energy conservation programs and various enhancements to program participation tracking tools and website functionality.

Operating Experience

In 2008, Newfoundland and Labrador Hydro and Newfoundland Power launched a joint energy conservation initiative which included the takeCHARGE website. This website is an integral part of the Company's customer energy conservation communications portfolio. It serves as the primary communication channel to which customers are directed for information regarding customer energy conservation programs, rebate and eligibility details, as well as energy efficiency education and awareness resources.

In 2015, there were over 368,000 visits to the takeCHARGE website, which was an increase of 97% over 2014 activity. This is consistent with promotion of the takeCHARGE website as the primary resource for customer conservation inquiries and information, and reflects ongoing promotion, program changes, and website enhancements implemented in 2015. It also reflects the broad trend toward increasing customer expectations for self-service options, particularly through mobile devices. In 2015, the proportion of takeCHARGE website visits using mobile devices increased by 115% compared to 2014.

Justification

Website enhancements are justified based on improvements to customer service and promotion of energy efficiency. As customer energy conservation programs and associated incentives and information evolve as proposed in the *5-Year Energy Conservation Plan: 2015-2019*, it is necessary that the takeCHARGE website and related tools are updated to ensure these new programs and information resources can be offered to customers.

These enhancements will expand customers' access to the energy conservation tools and information which are integral to the Company's customer energy conservation initiatives, by enabling choice between access to the stranded website and access by mobile device. This will enhance the customers' ability to access information on conservation opportunities independent of location, time of day or type of device used, and will support continued efficiency in the Company's response to customer expectations in this area.

4.0 Various Minor Enhancements ($305,000)

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 modifications to customer, operations and engineering applications performed in response to severe weather events, employee self-service functionality to improve timesheet entry, and improved customer work request functionality to include new work types.[4]

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.

[4] Improvements also include customer outage communication, vehicle tracking, and outage management.

Appendix A
Net Present Value Analysis

NET PRESENT VALUE ANALYSIS

Contact Centre Enhancements

		Capital Impacts						Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software A	New Hardware B	Software	Hardware	Residual CCA	Total C	Labour D	Non-Lab D	Labour E	Non-Lab E	Net Operating Savings F	Income Tax G	After-Tax Cash Flow H
0	2018	($121,000)	$0	$60,500	$0		$60,500	$0	$0	$25,000	$0	$25,000	$10,650	($85,350)
1	2019	$0	$0	$60,500	$0		$60,500	$0	$0	$25,625	$0	$25,625	$10,463	$36,088
2	2020	$0	$0	$0	$0		$0	$0	$0	$26,266	$0	$26,266	($7,880)	$18,386
3	2021	$0	$0	$0	$0		$0	$0	$0	$26,922	$0	$26,922	($8,077)	$18,846
4	2022	$0	$0	$0	$0		$0	$0	$0	$27,595	$0	$27,595	($8,279)	$19,317
5	2023	$0	$0	$0	$0		$0	$0	$0	$28,285	$0	$28,285	($8,486)	$19,800
6	2024	$0	$0	$0	$0		$0	$0	$0	$28,992	$0	$28,992	($8,698)	$20,295
7	2025	$0	$0	$0	$0	$0	$0	$0	$0	$29,717	$0	$29,717	($8,915)	$20,802
7 Yr	Present Value (See Note I)	@		5.62%										$40,688

NOTES: A is the sum of the software additions by year.
B is the sum of the computer network hardware additions by year.
C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
D is any software maintenance fees and internal support costs associated with the project. The labour cost estimates are escalated to current year using the GDP Deflator Index. The non-labour costs are escalated by The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
E is the reduced operating costs. The non-labour cost estimates are escalated to current year using the GDP Deflator Index. The labour costs are escalated by The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
F is the sum of columns D, and E.
G is the impact on taxes from the CCA and operating cost deductions. It is equal to column C (total) less column F times the tax rate.
H is the after tax cash flow which is the sum of the capital expenditure (columns A + B) plus operating expenditures (column F) plus income tax (column G).
I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

2017 System Upgrades

July 2016

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1.0 Introduction

Newfoundland Power (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 applications upgrades and continuation of the Microsoft Enterprise agreement.

2.0 Business Applications Upgrades ($1,481,000)

Business applications upgrades involve third party software that supports the Company's business applications. For 2017, upgrades are proposed for the Company's meter reading system, mobile maintenance inspection application, database management systems, Dynamics Great Plains financial management system and software development and testing tools.

Table 1 summarizes the cost associated with these items.

Table 1
Business Applications Upgrades
Project Expenditures
($000s)

Cost Category	2017 Estimate
Material	383
Labour – Internal	814
Labour – Contract	-
Engineering	-
Other	284
Total	**1,481**

2.1 Description

The upgrades to the Company's business applications ensure that these applications continue to function in a stable and reliable manner with the appropriate level of vendor support. Each year, the Company's software applications are reviewed to determine if upgrades are required.

For 2017, upgrades include:

2.1.1 Meter Reading System Upgrade ($493,000)

This item involves upgrading the Itron meter reading system to a version that is fully supported by the vendor. Increasing failure rates and vendor support calls also indicate the software has reached the end of its useful life. This application was last upgraded in 2012.[1]

The meter reading infrastructure is a critical component of the Company's meter reading and customer billing functions. The proposed upgrade will ensure consistent and effective operation of the Company's collection and processing of approximately 3 million customer meter readings annually. The upgraded software supports all current types of customer meters as well as providing functionality required to utilize advanced meter functions.

The upgrade will also expand the mobile capabilities of the meter reading infrastructure. The upgraded infrastructure will leverage two way communications, allowing the Company to securely communicate with meters remotely. By using this technology in strategic locations, a field service representative can complete actions that would have previously required a visit to the customer premises.

2.1.2 Mobile Maintenance Inspection Application Upgrade ($286,000)

This item involves upgrading the current application used for capturing the results of inspections conducted on the Company's distribution and transmission assets. The existing application was installed in 2011. Since that time the mobile computers used to operate the mobile inspection application have been replaced.[2] This has resulted in usability issues with the application as it was not designed to work on the newer models of Panasonic rugged devices.

Also, the current application is unable to utilize the GIS mapping capabilities available through the Company's GIS application, ESRI ArcGIS. This upgrade will allow field inspectors and planners the ability to leverage GIS maps to improve work identification, planning and execution, including reducing the likelihood of duplicate work requirements being identified.

2.1.3 Database Management Software Upgrade ($215,000)

This item involves upgrading the Company's database management software ("DBMS") to the latest version supported by the vendor. The existing application was installed in 2009. The Company operates multiple versions of DBMS from Microsoft and Oracle to support the over 50 database applications the Company has in service.

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[1] The Company is moving to 100% Automatized Meter Reading (AMR) meters by the end of 2017. The Itron meter reading system, including the Itron handheld meter reading equipment will continue to be used to collect meter readings from the new AMR meters.

[2] The computers used for distribution and transmission inspections, Panasonic U-1, are no longer being manufactured and were replaced by the Panasonic ToughPad.

The version of DBMS selected for a particular application is typically the latest version available from the vendor at the time of implementation. Versions of SQLServer DBMS currently in use by the Company are no longer supported by the vendor, Microsoft. The databases affected by the unsupported software are installed as part of applications operating in Customer Relations, Operations and Engineering.

2.1.4 Microsoft Dynamics Great Plains Upgrade ($321,000)

This item involves an upgrade to the Company's financial management system, Microsoft Dynamics Great Plains ("Dynamics GP") to the most current vendor supported version of the software. The version currently used by the Company will no longer be supported by the vendor after April 10, 2018. Dynamics GP is used to manage Company resources including financial resources, project accounting, payroll and materials management/purchasing. The Dynamics GP application was initially implemented in 2002.

The upgrade involves ensuring the new version of the software continues to support Company operations. Modifications were made to the original application to meet Company requirements during the initial implementation to integrate with other Company applications including Customer Service System (CSS), Technical Work Request system (TWR) and the Company's asset management system (Avantis). These modifications will be transferred to the new version. In addition, other applications that integrate with Dynamics GP to support purchasing functions, electronic invoicing and warehouse management will be required to be upgraded to ensure compatibility with the upgraded version of Dynamics GP.

2.1.5 Software Development Environment Upgrade ($166,000)

This item involves the upgrade of technologies used to design and develop corporate applications such as TWR and CSS. These technologies include software to program, test, integrate, deploy and operate corporate applications. Examples of this software include (i) Microsoft Visual Studio (used for programming and testing), and (ii) Microsoft BizTalk Server (used for integrating business applications).

Software development practices require segregated environments for prototyping and software development, testing, staging and production. This is necessary to ensure software implementation minimizes disruption to normal operations, and meets functional requirements, operational performance criteria, security standards and business continuity/disaster recovery requirements.

In addition, there is increasing demand for mobile enabled applications to enhance customer service offerings and to provide employee productivity gains. This requires alternate approaches to software development, testing and implementation. Establishing a software development environment for mobile applications ensures the same rigor as corporate applications used on the desktop computer particularly in the areas of security, usability and performance.

2.2 Operating Experience

System upgrades help ensure the reliability and effectiveness of the Company's business applications and mitigate risks associated with technology related problems. The timing of the upgrades is based on a review of the risks and operational experience of the applications being considered for upgrade. System upgrades are also required to ensure compatibility with upgrades in hardware platforms that occur when shared servers are upgraded. This ensures adherence to vendor licensing requirements.

As well, upgrades are often completed in order to take advantage of functional or technical enhancements provided by the vendor in new versions of a software application.

2.3 Justification

Investments in Business Applications Upgrades are necessary to replace outdated technology that is no longer supported by vendors. This will enable the Company 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 The Microsoft Enterprise Agreement ($195,000)

Description

This agreement covers the purchase of Microsoft software and provides access to the latest versions of each software product purchased under this agreement at least-cost.

Through the Microsoft Enterprise agreement, the Company achieves overall cost savings. This is a fixed price annual agreement based on the number of eligible employees that utilize Microsoft software on Company assigned personal computers.[3] Under this agreement, the Company distributes its purchasing costs for these licenses over three years, as outlined in Schedule C.

Operating Experience

The Company has had the Microsoft Enterprise agreement in place providing access to the latest versions of business software for over 10 years.[4] The terms of the agreements are typically 3 years duration, with requirements reviewed and adjusted annually. The current agreement expires on May 31, 2018.

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[3] Personal computers include desktops, laptops, tablets and other mobile computing devices.

[4] The agreement covers software applications such as Microsoft Office, Outlook, SharePoint, SQL Server and other applications used by employees in the completion of their normal duties.

Justification

The Microsoft Enterprise Agreement is the least cost option to ensure access to current Microsoft software products.

2017 Shared Server Infrastructure

July 2016

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1.0 Introduction

Shared server infrastructure consists of over 100 shared servers that are used for routine operation, testing, and disaster recovery of Newfoundland Power's (the "Company") business applications. The Company relies on these shared servers to ensure the efficient operation and support of its customer service, internet, engineering and operations, and business support systems.

Each year, an assessment is completed to determine 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.

2.0 Description

This project includes the addition, upgrade and replacement of computer hardware components and related technology associated with shared server infrastructure.

Table 1 summarizes the cost associated with these items.

Table 1
Shared Server Infrastructure Upgrades
Project Expenditures
($000s)

Cost Category	**2017 Estimate**
Material	275
Labour – Internal	231
Labour – Contract	-
Engineering	-
Other	155
Total	**661**

For 2017, this project includes:

1. The replacement of server infrastructure used to manage the Company's production computing environment.[1] This equipment has reached the end of its useful life. The estimated cost for this project is $155,000.

[1] Allows the Company to monitor, alert and respond to IT issues that could affect normal operations if not addressed promptly.

2. The installation of new security management infrastructure. This includes software to protect the Company's email system from security threats, improve the Company's network access control ("NAC") capabilities and infrastructure to enforce policies to prevent users from visiting malicious places on the internet. This project also includes software to provide real-time internet activity information for Company computers and mobile devices.[2] The estimated cost for this project is $406,000.

3. The replacement of 15 workgroup multi-function printers purchased between 2008 and 2009. This equipment has reached the end of its useful life. The estimated cost of the project is $100,000.

3.0 Operating Experience

The shared server infrastructure project includes the purchase, implementation and management of the hardware and software related to the operation of shared servers. Shared servers are computers that support applications used by employees and customers. Management of these shared servers, and their components, is critical to ensuring that these applications are available for the Company to operate efficiently and provide service to customers.

Factors considered in determining when to upgrade, replace or add server components include:

(i) the level of support provided by the vendor;
(ii) the current performance of the components;
(iii) the ability of the components to meet future growth;
(iv) the cost of maintaining and operating the components using internal staff;
(v) the cost of replacing or upgrading the components versus operating the current components;
(vi) the criticality of the applications running on the shared server components; and
(vii) the business or customer impact should the component fail.

Gartner Inc. has indicated that computer servers have a useful life of approximately 5 years.[3] By making appropriate investments in its shared server infrastructure, the Company's experience is that the average 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 customer and corporate information.

4.0 Justification

Sharing 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

[2] Security threats from email include phishing, ransomware and malware. NAC ensures only the Company approved assets and users are allowed to connect to the network, reducing overall security risk.

[3] Gartner Inc. is a leading provider of research and analysis on the global Information Technology industry.

Company’s electrical system infrastructure as it deteriorates. Instability within the shared server infrastructure has the potential to impact large numbers of employees and customers, and therefore is critical to the Company’s overall operations and to the provision of least cost customer service.

Investments in shared server infrastructure are based on evaluating the alternatives of modernizing or replacing technology components and selecting the least-cost alternative.

Rate Base:
Additions, Deductions & Allowances

July 2016

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1.0 Introduction

1.1 General

In the 2017 Capital Budget Application (the "Application"), Newfoundland Power seeks final approval of its 2015 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2015 average rate base of $1,019,082,000 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 results 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. 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 are provided in this report. This includes two historical years, the current year and the following year. The 2016 and 2017 forecast rate base additions and deductions are consistent with the calculation of the Company's 2016 and 2017 forecast average rate base approved in Order No. P.U. 25 (2016).[1] 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 2014 and 2015, and the forecast additions for 2016 and 2017.

Table 1
Additions to Rate Base
2014-2017F
($000s)

	2014	**2015**	**2016F**	**2017F**
Deferred Pension Costs	103,939	98,829	94,775	93,314
Credit Facility Issue Costs	72	56	-	-
Cost Recovery Deferral – Seasonal/TOD Rates	68	49	-	-
Cost Recovery Deferral – Hearing Costs	322	-	800	400
Cost Recovery Deferral –Regulatory Amortizations	1,107	-	-	-
Cost Recovery Deferral – 2012 Cost of Capital	588	-	-	-
Cost Recovery Deferral – 2013 Revenue Shortfall	1,126	-	-	-
Cost Recovery Deferral – Conservation	4,937	7,463	10,324	13,659
Customer Finance Programs	1,136	1,211	1,136	1,136
Total Additions	113,295	107,608	107,035	108,509

Additions to rate base were approximately $107.6 million in 2015. This is approximately $5.7 million lower than 2014. The lower additions to rate base in 2015 reflect a decrease in deferred pension costs and the conclusion of a number of regulatory amortizations resulting from the 2013 General Rate Application. This was somewhat offset by an increase in the deferred recovery of annual customer energy conservation program costs.

This section outlines the additions to rate base in further detail.

[1] In Order No. P.U. 25 (2016), the Board approved Newfoundland Power's forecast average rate base for 2016 and 2017 applied for in the Company's compliance application arising out of Order No. P.U. 18 (2016).

2.2 Deferred Pension Costs

Table 2 shows details of changes in Newfoundland Power's deferred pension costs from 2014 through 2017.

Table 2
Deferred Pension Costs
2014-2017F
($000s)

	2014	2015	2016F	2017F
Deferred Pension Costs	103,939	98,829	94,775	93,314

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).[2]

Table 3 shows details of changes in Newfoundland Power's deferred pension costs from 2014 through 2017.

Table 3
Deferred Pension Costs
2014-2017F
($000s)

	2014	2015	2016F	2017F
Deferred Pension Costs, January 1st	101,159	103,939	98,829	94,775
Pension Plan Funding[3]	13,864	10,213	3,250	3,361
Pension Plan Expense	(11,084)	(15,323)	(7,304)	(4,822)
Deferred Pension Costs, December 31st	103,939	98,829	94,775	93,314

2.3 Credit Facility Costs

In Order No. P.U. 1 (2005), the Board approved Newfoundland Power's issue of a $100 million committed revolving term credit facility.

2 Deferred pension costs were approved for inclusion in average rate base in Order No. P.U. 19 (2003).
3 Pension funding for 2014 and 2015 includes special funding payments of $10.7 million and $7.0 million respectively. There are no special funding payments forecast for 2016 and 2017.

In August 2014, the committed credit facility was renegotiated to extend its maturity date to August 2019. Costs related to this amendment totalled $80,000 and are being amortized over the 5-year life of the agreement, beginning in 2014.

For 2014 and 2015, the unamortized credit facility costs are included in rate base as these costs have not yet been reflected in the Company's revenue requirements.

In the 2016/2017 General Rate Application, the unamortized credit facility costs for 2016 and 2017 are included as a component of the Company's cost of capital. As these costs are reflected in revenue requirements for 2016 and 2017, they are not included in rate base for those years.

Table 4 shows details of Newfoundland Power's amortization of deferred credit facility issue costs for 2014 through 2017.

Table 4
Deferred Credit Facility Issue Costs
2014-2017F
($000s)

	2014	**2015**	**2016F**	**2017F**
Balance, January 1st	-	72	56	-
Cost	80	-	(56)	-
Amortization	(8)	(16)	-	-
Balance, December 31st	72	56	-	-

2.4 Cost Recovery Deferral – Seasonal/Time-of-Day Rates

In Order No. P.U. 8 (2011), the Board approved Rate #1.1S Domestic Seasonal- Optional (the "Optional Seasonal Rate"), with effect from July 1, 2011. Order No. P.U. 8 (2011) also approved the Optional Seasonal Rate Revenue and Cost Recovery Account to provide for the deferral of annual costs and revenue effects associated with implementing the Optional Seasonal Rate and the operating costs associated with a two-year study to evaluate time-of-day rates.

Newfoundland Power is required to file an application with the Board no later than the 1st day of March each year for the disposition to the Rate Stabilization Account ("RSA") of any balance in this account.

In Order No. P.U. 13 (2013), the Board approved that Newfoundland Power would maintain the Account until its next general rate application. In the 2016/2017 General Rate Application, Newfoundland Power did not propose that the Optional Seasonal Rate Revenue and Cost Recovery Account be maintained beyond 2015. Accordingly, the disposition of the December 31, 2015 balance was the final disposition to the RSA.[4]

[4] The disposition of the December 31, 2015 balance in the Optional Seasonal Rate Revenue and Cost Recovery Account to the RSA as of March 31, 2016 was approved by the Board in Order No. P.U. 10 (2016).

Table 5 shows details of the Optional Seasonal Rate Revenue and Cost Recovery Account for 2014 through 2017.

Table 5
Seasonal/TOD Rates
2014-2017F
($000s)

	2014	2015	2016F	2017F
Balance, January 1st	95	68	49	-
Additions	68	49	-	-
Reductions	(95)	(68)	(49)	-
Balance, December 31st	68	49	-	-

2.5 Cost Recovery Deferral – Hearing Costs

In Order No. P.U. 13 (2013), the Board approved the deferred recovery over a 3-year period, beginning in 2013, of external costs related to the Company's 2013 General Rate Application. The actual external costs incurred for the 2013 General Rate Application were $965,000. The deferred hearing costs were fully amortized in 2015.

In Order No. P.U. 18 (2016), the Board approved hearing costs of up to $1.0 million related to the 2016/2017 General Rate Application be recovered in customer rates over the period July 1, 2016 through December 31, 2018.

Table 6 shows details of the changes in Newfoundland Power's deferred hearing costs from 2014 through 2017.

Table 6
Deferred Hearing Costs
2014-2017F
($000s)

	2014	2015	2016F	2017F
Balance, January 1st	644	322	-	800
Cost	-	-	1,000	-
Amortization	(322)	(322)	(200)	(400)
Balance, December 31st	322	-	800	400

2.6 Cost Recovery Deferral – 2010 Regulatory Amortizations

In Order No. P.U. 30 (2010), the Board approved the deferred recovery in 2011, until a further Order of the Board, of $2.4 million in costs ($1.6 million after-tax) related to the expiry of certain regulatory amortizations in 2010.

In Order No. P.U. 22 (2011), the Board approved the deferred recovery in 2012, until a further Order of the Board, of $2.4 million in costs ($1.7 million after-tax) related to the expiry of certain regulatory amortizations in 2010.

In Order No. P.U. 13 (2013), the Board approved the amortization of these deferrals equally over the period January 1, 2013 through December 31, 2015.

Table 7 shows the cost recovery deferral amortizations for 2014 through 2017 related to the expiry of regulatory amortizations in 2010.

Table 7
Cost Recovery Deferral – Regulatory Amortizations
2014-2017F
($000s)

	2014	**2015**	**2016F**	**2017F**
Balance, January 1st	2,214	1,107	-	-
Cost	-	-	-	-
Amortization	(1,107)	(1,107)	-	-
Balance, December 31st	1,107	-	-	-

2.7 Cost Recovery Deferral – 2012 Cost of Capital

In Order No. P.U. 17 (2012), the Board approved the deferred recovery of the amount of the difference in revenue for 2012, relating to the determination of Newfoundland Power's 2012 cost of capital of $2.5 million ($1.8 million after-tax).

In Order No. P.U. 13 (2013), the Board approved the amortization of the deferral equally over the period January 1, 2013 through December 31, 2015.

Table 8 shows the 2012 cost of capital amortizations for 2014 through 2017.

Table 8
Cost Recovery Deferral – 2012 Cost of Capital
2014-2017F
($000s)

	2014	2015	2016F	2017F
Balance, January 1st	1,177	588	-	-
Cost	-	-	-	-
Amortization	(589)	(588)	-	-
Balance, December 31st	588	-	-	-

2.8 Cost Recovery Deferral – 2013 Revenue Shortfall

In Order No. P.U. 13 (2013), the Board approved the proposed amortization over 3 years, commencing in 2013, of the 2013 revenue shortfall resulting from the implementation of new rates after January 1, 2013.[5]

In Order No. P.U. 23 (2013), the Board approved the revenue shortfall in the amount of $4.0 million ($2.8 million after-tax).

Table 9 shows the 2013 revenue shortfall amortization for 2014 through 2017.

Table 9
Cost Recovery Deferral – 2013 Revenue Shortfall
2014-2017F
($000s)

	2014	2015	2016F	2017F
Balance, January 1st	2,252	1,126	-	-
Cost	-	-	-	-
Amortization	(1,126)	(1,126)	-	-
Balance, December 31st	1,126	-	-	-

[5] Per Order No. P.U. 13 (2013), the amortization was from the effective date of the new rates (July 1, 2013) to December 31, 2015, using the straight-line method.

2.9 Cost Recovery Deferral – Conservation

Table 10 shows details of the forecast amortizations of the deferred cost recovery related to conservation for 2014 through 2017.

Table 10
Cost Recovery Deferral – Conservation
2014-2017F
($000s)

	2014	2015	2016F	2017F
Balance, January 1st	2,085	4,937	7,463	10,324
Cost	3,150	3,274	4,077	5,133
Amortization	(298)	(748)	(1,216)	(1,798)
Balance, December 31st	4,937	7,463	10,324	13,659

In Order No. P.U. 13 (2013), the Board approved the deferral of annual customer energy conservation program costs and the amortization of annual costs over 7 years, beginning in 2014, with recovery through the RSA.

2.10 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 2014 through 2017.

Table 11
Customer Finance Programs
2014-2017F
($000s)

	2014	2015	2016F	2017F
Balance, January 1st	1,363	1,136	1,211	1,136
Change	(227)	75	(75)	-
Balance, December 31st	1,136	1,211	1,136	1,136

3.0 Deductions from Rate Base

3.1 Summary

Table 12 summarizes Newfoundland Power's deductions from rate base for 2014 and 2015, and the Company's forecasts for 2016 and 2017.

Table 12
Deductions from Rate Base
2014-2017F
($000s)

	2014	2015	2016F	2017F
Cost Over Recovery – 2016 Revenue Surplus	-	-	1,465	733
Weather Normalization Reserve	1,640	(4,411)	-	-
Other Post Employment Benefits ("OPEBs")	32,435	39,208	45,829	51,608
Customer Security Deposits	660	1,286	700	700
Accrued Pension Obligation	4,635	4,955	5,266	5,589
Accumulated Deferred Income Taxes	2,529	1,268	2,320	5,135
Demand Management Incentive Account	446	-	-	-
Excess Earnings	49	49	-	-
Total Deductions	42,394	42,355	55,580	63,765

Deductions from rate base were approximately $42.4 million in 2015. Newfoundland Power's total deductions from rate base in 2015 are consistent with 2014. In 2015, the increase in the OPEB liability from 2014 was offset by a negative balance in the weather normalization account. The increase in the OPEBs liability primarily reflects the amortization of the OPEB regulatory asset[6] and amortization of the employee future benefits regulatory asset[7] related to OPEBs.

This section outlines the deductions from rate base in further detail.

3.2 Cost Over Recovery – 2016 Revenue Surplus

The Board's determinations on Newfoundland Power's 2016/2017 General Rate Application in Order No. P.U. 18 (2016) resulted in a $2.6 million ($1.8 million after-tax) surplus in the recovery of the revenue requirements for 2016 (the "2016 Revenue Surplus"). The order

[6] In Order No. PU. 31 (2010), the Board approved, beginning in 2011, the adoption of the accrual method of accounting for OPEBs and related income tax. In addition, the Board approved a 15-year straight line amortization of a transitional balance starting in 2011.

[7] In Order No. PU. 11 (2012), the Board approved the opening balances for regulatory assets and liabilities associated with employee future benefits to be recognized for regulatory purposes under U.S. GAAP as of January 1, 2012.

provided for credit of the 2016 Revenue Surplus through a regulatory amortization beginning on July 1, 2016 and concluding on December 31, 2018.

Table 13 shows the 2016 revenue surplus amortization for 2016 and 2017.

Table 13
Cost Overy Recovery – 2016 Revenue Surplus
2014-2017F
($000s)

	2014	2015	2016F	2017F
Balance, January 1st	-	-	-	1,465
Credit	-	-	1,832	-
Amortization	-	-	(367)	(732)
Balance, December 31st	-	-	1,465	733

3.3 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.

In Order No. P.U. 13 (2013), the Board approved the disposition of the annual balance in the Weather Normalization Reserve Account through the RSA. The Board also approved, with effect from January 1, 2013, the amortization over 3 years, commencing in 2013, of the 2011 year-end balance in the Weather Normalization Reserve Account of $5.0 million.

Table 14 shows details of changes in the balance of the Weather Normalization Reserve from 2014 through 2017.

Table 14
Weather Normalization Reserve
2014-2017F
($000s)

	2014	2015	2016F	2017F
Balance, January 1st	5,058	1,640	(4,411)	-
Operation of the reserve	(33)	(4,411)	-	-
Transfers to the RSA	(1,712)	33	4,411	-
Amortization	(1,673)	(1,673)	-	-
Balance, December 31st	1,640	(4,411)	-	-

The disposition of the December 31, 2015 balance in the Weather Normalization Reserve Account to the RSA as of March 31, 2016, was approved by the Board in Order No. P.U. 11 (2016).

3.4 Other Post Employment Benefits

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.

In Order No. P.U. 31 (2010), the Board approved, beginning in 2011, the adoption of the accrual method of accounting for OPEBs and related income tax. In addition, the Board approved a 15-year straight line amortization of a transitional balance starting in 2011.

In Order No. P.U. 11 (2012), the Board approved the opening balances for regulatory assets and liabilities associated with employee future benefits to be recognized for regulatory purposes under U.S. GAAP as of January 1, 2012.

Table 15 shows details of the changes related to the net OPEBs liability from 2014 through 2017.

Table 15
Other Post Employment Benefits
2014-2017F
($000)

	2014	2015	2016F	2017F
Regulatory Asset	52,808	47,328	43,197	39,678
OPEB Liability	85,243	86,536	89,026	91,286
Net OPEBs Liability	32,435	39,208	45,829	51,608

3.5 Customer Security Deposits

Customer security deposits are provided by customers in accordance with the Schedule of Rates, Rules and Regulations.

Table 16 shows details on the changes in customer security deposits from 2014 through 2017.

Table 16
Customer Security Deposits
2014-2017F
($000)

	2014	**2015**	**2016F**	**2017F**
Balance, January 1st	840	660	1,286	700
Change	(180)	626	(586)	-
Balance, December 31st	660	1,286	700	700

3.6 Accrued Pension Obligation

Accrued pension obligation is the cumulative costs of Newfoundland Power's unfunded pension plans net of associated benefit payments.

Table 17 shows details of changes related to accrued pension obligation for 2014 through 2017.

Table 17
Accrued Pension Obligation
2014-2017F
($000)

	2014	**2015**	**2016F**	**2017F**
Balance, January 1st	4,325	4,635	4,955	5,266
Change	310	320	311	323
Balance, December 31st	4,635	4,955	5,266	5,589

3.7 Accumulated Deferred Income Taxes

Accumulated deferred 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 deferred income taxes with respect to timing differences related to plant investment,[8] pension costs[9] and other employee future benefit costs.[10]

Table 18 shows details of changes in the accumulated deferred income taxes from 2014 through 2017.

Table 18
Accumulated Deferred Income Taxes
2014-2017F
($000)

	2014	2015	2016F	2017F
Balance, January 1st	1,872	2,529	1,268	2,320
Change	657	(1,261)	1,052	2,815
Balance, December 31st	2,529	1,268	2,320	5,135

3.8 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 19 shows details of the DMI Account from 2014 through 2017.

Table 19
DMI Account
2014-2017F
($000)

	2014	2015	2016F	2017F
Balance, January 1st	(272)	446	-	-
Transfers to the RSA	272	(446)	-	-
Operation of DMI	446	-	-	-
Balance, December 31st	446	-	-	-

8 In Order Nos. P.U. 20 (1978), P.U. 21 (1980) and P.U. 17 (1987), the Board approved the Company's use of Tax Accrual Accounting to recognize deferred income tax liabilities associated with plant investment.

9 In Order No. P.U. 32 (2007), the Board approved the use of Tax Accrual Accounting to recognize deferred income taxes related to timing differences between pension funding and pension expense.

10 In Order No. P.U. 31 (2010), the Board approved the use of Tax Accrual Accounting to recognize deferred income taxes related to timing differences between other employee future benefits recognized for tax purposes (cash payments) and other employee future benefit expense recognized for accounting purposes (accrual basis).

3.9 Excess Earnings

In Order No. P.U. 23 (2013), the Board approved the definition of the Excess Earnings Account. In 2013, Newfoundland Power's regulated earnings exceeded the upper limit of allowed regulated earnings by $49,000.[11]

In the Company's 2016/2017 General Rate Application, the 2013 excess earnings amount was included in the Company's 2016 revenue requirement.[12] Accordingly, there is no balance in the excess earnings account as of December 31, 2016.

Table 20 shows details of the Excess Earnings Account from 2014 through 2017.

Table 20
Excess Earnings Account
2014-2017F
($000)

	2014	**2015**	**2016F**	**2017F**
Balance, January 1st	49	49	49	-
Change	-	-	(49)	-
Balance, December 31st	49	49	-	-

4.0 Rate Base Allowances

4.1 Summary

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.

4.2 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.

[11] The allowed regulated earnings are based on a return on rate base of 7.92% plus 18 basis points approved in Order No. P.U. 23 (2013).
[12] The Company's 2016 and 2017 revenue requirements were approved in Order No. P.U. 25 (2016).

Table 21 shows details on changes in the cash working capital allowance from 2014 through 2017.

Table 21
Rate Base Allowances
Cash Working Capital Allowance[13]
2014-2017F
($000)

	2014	2015	2016F	2017F
Gross Operating Costs	482,094	500,372	519,057	521,148
Income Taxes	11,044	11,622	16,328	14,744
Municipal Taxes Paid	16,771	17,538	16,331	16,454
Non-Regulated Expenses	(1,989)	(1,799)	(2,183)	(2,352)
Total Operating Expenses	507,920	527,733	549,533	549,994
Cash Working Capital Factor	1.69%	1.69%	1.336%	1.353%
	8,584	8,919	7,342	7,441
HST Adjustment	(2,180)	(2,180)	1,087	960
Cash Working Capital Allowance	6,404	6,739	8,429	8,401

4.3 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.[14]

[13] The cash working capital allowance for 2014 and 2015 is calculated based on the method used to calculate the 2013/2014 Test Year average rate base approved by the Board in Order No. P.U. 13 (2013). The cash working capital allowance for 2016 and 2017 is calculated based on the method used to calculate the 2016/2017 Test Year average rate base approved by the Board in Order No. P.U. 18 (2016).

[14] 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.

Table 22 shows details on changes in the materials and supplies allowance from 2014 through 2017.

Table 22
Rate Base Allowances
Materials and Supplies Allowance
2014-2017F
($000)

	2014	**2015**	**2016F**	**2017F**
Average Materials and Supplies	7,253	8,107	8,169	8,550
Expansion Factor[15]	22.53%	22.53%	20.61%	20.61%
Expansion	1,634	1,827	1,684	1,762
Materials and Supplies Allowance	5,619	6,280	6,485	6,788

15 The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of the 2014 and 2015 rate base, including a materials and supplies allowance based upon an expansion factor of 22.53%, was approved by the Board in Order No. P.U. 13 (2013). The materials and supplies allowance for 2016 and 2017, based upon an expansion factor of 20.61%, was approved by the Board in Order No. P.U. 18 (2016).